SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES AND RECOMMENDATIONS

A Report to Congress
Regarding the Recommendations of Regional Joint Boards
For The Study of Economic Dispatch
Pursuant to Section 223 of the Federal Power Act
As Added by Section 1298 of the Energy Policy Act of 2005

Federal Energy Regulatory Commission
July 31, 2006

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EXECUTIVE SUMMARY

Section 1298 of the Energy Policy Act of 2005[1] (EPAct 2005) added new section 223, "Joint Boards on Economic Dispatch," to the Federal Power Act (FPA).[2] Section 223 requires the Federal Energy Regulatory Commission (Commission) to convene joint boards on a regional basis pursuant to FPA section 209 [3] "to study the issue of security constrained economic dispatch for the various market regions," "to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating . . . affects or enhances the reliability and affordability of service to customers in the region concerned, and "to make recommendations to the Commission regarding such issues." Section 223 requires the Commission to designate appropriate regions to be covered by each joint board, to request each state to nominate a representative for the appropriate regional joint board, and to designate a member of the Commission to chair and participate as a member of each joint board. It also directs the Commission to issue a report to Congress regarding the recommendations of the joint boards within one year of enactment of EPAct 2005. This report is submitted in response to section 223's directives.

The Commission designated four market regions for the joint boards, established the joint boards, designated a Commissioner to chair each board, and requested each state to nominate a board representative to the appropriate joint board. The four joint board regions are: PJM-MISO (consisting of the states of Delaware, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Virginia, West Virginia, Wisconsin, and the District of Columbia); Northeast (consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont); South (consisting of the states of Alabama, Arkansas, Florida, Georgia, Kansas, Louisiana, Mississippi, Missouri, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, and Texas); and West (consisting of the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming).

The joint boards convened for two public meetings. Each regional joint board developed a specific set of issues for its region from material provided at public meetings or submitted in writing later. The boards then formulated recommendations regarding these issues and submitted reports to the Commission. The boards' recommendations

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[1] Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005) (to be codified at 16 U.S.C. § 824).

[2] 16 U.S.C. §§ 824 *et seq.* (2000).

[3] 16 U.S.C. § 824h (2000); *see* 18 C.F.R. §§ 385.1301-.1306 (2005).

were presented to the Commission at the Commission's July 20, 2006 public meeting.

None of the joint boards recommends fundamental changes in the way security constrained economic dispatch (SCED) is conducted in their respective regions. For example, regions where centralized dispatch predominates (PJM-MISO and the Northeast) do not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (the South and the West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing regional transmission organizations (RTOs) that dispatch the system on a centralized basis (PJM-MISO and the Northeast), there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for broad changes. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis.

Joint board recommendations reflected a variety of responses to the issues. There were no recommendations for Congressional action and only a few recommendations for the Commission. For example, the Northeast joint board recommends that the New York ISO and ISO New England work together to resolve trading seams issues and file a plan and timeline with the Commission. That board also recommends that the Commission request the ISO-RTO Council to identify best dispatch practices to guide future improvements in dispatch tools. As part of its investigation of dispatch practices, the Department of Energy (DOE) recommends that the Commission and DOE explore proposals for standard terms in the contracts between generators and dispatchers regarding placing and accepting supply offers, operating requirements, and non-performance penalties. [4]

Most joint board proposals calling for some form of action were directed to existing entities within the region, such as RTOs, other regional groups or state commissions. The major issues addressed by the boards are the geographic scope of the dispatch, transparency of dispatching and pricing information, independence of the dispatcher from market interests, and demand response. The joint boards also addressed the pertinent recommendations made in the DOE Report. Most of the joint board recommendations are discussed in the body of this report and are described in detail in the reports of the joint boards, included as appendices to this report.

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[4] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005 (DOE Report) at p. 51..

I. INTRODUCTION

Section 1298 of the Energy Policy Act of 2005[5] adds new section 223, "Joint Boards on Economic Dispatch," to the Federal Power Act (FPA).[6]
New FPA section 223 states:

> (a) In General- The Commission shall convene joint boards on a regional basis pursuant to section 209 of this Act to study the issue of security constrained economic dispatch for the various market regions. The Commission shall designate the appropriate regions to be covered by each such joint board for purposes of this section.
> (b) Membership- The Commission shall request each State to nominate a representative for the appropriate regional joint board, and shall designate a member of the Commission to chair and participate as a member of each such board.
> (c) Powers- The sole authority of each joint board convened under this section shall be to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.
> (d) Report to the Congress- Within one year after enactment of this section, the Commission shall issue a report and submit such report to the Congress regarding the recommendations of the joint boards under this section and the Commission may consolidate the recommendations of more than one such regional joint board, including any consensus recommendations for statutory or regulatory reform.

This report is submitted in response to section 223's directives. The report is organized as follows. This section summarizes the statutory basis for the report and the process followed in convening the joint boards. The second section, *Security Constrained Economic Dispatch: Concept and Regional Application* provides the definition of Security Constrained Economic Dispatch (SCED) used in this report and summarizes the four regional board reports describing how SCED is practiced in each joint board region. The third section, *Review of Joint Board Issues and Recommendations,* presents a synopsis of the issues considered and the recommendations made by each board.

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[5] Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005) (to be codified at 16 U.S.C. § 824).

[6] 16 U.S.C. §§ 824 *et seq.* (2000).

Process for Convening Joint Boards

On September 30, 2005, the Commission issued an order convening joint boards in the following four regions: the Northeast, Pennsylvania-New Jersey- Maryland and the Midwest Independent Transmission Operator (PJM-MISO), the West, and the South.[7] A FERC Commissioner was designated to chair each board; and states were requested to nominate a board representative to the appropriate joint board. Further, the Commission announced that it planned to hold the first meetings of the joint boards in the month of November 2005, if not earlier. Representatives from Canada and Mexico were also invited to participate, as observers, on the appropriate joint boards.

The Northeast Joint Board comprises the states covered by the New York ISO (NYISO) and ISO-New England (ISO-NE): Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The PJM-MISO Joint Board comprises the states served primarily by the PJM RTO and the Midwest ISO (MISO): Delaware, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Virginia, West Virginia, Wisconsin, and the District of Columbia. The West Joint Board includes all the states in the Western Interconnection: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. Finally, the South Joint Board includes Alabama, Arkansas, Florida, Georgia, Kansas, Louisiana, Mississippi, Missouri, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, and Texas. The Commission recognized that some states have utilities in more than one delineated market area, and permitted these states to have representatives on more than one joint board.

FERC Chairman Joseph T. Kelliher chaired the South board; Commissioner Nora Mead Brownell chaired the Northeast and PJM-MISO boards; and Commissioner Suedeen G. Kelly chaired the West board. Upon receiving nominations for each joint board member, the Commission issued a notice listing the members on October 21, 2005.[8] In addition, one or two Vice Chairs were selected for each board. Table 1 shows the Chair, the Vice-Chair(s) and the member states on each board. The names of all members of the joint boards are listed in Appendix A of this report.

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[7] *Joint Boards on Security Constrained Economic Dispatch*, 112 FERC ¶ 61,353 (2005). The Commission established the joint boards in Docket No. AD05-13-000, where all orders, notices and filings in this proceeding are available.

[8] These members changed over time and the Commission staff maintained an updated list on its website at http://www.ferc.gov/industries/electric/indus-act/joint-boards.asp. This webpage also provided additional details on this proceeding.

The joint boards convened for two public meetings, in November 2005 and February 2006. The initial meetings of the West and South Joint Boards were held on November 13, 2005 in California. The initial PJM-MISO Joint Board meeting was held in Illinois on November 21, 2005. Finally, the initial Northeast Joint Board meeting was held in Massachusetts on November 29, 2005. The notices announcing the agenda and participants at each of the meetings are included as Appendix B.[9]

Upon the conclusion of the initial meetings, the Chairs of each joint board instructed Commission staff to draft a list of recommendations gleaned from the discussion and presentations at each of the meetings. Commission staff then circulated the list for each region to the joint board members for their comment. In addition, various comments were filed with the Commission after the meetings and placed in the public record.

On January 6, 2006, the Commission announced that it would convene follow-up meetings in Washington, D.C. on February 12-13, 2006 to further discuss the draft list of recommendations. In addition, the joint board members discussed preparation and completion of their respective studies and recommendations to the Commission.

The final reports from each board were filed with the Commission in May and July 2006 and are included as Appendices to this report. The boards' recommendations were presented to the Commission at the Commission's July 20, 2006 public meeting. The boards' reports and recommendations draw on the discussions at the joint board meetings, contributions of members of each board and their staffs, and other materials provided to each board during the course of the study. Each board also considered a report on economic dispatch completed by the Department of Energy (DOE)[10] pursuant to the Section 1234 of Energy Policy Act of 2005. This section directs DOE, in consultation and coordination with the states, to study economic dispatch, including the ability of non-utility generation resources to offer their output for inclusion in economic dispatch, and to report to Congress within 90 days, *i.e.*, by November 7, 2005. [11]

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[9] The notices and the transcripts of the meetings are also available on the Commission's website, in eLibrary under Docket No. AD05-13-000.

[10] United States Department of Energy, *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005* (2005)(DOE Report).

[11] Pub. L. No. 109-58, § 1234, 119 Stat. 594, 960 (2005.

Table 1: Chair, Vice Chair(s) and Member States of Regional Joint Boards				
	Regional Board			
	Northeast	**PJM-MISO**	**South**	**West**
Chair	Commissioner Nora Mead Brownell	Commissioner Nora Mead Brownell	Chairman Joseph T. Kelliher	Commissioner Suedeen G. Kelly
Vice Chair(s)	Commissioner Paul G. Alfonso, Massachusetts; Chairman William M. Flynn, New York	Commissioner Kevin K. Wright, Illinois; Commissioner Kenneth D. Schisler, Maryland	Commissioner Sam J. Ervin IV, North Carolina	Commissioner Marsha H. Smith, Idaho
Member States	Connecticut Maine Massachusetts New Hampshire New York Rhode Island Vermont	Delaware District of Columbia Illinois Indiana Iowa Kentucky Maryland Michigan Minnesota Missouri Montana Nebraska, New Jersey North Carolina North Dakota Ohio Pennsylvania South Dakota Virginia West Virginia Wisconsin	Alabama, Arkansas Florida Georgia Kansas Louisiana Mississippi Missouri New Mexico North Carolina Oklahoma South Carolina Tennessee Texas	Arizona California Colorado Idaho Montana Nevada New Mexico Oregon South Dakota Texas Utah Washington Wyoming

II. SECURITY CONSTRAINED ECONOMIC DISPATCH: CONCEPT AND REGIONAL APPLICATION

Before identifying the joint boards' issues and recommendations regarding security constrained economic dispatch, or SCED, it is important to define what is meant by SCED and to describe the way it is implemented in the regions. For purposes of the four regional joint boards' studies, the Commission adopted the definition of SCED from Section 1234 of EPAct 2005: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[12] This definition describes the basic way utilities dispatch their own and purchased resources to meet electricity load. All four joint boards generally agreed with this definition and with the basic process for implementing SCED.

The next sections describe the basic SCED process, and then generally describe how that process is carried out in the four regions. More detailed descriptions of how SCED is carried out in the regions may be found in the joint board final reports.

The Basic Concept of Security Constrained Economic Dispatch

There are a number of unique challenges to supplying electricity: production must be simultaneous with demand; demand varies greatly over the course of a day, week, and season; the costs of different types of generating units vary greatly; and expected and unexpected conditions on the transmission network affect which generating units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch, in order to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

There are two stages, or time periods, to the economic dispatch process: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum

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[12] *Joint Boards on Security Constrained Economic Dispatch*, 112 FERC ¶ 61,353 at P14 (2005).

output levels, and the minimum time a generator must run once it is started. Operators must also take into account generating unit costs, such as fuel and non-fuel operating costs and costs of environmental compliance.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security constrained" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace cheaper units

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load.

Implementation of Security Constrained Economic Dispatch in the Joint Board Regions

The basic ways that SCED is implemented in the joint board regions may be thought of as falling into two categories. The first way of implementing SCED is having the dispatch performed by individual utilities or holding companies, primarily with their own generation, or other generation directly under their control. Generation is dispatched based on the costs of operating each generating unit. Dispatch in the South and West regions is generally, although not exclusively, done this way. The second way of implementing SCED is having the dispatch performed on a market basis by an independent entity for all resources across a region. Generators are selected for dispatch based on their supply offer bids into day-ahead and real-time markets. The level of dispatch may also be affected by bids by demand side resources. Locational marginal prices (LMP) result from the dispatch. Dispatch in the Northeast and the PJM-MISO regions is done this way.

Of course, actual dispatch practices in the regions reflect differences in regional characteristics and preferences. The rest of this section summarizes the way SCED is actually implemented in the regions *as described in the joint board reports*.

West

Dispatch in the West is primarily accomplished by individual utilities, but with a number of coordination arrangements to address specific resource characteristics and trading opportunities. The presence of significant hydropower resources in the Northwest makes Western Interconnection generation dispatch significantly different from dispatch in the Eastern Interconnection. The West also has a long history of coordination in the Northwest aimed at optimizing power and non-power river demands. Another factor affecting Northwest dispatch is the operation of Bonneville Power Authority transmission assets, which are closely connected to the operation of hydropower resources. Although the presence of significant hydropower resources in the Northwest affects the overall operation and dispatch of the system, the basic dispatch remains decentralized.

The California ISO (CAISO) is the only multi-utility market area in the West that is centrally organized and dispatched. The CAISO performs a dispatch covering most of California by using market bids to balance generation and load.

The overall pattern of dispatch in the West also depends to a large extent on differences between the resources and loads in each subregion. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in the north to peak loads in the south, while power in the winter flows from south to north to meet the peak loads in the Northwest. A north-south transmission system has developed to support this pattern. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west in California and the Northwest. The transmission systems also reflect the need to move power westward from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power comes from baseload plants that run year round.

South

The practice of economic dispatch in the South varies by utility and subregion. In most of the South, economic dispatch is performed on a system-by-system basis. Some utilities in the region dispatch across large multi-state areas. For example, Entergy is a collection of utilities in a holding company, and dispatches for its operating companies in Arkansas, Louisiana, Mississippi, and Texas from its own generation resources and purchases from non-utility generators. Similarly, Southern Company dispatches for its footprint in Alabama, Georgia, and Mississippi using the generation resources of its operating companies and purchases from non-utility generators and other market participants.

Economic dispatch in the Florida Reliability Coordinating Council is performed by eleven Balancing Authorities, (formerly referred to as control areas) through their own economic dispatch energy management system. One balancing authority in the region also acts as a "power pool" for its members. Balancing authority resources are supplemented by wholesale market purchases.

The Electric Reliability Council of Texas (ERCOT) is the only organized market in the South region, consisting of a single area organized out of 10 control areas. In ERCOT there are two entities responsible for the dispatch of the system: qualified scheduling entities (QSEs) and ERCOT.[13] QSEs perform the commitment and dispatch processes by taking into account their portfolios and any other offers on the bilateral markets. ERCOT will then modify or supplement that dispatch to meet total system load, maintain system frequency and manage transmission congestion if necessary. ERCOT administers a balancing energy market which allows all generation, regardless of ownership, to bid and provide balancing energy. ERCOT manages transmission congestion with zonal and intra-zonal arrangements.

Members of the Southwest Power Pool (SPP) are planning to implement an energy imbalance market within the SPP footprint. SPP will perform a real-time security constrained economic dispatch of the entire market footprint. Currently, however, economic dispatch is performed individually by multiple control areas located in the SPP footprint. Each owner of generation performs its own economic dispatch using its own portfolio of resources including generation, purchases and sales, and demand side management.

PJM-MISO

PJM and MISO each implement SCED using a regional, market-based approach. The dispatch is based on supply offers from generators within each RTO to sell energy, along with non-price responsive load needs and price responsive bids to purchase energy. Each RTO considers the resources owned/operated by their respective market participants and then each evaluates its respective market sellers' offers as a single resource pool. The regional resources available to the RTO result in a dispatch stack containing generators from all generation-owning members of the RTO region, including utility and non-utility generation owners, as well as some generation resources outside the RTO.

The dispatch results in a locational marginal price, or LMP, at each location, defined as the marginal cost of serving the next increment of load at the location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. If there are no transmission constraints, LMPs will generally not vary significantly across the RTO

[13] Transcript of the first South Joint Board Meeting, November 13, 2005, Palm Springs, CA, at 63.

region. When there are transmission constraints, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will generally set the LMP in that area. All sellers in the area receive the clearing price for energy and all buyers pay the clearing price in the area.

PJM and MISO have a Joint Operating Agreement (JOA) to closely coordinate their operations. Generally, the JOA facilitates administration of coordinated markets, permitting more efficient and reliable system operation, and would allow additional utilities to integrate more easily into the PJM and MISO markets. The JOA contemplates that the RTOs will progressively integrate their operations.

Northeast

SCED in the Northeast is performed by two organizations, ISO-NE and NYISO. ISO-NE and NYISO each implement SCED using a regional, market-based approach, similar to the approach described for PJM-MISO above. Both entities operate day-ahead and real-time energy markets that constitute the commitment and dispatch components of SCED described earlier. There is much in common between the two regions in how they perform SCED. Both NYISO and ISO-NE have consolidated control areas and perform the dispatch function centrally. They both incorporate transmission constraints and unit operational constraints within the dispatch and commitment software. They both include all available resources without regard to ownership. Both regions have significant load pockets, e.g., New York City, Long Island, Boston and Southwest Connecticut, that require the dispatch of higher cost local generation.

III. REVIEW OF JOINT BOARD ISSUES AND RECOMMENDATIONS

Each regional joint board developed a specific set of issues for its region from material provided at public meetings or submitted separately. Principal sources included the DOE Report, suggested discussion topics proposed by Commission staff for public discussion, and input from states and industry participants in each region. A set of issues was developed at the first meeting of each board, and formed the starting point for subsequent board discussion and recommendations.

Although there was considerable discussion of the issues surrounding SCED and its impact on customers, none of the joint boards recommends fundamental changes in the way SCED is conducted in their respective regions. For example, regions where centralized dispatch predominates (PJM-MISO, Northeast) did not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (South, West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing RTOs, there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for fundamental changes in the way the RTOs operate the dispatch. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis, as long as these initiatives could be demonstrated to provide benefits to customers and gain appropriate state and federal approvals. However, these boards did not call for any specific initiatives and opposed any form of mandated modification.

Joint board recommendations reflect a variety of responses to the issues, including recommending no action (or no immediate action) on a particular issue, simply encouraging continuing activities by industry, endorsing particular outcomes without specific recommendations for action by any group, and proposing actions to achieve a particular result. Most proposals calling for some form of action are directed to existing entities within the region, such as RTOs, other regional groups or state commissions. There are no recommendations for Congressional action and only a few recommendations for Commission involvement, generally to encourage or facilitate activity.

The most widely addressed issues and associated recommendations are discussed in the remainder of this section.[14] Although the specific formulation of any given issue

[14] This section describes the principal joint board recommendations and related issues. The more detailed issues discussed, and recommendations made, can be found in

varied across regions, due to the different characteristics of SCED as implemented in the regions, there are general issues that arise in more than one region. For purposes of this section, these issues are organized as follows:

- Broadening the geographic scope, through consolidation of areas or reduction of seams between areas
- Transparency of dispatching or pricing information
- Independence of the dispatcher
- Including demand response and other factors in the dispatch
- Recommendations from the DOE Report

In addition, some topics received significant discussion in only one region. These topics are also discussed in this section. Further details on recommendations can be found in the individual board reports.

Broadening the Geographic Scope of Dispatch

This issue is a common point of discussion in all four regions, but the nature of the discussion depended on the current regional dispatch practices. In some cases, it takes the form of consolidation or merging of areas, in others, improvement in seams management (i.e., better coordination of dispatch across areas without explicit merging of the dispatch). Although many board members agree, in theory, with the principle that dispatch over a wider geographic range of resources should result in lower costs to produce power, there is also recognition of the practical impediments to achieving this objective, and there are no consensus recommendations across regions on how to proceed. Nevertheless, several regions recommend further study, or encourage the continuation of existing work.

In the Northeast, broadening of the dispatch was focused on two types of "seams," the first being coordination between the two RTOs in the region (ISO-NE and NYISO), and the second being coordination with external areas. For the first issue, the Northeast Joint Board recommends "that both NYISO and ISO-NE work together and with the market participants towards the development of mechanisms to address the specific seams issues,"[15] and "meet within 90 days to coordinate their initiatives and file a plan

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Appendices to this report, containing each of the joint board reports filed with the Commission. The Appendices also note minority viewpoints and contain some individual board members' alternative perspectives as appendices or attachments.

[15] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the Northeast Region* (Northeast Report), May 24, 2006, p. 14.

with FERC describing the time line to address the seams discussed in this section."[16] Regarding coordination with external areas, the board recommends a technical evaluation of electrical connections with those areas to identify potential operating adjustments and system upgrades, and a market impact analysis to determine whether the identified improvements would provide net benefits.

The PJM-MISO Joint Board recommendation on broadening the dispatch encourages continued timely analyses of the cost and technical feasibility of expanding the geographic scope of SCED. The board recommends that the analysis encompass the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. In addition, each RTO was encouraged to analyze the cost and technical feasibility of expanding its geographic area to include areas not currently under RTO-managed SCED. However, the board emphasized that actions to expand the geographic scope of PJM or MISO SCED should be cost effective and subject to relevant state law.[17] The PJM-MISO Joint Board also recommends improvements in seams coordination under both the current JOA between PJM and MISO and also under common market proposals being developed by the two RTOs.[18]

The West Joint Board recognized the potential for improved dispatch through consolidation in some subregions in the Western Interconnection, and the potential for improving coordination of dispatch between control areas within the hour. The board recommends studies to assess the value of larger control areas for improving the dispatch of renewables such as wind, and studies to address the problems of large control areas scheduling imports and exports within the hour.[19]

The South Joint Board viewed proposals presented for broadening the scope of dispatch as requiring an RTO or independent third party, and the South Joint Board members "do not recommend that an expanded regional dispatch should be involuntarily implemented in the South at this time."[20]

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[16] *Id.*

[17] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the PJM-MISO Region* (PJM-MISO Report), May 24, 2006, p. 38.

[18] Id.

[19] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the West Region* (West Report), May 12, 2006, p. iii.

[20] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the South Region* (South Report), July ??, 2006, p. 11.

Transparency and Access to Information

In discussions of this issue at the joint board meetings, transparency generally connoted the ability of market participants to see the price at which electricity was sold or purchased, and to have access to sufficient information to be able to determine under what terms the electricity was being sold and how the price was established. Since SCED is implemented in different ways in each region, and sometimes even within a region, this general theme gave rise to different concerns and different recommendations in each region.

In the Northeast, transparency is viewed in terms of the ability to see how the price was determined from the bids submitted, so that the issue is framed in terms of access to the bid data. The Northeast Joint Board recommends the RTOs pursue making bid data available to the market with a shorter lag time.[21]

In PJM-MISO, the issue of transparency of the RTO spot price was referenced as a benefit of the organized market,[22] and there was discussion of the importance of the transparency provided by the organized market process,[23] but there were no recommendations regarding changes in release of bid information or other measures to enhance transparency. There were concerns by state regulators regarding their ability to have sufficient information on market operations to conduct oversight activities. The board recommended revisiting RTO policies regarding the issue of state regulator access to information.

The South Joint Board expressed support for "appropriate, cost-effective, improvements in the transparency with which the regional transmission system is planned and operated and the manner in which transmission congestion is managed."[24] However, the Joint Board felt that many of these issues were already being addressed in proposed Commission reforms of the Open Access Transmission Tariff (OATT) and did not see a need for the board to comment further on the issue.

The West Joint Board viewed transparency in terms of access to pricing information and also in terms of transparency that could be added by an independent entity. With respect to access to pricing information, the board noted the "numerous, robust trading hubs"[25] in the Western Interconnection and did not see a need for further

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[21] Northeast Report, p. 13.

[22] PJM-MISO Report, p. 21 and p. 30.

[23] PJM-MISO Report, p.33.

[24] South Report, p. 11.

[25] West Report, p. 11.

recommendations in this area. With regard to the increased transparency that could be added by an independent entity, the board did not believe this transparency was sufficient to justify the creation of such an entity.[26]

Independence

The issue of independence (a principal subject of the DOE Report) focuses on the relationship of the dispatching entities to the owners of the resources being dispatched. More specifically, the issue was raised in joint board discussions in terms of how transmission-owning utilities dispatch resources they do not own, and whether dispatch by an independent third party (possibly, but not necessarily, an ISO or an RTO) was a better alternative to utility dispatch.

In the regions where RTOs operate the dispatch, the RTO is regarded as sufficiently independent from market participants, and neither the Northeast nor PJM-MISO Joint Boards recommends any changes to the basic RTO independence structure. The PJM-MISO board does emphasize the importance of independence and addresses a recommendation on independence to the RTOs, emphasizing the need to continue to strive for independence, and the role of state and federal regulators in overseeing RTO independence.[27]

With respect to the development of independent entities outside the existing RTOs in the region, the South Joint Board concludes that voluntary formation of such entities should be encouraged where they are cost effective, subject to a test of their benefits to customers, and with appropriate state regulatory approvals.[28]

Concerned that "independent dispatch entities not be created for their own sake," and believing there still needs to be a better demonstration of potential benefits from independent entities, the West Joint Board does not recommend further analysis at this time.[29]

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[26] West Report, p. 17.

[27] PJM-MISO Report Summary, recommendation 12.

[28] South Report, p. 13.

[29] West Report, p. 15.

Inclusion of Demand Response and Other Factors in Dispatch

Most regions discuss demand response in terms of RTO or state-level initiatives that vary considerably across regions. Improving demand response is generally regarded as a potentially important way of reducing costs and increasing overall reliability, but the boards do not propose specific recommendations for incorporation of these programs into the dispatch, beyond programs currently implemented by RTOs or conducted under state direction.

After review of the progress of demand response in the NYISO and in ISO-NE, the Northeast Joint Board concludes that the RTOs were making significant progress on including demand response initiatives at the wholesale level. Accordingly, the Northeast Joint Board does not recommend any additional demand response requirements for the RTOs.[30]

The PJM-MISO Joint Board expresses more concerns about progress on demand response than the Northeast Joint Board did. Concerned about the lack of price-responsive demand and its impact on prices, the board recommends that PJM and MISO "must develop more ways for demand response to participate in the dispatch."[31] The board recommendation also emphasizes that improvement in demand response is not a responsibility of RTOs alone and encourages the RTOs to work closely with appropriate state regulators and policymakers.[32]

In the West, the issue of including demand response in the dispatch arose in the context of discussion of the demand response initiatives of California and the CAISO. The West Joint Board addressed demand response initiatives, and related programs such as renewable portfolio standards that can affect the operation of the dispatch, in terms of the definition of SCED. In this context, the West Joint Board recommended broadening the definition of SCED to include public policies that affect the dispatch in addition to purely economic or security considerations.[33]

The issue of including demand response in the dispatch was not raised in the South Joint Board report.

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[30] Northeast Report, p. 16.

[31] PJM-MISO Report, p. 46.

[32] PJM-MISO Report, p. 46 and Summary, recommendation 16.

[33] West Report, p. 22.

Other Topics Addressed in Joint Board Recommendations

There were several topics that received attention in the board discussions, but were not as prominent in joint board recommendations as the issues discussed above. These included the topic of efficient dispatch as an alternative to economic dispatch, the use of a pay-as-bid approach as an alternative to the uniform clearing price in the RTO dispatch, and the benefits of SCED, particularly as implemented in RTOs. Joint board discussions and recommendations on these topics are summarized in this section.

The topic of "efficient dispatch" appears to have arisen during discussions leading up to EPAct 2005 concerning measures that could result in a more efficient use of scarce natural gas resources[34] and potentially exert downward pressure on natural gas prices.[35] Efficient dispatch is typically taken to mean dispatching the units with the lowest heat rate first, i.e., those that use the least amount of natural gas to generate a megawatt of electric energy. Economic dispatch meets electricity demand at the lowest cost. DOE noted that economic dispatch would generally result in running higher efficiency natural gas units before lower efficiency units but that efficient dispatch would presumably modify economic dispatch to ensure that the more physically efficient gas-fired units are always dispatched before less efficient units. DOE expressed skepticism about implementing a new procedure that would add costs to the dispatch without clearly commensurate benefits.[36]

The South Joint Board endorses the use of economic dispatch, but felt that commenting on the broader issue of efficient dispatch was beyond the scope of their task.[37] The PJM-MISO Joint Board believes an economic dispatch, properly performed, would include the issues of concern in efficient dispatch, and the issue was "resolved, at least for the time being, in favor of economic dispatch."[38]

The use of pay-as-bid as an alternative to uniform price for setting prices in the dispatch was addressed by both the Northeast and PJM-MISO Joint Boards. In the uniform price approach, currently used by the RTOs, electricity is bought and sold at a single price at each location. Under the pay-as-bid alternative, each generator would be paid the price of their bid to supply power to the RTO at the generator's location. Although the was considerable discussion of the potential benefits of switching to a pay-

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[34] DOE Report, p. 11.

[35] Transcript of First West Joint Board Meeting, Palm Springs CA, November 13, 2006, p. 136.

[36] DOE Report, p.6-7.

[37] South Report, p. 9.

[38] PJM-MISO Report, p. 35.

as-bid approach, both RTOs noted that many other factors favor the uniform price approach, and neither recommends changes to their current pricing approach.[39]

On the topic of benefits from SCED, the Northeast Joint Board observes that SCED is not a new procedure, and maintains it is important to distinguish the implementation of SCED and the implementation of markets based on the SCED, since SCED does not require a market-based approach. The Northeast Joint Board examined data collected by the New York Power Pool (NYPP) when it was formed in 1977, that indicated $281 million in savings for the year 1981 ($600 million in 2006 dollars.) The boards did not attempt to assess the broader benefits of the market-based SCED as implemented in their regions. The PJM-MISO Joint Board made the only specific recommendation regarding benefits, emphasizing the ongoing importance of demonstrating benefits from SCED and recommending that the RTOs establish a clear benchmark to assess the degree to which the reliability and least cost objectives of SCED are being captured. The board also encouraged the RTOs to assess the benefits of standardized reliability rules.[40]

Recommendations from the DOE Report to Congress

The DOE Report to Congress contained three recommendations that are relevant to the issues addressed by the joint boards, and each joint board addressed some or all of these three issues in their reports.

First DOE Recommendation: review dispatch practices

The DOE Report recommended that the joint boards consider conducting in-depth reviews of selected dispatch entities, including some Investor Owned Utilities (IOUs), to determine how they conduct Economic Dispatch.[41] None of the boards believed this effort was feasible within the time and resources available to them, and they did not

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[39] Further details on this issue can be found in Appendices containing the Northeast and PJM-MISO Reports, and in the following studies filed in Docket No. AD05-13: Natalia Fabra, David Harbord et al , "Designing Electricity Auctions: Uniform, Discriminatory and Vickrey", filed May 3, 2006; Giulio Federico and David Rahman titled "Bidding in an Electricity Pay-as-Bid Auction"; filed May 3, 2006; Par Holmberg, "Comparing Supply Function Equilibria of Pay-As-Bid and Uniform-Price Auctions"; filed May 3, 2006; and "California Power Exchange's Blue Ribbon Panel Report re the study on the Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing", filed December 1, 2005.

[40] PJM-MISO Report, p. 35-36.

[41] DOE Report, p. 52.

propose specific recommendations for future work.

In the Northeast and PJM-MISO regions, the joint boards do not recommend any additional steps beyond the current reviews that RTOs perform to review their dispatch practices.

The South Joint Board sees potential merit in a study of dispatch practices, and concludes that such a study conducted "in a dispassionate, fact-based manner might resolve some of the issues that were raised by various participants in the Joint Board process." [42] Although the South Joint Board states it would tend to be supportive of such a study, the board did not make a recommendation, believing there would need to be further clarification of the nature and scope of the study, the data needed and available, the funding source, and the resources to be used before any recommendation to pursue the study could be made.

The West Joint Board recommends not pursuing such a study. The West Joint Board believes that the dispatch needs to remain flexible and that going into the details of how particular utility dispatches are conducted would delve too deeply into local deviations from pure economic dispatch, without adding much value.[43]

Second DOE Recommendation: standardize dispatch contract terms

The DOE Report recommended that the Commission and DOE explore Electric Power Supply Association (EPSA) and Edison Electric Institute (EEI) proposals for more standard contract terms for placing and accepting supply offers, operating requirements, and non-performance penalties and encourage stakeholders to undertake these efforts.[44] The Northeast and PJM-MISO Joint Boards did not comment on this recommendation. The South Board agrees that exploration of these issues could be helpful, but has a number of concerns including that any such exploration "be undertaken with the understanding that adequate flexibility in wholesale contracting should be preserved in the interests of assuring the most economical service for customers,"[45] and makes no recommendation to pursue the proposals. The West Joint Board finds this recommendation to be a reasonable one to pursue, as long as the development of such a contract is pursued on a regional rather than a national basis.[46]

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[42] South Report, p. 14.

[43] West Report, p. 23.

[44] DOE Report, p. 51.

[45] South Report, p. 14.

[46] West Report, p. 24.

Third DOE Recommendation review dispatch tools

The DOE report recommended that economic dispatch technology tools be scrutinized. These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.[47]

The Northeast Joint Board notes that RTOs and ISOs have the most advanced dispatch tools, and recommends that the Commission request the ISO-RTO Council (IRC) "take the lead in identifying 'best practices' to guide future improvements to these tools."[48] The other joint boards did not recommend any action.

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[47] DOE Report, p. 53.

[48] Northeast Report, p. 20.

Appendix A: Joint Board Members

The members of the Northeast Joint Board are:

- Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Paul G. Afonso, Massachusetts Department of Telecommunications and Energy, Vice Chair of the Joint Board
- Chairman William M. Flynn, New York State Public Service Commission, Vice Chair of the Joint Board
- Commissioner Jack R. Goldberg, Connecticut Department of Public Utility Control
- Chairman Kurt Adams, Maine Public Utilities Commission
- Chairman Thomas B. Getz, New Hampshire Public Utilities Commission
- Chairman Elia Germani, Rhode Island Public Utilities Commission
- Chairman James Volz, Vermont Public Service Board

The members of the PJM/MISO Joint Board are:

- Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Kevin K. Wright, Illinois Commerce Commission, Vice Chair of the Joint Board
- Chairman Kenneth D. Schisler, Maryland Public Service Commission, Vice Chair of the Joint Board
- Commissioner Dallas Winslow, Delaware Public Service Commission
- Chair Agnes A. Yates, District of Columbia Public Service Commission
- Chairman David Lott Hardy, Indiana Utility Regulatory Commission
- Chairman John Norris, Iowa Utilities Board
- Chairman Mark David Goss, Kentucky Public Service Commission
- Commissioner Laura Chappelle, Michigan Public Service Commission
- Commissioner Kenneth Nickolai, Minnesota Public Utilities Commission
- Chairman Jeff Davis, Missouri Public Service Commission
- Chairman Greg Jergeson, Montana Public Service Commission
- Mr. Paul Malone, Regulatory, Planning & Contracts Manager, Nebraska Public Power District
- Commissioner Frederick F. Butler, New Jersey Board of Public Utilities
- Commissioner Sam J. Ervin IV, North Carolina Utilities Commission
- Commissioner Susan E. Wefald, North Dakota Public Service Commission
- Chairman Alan R. Schriber, Public Utilities Commission of Ohio

- Chairman Wendell F. Holland, Pennsylvania Public Utility Commission
- Chairman Gary W. Hanson, South Dakota Public Utilities Commission
- Director Pat Miller, Tennessee Regulatory Authority
- Mr. Howard Spinner, Director, Division of Economics and Finance, Virginia State Corporation Commission
- Mr. Earl Melton, Director, Engineering Division, Public Service Commission of West Virginia
- Chairperson Daniel R. Ebert, Public Service Commission of Wisconsin
- Assistant Deputy Minister Garry Hastings, Department of Energy, Science & Technology, Manitoba (observer)

The members of the South Joint Board are:

- Chairman Joseph T. Kelliher, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Sam J. Ervin, IV, North Carolina Utilities Commission, Vice Chair of the Joint Board
- President Jim Sullivan, Alabama Public Service Commission
- Chairman Sandra L. Hochstetter, Arkansas Public Service Commission
- Commissioner J. Terry Deason, Florida Public Service Commission
- Ms. Pandora Epps, Internal Consultant, Georgia Public Service Commission
- Chair Brian J. Moline, Kansas Corporation Commission
- Commissioner James M. Field, Louisiana Public Service Commission
- Dr. Christopher Garbacz, Director, Economics and Planning Division, Mississippi Public Utilities Staff, representing the Mississippi Public Service Commission
- Commissioner Steve Gaw, Missouri Public Service Commission
- Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
- Chairman Jeff Cloud, Oklahoma Corporation Commission
- Vice Chairman G. O'Neal Hamilton, South Carolina Public Service Commission
- Mr. Pat Miller, Director, Tennessee Regulatory Authority
- Commissioner Julie Caruthers Parsley, Public Utility Commission of Texas

The members of the West Joint Board are:

- Commissioner Suedeen Kelly, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the Joint Board
- Commissioner Marc L. Spitzer, Arizona Corporation Commission
- Commissioner Dian M. Grueneich, California Public Utilities Commission

- Chairman Gregory Sopkin, Colorado Public Utilities Commission
- Commissioner Thomas J. Schneider, Montana Public Service Commission
- Mr. Richard L. Hinckley, General Counsel, Public Utilities Commission of Nevada
- Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
- Chairman Lee Beyer, Oregon Public Utility Commission
- Commissioner Dustin Johnson, South Dakota Public Utilities Commission
- Commissioner Barry Smitherman, Public Utility Commission of Texas
- Chairman Ric Campbell, Utah Public Service Commission
- Chairman Mark Sidran, Washington Utilities and Transportation Commission
- Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission

Appendix B: Agenda for First Joint Board Meetings

Agenda for First Northeast Joint Board Meeting

AGENDA FOR THE NORTHEAST JOINT BOARD MEETING

FERC Commissioner Nora Mead Brownell, Chair
Massachusetts DTE Chairman Paul Afonso, Vice Chair
New York PSC Chairman Bill Flynn, Vice Chair
November 29, 2005

- Opening Remarks by chair and vice chairs

- Presentation: FERC staff
  - Economic dispatch: concepts, practices, and issues

- Presentation: U.S. Department of Energy
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act [pending issuance of the report]

- Panel: Regional Transmission Organizations

  - To address:
    - What are the benefits and costs of SCED, compared to the previous system used for dispatch, or to other potential alternatives? What specific benefits has SCED offered? Can you quantify these benefits, and, if so, please do so.
    - What lessons did you learn in implementing SCED? In particular, were there unanticipated benefits or costs that should be kept in mind when considering changes or improvements to the current SCED?
    - How does the operation of SCED relate to the operation of the regional market? How would a market operate in your region without SCED?
    - What effect has SCED had on the reliability of the electric system in your region? Can you quantify the effect, and, if so, please do so.
    - What effect has SCED had on the cost of electric energy in your region, after adjusting for input costs such as fuel? Can you quantify the effect, and, if so, please do so.
    - How can an RTO's/ISO's SCED resources be more optimally dispatched?

  - Panelists:
    - Mark Lynch, President and CEO, New York Independent System Operator
    - Gordon van Welie, President and CEO, ISO New England

  - Question and answer session

- Lunch
- Panel: Stakeholders
    - o To address:
        - Current application of economic dispatch in region (what quantitative and qualitative benefits have been realized, what lessons have been learned, what noteworthy improvements have been made)
        - Possible improvements to current economic dispatch practices (what weaknesses currently exist that should be a high priority for improving, what improvements have been requested that the RTOs/ISOs have not addressed, if you could start from scratch, how should economic dispatch be facilitated in your region)
        - How does economic dispatch affect the markets – spot, day-ahead, bilaterals?
        - Further consolidation of economic dispatch by integrating the two New York and New England dispatch systems into one system?
    - o Panelists:
        - Daniel W. Allegretti, Vice President - Regulatory and Legislative Affairs, Constellation
        - Richard Bolbrock, Vice President – Power Markets, Long Island Power Authority
        - Kevin Burke, President and Chief Executive Officer, ConEdison
        - Michael Calviou, Vice President - Transmission Commercial and Regulatory, National Grid
        - Steve Corneli, Vice President – Regulatory and Governmental Affairs, NRG Energy
        - Doug Horan, Senior Vice President - Strategy, Law and Policy, NStar
        - Edward N. Krapels, Director, ESAI Gas and Power Services (on behalf of Neptune LLC)
        - Robert M. Loughney, Couch, White, Brenner, Howard & Feigenbaum
        - Tom Rudesbusch, Duncan, Weinberg, Genzer and Pembroke PC (on behalf of the New York Association of Public Power)
        - Donald Sipe, Preti Flaherty Beliveau Pachios & Haley LLC (representing the Industrial Energy Consumer Group)
    - o Question and answer session
- Break

- Board members' discussion
    - Issues and objectives to be addressed in joint board report
- Closing remarks -- chair and vice chairs

Agenda for First PJM-MISO Joint Board Meeting

AGENDA FOR THE PJM/MISO JOINT BOARD MEETING

FERC Commissioner Nora Mead Brownell, Chair
Maryland PSC Chairman Ken Schisler, Vice Chair
Illinois Commerce Commission Chairman Kevin Wright, Vice Chair
November 21, 2005

- Opening Remarks by chair and vice chairs

- Presentation: FERC staff
  - Economic dispatch: concepts, practices, and issues

- Presentation: U.S. Department of Energy
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act [pending issuance of the report]

- Panel: Regional Transmission Organizations

  - To address:
    - What are the benefits and costs of SCED, compared to the previous system used for dispatch, or to other potential alternatives? What specific benefits has SCED offered? Can you quantify these benefits, and, if so, please do so.
    - What lessons did you learn in implementing SCED? In particular, were there unanticipated benefits or costs that should be kept in mind when considering changes or improvements to the current SCED?
    - How does the operation of SCED relate to the operation of the regional market? How would a market operate in your region without SCED?
    - What effect has SCED had on the reliability of the electric system in your region? Can you quantify the effect, and, if so, please do so.
    - What effect has SCED had on the cost of electric energy in your region, after adjusting for input costs such as fuel? Can you quantify the effect, and, if so, please do so. How can RTOs be more optimally dispatched?

  - Panelists:
    - Jim Torgerson, President and Chief Executive Officer, Midwest ISO
    - Phil Harris, President and Chief Executive Office, PJM Interconnection

  - Question and answer session

- Lunch

- Panel: Stakeholders

    - To address:
        - Current application of economic dispatch in region (what quantitative and qualitative benefits have been realized, what lessons have been learned, what noteworthy improvements have been made)
        - Possible improvements to current economic dispatch practices (what weaknesses currently exist that should be a high priority for improving, what improvements have been requested that the RTOs have not addressed, if you could start from scratch, how should economic dispatch be facilitated in your region)
        - How does economic dispatch affect the markets – spot, day-ahead, bilaterals?
        - What effect do non-participants have on economic dispatch?

    - Panelists:
        - Doug Collins, Direct System Planning, Alliant Energy
        - Fred Kunkel, Manager Transmission Service, Wabash Valley Power
        - Ed Tatum, Assistant Vice President – Rates and Regulation, Old Dominion Electric Cooperative
        - Steven Naumann, Vice President - Wholesale Market Development, Exelon Corp.
        - John Orr, Constellation
        - Joseph Welch, President and Chief Executive Officer, International Transmission Company
        - Brett A. Kruse, Manager – Market Integration Service, Calpine
        - TBA, industrial customer

    - Question and answer session

- Break

- Board members' discussion
    - Issues and objectives to be addressed in joint board report

- Closing remarks -- chair and vice chairs

Agenda for First South Joint Board Meeting

AGENDA FOR THE SOUTH JOINT BOARD MEETING
November 13, 2005

Note: questions from, and discussion among, board members appropriate after all presentations.

- Opening remarks (1:00-1:05 p.m.)
  - FERC Chairman Joseph Kelliher, Chair of South Joint Board

- Remarks (1:05-1:10 p.m.)
  - Mississippi PSC Commissioner Michael Callahan, Vice Chair of South Joint Board

- Presentation by FERC staff (1:10-1:40 p.m.)
  - Economic dispatch: concepts, practices and issues

- Presentation: U.S. Department of Energy (1:40-2:10 p.m.)
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act

- Stakeholder panel (2:10-3:40 p.m.)

  - Current application of economic dispatch in region
    - Who performs the dispatch?
    - How is the dispatch determined?
    - What is the geographic scope of the dispatch?
    - Are there resources not included in the dispatch? Would including them improve the dispatch?
    - Are there resources that present challenges in incorporating them into the dispatch (e.g., hydro resources)?
    - How do transmission congestion and the dispatch affect each other? How would improvements in one affect the other?
    - How are individual dispatches in the region coordinated?
    - How is the dispatch communicated to affected generation operators?
    - Are there technical/infrastructure impediments that interfere with implementing the economic dispatch?

  - Possible improvements to current economic dispatch practices
    - What are the potential benefits and costs of those improvements?
    - Are there institutional, regulatory, or statutory impediments to the identified improvements?

- Additional topic for ERCOT:
  - What are the benefits and costs of the way ERCOT dispatches now compared to the way dispatch was done prior to the ERCOT-wide dispatch?

- Additional topic for SPP:
  - Describe the way SPP's imbalance proposal would change the dispatch in SPP.
  - What are the benefits and costs of SPP's imbalance proposal compared to the way dispatch is performed now?

Panelists:

- Scott Henry, Vice President of Energy Policy, Duke Power
- John Hurstell, Vice President of Energy Management, Entergy Corporation
- Robert Priest, General Manager, Clarksdale Public Utilities
- David Beam, Senior Vice President of Power Supply, North Carolina Electric Membership Cooperative
- Sam Henry, President and Chief Executive Officer, SUEZ Energy Marketing North America
- Robert O'Connell, Manager, Regulatory Affairs, Williams Power
- Carl Monroe, Senior Vice President, Operations and Chief Operating Officer, Southwest Power Pool
- Kent Saathoff, Director of System Operations, ERCOT
- Industrial customer, TBD

- Break (3:40-3:55 p.m.)

- Board members' discussion (3:55-4:50 p.m.)
  - Issues and objectives to be addressed in joint board report (see Attachment B of this notice).

  ["Open microphones" for audience participation]

- Closing remarks by Chairman Kelliher and Commissioner Callahan (4:50-5:00 p.m.)

Agenda for First West Joint Board Meeting

AGENDA FOR THE WEST JOINT BOARD MEETING
November 13, 2005

Note: questions from, and discussion among, board members appropriate after all presentations.

- Opening remarks (1:00-1:05 p.m.)
    - FERC Commissioner Suedeen Kelly, Chair of West Joint Board

- Remarks (1:05-1:10 p.m.)
    - Idaho PUC Commissioner Marsha Smith, Vice Chair of West Joint Board

- Presentation by FERC staff (1:10-1:40 p.m.)
    - Economic dispatch: concepts, practices and issues

- Presentation: U.S. Department of Energy (1:40-2:10 p.m.)
    - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act

- Stakeholder panel (2:10-3:40 p.m.)

    - Current application of economic dispatch in region
        - Who performs the dispatch?
        - How is the dispatch determined?
        - What is the geographic scope of the dispatch?
        - Are there resources not included in the dispatch? Would including them improve the dispatch?
        - Are there resources that present challenges in incorporating them into the dispatch (e.g., hydro resources)?
        - How do transmission congestion and the dispatch affect each other? How would improvements in one affect the other?
        - How are individual dispatches in the region coordinated?
        - How is the dispatch communicated to affected generation operators?
        - Are there technical/infrastructure impediments that interfere with implementing the economic dispatch?

    - Possible improvements to current economic dispatch practices
        - What are the potential benefits and costs of those improvements?
        - Are there institutional, regulatory, or statutory impediments to the identified improvements?

    - Additional topic for California ISO:

- What are the benefits and costs of the way CAISO dispatches now compared to the way dispatch was done prior to CAISO?

Panelists:

- Mark Rothleder, Principal, Market Developer, California ISO
- Doug Larson, Vice President – Regulation, PacifiCorp
- John Coggins, Manager – Supply and Trading, Salt River Project
- Kieran Connolly, Manager-Regional Coordination, Bonneville Power Administration
- Marcie Edwards, General Manager, Anaheim Public Utilities
- Richard Kurtz, Vice President of Power Services, Arizona Electric Power Cooperative
- Robert Kahn, Executive Director, Northwest Independent Power Producers Coalition
- Greg Patterson, Director, Arizona Competitive Power Alliance
- Industrial customer, TBD

- Break (3:40-3:55 p.m.)

- Board members' discussion (3:55-4:50 p.m.)
    - Issues and objectives to be addressed in joint board report (see Attachment B of this notice).

    ["Open microphones" for audience participation]

- Closing remarks by Commissioner Kelly and Commissioner Smith (4:50-5:00 p.m.)

Appendix C: Northeast Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security	)	**Docket No. AD05-13-000**
Constrained Economic Dispatch	)	

Study and Recommendations Regarding Security Constrained Economic Dispatch (SCED) in the Northeast

by

The Joint Board on Economic Dispatch for the Northeast Region

May 24, 2006

I. Overview

The Northeast Joint Board is one of four joint boards designated by the Commission under EPAct2005, Section 1298 Economic Dispatch. The members of the Northeast Joint Board are:

Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
Commissioner Paul G. Afonso, Massachusetts Department of Telecommunications and Energy, Vice Chair of the Joint Board
Chairman William M. Flynn, New York State Public Service Commission, Vice Chair of the Joint Board
Commissioner Jack R. Goldberg, Connecticut Department of Public Utility Control
Chairman Kurt Adams, Maine Public Utilities Commission
Chairman Thomas B. Getz, New Hampshire Public Utilities Commission
Chairman Elia Germani, Rhode Island Public Utilities Commission
Chairman James Volz, Vermont Public Service Board

The Northeast Joint Board met in public session on November 29, 2005 in Boston Massachusetts and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1)"to consider issues relevant to what constitutes '*security constrained economic dispatch*'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

In the following sections, this report provides a description of the basic concept of Security Constrained Economic Dispatch (SCED); describes background on the variations in dispatch procedures in the Northeast, and gives a summary of the issues raised and considered by the board, together with any recommendations made to address these issues. The principal sources for these sections are presentations to the board and written comments submitted, discussions among the Joint Board members, the DOE report under EPAct 2005, Section 1234 and the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: The Basics in the Northeast Region

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[1] This definition describes the basic way all utilities or ISOs/RTOs dispatch resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand, demand varies greatly over the course of a day, week, and seasons, the costs of generation from different types of units vary greatly, and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

SCED occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, SCED decides which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast and transmission constraints. SCED uses either cost-based or bid-based offers to select the most economic generator mix, considering transmission constraints. In selecting the most economic generators to commit, SCED also takes into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, minimum time a generator must run once it is started, and environmental restrictions.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive

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[1] September 30, 2005 order at P14. These operations are normally automated and carried out by computer software; however, the operations are monitored by transmission engineers who can override the software when necessary.

generators may have to replace cheaper units.[2] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, SCED decides in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and SCED must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints and in some cases even the network model might vary in economic dispatch software.

The economic dispatch problem is generally considered to be a mathematically simpler problem to solve, although recent advances (e.g. the use of mixed-integer-programming (MIP) for unit commitment) have advanced the available technology to the point where many earlier limitations on problem size have been eliminated. Advances in hardware and software now make it technologically feasible to undertake security constrained economic dispatch over large regions.

In addition to differences in models used in economic dispatch software, a major factor that can impact the benefits of economic dispatch is whether or not all available resources are considered. In non-organized markets this may not always be possible due to various reasons including limitations in open access transmission tariffs based on Order 888.

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[2] If the more expensive units are not allowed to set the market prices, these units are referred to as "out of merit" and their above market costs must be recovered through uplift.

III. Economic Dispatch in the Northeast

Security Constrained Economic Dispatch (SCED) in the northeast is performed primarily by two entities – ISO New England (ISONE), which has been designated as a Regional Transmission Organization (RTO) and the New York ISO (NYISO). Both entities operate day-ahead and real-time energy markets that constitute the commitment and dispatch components of SCED described in the last section. There is a long history of SCED is the Northeast under these entities and prior to this under the NY Power Pool and NEPOOL.

There is much in common between the two regions in how they perform SCED. Both NYISO and ISO-NE have consolidated control areas and perform the dispatch function centrally. SCED has been performed in both regions since the 1970s under the predecessor power pools and continues with enhancements under the markets that have been in operation since 1999. They both incorporate transmission constraints and unit operational constraints within the dispatch and commitment software. They both include all available resources without regard to ownership. Both regions have significant load pockets, e.g., New York City, Long Island, Boston and Southwest Connecticut that require higher cost local generation. Both regions have had limitations on reflecting the full spectrum of physical constraints in their software that has resulted in uplifts, i.e., costs that are not included in the market price and are administratively allocated to participants. Currently, this appears to be a bigger problem in New England.

A. NYISO and NYPP

The NYPP was formed in response to the Northeastern blackout of 1965. By 1977 it had implemented a form of SCED that dispatched all of the utility-owned generation in New York State based not on market-driven bidding, but on regulated generator costs. The NYPP SCED did not incorporate non-utility generation. Nevertheless, it produced substantial savings by dispatching generation on a least-cost basis and by taking advantage of supply and load diversity across the pool. The resulting savings were split among the NYPP's utility members and went to the ultimate benefit of ratepayers.

The NYPP SCED made it possible for energy transactions to be scheduled and priced more efficiently than was possible before 1977. Prior to the SCED, the NYPP could only facilitate bilateral transactions among its member utilities by acting as an intermediary. This was done through telephone calls and allowed transactions to be scheduled on, at best, an hourly basis. Under SCED, transaction scheduling and pricing was fully automated and took place every five minutes. In addition, the adoption of SCED allowed the NYPP to develop an "Interchange Evaluation" program, which evaluated energy transactions between neighboring control areas in the United States and Canada, including New England, the mid-Atlantic, Ontario and Quebec. This evaluation improved inter-control area energy deliveries in the Northeast and made out-of-state economic resources more readily available to the NYCA.

The adoption of SCED also permitted a more efficient allocation of Operating Reserves among NYPP members to satisfy total pool requirements. The NYPP estimated that SCED, and the various external transaction scheduling improvements that it made possible, was responsible for $281 million in savings in 1981, which would translate to approximately $600 million in 2005 dollars.

In the 1990s, the NYPP's members formed the NYISO. From its inception in 1999, the NYISO used a bid-based SCED that was open to all electricity resources in the NYCA, and to out-of-state suppliers selling into New York, that chose to participate in it. The NYISO SCED is a key part of the NYISO's market that uses a locational-based marginal pricing system ("LBMP") very similar to the locational marginal pricing (LMP) regimes that have evolved in the ISO New England, PJM Interconnection, and Midwest Independent System Operator regions.

The NYISO implemented major enhancements to its real-time dispatch and market software on February 1, 2005. It now has fully co-optimized day-ahead and real-time markets for energy, three different reserves products, and regulation that produce the lowest possible total cost for these products consistent with reliability constraints. The NYISO's new software platform includes a real-time unit commitment ("RTC") function that complements the NYISO's day-ahead security constrained unit commitment process using the superior information that becomes available closer to the actual real-time dispatch. RTC is capable of looking two and a half hours ahead and can commit "quick start" resources such as hydro units and certain gas turbines in fifteen minute increments in order to facilitate a more efficient co-optimized, least-cost SCED for energy ancillary services. The RTC is integrated with and uses the same software as the NYISO's real-time dispatching system, which helps them to work together to produce the best possible dispatch and price signals. There are nearly three hundred active market participants in the NYISO markets today. In 2005, the NYISO settled electricity transactions totaling approximately $10.7 billion and has cleared over $40 billion of wholesale transactions since its inception in 1999.

B. ISO-NE and NEPOOL

The New England Power Pool (NEPOOL) was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among utilities in the six-state region. During the next three decades, NEPOOL created a regional power grid that now includes more than 350 separate generating plants and more than 8,000 miles of transmission lines.

ISO New England was created in 1997 in a region where 88 percent of the region's generation is unregulated, the most in the nation. Working closely with the NEPOOL, now a group of generators, utilities, marketers, public power companies and end users, ISO New England implemented wholesale markets in 1999. Today, more than 260 Market Participants complete in excess of $10 billion of wholesale electricity transactions annually, about a quarter of the power sold in the region (the remainder is sold through negotiated, long-term contracts).

ISO New England has enhanced these markets, notably in 2003, by adding features such as a Day-Ahead Market. In the five years following the opening of wholesale markets in 1999, New England's capacity has increased by 40 percent. Wholesale electricity prices in New England, adjusted for fuel costs, have declined by 5.7 percent since the first full year of market operations. Prices dropped by 11 percent during the four-year period from 2001-2004.

Security Constrained Economic Dispatch (SCED) is an essential component of the ISO-NE markets. It figures in the day-ahead unit commitment performed under the day-ahead market and in the real-time balancing market.

New England's Economic Dispatch is coordinated with the Economic Dispatch of neighboring control areas through hourly exports and imports of power. These exports and imports are generally scheduled by market participants responding to electricity prices in each control area, with participants seeking to buy power in the lower priced control area and sell in the higher priced control area. If the volume of transactions increases until either the prices at the source and delivery points are equal, or until the transfer limits are reached, than the dispatch is efficiently coordinated between the control areas. Because this efficient coordination does not regularly occur between New York and New England, the two control areas are investigating ways to improve the coordination. Possible solutions include the two ISO's explicitly coordinating interface flows and reducing the lead time required for participants to schedule flows across the interface between the regions.

IV. Observations and Issues

This section describes the issues considered by the Joint Board and identifies any recommendations in the record. Based on the discussion at the initial meeting, there appeared to be an overall consensus that economic dispatch and markets have created benefits for customers in the Northeast. There is a long history of economic dispatch in the region that was mentioned by many participants along with an emphasis on least cost security constrained dispatch without regard to ownership[3]. There was some disagreement on the precise measure of these benefits.

A. Observations

- *Benefits from economic dispatch*

The NYISO estimated the benefits of SCED at roughly 100 million dollars per year from 1977 to 1999 yielding a cumulative benefit of 2 billion dollars[4]. A savings of 281 million dollars or roughly 24 percent of the total market transactions was cited in 1981. Precise estimates for the period since 1977 were not cited. However, the NYISO has made several enhancements to SCED since then and estimates that the benefits have likely increased even further. The NYISO cited estimated a five percent decline based on average monthly costs on a fuel adjusted basis from 2000 – 2004[5].

ISO-NE cited an estimated total savings due to the regional economic dispatch from 1970 – 1977 at over $1.4 billion in 2004 dollars[6]. The ISO-NE cited a 5.6 percent reduction in the average wholesale cost of electricity from 2000-2004 which translates to a 700 million dollars per year after netting out fuel costs[7]. The ISO-NE also noted a 5 - 6 percent improvement in generator availability and significant new investment as a result of the advent of markets.

Despite the extensive references to the benefits of economic dispatch and markets in general, there were also concerns raised on related market issues (e.g., the impact of high gas prices on uniform price markets) as well as a discussion of further improvements than can be made, e.g. improved inter-regional coordination, better modeling of constraints in software etc. In the remainder of this section, we summarize some of the major issues that were brought up.

- *Benefits of economic dispatch and benefits of markets*

There was considerable discussion at the meeting on the benefits that have been realized through markets. Some participants suggested that since economic dispatch is a required enabler of markets, it makes sense to look at the benefits created by the market as a whole when evaluating the benefits of economic dispatch[8]. Others disagreed observing that

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[3] Mr. Bolbrek at p 111 of transcript.
[4] Mark Lynch at p 49 of transcript.
[5] Mark Lynch at p 59 of transcript.
[6] Gordon van Welie at p 66 of transcript.
[7] Gordon van Welie at p 68 of transcript.
[8] Gordon van Welie at p 67 of transcript.

economic dispatch does not necessarily require markets[9].

Some participants observed that improvements in generation availability may not be entirely attributable to the introduction of LMP based day-ahead markets but rather a result of how capacity credits are calculated[10]. Measuring the benefits of economic dispatch precisely can be complex[11].

- *Concerns about efficient vs. economic dispatch*

Some participants raised questions about whether economic dispatch can ensure efficient dispatch[12]. The difference between economic and efficient dispatch has been discussed in the recent DOE report related to section 1234 of EPACT. The reasons the two can be different are two-fold (1) if the entire set of available resources is not considered as an input to the economic dispatch algorithm, the result will not be efficient[13], and (2) if offer prices do not reflect costs, the dispatch may not be efficient from a heat-rate perspective[14].

B. Specific Market and Dispatch Issues

- *Wider geographical scope of economic dispatch*

Some improvements such as the elimination of pancaking in rates have already been made[15]. Other improvements that are under way include better inter-regional transaction scheduling and pricing of external nodes[16]. Overall, there appears to be consensus that better coordination of dispatch across interfaces within the region (e.g. New York and New England) as well as interfaces with external areas (e.g., PJM and Canada) is desirable. However, some participants also raised caution on what might be a reasonable expectation of benefits.

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[9] Mr. Rudebusch at p 162 of transcript.
[10] Mr. Bolbrock at p85 of transcript.

[11] Mr. Burke at p 99 of transcript.

[12] Keating, Meyer and Meroney at pp 26-30 of transcript.

[13] Meroney at p 28 of transcript.

[14] Keating at p 30 of transcript.

[15] Mark Lynch at p. 60 of transcript.
[16] Gordon van Welie at p 78 of transcript.

There is disagreement on specific approaches to improve coordination of economic dispatch between New York and New England. Some participants favored improvements realized through improved transaction scheduling by market participants on a shorter time frame than is available currently, while others favored a stronger integration using a "Virtual Regional Dispatch" (VRD) model[17]. Both the New York ISO and ISO New England have looked at the VRD approach for some time with little actual progress on implementation. More recently, they have started looking at taking smaller steps by improving the granularity of scheduling across their boundaries under the Interregional Transaction Scheduling or ITS project. By allowing schedules to be submitted closer to real-time and more frequently, the expectation is that market participants would be able to capture at least some of the benefits that can come from a fully integrated economic dispatch. Some participants raised concerns about implementation complexity and costs[18].

- *Concerns about uniform price markets*

In response to the recent high gas prices and their impact on electricity prices, there have been concerns expressed about uniform clearing price markets and whether there could be additional savings under other market models[19]. A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited[20]. However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix[21]. Some participants noted that economic dispatch does not necessarily require a single clearing price methodology and took issue with prices set by gas fired plants being paid to coal and nuclear plant[22]. Other participants noted that the alternative design of pay-as-bid auctions could potentially result in lower overall prices but this would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity[23].

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[17] See comments submitted by National Grid, Dan Allegretti at p 106 and Michael Calviou at p 118 of transcript.
[18] Mr. Loughney at p 160 of transcript.
[19] Commissioner Brownell at p 97 of transcript.
[20] Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.
[21] Bob Loughney at p 158 of transcript.
[22] Mr. Rudebusch at p 162 of transcript.
[23] Harry Singh at p 187 and Don Sipe at p 198 of transcript.

- *Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch*

Some participants raised concerns about dispatch actions taken outside the security constrained economic dispatch software[24]. Such actions are necessary when either the operational constraints of generators or transmission constraints cannot be fully represented within the software. Generating sources dispatched in this manner do not affect the calculation of market prices and are paid separately via an uplift payment. If uplifts are improperly allocated to market participants they can have additional adverse affects on markets. One example cited at the conference was the impact of uplifts allocations in New England and their impact on virtual trading. The allocation has recently been modified to address the problem[25]. One participant noted that the biggest issue is the challenge in reflecting all security constraints in security constrained unit commitment and security constrained economic dispatch[26].

There have been recent improvements to dispatch models used in the Northeast. For example, NYISO introduced in February 2005, enhancements to its real time dispatch software that allows co-optimization of energy and reserves in addition to a shortened evaluation period for real-time unit commitment[27].

Uplifts can often result from limitations of software in modeling physical constraints, e.g. combined cycle plants in unit commitment in the Boston area. The economic impact of such uplifts can in some instances be greater than efficiency gains on seams issues. The ISO-New England has therefore made addressing this issue a high priority[28].

Other improvements such as the use of Mixed Integer Programming (MIP) software for better combined cycle generator modeling are being considered but are in the research and development phase[29].

- *Incorporation of demand response into economic dispatch*

There are opportunities for better integration of demand response in economic dispatch that can further improve infrastructure utilization[30]. This is an area where state regulators

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[24] Pete Fuller at p. 43, Dan Allegretti at p 105 and Steve Corneli at p 139 of transcript.
[25] Steve Corneli at p 140 of transcript.
[26] Steve Corneli at p 138 of transcript.
[27] Mark Lynch at pp 59-60 of transcript.
[28] Gordon van Welie at p 78 of transcript.
[29] Gordon van Welie at p74 of transcript.
[30] Gordon van Welie at p 72 and p 83 of transcript and Burke at p 93 of transcript.

and the RTOs can work together. Participants noted that while organized markets have generally similar demand response programs, there are also differences. For example, ISO New England considers demand response to be a critical resource that can be drawn upon in the absence of quick start peaking resources and has made efforts to incorporate demand response into its commitment and dispatch software[31].

- *Further Improvements in market transparency*

Many participants noted the significance of transparent price signals in making markets work better and encouraging investment. Some participants expressed a desire to allow releasing market bid data sooner than the six-month lag with which is released currently[32]. They cited other markets such as the UK and Australia where this is done on a daily basis and argued that US markets have now matured enough to allow this data to be released sooner. The ISO-NE responded saying they would be open to such a suggestion and the right venue to discuss it would be the stakeholder committee process[33].

- *Better utilization of the interconnections with External Areas*

Additional benefits of economic dispatch may be possible by looking by looking at external interfaces with regions outside New York and New England. A specific example was the 2000 MW limit on the Phase 2 HVDC U.S. Interconnector between New England and Quebec that is currently being used at 1200 MW due to constraints further down the system in New York and PJM[34]. A decrease in flows from Quebec to New York may be able to yield as much as three times higher flows into New England. Thus, further benefits for the region may be possible by improved coordination between New York, New England and Quebec.

- *Capacity markets and new investments*

One participant noted that existing markets have not performed well in promoting new investment through price signals. Instead, new investment is largely driven by contracts arranged via RFPs. A missing element of markets in the region relates to the refinement

[31] Gordon van Welie at p 90 of transcript.
[32] Michael Calviou at p 122 and Doug Horan at p 148 of transcript.
[33] Gordon van Welie at p 129 of transcript.
[34] See Michael Calviou at p 120 of transcript.

of existing mechanisms for capacity markets[35].

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, The Value of Economic Dispatch, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

- FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct ED. [36] These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices should from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow NUGs and other resources to compete effectively and serve load.

- FERC and DOE should explore EPSA and EEI proposals for more standard contact terms and encourage stakeholders to undertake these efforts.[37] Specifically, the EEI proposed that NUGs should commit to provide energy at specified price for specified time to meet unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

- Current economic dispatch technology tools deserve scrutiny.[38] These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

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[35] Steve Corneli at p 142 of transcript.

[36] The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005, United States Department of Energy, November 7, 2005, page 52.

[37] Ibid, p 51.

[38] Ibid, p 53.

V. Board Recommendations

A. Further Improvements in Market Transparency

While not directly related to the implementation of SCED, improved market transparency is important for monitoring and establishing confidence in the pricing and dispatch determined by SCED. A proposal was made to allow market bid data to be released with a less than six-month lag. The six-month lag was introduced to protect market participants from having to reveal current operations and competitive bidding strategies, and to discourage collusion. However, a shorter lag period would provide quicker public access to bid data, which would strengthen public monitoring of market behavior and help ensure confidence in the competitiveness of the markets; it would also enhance the ability of market participants to quickly identify inefficiencies. One party suggested that a month's delay would be sufficient to protect market participants.[39] Another party observed that other electricity markets in the U.K. and Australia release bid data on the day or the day after the market outcome.[40] ISO-NE and NYISO stated that they were open to suggestions on making market bid data available with a shorter lag time and that this should be pursued through the appropriate ISO committee processes.[41] No party objected to this proposal.

APPA submitted comments questioning whether bids reflected actual marginal costs, or whether bids might be inflated due to market power.[42] This question cannot be answered solely by providing better access to bid data; it also requires information about "actual" marginal costs, which involve confidential supplier information. For this reason, APPA requested an analysis by the Northeast Joint Board comparing generator bids to their actual marginal costs, as supplied to ISO-NE and NYISO.

<u>Recommendation:</u> 1) ISO-NE and NYISO should pursue, with market participant input, making market bid data available to the market with a shorter lag time. 2) **NYISO and ISO-NE have market monitoring responsibilities with FERC oversight. For example, NYISO's Market Power Mitigation Measures (OATT Attachment H) defines procedures for calculating "reference levels" for bids based on estimates of actual marginal costs, and establishes mitigation measures (including reducing bids to reference levels) when the bids appear to represent an abuse of market power (i.e. would raise prices significantly above competitive levels). Any concerns associated with market power should be addressed as part of ISO market monitoring efforts, not in this proceeding.**

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[39] NSTAR Electric – Doug Horan, p. 149 of transcript.

[40] National Grid - Michael Calviou, p. 122 of transcript.

[41] Gordon van Welie at p. 129 of transcript; Mark Lynch at p. 13 of 2/13 transcript.

[42] American Public Power Association, "Re: Joint Boards on Security Constrained Economic Dispatch, Docket No. AD05-13-000 (Northeast Region)", letter of 2/17/2006.

B. Wider geographical scope of economic dispatch

Participants generally agreed that just as there are significant benefits associated with utilizing SCED in any given region, there are additional benefits to be derived by expanding the scope of economic dispatch over a wider geographic area, but there are also significant impediments and drawbacks to implementing a single SCED regime for, for example, the New York and New England regions combined. However, much of the benefit of a larger scope can be obtained by improvements that would allow electricity to flow between regions in a more economically efficient manner. The impediments to those more efficient flows are commonly referred to as "seams" issues, and these issues can relate to differing regional market rules, operating or scheduling protocols, and many other causes. Much progress has already been made in this area, with the elimination of through-and-out rates and improved transaction checkout procedures between New York and New England. The main focus of the participants in the Northeast to address this problem centered on two general proposals commonly referred to as Intra-hour Transaction Scheduling (ITS) and Virtual Regional Dispatch (VRD)[43]. The ITS proposal focuses on improving the processes to allow market participants to more effectively be able to schedule power flows between regions in response to changing prices and system conditions, and in particular to be able to do so in a shorter timeframe than is now possible. The VRD proposal would allow ISOs and RTOs themselves to change interchange power flows between each other if appropriate when the interchange schedule set by market participants' transaction schedules result in an inefficient dispatch.

Recommendation: Thus far neither proposal has been developed in sufficient detail to be implemented. We recommend that both NYISO and ISO-NE work together and with the market participants towards the development of mechanisms to address the specific seams issues discussed here. As an initial step, both NYISO and ISO-NE should meet within 90 days to coordinate their initiatives and file a plan with FERC describing the time line to address the seams discussed in this section.

C. Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch

Market participants[44] correctly pointed out that not all unit and system constraints are modeled in the security constrained economic dispatch software used by ISO-NE and

[43] It should be noted a major seam, transmission rate pancaking between the two control areas, has already been eliminated.

[44] Pete Fuller (p. 43), Dan Allegretti (p. 105), Steve Corneli (p. 139) in 11/29/05 Northeast Joint Board for Economic Dispatch transcript.

NYISO. The resulting impacts vary from the need for human intervention in the dispatch to the addition of uplift charges which distort market prices[45]. Component models for multiple combined-cycle unit configurations are being refined and their use would allow for more accurate modeling of large units[46] and result in an improved economic dispatch. Where these improved models have not yet been incorporated into the dispatch, they should be scheduled for inclusion in the next software upgrade.

The increased modeling of system constraints (e.g. include voltage and stability constraints) would result in more precise dispatches and result in better market signals[47]. Technology, however, stills need to advance before implementation can be initiated. The principle tool for incorporating additional system constraints is the security constrained optimal power flow (OPF) program. The basic difference between today's security constrained unit dispatch software and a security constrained OPF is the use of an AC power flow instead of a DC power flow-based program. The switch to AC-based software would increase the run time for a single scenario from minutes to well over an hour with today's technology. Therefore, the use of a security constrained OPF even in the day-ahead markets is impractical at this time. The ISOs should monitor the technology for increased processing speed with the goal of switching to a security constrained OPF for economic dispatch when it is feasible.

Recommendation: The NYISO and ISO-NE should incorporate additional unit and system constraints in economic dispatch software as modeling and technology improve.

D. Incorporation of demand response into economic dispatch

Some participants called for better integration of demand response into economic dispatch and for state regulators and RTOs to work together on this. The NYISO already allows demand response programs – the Special Case Resource and Day Ahead Demand Response program - to participate and compete with generation. In addition, FERC has recently directed the NYISO to allow demand response participants to offer demand side response in the ancillary services market[48]. Continued improvements should be coordinated through the NYISO working groups, to ensure that the proposals will be practical and will work as intended.

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[45] Commissioner Nora Brownell (p. 16) in 2/13/06 Northeast Joint board for Economic Dispatch transcript.

[46] Gordon van Welie (p. 74) in 11/29/05 transcript.

[47] Ibid.

[48] ER04-230-010, ER04-230-014 and ER04-230-019; Letter from FERC to NYISO dated January 26, 2006.

ISO-NE currently administers five demand response programs including three real-time programs that support system reliability and two programs that provide incentives for demand to respond to high real-time or day-ahead wholesale market prices. ISO-NE's goal is to transform these currently out-of-market programs into ones that are directly integrated into the region's wholesale and retail electricity markets. To this end, ISO-NE's Ancillary Services Markets (Phase II) project will integrate "asset-related demands" into real-time operations, which would allow demand resources to more efficiently balance load and generation and offer reserve services in real time. Additionally, ISO-NE will also be implementing a Demand Response Reserves Pilot Project to determine the ability of small demand resources (e.g., less than 5 MW) to meet operational requirements for reserve resources and to investigate more cost-effective communication and telemetry solutions that would allow small resources to participate in the wholesale electricity markets. Finally, ISO-NE will be engaged in a project to integrate demand resources into the Forward Capacity Market, should the Commission approve the recently-filed settlement agreement in FERC Docket Nos. ER03-563-000, -030, and -055.

Further, NYPSC is actively promoting dynamic electric pricing for large customers that would facilitate Demand Response. For example, the NYPSC recently implemented mandatory hourly pricing as the default rate for large customers[49]. This could place over 5,000 MW of load on the hourly pricing default tariff in the coming months. Currently, none of the New England States require default service to be priced on a dynamic basis. Accordingly, ISO-NE has approached the New England Conference of Public Utility Commissioners (NECPUC) to analyze, design, and implement dynamic pricing solutions that would capture greater price-responsive demand in the New England region. To date, ISO-NE has sponsored studies quantifying the benefits of dynamic pricing and recently submitted testimony in a Connecticut regulatory proceeding recommending that a dynamic rate be applied to default service for customers with maximum demands greater than or equal to 350 kW. The proposed rate included a three-part, time-of-use, variable peak pricing design applicable to the commodity portion of service where the Peak Period Rate would be based on the average of the corresponding hourly Day-Ahead Energy Market prices during the peak period (defined as 1:00 p.m. to 7:00 p.m. weekdays) for the applicable day and Load Zone.

Recommendation: **We believe that incorporation of Demand Response in the wholesale market is making progress in both NYISO and ISO-NE. In addition, regulators in New York are promoting dynamic pricing for retail electric customers. Efforts are underway in New England to include these resources in developing markets. We expect these efforts to continue, and as a result to provide greater opportunities for market participation by these resources. With these ongoing**

[49] Case 03-E-0641, Proceeding on motion of the Commission regarding expedited implementation of mandatory hourly pricing for commodity service.

initiatives, we do not recommend any additional requirements as part of this proceeding.

E. Better utilization of the interconnections with External Areas:

Increased use of interconnection capability provides opportunities for additional economic interchange of energy. However, it has long been recognized in regional planning that power transfers between control areas can impact system operations in other control areas. To date, most analysis has revolved around the principle of "do no harm" such that if inter-tie transfers produced negative operational impacts in the other control areas, the transfer levels are limited to below those impact thresholds. Economic studies have generally not taken place to determine if it would be beneficial to increase the inter-tie transfers and make arrangements with the other control area to take mitigating measures. An example offered is the Quebec-New England inter-tie where transfer levels are limited by constraints in New York and PJM. There are some indicators that a 100 MW reduction in transfers between Quebec and New York, coupled with leaving the 100 MW system capacity in New York unloaded, would increase the transfer capability from Quebec to New England by 300 MW.[50]

__Recommendation:__ **The ISOs should investigate better utilization of their interconnections with other areas which could provide additional economic transaction opportunities. The ISOs should perform a technical evaluation of its inter-ties, including the Quebec-New England inter-tie, to determine a) what operating adjustments in other control areas could be made to accommodate increased use of the inter-ties; and, b) what system upgrades would be required to fix the constraint.[51] The ISOs should then perform a market-impact analysis of the expanded use of the inter-ties. As a threshold, the analysis should determine if there would be a net region-wide benefit from the proposed increased use of the inter-ties and how they would be spread across control areas. If there is not a net benefit, inter-tie maximization should be deferred. If there is a net regional benefit, operating adjustments and cost impact mitigation strategies should be identified and protocols developed to make these opportunities available to the market. The possibility of system upgrades should be included in regional planning processes for evaluation in those forums.**

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[50] Michael Calviou (p. 120) in 11/29/05 transcript.

[51] Commissioner Nora Brownell (p.20) in 2/13/06 transcript.

F. Refining capacity markets

Some participants called for refinements to capacity markets in order to promote new investment. Commissioner Brownell noted that there were many efforts underway across the northeast regarding capacity markets, but due to ex-parte rules, it would not be appropriate to address those efforts here.[52]

<u>Recommendation:</u> No further action is recommended in the context of this proceeding given the current proceedings underway. However, FERC should continue to evaluate potential seams issues with neighboring regions as new market designs are adopted.

G. Re-examining uniform price auctions

All suppliers in the spot market are paid the uniform spot market price determined by SCED, adjusted for line losses and congestion. Of course, most supply is sold prior to the spot market at contractual prices, so that only a small portion of supply is actually paid the spot price determined by SCED. However, the spot market price does provide a benchmark for comparison to contractual prices. Moreover, all suppliers must participate in SCED to coordinate overall supply and demand.

Some participants called for re-examining the use of uniform price auctions that allow gas fired generators to set the price for coal and nuclear plant.[53] Gordon van Welie (ISO-NE) explained that under the current uniform price auction, baseload units such as coal and nuclear plants may act as "price takers," bidding their marginal cost, which may be zero, in order to guarantee they are dispatched. They are paid the uniform clearing price, which is generally above their marginal cost; the difference goes towards recovering their capital investment and other fixed costs. The debate has been over the "pay-as-bid" approach, in which suppliers whose bids were accepted (and thus were dispatched) would be paid their individual bids rather than a uniform clearing price. However, under the pay-as-bid approach, baseload units would have to change their bidding strategy: In order to recover the same capital investment and other fixed costs, they would have to increase their bids to a level reflecting their estimates of the market clearing price. So there would not be much difference in the prices paid, but the pay-as-bid method would be less robust than the current uniform price auction in terms of producing efficient dispatch. Other participants elaborated that, under pay-as-bid, baseload units might submit bids slightly below their estimate of the market clearing price, in order to guarantee dispatch; this could potentially result in baseload units being

[52] Commissioner Brownell at p. 23 of transcript of 2/13/2006.

[53] Tom Rudebusch at p 162 of transcript.

paid a little bit less on some occasions, but it would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity. Moreover, adopting pay-as-bid in order to try to reduce payments to baseload units would discourage future investments in baseload generation.[54] A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited.[55] However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix.[56]

Some participants argued that, under the uniform price auctions, the only way loads can capture the benefits of lower cost coal and hydro resources is via long-term bilateral contracts or investments in new baseload projects.[57] Mr. Van Welie observed that the high prices facing consumers in the Northeast are due to their over-dependence on natural gas-fired generation. The solution is not to change the market design, but to change the siting rules to permit greater investment in new baseload generation that does not depend on natural gas.[58] Mark Lynch added that the Northeast's existing market design is producing all the right price signals; but to ensure new entry, the siting issues must now be resolved.[59]

Recommendation: The current uniform clearing price approach has been in place for several years. Comments in this proceeding do not justify a departure from the established uniform clearing price model. We do not make any recommendation about this approach at this time.

H. Review dispatch practices

The DOE report (p.52) noted a lack of easily comparable information regarding dispatch models and implementation by different entities and areas, and recommended that the FERC-State Joint Boards consider conducting in-depth reviews of selected dispatch entities, including some investor-owned utilities, to determine how they conduct economic dispatch. These reviews would document all deviations from pure least-cost, merit-order dispatch and distinguish entity-specific or regional practices from regulatory,

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[54] Harry Singh at p 187 and Don Sipe at p 198 of transcript.

[55] Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.

[56] Bob Loughney at p 158 of transcript.

[57] Tom Rudebusch at p. 163 of transcript.

[58] Gordon van Wylie at p. 172 of transcript.

[59] Mark Lynch at p. 175 of transcript.

environmental and reliability-driven constraints, with an eye toward identifying potential discrimination against certain resources. While discrimination against NUG resources is not an issue in the Northeast in that ISO-NE and the NYISO commit and dispatch resources without regard to ownership, the NYISO is currently, in conjunction with its review of rules applicable to wind and solar power, commencing a global review of its rules to ensure that all types of resources are treated equitably.

Recommendation: We do not recommend any additional steps be undertaken in this proceeding beyond what NYISO and ISO-NE are contemplating doing as part of their regular improvements to their operations.

I. Standardize Contract Terms

The DOE report (p.51) recommends that DOE and FERC should explore the EPSA and EEI proposals for more standard contract terms and conditions for NUG-to-buyer contracting and should encourage stakeholders to undertake these efforts, which should benefit the entire wholesale electric industry and its customers. These proposals relate to the conditions for inclusion of NUG resources in a utility's economic dispatch queue and their provision of ancillary services such as voltage support and regulation, along with associated performance standards, compensation and penalties. ISO-NE and the NYISO both dispatch generation resources without regard to ownership and compensate and penalize units according to established FERC-approved tariff rules.

Recommendation: This recommendation does not appear to be relevant to the Northeast Board, and for regions without organized markets might better be addressed in an industry forum such as the NAESB.

J. Review Dispatch Tools

The DOE report (p.53) noted the diversity of size and scope of the various dispatch areas and recommended scrutiny of the technical quality of current economic dispatch technology tools including software, data, algorithms, and assumptions, with an eye toward enhancements to these tools and elimination of any inherent resource biases.

Recommendation: Given that the most advanced tools and models to date have been developed and administered by the nation's ISOs and RTOs, it is recommended that FERC request of the ISO-RTO Council (IRC) to take the lead in identifying "best practices" to guide future improvements to these tools.

Appendix D: PJM-MISO Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	**Docket No. AD05-13-000**

Report on Security Constrained Economic Dispatch

By

The Joint Board for the PJM/MISO Region

Submitted to the Federal Energy Regulatory Commission on:

May 24, 2006

Summary of the PJM/MISO Region Joint Board Recommendations

This section summarizes the recommendations that are discussed in greater detail in Section V of the report. Not all Joint Board members agree on all aspects of this report or on all aspects of these recommendations. In particular, some Joint Board members believe that some aspects of these recommendations may be outside of the narrow scope of the *process* of security constrained economic dispatch and some Joint Board members believe the recommendations should remain within that scope. In addition, the Joint Board report does not address retail service, which is strictly a matter for states to decide.

1. An ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining market participant and state regulator confidence in the RTOs. The RTOs should establish a clear benchmark to assess the degree to which the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition, are being captured.

2. Appropriate efforts should be made to acquire necessary data to assess the impact of the SCED conducted by PJM and MISO on market participant forward bilateral contracting.

3. While it is not necessarily under the RTOs' control, developing common reliability rules applicable across each RTO's region or, ideally, across the combined region, could promote more efficient SCED operations. The RTOs are encouraged to assess the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region and pursue such standardization if its benefits exceed the costs for customers.

4. The RTOs' common market development effort should include proposals for improving SCED over the seam between PJM and MISO. As the RTOs consider any and all improvements in market and operations design and modifications to business practices, they should pursue such improvements with an eye to the effect of the change on the other RTO, and, ideally, develop all improvements jointly and in a cost-effective manner.

5. With the Joint Operating Agreement, PJM and MISO developed a method for addressing transmission constraints in one RTO through redispatch by the other RTO when doing so is cost effective. MISO has suggested a way to improve this limited coordinated dispatch by exchanging preliminary dispatch results and associated prices, as well as information on constraints affecting the dispatch and prices. The RTOs are encouraged to further explore this idea of additional SCED coordination, taking cost-effectiveness into account.

6. The RTOs are encouraged to continue timely analyses of the cost and technical feasibility issues involved with expanding the geographic scope of SCED. The continued analyses should encompass the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. In addition, each RTO should analyze the cost and technical feasibility of expanding its geographic area to include areas not currently under RTO managed SCED, as requested by utilities that seek voluntary membership in the RTO. However, as always, actions to expand the geographic scope of PJM or MISO SCED should be cost effective and subject to relevant state law.

7. Because adequate transmission infrastructure is important for the achievement of SCED's least-cost and reliability objectives, the RTOs should devote adequate resources and substantial management attention to the transmission expansion planning process.

8. The RTOs are encouraged to bring to the attention of state regulators any situations in which transmission facilities found to be needed in the RTO expansion plan, are, nevertheless, not getting implemented in a timely manner.

9. Provided that the RTO uses proper measures and a proper approach for inclusion of an economic transmission project (intended to address congestion issues) in its transmission expansion plan, the obligation on a transmission owner to exercise best efforts to implement such a project should be no different than its obligation to use best efforts to implement a baseline reliability project.

10. The RTOs are encouraged to continually improve their analytical modeling and forecasting capability to better assess beneficiaries of transmission expansion so as to improve transmission cost allocation.

11. The RTOs are encouraged to devote adequate resources and substantial management attention to joint transmission planning and expansion processes, so as to pull our respective geographic areas together, improve the operation of RTO-managed SCED, and facilitate a robust competitive electricity market.

12. RTO independence is critical for the RTOs' ongoing credibility. Accordingly, PJM and MISO are encouraged to continue to strive for independence as a bedrock principle. Both state and federal regulators have a role in the oversight of RTO independence.

13. Some state regulators believe that they do not currently have sufficient access to the data needed to evaluate and oversee the RTOs' operation of market-based SCED. The RTOs' policies for limited state regulator access to data should be revisited.

14. When determining their respective dispatches, MISO uses marginal losses and PJM uses average losses. The material presented to the Joint Board shows that, while there may be implementation issues to resolve, using marginal losses improves dispatch efficiency. Accordingly, the issues associated with losses as they apply to PJM and MISO SCED should be analyzed and appropriately resolved.

15. The operation of SCED must take transmission ancillary services into account. PJM and MISO have distinctly different methods of treating ancillary services. There are potentially significant efficiencies to be gained through improved co-optimization of ancillary services and energy in the dispatch and PJM and MISO are encouraged to continue to strive to improve on efficiencies gained in the area of ancillary services.

16. The PJM and MISO markets must develop more ways for demand response to participate in the dispatch. Improvement in demand response opportunities is not just an RTO responsibility.

The Joint Board encourages PJM and MISO to work with state regulators and policy-makers to improve SCED by improving cost effective demand responsiveness to price.

17. The Joint Board is not proposing any recommendations on the SCED framework issues of SCED definition, SCED history, or the debate over efficient versus economic dispatch at this time.

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I. BACKGROUND AND OVERVIEW

A. Convening of Joint Boards Pursuant to EPAct 2005

Section 1298 of the Energy Policy Act of 2005 ("EPAct") adds a new Section 223 to the Federal Power Act ("FPA") requiring the Federal Energy Commission ("FERC" or "Commission") to convene regional Joint Boards pursuant to FPA Section 209 to study the issue of security constrained economic dispatch ("SCED") for the various market regions.[1] FPA Section 209, in turn, authorizes the Commission to refer matters to joint boards that include state representatives.[2] Section 1298(c) guides the work of the SCED Joint Boards by stating:

> The sole authority of each joint board convened under this section shall be to consider issues relevant to what constitutes "security constrained economic dispatch" and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.[3]

On September 30, 2005, the FERC issued an "Order Convening Joint Boards pursuant to Section 223 of the Federal Power Act."[4] The Joint Board for the PJM Interconnection, LLC and Midwest Independent Transmission System Operator, Inc. ("PJM/MISO") region is one of four joint boards convened by the Commission in the September 30 Order.[5] The states included on the PJM/MISO Region Joint Board are: Delaware, District of Columbia, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Tennessee, Virginia, West Virginia and Wisconsin.[6]

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[1] Pub. L. No. 109-58, § 1298, 119 Stat. 594, ___ (2005).

[2] Section 209 of the FPA, 16 U.S.C. § 824h states in part,

The Commission may refer any matter arising in the administration of this Part to a board to be composed of a member or members, as determined by the Commission, from the State or each of the States affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold any hearings.

[3] Pub. L. No. 109-58, 1298(c), 119 Stat. 594, ___ (2005).

[4] Joint Boards on Security Constrained Economic Dispatch, 112 FERC ¶ 61,353 (Sept. 30, 2005) (Joint Board Order).

[5] References in this report to "the Joint Board" are to the Joint Board for the PJM/MISO Region unless specified otherwise.

[6] The members of the PJM/MISO Joint Board are Chair: Commissioner Nora Mead Brownell (Federal Energy Regulatory Commission); Vice Chair: Commissioner Kevin K. Wright (Illinois Commerce Commission); Vice Chair: Chairman Kenneth D. Schisler (Maryland Public Service Commission). Members: Commissioner Dallas Winslow (Delaware Public Service Commission); Chair Agnes A. Yates (District of Columbia Public Service Commission); Chairman David Lott Hardy (Indiana Utility Regulatory Commission); Chairman John Norris (Iowa Utilities Board); Chairman Mark David Goss (Kentucky Public Service Commission); Commissioner Laura Chappelle (Michigan Public Service Commission); Commissioner Kenneth Nickolai (Minnesota Public Utilities Commission); Chairman Jeff Davis (Missouri Public Service Commission); Chairman Greg Jergeson (Montana

The Commission's September 30 Order noted the directives in EPAct Section 1298 and summarized them as follows:

> Each joint board is authorized to: (1) "consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) " make recommendations to the Commission regarding such issues."[7]

Section 1298(d) of EPAct requires the Commission to submit a report to Congress by August, 2006, regarding the recommendations of the joint boards.

B. Summary of the DOE Report on the Value of Economic Dispatch

Section 1298 is not the only section of EPAct that addresses SCED. For example, Section 1234 of EPAct requires the U.S. Department of Energy ("DOE") to coordinate and consult with the States and to annually conduct a study and distribute a report on SCED issues.[8] While the PJM/MISO Region Joint Board's work effort was separate from that performed by the DOE under Section 1234, our report has been informed by the DOE's work.[9]

EPAct Section 1234 directs the United States Department of Energy ("DOE") to:

(1) study the procedures currently used by electric utilities to perform economic dispatch;
(2) identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch; and
(3) analyze the potential benefits to state and national residential, commercial, and industrial electricity consumers of revising economic dispatch procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

Public Service Commission) Mr. Paul Malone, Regulatory, Planning & Contracts Manager (Nebraska Public Power District); Commissioner Frederick F. Butler (New Jersey Board of Public Utilities); Commissioner Sam J. Ervin IV (North Carolina Utilities Commission); Commissioner Susan E. Wefald (North Dakota Public Service Commission); Chairman Alan R. Schriber (Public Utilities Commission of Ohio); Chairman Wendell F. Holland (Pennsylvania Public Utility Commission); Chairman Gary W. Hanson (South Dakota Public Utilities Commission); Director Pat Miller (Tennessee Regulatory Authority); Mr. Howard Spinner, Director, Division of Economics and Finance (Virginia State Corporation Commission); Mr. Earl Melton, Director, Engineering Division (Public Service Commission of West Virginia); Chairperson Daniel R. Ebert (Public Service Commission of Wisconsin). Assistant Deputy Minister Garry Hastings, Department of Energy, Science & Technology, Manitoba served as an "observer."

[7] Joint Board Order, at P14.

[8] Section 1234 of the Energy Policy Act, Pub. L. No. 109-58, § 1234, 119 Stat. 594, ___ (2005)

[9] The Commission's September 30 Order directs the joint boards to "take into account the DOE report as they proceed with their own efforts." See Joint Board Order at P15.

On November 7, 2005, DOE submitted its first annual report to Congress pursuant to Section 1234 of EPAct. The DOE's report is titled "*The Value of Economic Dispatch.*"

DOE's 2005 report was prepared using a survey of stakeholders and a literature search on economic dispatch issues. The EPAct states that the DOE's report may make recommendations to Congress and the states on legislative or regulatory changes related to economic dispatch.[10]

While the DOE Report has "the use of non-utility generation within economic dispatch" as one of its specific major focuses, it also examines economic dispatch more broadly. The DOE Report concludes that "there is room to improve economic dispatch practices to reduce total cost of electricity and increase grid reliability."[11] The DOE advises that "the FERC-State Joint Boards on Economic Dispatch (created pursuant to Sec. 1298 of EPAct) may wish to study these, starting with a more detailed examination of economic dispatch practices and administration than was possible" in the DOE's limited initial study.[12]

The DOE Report contains three recommendations that are directly or tangentially relevant to the SCED issues that the Joint Board considered. These three recommendations are described below.

- The FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some investor owned utilities, to determine how they conduct economic dispatch. These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices from regulatory, environmental and reliability-driven constraints. These reviews could assist the FERC and the states in rethinking existing rules or crafting new rules and procedures to allow non-utility generators and other resources to compete effectively and serve load.[13]

- The FERC and the DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts. Specifically, the EEI proposed that non-utility generators should commit to provide energy at a specified price for a specified time to meet a unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.[14]

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[10] Pub. L. No. 109-58, § 1234(c), 119 Stat. 594, ___ (2005).

[11] United States Department of Energy, The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005, November 7, 2005 at 6 (DOE Report).

[12] DOE Report, at 6.

[13] DOE Report at 52.

[14] DOE Report at 51.

- Given the diversity of size and scope of the dispatch areas now operating across the nation and the need for economic dispatch to continue to produce affordable, reliable outcomes, the technical quality of current economic dispatch technology tools—software, data, algorithms and assumptions—deserve scrutiny. Any enhancements to these tools, including identification and elimination of any resource biases in the calculation methods, will improve the reliability and affordability of the nation's electricity supplies.[15]

Although it is not explicitly stated, the DOE's recommendations appear to apply more directly to SCED in regions of the country where SCED is not centrally conducted by an independent RTO or ISO. However, the DOE recommendations are at least partially relevant for other regions and we have kept them in mind during our deliberations.

C. <u>Joint Board Sessions</u>

The Joint Board met in public session on November 21, 2005, in Chicago and on February 12, 2006, in Washington, D.C. under the leadership of Commissioner Nora Brownell as Chair and Chairman Kenneth Schisler and Commissioner Kevin Wright as co-Vice Chairs.[16] At the Chicago session, the Joint Board heard from a number of speakers including speakers from DOE, FERC, MISO, PJM, and several industry stakeholder representatives. The Joint Board also issued data requests to PJM and MISO in October, 2005 and on March 8, 2006. Finally, several interested parties filed Comments and other materials on Joint Board matters in Dkt. No. AD05-13-000 and those Comments are available on the Commission's web-site.

The Joint Board met informally via conference call on May 1, 2006, and subsequently conducted a vote of the members via e-mail on the report and recommendations.

In the following sections, this report provides: a general overview of the concept of SCED (Section II); a description of SCED as practiced in PJM and MISO (Section III); a review of issues raised and considered in the Joint Board process (Section IV); and a list of Joint Board recommendations (Section V). The principal sources for the material in these sections are: presentations to the Joint Board; written comments submitted by interested parties; discussions among the Joint Board members; the report submitted to Congress by DOE pursuant to Section 1234 of EPAct; and responses by PJM and MISO to Joint Board data requests.

Not all Joint Board members agree on all aspects of this report or on all aspects of the recommendations in Section V below. In particular, some Joint Board members believe that some aspects of the recommendations may be outside of the narrow scope of the *process* of security constrained economic dispatch and some Joint Board members believe the recommendations should remain within that scope. Accordingly, nothing in this report should be

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[15] DOE Report at 53.

[16] Transcripts from those sessions are available on the Commission's web-site at http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=2362&CalType=%20&Date=2%2f12%2f2006&CalendarID=116.

interpreted as being binding on individual Joint Board members or their respective agencies or preventing such members or agencies from taking positions that deviate from those adopted in this report should circumstances warrant. In addition, the Joint Board report does not address retail service, which is strictly a matter for states to decide.

II. GENERAL OPERATION OF SECURITY CONSTRAINED ECONOMIC DISPATCH

A. The Definition and Concept of SCED

The basics of SCED are described in this section to establish a common understanding of the issue before addressing details and recommendations. Section 1234(b) of EPAct defines "economic dispatch" as: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." FERC proposed to adopt this definition of economic dispatch as the definition of SCED for purposes of the Joint Board's work.[17] This definition was discussed at the first PJM/MISO Region Joint Board meeting and was generally used to guide the Joint Board's discussion.[18]

The definition of SCED is such that it takes, as a premise, that SCED will result in the production of energy "at the lowest cost" and that consumers will be "reliably" served. In some ways, the Joint Board's objective is to examine the extent to which MISO's and PJM's operation of SCED satisfies the expectations implied by the definition of SCED.

There are a number of unique challenges to supplying electricity. In particular, production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and by season; the costs of generation from different types of units vary greatly; and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load economically and reliably. SCED is designed to be an optimization process that takes account of these factors in selecting the generating units to dispatch so that a reliable supply of electricity at the lowest cost possible under the conditions prevailing in each dispatch time interval can be delivered.

B. The Process of Economic Dispatch

The economic dispatch process generally occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time). In the unit commitment stage, operators must decide which generating units should be committed to be on-line for each hour, for the next 24-hour period (hence the term "day ahead"), based on the load forecast and knowledge about the availability and expected performance of system facilities. In selecting the most economic generators to commit, system operators must

[17] Joint Board Order at P14.

[18] PJM/MISO Joint Board November 21, 2005 Meeting on Security Constrained Economic Dispatch, Docket No. AD05-13-000 at 20 (Nov. 21, 2005 Tr.).

take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. System operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance. System operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as environmental limits on annual unit output and non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

Forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the units committed can reasonably be expected to meet load reliably. This is the "security" aspect of the unit commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the economically optimal unit commitment cannot be carried out reliably, relatively more expensive generators may have to be committed in place of cheaper units.[19] This step also requires evaluation of possible contingencies. System operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day's dispatch.

In the unit dispatch stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment process and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz, per North American Electric Reliability Council ("NERC") standards. This is generally done through regulation reserves by using (or directing Balancing Authorities to use) Automatic Generation Control ("AGC") to follow system load and conditions as needed. In addition, transmission flows must be monitored to ensure that flows stay within reliability limits and voltage stays within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve changing the dispatch, curtailing schedules, or shedding load. System operators must frequently check conditions and issue adjusted unit dispatch instructions accordingly.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software generally has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail, while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints, and, in some cases even the network model, might vary in economic dispatch software.

Recent advances in computing technology (e.g. the use of mixed-integer-programming for unit commitment) have generally made the economic dispatch problem mathematically simpler to

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[19] This is known as "out of merit" unit commitment.

solve (all other things equal) than was historically the case. Available technology has advanced to the point where many earlier limitations on solvable problem size have been overcome. Advances in hardware and software now make it technologically feasible to undertake security constrained economic dispatch over very large regions.

In addition to differences in models used in economic dispatch software, a major factor that can impact the benefits of economic dispatch is whether or not all available economic resources are considered. In non-organized markets (i.e., outside of RTOs/ISOs) there are concerns expressed by some providing information to the Joint Board that this may not always occur due to various reasons, including limitations in open access transmission tariffs based on Order 888.[20] However, witnesses in the PJM/MISO Region Joint Board process did not generally raise significant issues about non-utility generators' level of access to the RTOs' unit dispatch process.[21]

III. EXAMINATION OF SCED IN PJM AND MISO

A. History of SCED

In their November 21 written Comments, both PJM and MISO explain that SCED is not new. As MISO explained, "SCED has always been the necessary tool for ensuring reliable operations in modern systems."[22] Similarly, AEP explained that, "Prior to the development of large RTOs, most, if not all, control areas throughout the United States utilized some form of security constrained economic dispatch to minimize the generation cost of supplying the load."[23]

PJM's Comments explain that the history of security constrained dispatch in PJM goes back to PJM's formation in 1927.[24] As PJM and MISO explain, the tools and methods of SCED have evolved and the scope of SCED, especially in the RTO regions, has expanded in recent times. However, the RTOs are not aware of any method other than SCED, in some form, for operating an electrical system to pursue the dual goals of least-cost and reliable operation.

B. PJM and MISO SCED Operations and Practices

There are four basic ways that SCED, as operated by PJM and MISO, differs from the general description of SCED as previously described: (1) PJM and MISO generally dispatch over a broader region; (2) PJM and MISO generally use demand bids and supply offers, rather than generating unit costs, as the economic measure for dispatch; (3) PJM and MISO generally use locational marginal pricing ("LMP"), rather than Transmission Line Loading Relief ("TLR"), as

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20 See, e.g., DOE Report at 45-47 and MISO Comments at 4-5.

21 For example, DOE's Mr. Meyer stated that, in conducting the DOE survey, they "did notice that the non-utility generators in the organized markets seemed generally pretty content with the way economic dispatch was going." Nov. 21 Tr., at 28.

22 MISO Comments at 9.

23 AEP Comments at 5.

24 PJM Comments at 1.

the method for managing transmission congestion; and (4) PJM and MISO have entered into a Joint Operating Agreement ("JOA") by which they coordinate elements of their dispatch and, in some circumstances, undertake redispatch in one RTO for congestion that appears in the geographic area of the other RTO. Each of these four differences will be discussed below.

PJM and MISO each consider the resources owned/operated by their respective market participants and then each RTO evaluates their respective market sellers' offers as a single resource pool. The broader regional resources available to the RTOs (as contrasted with individual utility dispatch) results in a dispatch stack containing generators from all generating-owning members of the RTOs and some generation resources outside the RTOs. Uncoordinated and separate dispatches by different individual utility companies in response to constraints (under most circumstances) would not be the same as an area-wide dispatch coordinated by either RTO, given the scope of the RTOs. It is also noteworthy that the sum of stand-alone dispatches by individual utility companies is not the same as a regional least cost dispatch when there are transmission constraints that affect and in turn are affected by the dispatch of multiple utility companies throughout the region. That there are economic and operational benefits from pooling generation resources is almost axiomatic. Other factors held constant, separate dispatches would inevitably result in higher total production costs to serve load.

PJM and MISO SCED is based on generation supply offers to sell energy along with non-price responsive load needs and price responsive bids to purchase energy. The RTOs use the voluntary offers and bids along with the load forecast to arrange a security-constrained, economic dispatch for each market interval (normally, every five minutes). The generation supply offers and dispatchable price responsive demand bids will have operating characteristics (e.g., unit ramp rate/load response rates, unit minimum run time/load response durations, etc.,) that the RTO must take into account. PJM and MISO schedule and dispatch generation (and dispatchable demand) in their respective areas using a security constrained dispatch methodology based on the prices and operating characteristics offered by generation suppliers and energy purchases/loads in the region. This methodology is intended to result in the most economic use of resources, as offered into the market, at any given moment, for the entire RTO area, taking into account all system conditions, contingencies, and transmission constraints, while ensuring that sufficient generation is dispatched to meet the energy requirements of the region.

The result of the dispatch is intended to provide reasonably transparent locational marginal prices. LMP defines the marginal cost of serving the next increment of load at each location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. During the operating day, resources are called on based upon the economics reflected in their offers. The RTOs strive to dispatch the lowest offer combination of power plants available at any given moment, subject to operational constraints. Generally, however, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the locational market-clearing price for energy in that area. If there are no transmission constraints, LMP will not generally vary across the RTO region (ignoring losses). All sellers in the area receive the clearing price for energy and all buyers in the area that are not bilaterally contracted or self scheduled pay this price. This single clearing price approach to achieving least-cost dispatch will be discussed further in a subsequent section of this report. A balancing market for energy results from this type of LMP-based SCED.

LMPs contain three elements: an energy charge, a congestion charge, and a charge for system energy losses. The energy charge is a single market-clearing price for energy. The market-clearing prices used for settlements will nonetheless differ between some locations whenever there is congestion on the RTO-controlled grid. Prices will also differ between locations due to energy losses. The LMPs for MISO include marginal losses while the PJM currently includes average losses. This difference between the PJM and MISO dispatch practice concerning losses will be discussed later in this report.

The primary means used by PJM and MISO for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. This re-dispatch could be implemented using non-market procedures such as TLR[25] or market-based procedures such as LMP. However, the market-based LMP approach used by both the PJM and MISO is designed to anticipate and avoid constraints by providing price signals that reflect a measure of congestion costs to market participants. That is, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (re-dispatch) the generation output to serve load, while TLR operates on an engineering-based priority system that does not take economics into account.[26]

The formation of RTOs in the Midwest region with inter-laced seams led the FERC to require PJM and MISO to enter into the JOA to closely coordinate their operations. The two RTOs filed their proposed JOA on December 31, 2003, and it was conditionally accepted by the Commission in March 2004.[27]

Generally, the JOA permits more efficient and reliable system operation, facilitates administration of coordinated markets, and would allow additional utilities to integrate into the PJM markets. The JOA contemplates that the RTOs will progressively integrate their operations. Specifically, the JOA includes, as Attachment 2, a Congestion Management Process, dated April 2, 2004, which outlines specifics of the integration process.

Phase 1 of the JOA provided for coordination of PJM's market-driven operation with MISO's non-market operation prior to MISO's energy market, which was launched on April 1, 2005. Under Phase 2, which applies to RTO-operated LMP-based markets, the two RTOs' additional operational integration includes generation redispatch and coordination to manage congestion; coordination to calculate consistent LMPs; and other actions to which the RTOs agree or that the

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25 AEP described the TLR feature as follows: "Transmission loading relief is used to ration the transmission capacity when the demand for transmission is greater than the available capacity. The FERC established rules under the open access policy for sale of available transmission capacity (ATC). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded. The TLR process is based on a priority system and does not consider economics." AEP Comments at 6.

26 At the November 21 Joint Board meeting, Mr. Kruse stated, "We also believe that the LMP pricing strategy allows for the most optimal use of transmission. The old TLR process certainly did not. And I think that shows, if you look at the non-coordinated areas, consistently that still rely on the old TLR process, it's just not the most economic, efficient way to manage congestion." Nov. 21 Tr., at 115.

27 Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251, order on reh'g and clarification, 108 FERC ¶ 61,143, order on clarification and denying reh'g, 109 FERC ¶ 61,166 (2004).

Commission requires.

While this section described the four basic ways that SCED, as operated by PJM and MISO, differs from the general operation of SCED, there are numerous detailed differences (e.g., co-optimization of energy with operating reserves and use of marginal losses). Indeed, many of the RTOs' efforts to continually improve their market design are really just efforts to improve their operation of SCED. This is the case because the RTOs' operation of real-time SCED and their operation of a balancing spot market are really the same thing. This is the principal distinction between the RTOs' SCED operation and traditional SCED operation.

IV. REVIEW OF ISSUES THAT WERE RAISED IN THE JOINT BOARD PROCESS

The issues reviewed in this section of the report were either discussed on the record at one of the two Joint Board meetings, provided in written Comments filed in the Joint Board docket, or provided by PJM or MISO in response to Joint Board data requests.

A. SCED Framework

1. Definition of SCED

The DOE's Report on "The Value of Economic Dispatch" states that the term "economic dispatch" has a common general meaning—"the practice of operating a coordinated system so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls)."[28] The DOE states however, that "most people" agree with the definition of the term that is used in EPAct and that was adopted by the Joint Board, namely, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." The DOE's Report did note that several respondents to the DOE's survey suggested that reliability would be better served if the definition referred to "security constraints" rather than "operating limits."[29] The DOE states that the details of how the definition of SCED is put into practice can vary significantly.[30]

2. Efficient Dispatch vs. Economic Dispatch

Concerning economic vs. efficient dispatch, DOE's Report states,

> In a recent hearing of the Senate Energy and Natural Resources Committee, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational

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[28] DOE Report at 9.

[29] DOE Report at 49.

[30] DOE Report at 9.

constraints of the generation fleet and the transmission system. Although economic dispatch will usually run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are always used before less efficient units. Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

> • The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers' electricity costs - for benefits that may not be large enough to offset these additional costs.
>
> • Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
>
> • A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives--which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.[31]

MISO's written Comments on this issue state:

> In recent weeks, there has been some discussion about whether the dispatch should be "economic" or whether it should be "efficient." This appears to be a false debate, a red herring based on some unknown confusion. An economic dispatch is an efficient dispatch. An economic dispatch will take into consideration all of the economic and operational factors that affect whether it is more economic to dispatch unit A before unit B or before unit C. In general, a system operator would not consider only a single factor, such as the heat rate of the units, and determine economic dispatch from that factor alone. As between any two units, it is more economic to dispatch a unit with a more efficient heat rate than a unit with a less efficient heat rate, *all other factors being* equal, but all other factors are often not equal. When all economic and operational factors are considered, the unit with the less efficient heat rate may be more or less economic to dispatch at a given moment because of these other factors.[32]

At the November Joint Board meeting, FERC's Mr. Luong explained that efficient dispatch does not take into account as many variables and possible constraints as does economic dispatch such

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[31] DOE Report at 11.

[32] MISO Comments at 7.

that efficient dispatch is a subset of economic dispatch.[33]

AEP commented that, "It should be noted that economic dispatch is not the same as efficient dispatch. Efficient dispatch only considers how well a generator converts the input fuel source into electricity as measured by its heat rate. Economic dispatch improves on efficient dispatch by taking into consideration not only the heat rate but also the cost of the fuel delivered to the plant, the variable cost of operation and maintenance, transmission losses, transmission constraints, etc."[34]

Exelon stated that it wishes to reiterate that

> Security Constrained Economic Dispatch (SCED) is the most cost efficient and effective way of dispatching an electrical system considering transmission constraints and operational limitations on generation, such as ramping limitations, minimum run times, minimum down times, and differing heat rates at different operating levels. For accurate price signals, all system limitations must be accounted for and an accurate load forecast must be included in the economic dispatch. So-called "efficient dispatch," on the other hand, dispatches solely on the basis of the generation units' rated efficiency and ignores other system and unit limitations. So called "efficient dispatch" thereby fails to dispatch on the basis of true economic efficiency. It is only by considering all system and unit limitations that an operator can in fact dispatch most efficiently.[35]

Overall, some people differentiated efficient dispatch from economic dispatch, while others argued that they were the same. A state regulator agreed with DOE that efficient dispatch would probably increase costs to consumers and its benefits are uncertain, but economic dispatch reduces consumer costs and improves wholesale competition.[36]

3. PJM and MISO SCED Technology Tools: Models, Software, and Algorithms

The DOE Report urged examination of the technical quality of current economic dispatch technology tools—software, data, algorithms and assumptions.[37] Accordingly, the Joint Board asked PJM and MISO in a data request to describe their dispatch tools. The response stated that the market applications, including dispatch algorithms, used by PJM and MISO are very similar. MISO's response noted that PJM and MISO share a common vendor for these systems and that vendor delivered systems developed on a common platform. The response stated that, although there are differences between the two markets that are expressed in the dispatch process, the basic mathematical formulation of the SCED function is the same. Significant differences in the

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33 Nov. 21 Tr., Mr. Luong at 42.

34 AEP Comments at 5.

35 Exelon Comments at 1-2.

36 Chairman Schriber Letter at 1 , and Nov. 21 Tr., Chairman Schriber at 25.

37 DOE Report at 53.

dispatch process between the two markets involve treatment of losses and ancillary services and these will be discussed in a subsequent section of this report.

MISO states that its entire EMS model covers 21,369 stations and 32,550 buses. PJM states that its network model consists of 6,995 stations and 12,660 buses.

MISO states that its network model contains approximately 94,800 analog telemetry points that are refreshed every 4-30 seconds and approximately 95,800 telemetry status points. In addition, MISO monitors 10,296 thermal facilities (lines and transformers) and 7,931 bus voltages with 6,920 contingency simulations executed approximately every 3 minutes.

PJM states that its network model has 39,000 measurement telemetry points refreshing every 2 to 15 seconds and 35,000 telemetry status points. PJM routinely monitors about 6,000 thermal facilities and 2,000 bus voltages with 4,000 contingency simulations executed every 90 seconds.

The RTOs state that they both use Areva's Unit Dispatch System ("UDS") to conduct real time dispatch. The UDS incorporates various data inputs, including the most recent State Estimator solution, short-term load forecasts, interchange schedule, hydro schedule, generating unit offers, status and ramp capability, and relevant transmission limits based on ongoing security analysis.

4. Locational Marginal Pricing vs. Transmission Line Loading Relief

The primary means used by PJM and MISO for relieving transmission congestion constraints is through LMP. Before market operation, the principal mechanism for managing transmission congestion was TLR. AEP described TLR as follows: "Transmission loading relief is used to ration the transmission capacity when the demand for transmission is greater than the available capacity. The FERC established rules under the open access policy for sale of available transmission capacity (ATC). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded. The TLR process is based on a priority system and does not consider economics."[38]

However, the market-based LMP approach used by both the PJM and MISO is designed to anticipate and avoid constraints by providing price signals that reflect a measure of congestion costs to market participants. That is, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (re-dispatch) the generation output to serve load, while TLR operates on an engineering-based priority system that does not take economics into account.

At the November 21 Joint Board meeting, Mr. Kruse stated, "We also believe that the LMP pricing strategy allows for the most optimal use of transmission. The old TLR process certainly did not. And I think that shows, if you look at the non-coordinated areas, consistently that still rely on the old TLR process, it's just not the most economic, efficient

[38] AEP Comments at 6.

way to manage congestion."[39]

Mr. Torgerson stated, "what we found is that prior systems relying on TLRs was inefficient because we'd call TLRs and it led to about a 12 percent under-utilization of the capacity on those constrained flow gates after the TLR was put into effect. With the economic dispatch, we get much closer, right to the edge of how much transmission capacity can actually be utilized."[40]

B. Market-Based SCED

1. Bid-Based vs. Cost-Based SCED

The DOE Report states that "economic dispatch principles and operation are the same in both regulated utility operations and centralized wholesale markets."[41] DOE states that a difference is that "in centralized markets, the merit order of available resources is determined using offer schedules for each resource rather than the variable production costs that are used to dispatch a set of utility-owned resources."[42]

In a data request question, the Joint Board specifically asked PJM and MISO to describe the benefits and detriments of using a bid/offer-based approach to receiving generator offers versus a cost-based approach.[43]

MISO's response to the Joint Board's question is:

> While bid-based and cost-based approaches are often discussed as though they are alternative paradigms, there is in fact only one primary area of difference. Under a "cost-based" approach a central agency or body is assigned the task of determining what an appropriate "cost" is for each generating unit. While it is theoretically possible that these "approved" costs could be updated quickly, in practice it is difficult for the central planner to acquire and analyze the data necessary to perform this calculation. In contrast, under a bid-based regime, competitive forces of the market are relied upon to "drive" bids down to their marginal cost. Since no central authority is required to "approve" the costs, bids can be adjusted quickly to reflect current market conditions.
>
> To the extent that an administrative process cannot "keep up with" changing conditions, then we can expect that dispatch under a cost-based approach will be less efficient than that arising from a competitive market driven process. Likewise, to the extent that competitive pressures do not constrain bids to their marginal costs

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[39] Nov. 21 Tr., at 115.

[40] Nov. 21 Tr., Mr. Torgerson at 63.

[41] DOE Report at 4.

[42] DOE Report at 4.

[43] Technically, the term "bid" in this context refers to load/demand bids to purchase from the RTO's market at a particular price or set of prices and "offer" refers to generator/seller offers to sell into the RTO's market at a particular price or set of prices. However, often the term "bid" is used to encompass both "bids" and "offers."

then we can expect that bid-based dispatch will not produce a least cost result.

> As a general rule, the longer that "costs" are fixed (because it is costly to review and adjust) we should expect a risk premium and a more expensive result, i.e., if costs are fixed for a year as compared to a month there will be a higher risk premium built into the cost numbers.[44]

PJM's response to the Joint Board's question is:

> The fundamental advantage of using bids, rather than "costs," to dispatch the units in the market is that a bid based approach has the benefit of using competitive market [sic] to discipline offers instead of relying on administrative oversight except where specific circumstances require intervention to avoid the exercise of market power. A bid-based approach encourages suppliers to provide alternative offers that may contain more flexible physical operating parameters. This flexibility enhances reliable system operations. The potential challenges with the bid-based approach are that market power could be exercised when the market is restricted to local areas by transmission limitations. In PJM, this challenge is fully addressed because the market design incorporates local market power mitigation rules. Under these local market power rules, generation offers are switched to cost-based offers when market power screening tests detect the potential for the exercises of market power in a localized area.
>
> While a cost-based approach may obviate the need for market power mitigation rules, because all offers are capped at cost, it is unlikely to produce desirable efficiencies and operating flexibility. For example, the cost-based administrative rule approach may incent suppliers to restrict physical generation offer parameters because of concerns that cost-based rules do not permit cost recovery in certain operating modes. This lack of flexibility would reduce the availability of potential dispatch solutions to the system operators, which in turn would adversely affect reliability. Indeed, as data from the PJM Market Monitoring Report indicates the beginning in market operations resulted in a significant decrease in the "forced outage" rate, most apparent during the period from 1996 to 2001, where it fell from about 12% to below 5%. This decline correlated to a time of relative tightness in system wide supply and indicates that generation owners make greater efforts to provide supply in a bid based market. This reflects efficient use of generation.
>
> As reported by the PJM MMU in the 2005 State of the Market Report, these efficiencies have not come at the cost of the exercise of market power. Indeed, as the MMU reports, the energy market, operated on a bid basis, is competitive. In particular, the MMU assessed the price-cost markup in the energy market and concluded that "data on the price-cost mark-up are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2005."[45]

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[44] MISO's March 22, 2006 Response to the Joint Board's March 8 data request question 1.

[45] PJM's March 22, 2006 Response to the Joint Board's March 8 data request question 1.

2. Single Clearing Price SCED Auction vs. Pay-As-Bid Approach

As explained above, traditional individual utility dispatch was done on a unit production cost basis. However, most RTOs , including PJM and MISO, use a bid/offer based auction approach to developing the dispatch stack.

LMP defines the marginal cost of serving the next increment of load at each location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. Generally, the bid of the marginal unit that must be dispatched to meet load within transmission-constrained boundaries will set the locational market-clearing price for energy. All sellers within the constrained area receive this price for energy and all buyers within the constrained area that are not bilaterally contracted or self-scheduled pay this price. Some have wondered how this method of using the bid of the marginal unit to set the market clearing price rather than paying each unit the price it bids can lead to a least-cost result.

In a data request, the Joint Board asked PJM and MISO to describe the benefits and detriments of using a single clearing price market design rather than using a pay-as-bid approach to clearing the SCED spot markets. Both RTOs support continued use of the clearing price approach. PJM provided the Joint Board with a paper written by Dr. Peter Crampton and Dr. Steven Stoft titled "Uniform-Price Auctions in Electricity Markets." MISO's response is representative:

> The merits of clearing price versus pay-as-bid schemes have been carefully considered at every ISO, and there is much literature on the topic. All ISOs have concluded that the clearing price approach is superior. The result is supported by numerous papers and consistently borne out in practice, where several pay-as-bid schemes have been attempted only to discover that they did not function as the promoters anticipated. As a result, the general trend at all ISOs has been to move away from any market rules premised on pay-as-bid approaches and to implement a clearing price approach based on marginal cost pricing.
>
> The allure of a pay-as-bid approach arises from a common assumption that is both incorrect in theory and discredited in practice. The assumption is that if the pricing rule is changed from a clearing price approach to a pay-as-bid approach, generators will not change their bidding behavior. If that assumption were true, then generators with lower costs would consistently bid lower, and loads could capture some benefit by buying power from the generators at their lower bid prices. The assumption is false. Ample experience has shown that if the rule is "the ISO will pay each generator what it bids," then generators will almost invariably change their bids. That is, generators in a pay-as-bid scheme have strong incentives to bid their expectation of what the clearing price would be, rather than to bid their own costs. Using a single market clearing approach will create "rents" for all but the marginal generator. That is, there will be a difference between the market clearing price and the offer of the generator. This difference, which is called a "rent," is in fact payment toward the fixed costs of the generator. Paying the generator for only the variable component of their costs will illicit [sic] one of three types of behavior. They will either (1) raise their offers to include a payment for capital, (2) require a

side payment for fixed costs that will not be included in the energy price and will most likely be a form of uplift or (3) to the greatest extent possible exit the dispatch process itself. None of these behaviors are compatible with the goal of efficiency.

There are many examples of this, particularly in those ISOs that originally used something other than LMP. In California, for example, pay-as-bid rules were used to price energy from plants that were dispatched to relieve congestion. The result was that California ISO experienced persistent "gaming" of bids by generators, because the pay-as-bid scheme created strong incentives to change their bids. In the worst cases, generators expecting to be constrained-off to relieve congestion repeatedly bid negative prices, which forced the ISO to pay extremely high payments to generators not to run. This generator behavior was a logical response by the generators to the pervasive incentives of the pay-as-bid system, which resulted in the ISO paying extremely high constrained-off payments.

In contrast, an approach that pays each generator the clearing price encourages generators to bid their costs, thus facilitating a least-cost dispatch and avoiding the gaming often associated with pay-as-bid schemes. In sum, the assumed benefits of a pay-as-bid scheme are illusory, because the scheme encourages generators to bid something other than their costs. The clearing price approach encourages generators to bid their costs, while facilitating an economic dispatch.[46]

3. Total Revenue Recovered by Generators Through the RTOs' LMP-Based SCED Compared to Aggregate Generator Production Cost

In his January 31, 2006 letter to Commissioner Brownell and filed in Dkt. No. AD05-13-000, Howard Spinner of the Virginia Corporation Commission urged the Joint Board to study "whether MISO/PJM region electric power is being produced in a least-cost manner given the constraints imposed by current system infrastructure."[47] Mr. Spinner expresses a concern that "wholesale electric prices may inappropriately diverge from production resource costs" and that this divergence may ultimately negatively impact retail electricity prices.[48] Mr. Spinner suggests some data and some analysis that could shed light on this issue.[49] This issue was addressed by the Joint Board members at the February 12 meeting.[50] Commissioner Brownell (Chairman of the Joint Board) urged PJM and MISO to "submit data" that "may answer some of these fundamental questions."[51] The RTOs did not provide data pursuant to that request from the Joint Board Chair.

Consequently, in a subsequent Joint Board data request, the RTOs were asked to discuss their position on this issue of potential divergence between aggregate wholesale electric market prices

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[46] MISO's March 22, 2006 Response to the Joint Board's March 8 data request question 3.

[47] Howard Spinner Letter at 4.

[48] Howard Spinner Letter at 2.

[49] Howard Spinner Letter at 3.

[50] Feb. 12 Tr., at 43-46.

[51] Feb. 12 Tr., at 46.

that result from RTO-managed SCED and aggregate generator production costs.

MISO's response is as follows:

> In a totally regulated regime, state commissions set retail rates at levels sufficient to recover the total revenue requirements for generation. The total revenue requirements include both "production costs" such as fuel and other variable operating costs, and fixed costs, which include capital costs of construction and maintenance and other ongoing operating costs that are fixed. If the total revenue requirements were not recovered through retail rates, then the utility would face severe financial problems that eventually would make it unable to continue reliable service in the short run or maintain adequate resources in the long run.
>
> In a market regime, an analogous principle applies. Market prices must recover both production costs and fixed costs. If market prices were artificially restricted to cover only the production costs, the fixed costs would not be recovered. In that case, market investors would refuse to build new facilities or maintain existing plants because they would know that their fixed costs could not be recovered.
>
> ISOs pay generators a "clearing price" based on the marginal costs of the dispatch. The marginal cost is not the "production cost" of each unit; it is, instead, the marginal cost of the marginal unit (or units) needed in the dispatch. The effect of using marginal "clearing price" approach is that over time, the combined set of clearing prices will recover both the "production costs" of generators and their fixed costs, just as would occur in a fully regulated regime. Similarly, just as retail rates in a regulated regime must recover the full revenue requirements, including both production and fixed costs, market prices must recover the full revenue requirements of the plants needed for dispatch. In turn, retail rates should reflect the full revenue requirements, whether in a regulated or market system.[52]

PJM's response to the data request is lengthier than MISO's. In general, PJM's response refers to a number of indicators in PJM's State of the Market Report that discount the hypothesis of divergence between wholesale electric market prices and generator costs as a result of SCED in the PJM marketplace. PJM states that the real issue is whether the units setting prices in PJM are doing so based on offers that include significant mark ups over marginal costs. PJM cites numerous measures in its State of the Market Report to show the contrary.[53]

4. Marginal vs. Average Losses in the Dispatch

The Joint Board notes that MISO uses marginal losses in its dispatch but PJM uses average losses. In a data request, the Joint Board asked the RTOs the following question:

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[52] MISO's March 22, 2006 Response to the Joint Board's March 8 data request question 2.

[53] PJM's March 22, 2006 Response to the Joint Board's March 8 data request question 2.

> Please describe the benefits and detriments of using marginal, rather than average losses, in the dispatch. How does the approach used affect the resulting dispatch? How does PJM's practice of using average losses affect the interface with the MISO market, which uses marginal losses?

Each RTO's response to this question was basically the same as follows:

> A marginal loss approach models the incremental increase or decrease in transmission losses that occur with incremental changes to the economic dispatch pattern. The average loss approach does not account for this incremental loss effect. The marginal loss approach is more efficient because it tends to minimize system losses as part of the dispatch algorithm which in turn minimizes the overall cost to serve load. PJM performed annual production cost analysis to evaluate the benefits of the marginal loss approach over the current average loss approach. The results of this analysis indicated that the annual production cost savings under the marginal loss approach was approximately $100 million across the entire market. The analysis indicated that the production cost savings under marginal loss-based dispatch were a result of a decrease in hourly system losses and a decrease in transmission congestion caused by the more efficient generation dispatch patterns to serve the hourly demand. However, while marginal loss implementation does increase market efficiency, certain practical implementation issues do exist with the marginal loss approach. The marginal loss impacts on locational pricing result in the need to develop allocation rules to distribute marginal loss revenues. The development of these business rules has created considerable debate in the RTO stakeholder process because of concerns with cost shifting versus the current approach. The current markets have also not developed marginal loss hedging products. These issues are not insurmountable but their resolution has created implementation complexities in RTOs where marginal losses have been implemented and has created considerable debate in the PJM stakeholder process.
>
> The PJM/MISO market to market coordination process has worked well in providing coordinated transmission congestion management between the PJM and MISO markets. Therefore, PJM does not believe the difference in the loss models between the RTOs has adversely impacted interregional transmission congestion coordination. However the difference in the transmission loss pricing may have a small impact on price convergence between the markets. Since marginal loss pricing is a relatively small impact compared to congestion pricing, the impact is limited.
>
> One of PJM's members has filed a complaint with FERC concerning PJM's treatment of marginal losses (FERC Dkt. EL06-55-000).

5. Transmission Ancillary Services Within SCED

SCED must take into account ancillary services such as downward-and-upward regulating margin requirements of the system and operating reserves.

In response to a Joint Board data request, the RTOs state that because the former control areas that make up the MISO footprint are still independent Balancing Authorities within the MISO market, MISO does not centrally dispatch the Regulation or Spinning Reserve services. Rather, each individual Balancing Authority is responsible for assigning the required amount of Regulation and Spinning Reserve within its area, and directing the deployment of those services based on its individual area control error ("ACE"). Each Balancing Authority calculates its own Regulation signal that is used to deploy the Regulation each assigns within its own area, and each Balancing Authority is responsible for responding to system disturbances. The individual Regulation and Spinning Reserve assignments made by the individual Balancing Authorities are communicated back to the MISO control center for inclusion in the UDS economic dispatch solutions. MISO states that development of an ancillary services market is underway with active participation from stakeholders in the Ancillary Services Task Force.

The RTOs state that PJM operates markets for both regulation and operating reserves. In order to account for the product substitution cost associated with their provision, the PJM ancillary service optimization software co-optimizes Regulation and Spinning Reserve with energy to assign the most cost-effective resources throughout the market to provide the services. These assignments are then fed into the UDS application such that they are respected in the economic dispatch solution. PJM is a single Balancing Authority with a single ACE. PJM therefore calculates a single Regulation signal based on a filtered value of that ACE that is used to deploy the Regulation assigned to individual units, and also deploys Spinning Reserve in response to system disturbances on an RTO-wide basis.

C. SCED Benefits

1. Quantifying the Benefits of SCED

At the first joint board meeting, both PJM and MISO presented data from several studies to show both qualitative and quantitative benefits of SCED.[54] Various entities questioned the studies and data used by PJM and MISO to reach their conclusions. The Wisconsin load serving entities argued against using MISO's March 26, 2004 study of savings in Wisconsin claiming it was flawed and suggested developing more accurate studies.[55] Chairman Jergeson also cautioned that the studies alleging net benefits due to the implementation of regional markets by PJM and MISO were offered in macro, region-wide format, often based on economic modeling rather than actual experiences.[56] His concern was that these studies failed to disclose the distribution of benefits and costs, both geographically and demographically.[57] The issue of benefit recipient was extensively discussed at the February 12 Joint Board meeting with distinctions made between the customer perspective and the generator perspective.[58] The effect of retail

[54] Nov. 21 Tr., Mr. Harris at 43-58 and Mr. Torgerson at 58-69.

[55] Wisconsin Load Serving Entities ("WLSE") Comments at 4-5.

[56] Nov. 21 Tr., Chairman Jergeson at 2.

[57] Nov. 21 Tr., Chairman Jergeson at 2.

[58] February 12 Tr., at 23 and 37.

ratemaking on the issue of benefits pass-through was discussed with speakers noting that many state ratemakers have authority over the reflection of off-system sales revenue as offsets to retail rates and the retention of in-state low cost generation benefits for in-state ratepayers.[59]

Most entities, including DOE and state regulators, noted the importance of credible studies that seek relevant information and use accurate data to determine the benefits and costs of SCED as conducted by PJM and MISO, understand the current market conditions and improve market performance.[60] Commissioner Hadley recommended that DOE, RTOs and the joint board members work together to come up with the questions that need to be asked and answered to study the benefits of SCED.[61]

2. The Effect of the RTO Spot Markets on Forward Bilateral Contracting

In their paper, "Uniform-Price Auctions in Electricity Markets," Drs. Cramton and Stoft emphasize the importance of forward bilateral contracts as a method to reduce price risk for both suppliers and consumers.[62]

In his remarks to the November 21 Joint Board meeting, Mr. Collins of Alliant Energy stated that, since the MISO real-time and day-ahead markets have begun operations, bilateral transactions have "shrunk considerably."[63] However, Mr. Orr of Constellation Energy remarked on the transparency of the RTOs' real time markets and described that one of the benefits of this is providing information so that market participants can decide "on an economic basis, how to deploy your assets and manage the risks for your constituency" and how to "manage risk forward off of that information."[64] Because of the importance of forward contracting and the apparent inconsistency of the two statements of the Joint Board witnesses, the Joint Board asked PJM and MISO a data request question about the impact of their day-ahead and real-time energy markets on the willingness and ability of market participants to bilaterally forward contract.

MISO responded by stating that,

> The MISO market tariff accepted by FERC accommodates bilateral transactions through certain provisions that allow market participants to schedule bilateral transactions through the energy markets. The duration, terms and conditions of such bilateral agreements are negotiated between market participants without involvement of MISO. As such, market participant performance with respect to

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59 February 12 Tr., at 39.

60 Wisconsin Load Serving Entities ("WLSE") Comments at 4, Nov. 21 Tr., Mr. Meyer, Tr., at 23 (discussing the limitations of using the existing studies), questions from Chairman Davis, Commissioner Chappelle, Chairman Hardy and Commissioner Wefald answered by Mr. Harris and Mr. Torgerson on the studies used by PJM and MISO, Nov. 21 Tr., at 76-85.

61 Nov. 21 Tr., Commissioner Hadley at 107-108.

62 This paper was provided to the Joint Board by PJM in response to Question #3 of the Joint Board March 8, 2006 data request. See, e.g., page 6 and 11 for a discussion of the importance of forward contracting.

63 Nov. 21 Tr. ,Mr. Collins at 113.

64 Nov. 21 Tr., Mr. Orr at 134.

> bilateral forward contracts is largely addressed by the parties to the agreement. In general, over 90% of all energy traded in the real time energy market is either pursuant to a bilateral contract between market participants or has cleared the day-ahead energy market.

PJM responded that,

> Every indication is that bilateral forward contracts have remained the main form of supply used to meet load obligations in PJM. This is supported by a growing rather than lessening volume of "bilateral eSchedules" used by market participants to settle through PJM the transfer of energy they agreed to buy or sell outside PJM's short run markets.
>
> At a more general level, PJM's transparent spot and day-ahead market prices provide the basis for most forward contract indexes in use today. Prior to the creation of these short term markets, participants would have had little independent basis for developing a forward price estimate for contracting purposes.
>
> As stated in the 2005 State of the Market Report, PJM does not have access to data that would allow PJM to accurately measure the amount of energy settled in our real-time market that has a forward hedging contract covering exposure to real-time prices. While some portion of the energy is certainly unhedged "balancing," large portions are likely hedged directly through physical bilateral contracts or financial derivative contracts.

3. Reliability

MISO stated that,

> The manner in which the system operator dispatches generators ensures that the grid is operated safely and reliably. Hence, an important starting point is to clarify that the dispatch is an essential reliability function; it is not an option or a policy choice. Every modern electricity system maintains reliable operations through its dispatch.[65]

MISO further stated that, "To ensure reliable operations the dispatch must be 'security constrained.'"[66] Mr. Torgerson added that reliability is aided by MISO's regional coverage.[67]

Mr. Harris stated that PJM is more reliable now that it is also the market operator than it was before it began operating markets.[68]

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[65] MISO Comments at 2.

[66] MISO Comments at 2.

[67] Nov. 21 Tr., Mr. Torgerson at 65.

[68] Nov. 21 Tr., Mr. Harris at 100.

Reliability was generally discussed in the Joint Board process in the context of discussing other matters, rather than as a particular focus of inquiry. For example, AEP stated that "Reliability is driven by the ability of the transmission system operator to understand the limitations of the transmission network and model these limitations in the transmission security analysis process."[69]

D. <u>SCED Scope</u>

1. Geographic Scope of SCED

The DOE Report looks into the question of how large a dispatch area should be. The DOE's Report states,

> the magnitude of the reliability and economic benefits realized from economic dispatch depends upon the size of the area that the integrated dispatch covers.[70]

The DOE Report also states that "economic theory suggests that the sum of separate cost-minimizing dispatch solutions for several independent but adjacent dispatch regions is likely to be larger than the cost-minimizing solution that would result if the entire area were combined and dispatched as one integrated system."[71] The DOE Report suggests that this is a mathematical issue of local versus global optimization or cost-minimization.[72] The DOE Report further states that a larger economic dispatch area "allows the dispatcher to take advantage of the load diversity across the area, to better allocate resources to load needs."[73] The DOE Report states that, as an operational matter, "the larger RTOs report that the bigger the area that SCED covers, the more likely that operational limits can be respected with a solution that melds economics and reliability quickly and easily."[74] DOE's speaker at the Joint Board meeting confirmed that DOE found that economic benefits tend to increase as the geographic scope and electrical diversity of the area under unified dispatch increases.[75]

AEP stated that, "In theory and practice as the size of the RTO/control area increases more resources (generation and transmission) are available under one control center to enhance the overall economic dispatch process. These additional resources allow for a more economic dispatch over the larger area, rather than separate multiple area dispatches, reducing transactional friction and more efficiently managing transmission congestion. This facilitates the determination of the opportunity cost of transmission, which depends critically on the marginal

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[69] AEP Comments at 10.

[70] DOE Report at 27.

[71] DOE Report at 28.

[72] DOE Report at 28.

[73] DOE Report at 28.

[74] DOE Report at 28.

[75] Nov. 21 Tr., Mr. Meyer at 21.

cost of power at different locations, and these costs are determined simultaneously with the dispatch."[76]

At the November Joint Board meeting MISO's Mr. Torgerson stated, "the optimization of dispatch across a wider region does lead to a more economic use of resources."[77] Mr. Torgerson also stated that every few seconds MISO looks at the 180,000 data points that are integrated into MISO's state estimator. PJM's Mr. Harris stated, "the technology is allowing these synergies to grow and develop because you have the large regions and you have the capability to do that."[78] Mr. Harris also stated that, with a new control center, PJM is looking at running a state estimator for the entire Eastern Interconnection.[79]

The concept of having a single dispatch across the combined PJM and MISO geographic areas was discussed at the November 21 Joint Board meeting.[80] Mr. Torgerson stated that the costs of taking that step might be prohibitive and referred back to the preliminary cost analysis done for the RTOs' joint and common market filing.[81] Mr. Harris suggested that the analysis of contingencies for a combined dispatch might create a significant data problem.[82]

The Joint Board notes that PJM and MISO have committed to conducting a cost/benefit analysis of a combined dispatch across the PJM/MISO geographic area.[83]

AEP stated that there are advantages and disadvantages to increasing geographic scope of SCED as follows,

> Advantages – *Theoretically,* the entire interconnection would provide the highest level of reliability and lowest cost over the entire region. Disadvantages – Due to technology limitations (such as limited theory on how to control and monitor large systems, need for infrastructure enhancements and mathematical problem formulation and algorithmic computational capability), it is not possible today to model and computationally solve the security constrained economic dispatch in real-time. The problem becomes more complex the bigger the control area becomes. The inability to solve the security constrained economic dispatch could reduce reliability and increase cost due to infeasible solutions.[84]

The Joint Board notes that the RTOs' common market filing states that "a single market encompassing an area with a peak load of over 247,000 MWs, may not be technologically

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[76] AEP Comments at 7

[77] Nov. 21 Tr., Mr. Torgerson at 61.

[78] Nov. 21 Tr., Mr. Harris at 51.

[79] Nov. 21 Tr., Mr. Harris at 55.

[80] Nov. 21 Tr., at 89-92.

[81] Nov. 21 Tr., at 91 referring to the RTO's October 31 filing in Dkt. No. ER04-375-017/ER04-375-018.

[82] Nov. 21 Tr., Mr. Harris at 92.

[83] See e.g., the RTOs' February 28, 2006 filing in Docket. No. ER04-375-017/ER04-375-018 at 7.

[84] AEP Comments at 8

feasible at this time."[85] However, the RTOs' common market filing provided no support for that statement. Accordingly, in a data request in the instant proceeding, the Joint Board specifically asked the RTOs what additional capability would be needed for their respective existing modeling and dispatch systems to handle additional generation and load. The RTOs responded that their existing systems could handle a 1,000 MW increase with no upgrades. Both RTOs responded that an increase of 50,000 MW of load and generation would require upgrades in computing capability and data storage capability. Both RTOs declined to speculate on the technological feasibility of managing increases in the magnitude of 100,000 to 150,000 MW without a more thorough technical evaluation.

A utility commenter suggested conducting a study to highlight the results and benefits of increasing generator competition over as wide an area as physically possible by increasing transmission capacity.[86]

2. PJM/MISO Common Market Issues

Some state regulators are concerned that if FERC allows PJM and MISO to continue proceeding down divergent market design paths, it will create difficulty for market participants seeking to operate in both PJM and MISO and perpetuate seams issues that negatively impact the market.[87] They recommended that any initiatives pursued by PJM or MISO should contribute to the development of a joint and common market, and FERC should make sure that any initiative that is an exception to this goal should include a clear explanation of how long any short-term necessary incompatibility would last.[88] Several commenters stated that a number of issues needed to be addressed by PJM and MISO in order to optimize SCED.[89] These issues include: a PJM/MISO joint and common market; a consistent PJM/MISO resource adequacy requirement; a consistent PJM/MISO long-term planning system to ensure a vibrant transmission grid; unified allocation of Firm Transmission Rights/Auction Revenue Rights; the development of compatible or unified ancillary service markets; and identifying differences in algorithms between PJM and MISO dispatch mechanisms.[90] There is concern that the duplicate RTO structures within Ohio and the lack of a common geographic footprint in the state for transmission matters as well as wholesale market transactions impedes SCED.[91]

Chairman Schriber asserted that different operational rules and business practices in PJM and MISO have stifled transactions with neighboring utilities across these RTO borders.[92] He

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[85] RTOs' October 31 filing in Docket. No. ER04-375-017/ER04-375-018 at 45.

[86] AEP Comments at 2.

[87] Comments of the Joint State Commissions in Dckt No. AD05-13 (Joint State Commission Comments) at 3-5 and 13.

[88] Joint State Commission Comments at 5.

[89] Joint State Commission Comments at 5, WPSRC Comments at 4-5, Nov. 21 Tr., Mr. Torgerson at 105 and Mr. Orr at 137-138.

[90] Joint State Commission Comments at 5, WPSRC Comments at 4-5, Nov. 21 Tr., Mr. Torgerson at 105 and Mr. Orr at 137-138. *See also* Nov. 21 Tr., Mr. Meyer at 29, and Mr. Orr at 130-131.

[91] Chairman Schriber Letter at 1.

[92] Chairman Schriber Letter at 2.

recommends that each RTO's operational rules and business practices must be reviewed and amended to recognize and accommodate cross RTO border trading if separate SCED is to facilitate an open and common market in the combined PJM/MISO region.[93]

It was also suggested that joint and common planning is needed to help address the loop flows that the dispatch of one system creates on the other.[94]

E. Transmission Infrastructure

1. The Importance of Adequate Transmission Capacity

The DOE Report identifies a number of "conditions that could exclude a resource from the dispatch stack."[95] One of those conditions is the "configuration of the existing transmission system."[96] The DOE states that,

> The existing transmission system's configuration limits the ability of dispatchers to accommodate additional generation from units located in certain transmission constrained locations within the system. In many cases, expanded transmission capacity will increase the deliverability of output from efficient generators to loads. But in many areas there are delays in building new transmission capacity that would reduce congestion and enable greater transmission flows.[97]

The DOE Report further states,

> Transmission adequacy affects how much generation can flow and how much grid reliability concerns will constrain different generation production and deliverability patterns. Easing key transmission constraints improves access to load for almost every generator as well as improving grid reliability. Therefore many respondents [to DOE's survey] reiterate the importance of enhanced transmission planning processes that address long-term economics as well as reliability, and of building a more robust transmission network that will enable customers to save money by reliably accessing more efficient generation than is possible with today's transmission system.[98]

AEP stated that, "Transmission constraints are the primary obstacle to minimizing the overall supply cost. Reliability is driven by the ability of the transmission system operator to understand

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93 Chairman Schriber Letter at 2.

94 AEP Comments at 9 and Chairman Schriber Letter at 2-3 (loop flows can produce congestion on the neighboring system, requiring more uneconomic (out of merit order) dispatch to overcome the loop flow effects, e.g., the Lake Erie loop flow.).

95 DOE Report at 45.

96 DOE Report at 46.

97 DOE Report at 46.

98 DOE Report at 50.

the limitations of the transmission network and model these limitations in the transmission security analysis process."[99] AEP also stated that, "The key to optimizing the economic dispatch and maintaining reliability is a robust transmission network. Investments in the transmission grid targeted at relieving transmission bottlenecks will not only improve reliability but will do more than any administrative change to help ensure that low cost generation will be fully utilized in the economic dispatch process."[100]

Several parties in the Joint Board process argued that a robust transmission network is the key to optimizing economic dispatch and ensuring dispatch and delivery of a low cost reliable supply of energy.[101] Commissioner Nickolai made the point that, although security constrained economic dispatch may be an efficient method of allocating scarce transmission resources, "if all we had was scarcity what we're going to see is prices that can just go up and up and up."[102]

Even in an RTO that enables all generation to bid into the market, transmission bottlenecks can and do limit the amount of low-cost energy that flows through to load. Under these circumstances, the dispatcher will necessarily redispatch out of merit (more expensive) energy from a local source to manage the congestion.[103] Therefore, without adequate transmission, lower cost generation will not displace higher cost generation to its full potential.[104] Some Joint Board participants, including Commissioner Butler, argued that constrained areas or load pockets such as the State of New Jersey need investments in transmission and generation to relieve the constraint and improve reliability and improve the "security constrained" part of economic dispatch.[105]

Some parties asserted that in order to get transmission built, long-term regional transmission planning, timely investment and cost recovery, and appropriate cost allocation are needed.

2. The Transmission Planning Process

Several commenters argued that a regional and long-term transmission planning process is necessary to build a robust transmission network.[106] One commenter recommended implementing a collaborative and inclusive transmission planning process for local transmission owners and wholesale transmission customers for reliability-based upgrades and economic

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99 AEP Comments at 6.

100 AEP Comments at 6.

101 Chairman Schriber Letter at 1 and 3, AEP Comments at 6 and 10, ITC Comments at 2-3, WPSRC Comments at 6, Mr. Tatum at 1 and Nov. 21 Tr., at 144, and Nov. 21 Tr., Mr. Welch at 152 and 155.

102 February 12 Tr., at 69.

103 Mr. Tatum Comments at 1, ITC Comments at 3 and Joint State Commission Comments at 9. Joint State Commissions include Delaware Public Service Commission, District of Columbia Public Service Commission, Illinois Commerce Commission, Kentucky Public Service Commission, Michigan Public Service Commission, New Jersey Board of Public Utilities, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission and Public Service Commission of West Virginia.

104 WPSRC Comments at 6, Nov. 21 Tr., Mr. Tatum. at 144, and Mr. Welch at 152 and 155.

105 New Jersey Board of Public Utilities (NJBPU) Comment at 2.

106 Joint State Commission Comments at 10, NJBPU Comments at 2 and 6, Nov. 21 Tr., Mr. Torgerson at 98-99, Mr. Tatum at 145, and Mr. Naumann at 166.

upgrades.[107] Another commenter contended that a properly executed consistent regional transmission planning process over a large geographic area, including siting and appropriate cost allocation for needed upgrades to the transmission system, is needed.[108] Other entities argued that PJM and MISO's long-term planning needs to be coordinated and done jointly to ensure an adequate transmission grid to optimize the ability of SCED in LMP markets.[109] One commenter argued that both RTOs conduct separate planning and that MISO's long-term planning is inadequate because it aggregates the plans of the transmission owners within its footprint and fails to include transmission projects by entities other than the transmission owners in its footprint.[110] MISO admitted that it needs to improve its long-term transmission planning and procedures.[111] While a state commission supported SCED and transmission planning, it argued that SCED should not solely dictate the transmission planning process. Instead, additional costs and benefits that are not accounted for in SCED must be addressed in the transmission planning process.[112]

Mr. Torgerson stated that, "We need long term transmission plans and we need to put the procedures in."[113]

3. Cost Recovery for Transmission Investments and Transmission Pricing/Cost Allocation

Mr. Harris emphasized the importance of transmission cost allocation.[114]

Commenters suggested that, in order to build transmission infrastructure, timely investments in the transmission grid are needed.[115] Some market participants desire more assurance with respect to cost recovery and cost allocation to provide new facilities.[116]

One commenter argued that the existing MISO transmission pricing proposals discourage generation and transmission construction, thus hampering the optimization of SCED.[117] It was

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[107] Nov. 21 Tr., Mr. Tatum at 145 and Comments at 2.

[108] Joint State Commission Comments at 10.

[109] Joint State Commission Comments at 10, WPSRC Comments at 2 and 6, Chairman Schriber Letter at 3, Nov. 21 Tr., Mr. Torgerson at 98-99, Mr. Tatum at 144 and Mr. Welch at 152.

[110] WPSRC Comments at 6.

[111] Nov. 21 Tr., Mr. Torgerson at 98.

[112] NJBPU Comments at 2 and 6. For instance, it suggests examining the cost of environmental and health impacts of emissions from coal burning plants that will be used to provide lower cost power. NJBPU at 3. In another example, NJBPU argues that its investment in cleaner technology will be undermined because coal-fired plants with advanced pollution control technology or plants fueled by natural gas will produce energy at a higher cost and thus be dispatched after a less expensive plant such as a coal-fired plant without advanced pollution controls. NJBPU Comments at 4.

[113] Nov. 21 Tr., Mr. Torgerson at 98-99.

[114] Nov. 21 Tr., Mr. Harris at 104.

[115] Joint State Commission Comments at 9, Mr. Tatum Comments at 2, ITC Comments at 4 and AEP Comments at 6 and 10. *See also* WPSRC Comments at 5-6, Nov. 21 Tr., Mr. Harris at 105, Mr. Welch at 169 and 173.

[116] Nov. 21 Tr., Mr. Harris at 103-104, Mr. Welch at 153 and 167-173.

[117] WPSRC Comments at 6.

recommended that transmission investment could be spurred by using formula rates, making transmission less risky, and creating state and Federal partnerships to build interstate facilities, and applying regional rates to regional transmission.[118] Others proposed flow-based pricing, but that may require considerable study and testing, and so, in the meantime, FERC should consider distance pricing mechanisms to replace license plate rates to more closely reflect the nature of the commerce being conducted on the interstate system.[119] Another commenter asserted that using postage stamp rates would provide incentives for generation and transmission investment.[120]

Chairman Schriber suggested that if non-incumbent merchant transmission owners built transmission additions, they should be allowed to recover their costs in the RTO's tariff on the same non-discriminatory basis as provided to generation-owning transmission companies.[121]

Commissioner Ervin mentioned SPP's FERC approved transmission cost allocation approach.[122]

4. Independent Transmission Companies

Some parties suggest that independent transmission companies (transcos) could help achieve the objectives of economic dispatch by improving transmission infrastructure and that the value of for-profit transcos needed to be recognized in the joint planning efforts by PJM and MISO.[123] A transco noted that as long as ownership of the transmission grid remained in the hands of generation owners protected by its congestion, the benefits of SCED could not be fully achieved because of constraints resulting in intra-market price differentials.[124] Some parties asserted that FERC and RTOs, with the assistance of state regulators, must develop the most efficient delivery routes to serve load and then allow existing transmission owners, merchant transmission developers, and for-profit transcos to bid on construction and ownership of transmission facilities.[125]

F. Effects of SCED on Generators

1. Participation by Non-Traditional Generation in SCED

Certain participants asserted that opportunities for non-traditional resources such as wind power

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118 Nov. 21 Tr., Mr. Tatum at 146 and Comments at 2, Mr. Welch at 170, ITC at 4, and Mr. Harris at 104.

119 Chairman Schriber Letter at 4.

120 WPSRC Comments at 6.

121 Chairman Schriber Letter at 2-3.

122 Nov. 21 Tr., Commissioner Ervin at 176.

123 ITC Comments at 1 and Chairman Schriber Letter at 2-3.

124 Chairman Schiber Letter at 2.

125 Chairman Schriber Letter at 4 and ITC Comments at 3.

to participate and compete equally with traditional resources such as fossil-fueled generation should be further explored and promoted.[126] They suggested that FERC should encourage the utilization and sharing of resources and the use of new technology and methods to analyze and incorporate the benefits of diversity of generation and load to drive down costs.[127]

2. Generation Fuel Diversity

Chairman Schisler raised the issue of generation fuel diversity and requested the panelists at the Chicago meeting to comment on this issue.[128] Mr. Harris responded that PJM, as the operator of the market, is "agnostic" as to generator fuel type.[129] Mr. Harris went on to explain that, in practice, the RTOs' market transparency has improved generator diversity with "green" sources becoming more significant.[130] Mr. Harris also mentioned the importance of state planning.[131]

3. The Incorporation of Low-Cost Generation Areas Into Regional SCED

Chairman Jergeson cautioned against changing the way Montana Dakota Utilities, the rural electric cooperatives, and WAPA serve the customers in eastern Montana.[132] He noted that over the years, these entities have demonstrated that they are capable of delivering comparatively low-cost electricity and no harm is occurring that needs to be fixed by a FERC/MISO/PJM fix. His recommendation was that SCED may be applied to the offers for sale of surplus power only after entities have satisfied their native load obligations.[133]

Mr. Torgerson addressed this issue as follows:

> They're not necessarily paying the LMP price for every transaction that occurs. I mean, the LMP price is usually just paid on the imbalance or on a very small amount of the transactions that happen. And in your state, I mean, you still have vertically integrated utilities, and you have, as state commissioners, you can determine, you know, what gets passed through to customers from your costs and from your generation, from the generation that they do. They're offering it into the market and we're dispatching it at $20. If they are offering it at $20, that's always something you've got to make sure that, you know, look at what they're really offering, and then their generators are going to run. They're going to have the power there and some of it is going to be exported. So, you'll have all that data and

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126 Joint State Commission Comments, at 12.

127 Joint State Commission Comments, at 12-13.

128 Nov. 21 Tr., Chairman Schisler 132.

129 Nov. 21 Tr., Mr. Harris at 86.

130 Nov. 21 Tr., Mr. Harris at 87.

131 Nov. 21 Tr., Mr. Harris at 87.

132 Chairman Jergeson Comment at 1.

133 Chairman Jergeson Comment at 1-2 (objecting to the application of economic dispatch that would require load serving entities to dispatch their lower cost generation into the regional market, but serve their own customers with higher cost regional market price).

information on what is actually being done. And then, as regulators, you know, you will look at all this information to determine what is appropriate in your state.[134]

G. Other SCED Issues

1. Demand-Side Participation in SCED

Some observers say that operators of the organized markets must develop more ways for demand-side response to participate in the dispatch.[135] Mr. Harris stated that it is important "how do we get, we truly get [ ] demand side functional and I really think that the [end]-state will be demand that can participate in the economics or real time dispatch. But each state has different rules in retail, different rules how demand would work, net metering rules. You know, how to really concentrate in that area so that we can really get the consumer participating in the economic value of the dispatch equation. And it almost has to be state by state but to the degree we get commonality in moving that forward and get a healthy, robust demand programs moving, we'll be much better served quicker and it solves a host of other issues when you get that into play."[136] Mr. Kruse agreed that "demand side management is certainly the forefront of the future for, for a lot of reasons."[137]

According to some state commissions, in order for demand response to fully participate in wholesale markets, considerable work is required to develop effective demand response programs, secure transmission owner, load serving entity and state regulatory support for those programs and build customer understanding and participation.[138] Commissioner Wright suggested that the Joint Board should address demand response as a potential competitive factor in the report that it provides to the Commission.[139] MISO noted that it should increase demand side participation in SCED in order to balance the supply side.[140] PJM has played a role in programs that foster demand response and distributed generation.[141]

Mr. Torgerson stated that MISO needs to "continue working on the ability for demand side to participate in the dispatch equation. There's some wonderful technologies on demand side. The opportunities are huge. The capabilities are there with the technology and, and the sooner we can

[134] Nov. 21 Tr., Mr. Torgerson at 95.

[135] Nov. 21 Tr., Mr. Torgerson at 98, Mr. Harris at 54 (PJM has seen benefits of demand response) and 104, and Mr. Kruk at 149.

[136] Nov. 21 Tr., Mr. Harris at 104.

[137] Nov. 21 Tr., Mr. Kruse at 119.

[138] Joint State Commission Comments at 10.

[139] Commissioner Wright Comment.

[140] Nov. 21 Tr., Mr. Torgerson at 98.

[141] The Joint State Commissions note that PJM has participated in programs that have encouraged several states to develop common rules and programs for demand response and distributed generation interconnection and integration. Joint State Commission Comments at 11. Other programs that identify and factor the environmental value of a particular generator into a buying decision helped states in the PJM region to ensure dispatch of cleaner generation. Joint State Commission Comments at 11.

get demand side to fully participate in the economics of the dispatch, the better we're going to be and it will really balance out the supply side devices."[142]

2. Accuracy of Data Input Into the Dispatch

The accuracy of data inputs into the dispatch is important. For example, Exelon stated:

> Ensuring to the maximum degree that dispatch assumptions are accurate is crucial to maximizing the benefits of SCED. If dispatch assumptions are not accurate or if the system operators do not commit and de-commit available generation appropriately, some of the benefits of economic dispatch are lost through out-of-market actions taken by PJM and MISO. For example, consistently over-committing generation or not releasing generation from the dispatch queue when it is no longer needed tends to skew the results of economic dispatch by shifting cost recovery out of the transparent economic dispatch price signals into non-transparent uplift costs commonly called operating reserve charges (PJM) or revenue sufficiency guarantee (MISO). Such out-of market actions, while sometimes necessary to preserve reliability and/or mitigate local market power, must be carefully monitored to ensure that appropriate price signals are sent to the market. Skewed price signals affect both the real time market and the longer-term forward bilateral market, and will result in increased total market costs over time.[143]

Similarly, DOE's Mr. Meyer stated that, "the economic dispatch is very dependent on the accuracy of load forecast[s]. And improvements in the accuracy of such forecasting will, by themselves, lead to improvements in the efficiency of economic dispatch."[144] DOE's Report states, "load forecasting is an unappreciated element of the dispatch challenge. Improving the quality of load forecasting will lead to improvements in both the reliability and cost-minimization impacts of economic dispatch."[145]

It was observed that improved forecasting by RTOs and market participants could bring further operational benefits.[146]

3. The Effect of Independence of the RTOs on Confidence in the RTOs' Market-Based SCED Process

At the November 21 Joint Board meeting, Mr. Kruse observed, "There's two key components that both of them [PJM and MISO] share. They're independent and they're transparent. Those

[142] Nov. 21 Tr., Mr. Torgersonat 98-99.

[143] Exelon Comments at 4.

[144] Nov. 21 Tr., at 26.

[145] DOE Report at 51.

[146] Nov. 21 Tr., Mr. Meyer at 26, Mr. Kruse at 118 (important that day ahead plans mirror real time plans as closely as possible), and Joint State Commission Comments at 10.

are the two key things from an independent participant that we expect in a market that helps make it work right, it helps us have confidence that the market's done the most economical way with no favorability to any of the other participants. Those are key in what makes the economic dispatch decisions work right."[147]

At the February 12 meeting, Commissioner Nickolai suggested that the Joint Board "review the governance of the RTOs to help assure that they truly are independent, to the extent that we can make them independent operators of the markets and the grid."[148] He raised a question about "the extent to which they are dependent actors versus the extent to which they feel that they must be agents of their members and transmission owners."[149] He stated that the assurance of independence is an important foundation for "confidence that the grid and the markets are going to be operated in a manner fully consistent with the goal of maximizing the economic benefit to the public."[150]

V. RECOMMENDATIONS OF THE JOINT BOARD FOR THE PJM-MISO REGION

The previous Sections of this report reviewed issues that were raised in the Joint Board process. Those sections are intended to be presented objectively. The discussion in those sections is intended merely to review and summarize material that was discussed at the Joint Board meetings; submitted in the Joint Board docket; provided by the DOE; or provided by MISO or PJM in response to a Joint Board data request.

As we were invited to do by Section 1298 of EPAct, we considered "issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned."[151] In contrast, this Recommendations section is not intended merely to be a review. Rather, it is a policy section designed to capture the majority views of the Joint Board members "and to make recommendations to the Commission regarding such issues" as invited by Section 1298 of EPAct. While we strove for consensus, not all Joint Board members agree on all aspects of this report or on all aspects of these recommendations. In particular, some Joint Board members believe that some aspects of these recommendations may be outside of the narrow scope of the *process* of security constrained economic dispatch and some Joint Board members believe the recommendations should remain within that scope. Accordingly, nothing in this report should be interpreted as being binding on individual Joint Board members or their respective agencies or preventing such members or agencies from taking positions that deviate from those adopted in this report should circumstances warrant.

In crafting the recommendations below, we are guided by our Joint Board Chairman, Commissioner Brownell, to strive for ways to ensure that SCED will enhance the reliability and affordability of service and produce the "best possible outcomes for customers."[152] We also

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147 Nov. 21 Tr., Mr. Kruse at 114-115.

148 Feb. 12 Tr., at 68.

149 Feb. 12 Tr., at 68.

150 Feb. 12 Tr., at 68.

151 Pub. L. No. 109-58, § 1298, 119 Stat. 594, ___ (2005).

152 Feb. 12 Tr., at 72.

agree with Mr. Harris that the RTOs should pursue operational excellence to make certain that they're doing everything as best they can which would include the dispatch and fine-tuning.[153] We acknowledge that SCED improvement is a continual process. We also agree with Mr. Meyer that we should continually examine whether market rules are "in some way affecting economic dispatch that we ought to try to learn more about."[154] Finally, we believe that implementation of each of these recommendations should be contingent on a showing of cost effectiveness.

A. SCED Framework

- The Joint Board is not proposing any recommendations on the SCED framework issues of SCED definition, SCED history, or the debate over efficient versus economic dispatch at this time.

The Joint Board accepts the definition of SCED as it appears in Section 1234 of EPAct and as proposed for our use by FERC in its September 30 Order--"the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." SCED is merely a very complicated constrained optimization problem that involves a touch of art along with the science.

We do note that the EPAct definition of SCED is designed in such a way as it takes as a premise that SCED will result in the production of energy "at the lowest cost" and that consumers will be "reliably" served. Such a definition might imply that, if energy is not being produced at the "lowest cost" or that consumers are not being "reliably" served, then SCED is not taking place. Yet, the evidence in this case shows that historically, system operators have always used some form of SCED. On the other hand, we intuitively know that, historically, energy has not always been produced in all regions of the country "at the lowest cost" and consumers in all places have not always been "reliably" served. Consequently, our examination cannot be on whether SCED exists in PJM and MISO. We know it does exist in PJM and MISO, as well as everywhere else, because material presented to the Joint Board shows that there is no other way to operate an electrical system. Accordingly, rather than considering only the existence or non-existence of SCED, our efforts were focused on assessing the extent to which the way PJM and MISO operate SCED (RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED) satisfies the least cost and reliability expectations implied by the definition of SCED.

The Joint Board accepts that SCED, in one form or another, has a long history. We agree with MISO that, "SCED has always been the necessary tool for ensuring reliable operations in modern systems."[155] No viable alternative to SCED, as a general system operating method, was offered in the record of this case and we are aware of no other viable alternative method for operating a modern electrical system. Alternative forms of conducting SCED were reviewed in Section IV above (in particular, alternative methods of pursuing the "least-cost" and "reliability" objectives of SCED), but SCED itself is unchallengeable.

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[153] Nov. 21 Tr., Mr. Harris at 99.

[154] Nov. 21 Tr., Mr. Meyer at 34.

[155] MISO Comments at 9.

The Joint Board believes that one of the principle focuses of the DOE Report—access by non-utility generators to the operator's SCED—is not a significant issue in the MISO or PJM areas. There was some discussion about improving opportunities for non-traditional resources such as wind power to participate through encouraging the use of new technology and methods to analyze and incorporate the benefits of diversity of generation into the dispatch. However, we did not hear any significant complaints from non-utility generators about access to PJM and MISO SCED.

The Joint Board extensively discussed the efficient vs. economic dispatch issue and that discussion is reviewed in Section V above. The Joint Board believes that MISO's statement that the debate over efficient dispatch is "a false debate, a red herring based on some unknown confusion" may be a bit hyperbolic.[156] However, the Joint Board agrees that, if done properly, economic dispatch will take into account all of the relevant economic, security, and operational factors. Efficient dispatch, on the other hand, would take into account a more limited number of factors. Accordingly, it is our position that the debate over economic vs. efficient dispatch is resolved, at least for the time being, in favor of economic dispatch.

The Joint Board recognizes PJM and MISO for using a common vendor for their dispatch systems. We accept the RTOs' representation that the basic mathematical formulation of the SCED function is the same for both RTOs. The fact that the common vendor delivered systems to PJM and MISO developed on a common platform potentially reduces disjoints at the PJM/MISO seam. Sometimes differences in outcomes result from differences in software. In the case of the PJM/MISO region, that is less likely to be the case.

B. <u>SCED Benefits</u>

1. Quantifying the Costs and Benefits of SCED

- An ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining market participant and state regulator confidence in the RTOs. The RTOs should establish a clear benchmark to assess the degree to which the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition, are being captured.

The first question in a SCED cost/benefit analysis might be costs and benefits compared to what? We know that SCED has a long history and that system operators have always used some form of SCED. Therefore, it would be meaningless to compare RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED with no SCED. It may be more appropriate to compare RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED with utility-by-utility cost based SCED. However, the RTOs took a number of incremental steps toward RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED. For example, MISO operated as a transmission functional control-only RTO for several years before initiating market operations.

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[156] MISO Comments at 7.

Which step should be considered the starting point for cost/benefit analysis? The multitude of cost/benefit studies discussed in the Joint Board process are not consistent on this framework.

Another issue involves the granularity of the benefits. Is it enough to show aggregate net benefits without accounting for net winners and net losers? The multitude of cost/benefit studies discussed in the Joint Board process are not consistent on granularity.

Many state regulators noted the importance of credible studies that seek relevant information and use accurate data to assess the benefits and costs of SCED as conducted by PJM and MISO.[157] As of February 12, 2006, some state regulators expressed their concern that the cost/benefit analyses that were provided were not sufficient to definitively resolve the cost/benefit issue.[158]

We understand that some cost/benefit studies are still being conducted, particularly by MISO. We believe that an ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining stakeholder confidence in the RTOs.

We recommend that the benchmark against which the benefits of RTO-managed SCED are measured be carefully considered and explicitly specified. We are also interested in analyses that illustrate the degree to which PJM and MISO have captured the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition.

2. Effect of the RTO Spot Markets on Forward Bilateral Contracting

- Appropriate efforts should be made to acquire necessary data to assess the impact of the SCED conducted by PJM and MISO on market participant forward bilateral contracting.

The importance of forward bilateral contracts as a method to reduce price risk for both suppliers and consumers has been well-documented in academic circles.[159]

Evidence presented to the Joint Board about the effect of the RTOs' spot energy markets on forward bilateral contracting appears to be in conflict, with one witness suggesting shrinkage in forward bilateral contracting and another suggesting that spot markets facilitate forward bilateral contracting.

Because of the importance of forward contracting and the apparent inconsistency of the two statements of the Joint Board witnesses, the Joint Board asked PJM and MISO a data request about the impact of their day-ahead and real-time energy markets on the willingness of market participants to bilaterally forward contract. In response, PJM stated in part that, "PJM does not have access to data that would allow PJM to accurately measure the amount of energy settled in

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157 Questions from Chairman Davis, Commissioner Chappelle, Chairman Hardy and Commissioner Wefald answered by Mr. Harris and Mr. Torgerson on the studies used by PJM and MISO. See Nov. 21 Tr., at 76-85.

158 Feb. 12 Tr., at 38.

159 See, e.g., "Uniform-Price Auctions in Electricity Markets," Drs. Cramton and Stoft. This paper was provided to the Joint Board by PJM in response to Question #3 of the Joint Board March 8, 2006 data request. See, e.g., page 6 and 11 for a discussion of the importance of forward contracting.

our real-time market that has a forward hedging contract covering exposure to real-time prices."

Whether the SCED spot energy markets operated by PJM and MISO facilitate or hinder forward bilateral contracting is an important consideration in judging the value of such SCED spot markets. Accordingly, we believe efforts should be made to collect data relevant to this question.

3. Reliability

- While it is not necessarily under the RTOs' control, developing common reliability rules applicable across each RTO's region or, ideally, across the combined region, could promote more efficient SCED operations. The RTOs are encouraged to assess the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region and pursue such standardization if its benefits exceed the costs for customers.

MISO stated that, "Without SCED, the lights would go out, under any system. However, reliability can be enhanced if the dispatch is (1) regional, (2) open to all generators, and (3) efficiently priced so that spot prices are consistent with SCED."[160]

One commenter stated that "Reliability is driven by the ability of the transmission system operator to understand the limitations of the transmission network and model these limitations in the transmission security analysis process."[161] Another commenter urged eliminating the multiple sets of reliability rules for the RTOs and stated that adopting common reliability rules will allow more efficient operations.[162]

In principle, we agree with both of these commenters. The better the RTOs are able to understand the transmission system they are operating and the better they model transmission system limitations in their analytical processes, the more likely it is that they will be able to operate the system nearer to its physical optimum without risking reliability. The greater the need on the part of the RTO to understand and reflect in operations modeling different reliability rules promulgated by different reliability authorities for different parts of the RTO geography, the more difficult the RTOs' job becomes and the less likely they will be to obtain optimal operation of the system (while still providing reliable operations).

We note that FERC has adopted a set of Electric Reliability Organization (ERO) rules and that an ERO application was submitted to FERC on April 4, 2006.[163] That application addresses the proposed relationship between the regional reliability organizations and the ERO. We hope that due consideration will be given to the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region.

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160 MISO Comments at 11.

161 AEP Comments at 10.

162 Nov. 21 Tr., Mr. Naumann at 132.

163 See FERC Dkt. No. RR06-1-000.

C. SCED Scope

1. Common Market/Cross-Border Trading

- The RTOs' common market development effort should include proposals for improving SCED over the seam between PJM and MISO. As the RTOs consider any and all improvements in market and operations design and modifications to business practices, they should pursue such improvements with an eye to the effect of the change on the other RTO, and, ideally, develop all improvements jointly and in a cost-effective manner.

- With the Joint Operating Agreement, PJM and MISO developed a method for addressing transmission constraints in one RTO through redispatch by the other RTO when doing so is cost effective. MISO has suggested a way to improve this limited coordinated dispatch by exchanging preliminary dispatch results and associated prices, as well as information on constraints affecting the dispatch and prices. The RTOs are encouraged to further explore this idea of additional SCED coordination, taking cost-effectiveness into account.

The Joint Board agrees with Chairman Schriber that different operational rules and business practices between PJM and MISO have stifled transactions with neighboring utilities across these RTO borders.[164] We recognize that, in the common market docket, the RTOs are pursuing efforts to increase consistency between each other's approach on several operations and market elements. However, we agree with Chairman Schriber that this effort is not sufficiently comprehensive. As the RTOs consider any and all improvements in market and operations design and modifications to business practices, they should pursue such improvements with an eye to the effect of the change on the other RTO, and, ideally, develop all improvements jointly.

The Joint Board also notes that, in its response to the Joint Board's data request 6, MISO stated,

> Further coordination between the PJM and MISO dispatches is at least theoretically possible, and this further coordination could, in theory, produce a result that would, in effect, be equivalent to a combined, single dispatch for the combined systems. In other words, PJM would continue to dispatch the PJM system, and MISO would continue to dispatch the MISO system. However, when arranging their respective dispatches, the two RTOs would exchange preliminary dispatch results and associated prices, as well as information on constraints affecting the dispatch and prices. With this information being shared, each RTO would then run its dispatch and pricing models again, and achieve a revised dispatch and pricing result, which would in turn be shared with the other RTO. This approach is a possible alternative to more formal consolidation of the two dispatches, and does not present the kinds of dispatch expansion problems described above if either PJM or MISO (or some combined entity) were asked to dispatch the combined system.

The Joint Board would like to see this idea of additional dispatch coordination further explored.

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164 Chairman Schriber Letter at 2.

2. Geographic Scope of SCED

- The RTOs are encouraged to continue timely analyses of the cost and technical feasibility issues involved with expanding the geographic scope of SCED. The continued analyses should encompass the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. In addition, each RTO should analyze the cost and technical feasibility of expanding its geographic area to include areas not currently under RTO managed SCED, as requested by utilities that seek voluntary membership in the RTO. However, as always, actions to expand the geographic scope of PJM or MISO SCED should be cost effective and subject to relevant state law.

The Joint Board agrees with DOE that "the magnitude of the reliability and economic benefits realized from economic dispatch depends upon the size of the area that the integrated dispatch covers."[165] The Joint Board agrees with the DOE that a larger economic dispatch area "allows the dispatcher to take advantage of the load diversity across the area, to better allocate resources to load needs."[166] We note DOE's statement that, as an operational matter, "the larger RTOs report that the bigger the area that SCED covers, the more likely that operational limits can be respected with a solution that melds economics and reliability quickly and easily."[167] In addition, the larger the dispatch area is, the fewer are the seams between dispatch areas.

We acknowledge that PJM and MISO each currently cover a very broad geographic footprint. However, the question naturally arises of whether there are there further efficiencies that can be gained through the separate expansion of each of the RTOs or through the consolidation (in whole or in part) of their existing dispatch areas.

There are two practical factors that arise in considering this concept of SCED geographic scope. The first is the issue of cost. The second is the issue of technical feasibility. The Joint Board notes the RTOs' reference to the preliminary cost analysis that the RTOs conducted in Dkt No. ER04-375 on the question of forming a single dispatch across the combined PJM/MISO region. The Joint Board also notes the RTOs' commitment to studying that cost/benefit issue further and providing additional analysis in Dkt. No. ER04-375.

The Joint Board directly addressed the issue of technical feasibility through a data request question to the RTOs. Both RTOs responded that their existing systems could handle a 1,000 MW increase with no upgrades. Both RTOs responded that an increase of 50,000 MW of load and generation would require upgrades in computing capability and data storage capability. Both RTOs declined to speculate on the technological feasibility of managing increases in the magnitude of 100,000 to 150,000 MW without a more thorough technical evaluation.

Consequently, the question of the most cost effective geographic scope of SCED that is technically feasible is relevant, but has not yet been fully answered. The Joint Board encourages continued timely analysis of the cost and technical feasibility issues involved with expanding the

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165 DOE Report at 27.

166 DOE Report at 28.

167 DOE Report at 28.

geographic scope of SCED. The continued analysis should encompass the possibility of each RTO expanding by adding geographic area that is not currently under RTO-managed SCED as well as the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. The benefits would include increased load and generator diversity and we note Mr. Kruse's presentation that the set of resources available for dispatch in MISO has overall less diversity than does the resource set available for PJM dispatch.[168] However, as always, actions to expand the geographic scope of PJM or MISO SCED should be cost effective and would be subject to relevant state law.

D. Transmission Infrastructure

The Joint Board agrees with the DOE statement that SCED operation must take into account the "configuration of the existing transmission system."[169] We also agree with commenters like AEP who stated, "The key to optimizing the economic dispatch and maintaining reliability is a robust transmission network."[170] We also agree with Commissioner Nickolai's wry commentary that, although security constrained economic dispatch may be an efficient method of allocating scarce transmission resources, "if all we had was scarcity what we're going to see is prices that can just go up and up and up."[171] We agree with commenters who asserted that in order to get transmission built, long-term regional transmission planning, timely investment, and appropriate cost allocation are needed.

1. The Transmission Planning Process and Transmission Expansion Obligations

- Because adequate transmission infrastructure is important for the achievement of SCED's least-cost and reliability objectives, the RTOs should devote adequate resources and substantial management attention to the transmission expansion planning process.

- The RTOs are encouraged to bring to the attention of state regulators any situations in which transmission facilities found to be needed in the RTO expansion plan, are, nevertheless, not getting implemented in a timely manner.

- Provided that the RTO uses proper measures and a proper approach for inclusion of an economic transmission project (intended to address congestion issues) in its transmission expansion plan, the obligation on a transmission owner to exercise best efforts to implement such a project should be no different than its obligation to use best efforts to implement a baseline reliability project.

PJM and MISO each have a transmission expansion planning process. However, numerous parties are not satisfied with those processes. MISO even went so far as to admit that it needs to

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168 Nov. 21 Tr., Mr. Kruse at 115-116.

169 DOE Report at 46.

170 AEP Comments at 6.

171 Feb. 12 Tr., at 69.

improve its long-term transmission planning and procedures.[172]

Transmission planning and expansion are keys to pulling our respective geographic areas together—improving the operation of RTO-managed SCED, and facilitating a robust competitive electricity market. We recognize that, although the RTOs have already produced several transmission expansion plans, the concept of regional planning (especially in the MISO area which did not form around an existing power pool) is still relatively new. While local area planning cannot be abandoned, the benefits of effective wide-area, RTO-managed, transmission planning are significant. RTO-managed planning must be regional, independent, transparent, and participatory. It must also be continually improving.

We recognize that PJM and MISO strive to improve their planning processes with each subsequent transmission expansion plan that they produce. We also recognize that MISO recently made some formal changes to the transmission planning part of its tariff as a result of its regional expansion criteria and benefits ("RECB") task force effort and that PJM is considering improvements to its planning process through its regional planning process working group ("RPPWG"). The Joint Board commends the RTOs for undertaking those efforts and urges them to continue to devote adequate resources and substantial management attention to the transmission expansion planning process.

Similarly, the planning horizon must extend far enough into the future to provide market participants as much information as possible about future scenarios and risks. The RTOs have the needed geographic scope and range of information and analytical tools to be particularly well-suited to do this. We understand both RTOs to be currently examining such issues.

We generally understand that, once a transmission project meets the relevant RTO criteria and is placed into the RTO's expansion plan, the relevant transmission owning utility generally has an obligation to exert best efforts to see the project through siting and construction to operation. However, "best efforts" is a squishy concept, particularly in the case of a utility that might not find the RTO's identified transmission expansion solution to be in the particular utility's (or holding company's) best economic interest. We would hope that the RTOs would bring such circumstances, if they ever occur, to the attention of relevant state regulators, or to the Organization of PJM States, Inc. ("OPSI") and Organization of MISO States ("OMS") regional state committees, in a timely manner.

We also understand that there is some question about whether transmission owning utility obligations to undertake so-called economic transmission expansion projects (those aimed at cost effectively relieving transmission congestion) that the RTO finds necessary and includes in its transmission expansion plan are as strong as the obligations that apply to so-called baseline reliability projects. Commissioner Nickolai stated that, "we need to write a piece here that needs to make clear that it's going to take something enforceable in order to make sure that utilities are bringing additional resources to the table to keep those markets viable as the demand increases."[173] With respect to transmission, we agree. Provided that the RTO uses proper measures and a proper

[172] Nov. 21 Tr., Mr. Torgerson at 98.

[173] Feb 12 Tr., Commissioner Nickolai at 70.

approach to inclusion of a project in its transmission expansion plan, the obligation to undertake an economic project should be no different than the obligation to undertake a reliability project.

2. Transmission Cost Allocation

- The RTOs are encouraged to continually improve their analytical modeling and forecasting capability to better assess beneficiaries of transmission expansion so as to improve transmission cost allocation.

Both RTOs have transmission cost allocation policies in their tariffs. Both RTOs are working on improving their cost allocation policies. Yet there is still dissatisfaction about the state of affairs with respect to transmission cost allocation.

The Joint Board recognizes that transmission cost allocation is a contentious and difficult subject. Nevertheless, improper cost allocation constitutes a barrier to the development of cost-effective transmission expansion and perpetuates less-than-optimal SCED. This is particularly the case with respect to so-called economic transmission expansion. Much of the controversy in transmission cost allocation derives from the imperfect ability to accurately model future unknowns. While complex, current beneficiaries of transmission expansion can often be identified. However, transmission lines have long lives and beneficiaries can and probably will change over time and in unforeseeable ways. The Joint Board acknowledges these difficulties, but encourages the RTOs to continually improve their analytical modeling and forecasting capabilities so as to reduce the range of foreseeable uncertainty scenarios.

3. Joint PJM/MISO Transmission Planning

- The RTOs are encouraged to devote adequate resources and substantial management attention to joint transmission planning and expansion processes so as to pull our respective geographic areas together, improve the operation of RTO-managed SCED, and facilitate a robust competitive electricity market.

Some parties commented that PJM and MISO's long-term planning needs to be coordinated and done jointly to ensure an adequate transmission grid to optimize the ability of SCED in LMP markets.[174] We understand that PJM and MISO have a joint planning process in place under the JOA and that the RTOs are proceeding with initial efforts to conduct a joint plan.

Given the interwoven nature of the boundary between PJM and MISO, joint transmission planning is critical. For example, it was also suggested that joint and common planning is needed to help address the loop flows that the dispatch of one system creates on the other.[175]

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[174] Joint State Commission Comments at 10, WPSRC Comments at 2 and 6, Chairman Schriber Letter at 3, Nov. 21 Tr., Mr. Torgerson at 98-99, Mr. Tatum at 144 and Mr. Welch at 152.

[175] AEP Comments at 9 and Chairman Schriber Letter at 2-3 (loop flows can produce congestion on the neighboring system, requiring more uneconomic (out of merit order) dispatch to overcome the loop flow effects, e.g., the Lake Erie loop flow.).

The most effective transmission expansion project to address a reliability or economic issue in one RTO may be in the other RTO. Similarly, cross-boundary solutions to problems should get no less consideration in the planning process than within-RTO solutions.

We understand that inter-RTO transmission planning and expansion are new concepts. Nevertheless, their importance is significant. We hope and trust that the RTOs' joint planning and expansion processes will receive the needed attention and resources that they deserve so as to pull our respective geographic areas together, to improve the operation of RTO-managed SCED, and to facilitate a robust competitive electricity market.

E. RTO Independence

- RTO independence is critical for the RTOs' ongoing credibility. Accordingly, PJM and MISO are encouraged to continue to strive for independence as a bedrock principle. Both state and federal regulators have a role in the oversight of RTO independence.

At the February 12 meeting, Commissioner Nickolai suggested that the Joint Board "review the governance of the RTOs to help assure that they truly are independent, to the extent that we can make them independent operators of the markets and the grid."[176] He raised a question about "the extent to which they are [in]dependent actors versus the extent to which they feel that they must be agents of their members and transmission owners."[177] He stated that the assurance of independence is an important foundation for "confidence that the grid and the markets are going to be operated in a manner fully consistent with the goal of maximizing the economic benefit to the public."[178]

We agree with Commissioner Nickolai that RTO independence is a critical foundation for supporting stakeholder confidence in the RTOs' markets and operations, including SCED. To assure their long-term effectiveness and credibility, the RTOs must be careful not become an advocate for any one position or sector. They instead need to be neutral operators of the market and an impartial information resource to all.

Transmission revenues, which are determined at least partly by the RTOs' SCED operations, are paid by customers in the RTO region. MISO's fiduciary obligation to maximize transmission revenues, for example, may, at least partly, affect MISO's SCED operations and customer costs. PJM may have similar issues. We stress that no evidence was presented in the Joint Board process to call PJM's or MISO's independence into question. However, we believe that ongoing oversight of RTO independence is prudent.

176 Feb. 12 Tr., at 68.

177 Feb. 12 Tr., at 68.

178 Feb. 12 Tr., at 68.

F. Market-Based SCED

1. Market Monitoring

- Some state regulators do not believe that they currently have sufficient access to the data needed to evaluate and oversee the RTOs' operation of market-based SCED. The RTOs' policies for limited state regulator access to data should be revisited.

The Joint Board examined the single clearing price SCED auction vs. the pay-as-bid approach. In particular, we found value in the Cramton/Stoft paper that PJM provided. This issue should not be forgotten because the soundness of the single clearing price approach depends directly on the competitive behavior of the marginal bidder. Market conditions and market participant behavior in a market-based SCED require constant regulatory oversight. However, for the purposes of this report, and subject to the discussion below, the Joint Board is satisfied with the RTOs' response to our data request concerning the single clearing price SCED auction vs. the pay-as-bid approach.

The Joint Board extensively considered the bid-based vs. cost-based approach to SCED.[179] Each of these methods has merits and shortcomings. As the RTOs explained in their response to the Joint Board's data request, the cost-based approach requires extensive administrative oversight and constantly risks being out-of-date. On the other hand, the bid-based approach leads naturally to offers at marginal cost (the most efficient outcome) provided that sufficient competitive pressures exist in the market. Accordingly, under bid-based SCED, vigilance must be maintained by the RTOs' Market Monitoring Units, state regulators, and federal regulators on monitoring the level of competitive pressure in the market.

Similarly, the reasonableness of using the single clearing price auction approach, rather than a pay-as-bid approach, to clearing the real-time market and operating SCED depends directly on the assumption that the marginal unit in any particular dispatch interval is acting competitively and bidding at its marginal cost.

If the competitive market assumption or the competitive behavior assumption is false, and market power mitigation is not imposed, then SCED, as managed by PJM and MISO, may not produce optimal (e.g., least-cost) results within or outside a zone of reasonableness.

PJM's response to the Joint Board's March 8 data request Question 2 stated that "It is reasonable to seek to assess the competitiveness of wholesale power markets in PJM." PJM goes on to state, "That is the primary focus of the PJM Market Monitoring Unit (MMU)." PJM is off-the-mark, however, if it is suggesting that we should be satisfied that the PJM MMU (and its counter-part for MISO) is focused on the competitiveness of wholesale power markets, and that there is no need for Joint Board member agencies to be concerned about this critical issue. Given our charge to ensure the "best possible outcomes for consumers," the acceptability of continuing RTO-managed bid-based SCED

[179] We note that both PJM and MISO initially used cost based approaches before evolving to a bid-based approach.

depends directly on the competitiveness of the market and the exercise of competitive behavior by the marginal resources. State regulators have a vital role in market monitoring and must have the ability to conduct critical analyses and oversight of RTO markets along with the RTOs or the RTOs' market monitoring units.

Accordingly, state regulators must have access to the data and information necessary for us to confirm the competitiveness of the RTOs' market outcomes and the competitiveness of market behavior. There is no other way for us to achieve the level of confidence that is needed for sustained support of RTO-managed bid-based dispatch. Some state regulators believe that the RTOs have not been sufficiently forthcoming with the data needed by state regulators and the RTOs' policies for limited state regulator access to data need to be revisited.

Monitoring data regarding market behavior and market outcomes in a timely manner is important for identifying potentially anticompetitive market behavior, which could adversely affect the affordability and reliability of service from the RTOs' SCED operations. Monitoring such data in a timely manner is also important for other policy and technical decisions, such as states' decisions regarding expansion of generation, demand-response, and transmission resources, that also influence the affordability and reliability of service from the RTOs' SCED operations.

2. Marginal vs. Average Losses in the Dispatch

- When determining their respective dispatches, MISO uses marginal losses and PJM uses average losses. The material presented to the Joint Board shows that, while there may be implementation issues to resolve, using marginal losses improves dispatch efficiency. Accordingly, the issues associated with losses as they apply to PJM and MISO SCED should be analyzed and appropriately resolved.

The Joint Board notes that MISO uses marginal losses in its dispatch but PJM uses average losses. The Joint Board notes that on May 1, 2006, FERC issued an Order in Dkt. No. EL06-55 requiring PJM to implement a locational marginal loss method for allocating transmission line losses by September 2006. According to PJM, it may not be able to implement marginal losses in this time frame, and may request an extension within which to comply with the Order.

Given that at least temporarily PJM and MISO will be operating on different dispatch methodologies, the Joint Board explored the marginal and average losses dispatch topic through a data request. Both RTOs agree that, "The marginal loss approach is more efficient because it tends to minimize system losses as part of the dispatch algorithm which in turn minimizes to overall cost to serve load." Both RTOs also agreed that, "while marginal loss implementation does increase market efficiency, certain practical implementation issues do exist with the marginal loss approach." The RTOs state that, "These issues are not insurmountable but their resolution has created implementation complexities in RTOs where marginal losses have been implemented." Finally the RTOs state that,

> The PJM/MISO market to market coordination process has worked well in

providing coordinated transmission congestion management between the PJM and MISO markets. Therefore, PJM does not believe the difference in the loss models between the RTOs has adversely impacted interregional transmission congestion coordination. However the difference in the transmission loss pricing may have a small impact on price convergence between the markets. Since marginal loss pricing is a relatively small impact compared to congestion pricing, the impact is limited.

The Joint Board recognizes that the efficiency gains available from uniform use of marginal losses across PJM and MISO may be small compared to the efficiency gains achieved through the adoption of LMP congestion pricing. However, that is not the point. Consistent with our charge to ensure that the "best possible outcomes for customers" are achieved, we believe that the issues associated with losses as they apply to PJM and MISO SCED should be analyzed and appropriately resolved.

3. Ancillary Services/Multiple MISO Control Areas

- The operation of SCED must take transmission ancillary services into account. PJM and MISO have distinctly different methods of treating ancillary services. There are potentially significant efficiencies to be gained through improved co-optimization of ancillary services and energy in the dispatch and PJM and MISO are encouraged to continue to strive to improve on efficiencies gained in the area of ancillary services.

SCED must take into account ancillary services such as downward-and-upward regulating margin requirements of the system and operating reserves.

PJM and MISO have distinctly different methods of treating ancillary services. PJM operates markets for both regulation and operating reserves and co-optimizes these ancillary services with energy to improve the assignment of the more cost-effective resources throughout the market.

MISO currently does not centrally dispatch the Regulation or Spinning Reserve services. Rather, each individual Balancing Authority is responsible for assigning the required amount of Regulation and Spinning Reserve within its area, and directing the deployment of those services based on its individual ACE. The individual Regulation and Spinning Reserve assignments made by the individual Balancing Authorities are communicated back to the MISO control center for inclusion in the UDS economic dispatch solutions. The Joint Board notes that on April 3, 2006, in Dkt. No. ER04-691-000, MISO submitted an informational filing to FERC regarding the centralization of some control area functions. The Joint Board also notes that consideration of ancillary services market issues is underway in the MISO stakeholder process.

G. Demand-Side Response

- The PJM and MISO markets must develop more ways for demand response to participate in the dispatch. Improvement in demand response opportunities is not just an RTO responsibility. The Joint Board encourages PJM and MISO to work with state regulators and policy-makers to improve SCED by improving cost effective demand responsiveness to price.

Most of the electricity demand enters into the SCED algorithm as non-price responsive must-serve "load." It is treated as load that must be served and energy that must be provided regardless of price, taking into account the practical limits of the system.[180] Such large levels of non-price responsive demand provide conditions precedent for volatile spot prices.

Cramton and Stoft describe a normal two-sided, single clearing price auction as follows:

> Buyers with bids at or above the clearing price pay the clearing price for the quantity purchased. Suppliers with offers at or below the clearing price are paid the clearing price for the quantity sold.[181]

This market design works best with adequate levels of price responsive demand.

There was general consensus among participants in the Joint Board and commenters that the PJM and MISO markets must develop more ways for demand response to participate in the dispatch.[182] Demand response capability increases the efficiency of SCED by increasing dispatch flexibility and resource diversity. Increasing demand response is not just the RTOs' responsibility. It will require the full participation of state policy makers and industry participants as well. However, the RTOs are in a unique position to assist due to their role in centralized transmission control and regional market operation. Therefore, we urge the RTOs to work with state regulators and policy-makers to improve SCED by improving demand responsiveness to price.

VI. CONCLUSION

In crafting the recommendations above, we were guided by our Joint Board Chairman, Commissioner Brownell, to strive for ways to ensure that SCED will enhance the reliability and affordability of service and produce the "best possible outcomes for customers."[183] We believe our recommendations reflect that focus and respond directly to Congress's invitation for us to develop recommendations on SCED that will enhance "the reliability and affordability of service to customers in the region."[184] If improved benefits of the PJM and MISO organized markets are going to be realized, the RTOs and regulators must remain vigilant in exploring and implementing cost-effective improvements in the RTOs' SCED operations.

We acknowledge that implementation of some or all of these recommendations cannot proceed without the development of stakeholder consensus. We further realize that time may be needed

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[180] Hence, the importance of accurate load forecasting as noted in the DOE Report at 51.

[181] "Uniform-Price Auctions in Electricity Markets" at 2.

[182] Nov. 21 Tr., Mr. Torgerson at 98, Mr. Harris at 54 (PJM has seen benefits of demand response) and 104, and Mr. Kruk at 149.

[183] Feb. 12 Tr., at 72.

[184] Pub. L. No. 109-58, § 1298, 119 Stat. 594, ___ (2005).

to conduct more detailed studies (including cost/benefit analyses) and to build the needed consensus. Finally, we believe that implementation of each of these recommendations should be contingent on a showing of cost effectiveness. Nevertheless, we believe that these recommendations form an agenda for RTO management to pursue. Just as market improvements are not implemented without careful planning and broad support, we expect that none of these recommendations will be dropped without the same kind of planning and public consideration.

At the February 12 Joint Board meeting, Commissioner Brownell referred to the Joint Board process as the "beginning of a model that I hope will be continued to resolve issues that are thorny and difficult, but because of the shared nature of our jurisdiction, I think it will be increasingly important to use forums like this to address issues that are regional, but obviously have state implications."[185] We hope so too. We look forward to seeing the current SCED Joint Board process through to fruition and also look forward to working together with our FERC colleagues on further joint board endeavors.

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[185] Feb. 12 Tr., at 3.

Attachment A

Dissenting and Concurring Comments of the Indiana Utility Regulatory Commission to the Joint Board Report

SECURITY CONSTRAINED ECONOMIC DISPATCH

The Indiana Utility Regulatory Commission ("IURC") concurs with the Joint Board's discussion and conclusion on the *process* of Security Constrained Economic Dispatch ("SCED") that was the charge to the FERC – State Joint Board from Congress pursuant to the Energy Policy Act of 2005 (EPAct05).[186] Nonetheless, the Report's excursions from this specific charge create unintended and unfortunate misapprehensions in the readers mind.

A. THE REPORT EXCEEDS THE SCOPE REQUESTED BY CONGRESS AND THEREBY DEPRIVES PARTIES OF DUE PROCESS

The IURC believes that this Report by the Joint-Board exceeds the scope envisioned by Congress. The IURC is, therefore, concerned that stakeholders and state commissions that provided information to the Joint Board responsive to the narrow scope were unfairly deprived of providing information on the more expansive scope contained in the Joint Board Report.[187] As a

[186] Specifically, the FERC Order establishing the Joint Board said that each Joint Board is authorized to:
(1) "consider issues relevant to what constitutes 'security constrained dispatch'";
(2) "consider how such a mode of operating an electric system affects or enhances the reliability and affordability of service to customers in the region concerned"; and
(3) "make recommendations to the Commission regarding such issues."

The DOE was tasked with working with States to:
(1) study the procedures currently used by electric utilities to perform economic dispatch;
(2) identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch; and
(3) analyze the potential benefits to state and national residential, commercial, and industrial electricity consumers of revising economic dispatch procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

[187] By way of additional examples of Recommendations that were extra topical contained in the Joint Board Report, some states believed that the FERC Orders limiting state commission access to confidential information from the PJM, the Midwest ISO, and the Midwest ISO's Independent Market Monitor should be revisited. Some states wanted to stress the importance of the independence of the governing structures of the RTOs. The IURC is not aware that any party questioned the importance of independent governance. Rather, there was considerable comment by Independent Power Producers – the area of primary interest to the Department of Energy - that complimented the independence of the RTO governance from market participants in contrast to discriminatory terms and conditions offered by individual utilities in regions not served by RTOs. One of the Recommendations noted correctly that some matters are outside their control but still charged the RTOs to apparently consider actions beyond their authority.

> *While it is not necessarily under the RTOs' control, developing common reliability rules applicable across each RTO's region or, ideally, across the combined region, could promote more efficient SCED operations. The RTOs are encouraged to assess the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region and pursue them if they exceed the costs.*

result, the "Recommendations" that were contained in the Report were not as well-informed as they could have been had the enlarged scope of the Joint Board discussions been appropriately noticed.

Specifically, the IURC understood the charge by Congress to address the *process* of security constrained economic dispatch. Some topics, such as the Recommendation for RTOs to offer additional demand response, while improving the *outcomes* of SCED, are extra topical because the fundamental processes of the dispatch would not change with additional demand-response. Moreover, despite the Recommendation in the Joint Board's Report that RTOs offer more demand-response programs, it is unclear what unilateral action RTOs would be encouraged to take since some states regard demand response to be state jurisdictional.

B. RECOMMENDATIONS WERE NOT SUBJECTED TO VOTES OF THE JOINT BOARD

Because stakeholders and state commissions could not have reasonably anticipated the more expansive scope of the Joint Board discussions, it would be difficult for the Congress to assess the weight that should be accorded to the Recommendations in the Report. Moreover, because no votes were taken on the Recommendations nor was there any discussion of prioritization of the Recommendations it is impossible for Congress to assess the appropriate weight of any of the Recommendations. The IURC is concerned that, by characterizing the comments in the Joint Board's report as "Recommendations," each of the Recommendations may be inappropriately thought to carry the imprimatur of each state.

C. THE INTEREST IN A MORE EXPANSIVE LIST OF ISSUES WARRANTS FURTHER STATE – FEDERAL DIALOGUE

For those topics that were discussed by one or more participants that were extra topical but included as Recommendations, the IURC would prefer that those topics be the subject of further FERC -State Joint Board discussions. The limited amount of time for discussions was not sufficient for a full airing of the SCED issues that were the charge of the Congress and certainly not enough to address all of the issues contained in the Joint Board Report. The IURC is, therefore, concerned that the Joint Board Report trivializes important issues such as the on-going need for RTOs to quantify costs and, where possible, the benefits of RTO facilitated markets. Further discussions would allow all state commissions and stakeholders to have a more complete discussion of these important issues.

The IURC understands the desire of some state commissions to use this Report to inform Congress on a variety of issues that were not specifically the charge to the Joint Board. The IURC, while concurring that providing Congress with important information is good public policy, believes such information would be improved by having further Joint Board discussions on matters that are critical to the Federal Energy Regulatory Commission, state commissions, and stakeholders.

D. THE RECOMMENDATIONS MAY LEAVE AN ERRONEOUS IMPRESSION THAT IMPORTANT ISSUES ARE NOT BEING ADDRESSED AND THEREBY MINIMIZING THE COMPLEXITY AND CONTROVERSIES

The IURC is concerned that some of the Recommendations may give Congress the impression that state commissions, stakeholders, the Midwest ISO and the PJM are not seriously addressing critical issues. By way of examples, the Recommendations include pricing of economic and reliability transmission projects. The Report makes no mention that these matters have been and are being addressed by the Midwest ISO, the PJM, stakeholders, and state commissions. As importantly, the Joint Board's Report makes no mention that these topics have proven to be very controversial and complex.

The IURC does not believe it is sufficient to allege that the RTOs are not devoting enough resources to a specific issue. Rather, it is incumbent upon the Joint Board to offer substantive suggestions and, ideally, to explicitly acknowledge that state commissions have a commensurate obligation to dedicate resources. The lack of substantive suggestions contained in the Report is indicative of the complexity of the issues. The IURC does not believe that the public interest is well-served by the vague suggestions that more attention needs to be given to these topics.

E. THE REPORT DOES NOT ADEQUATELY EMPHASIZE THE NEED FOR COST-EFFECTIVENESS AND ACHIEVING NET BENEFITS

The IURC is concerned that Congress may be left with the impression that the Joint Board is not concerned that the enhancements contained in the Recommendations provide net benefits to wholesale markets and, ultimately, to consumers.

The IURC, because its utilities are in two Regional Transmission Organizations, has a deep interest in the efficient development of the PJM and Midwest ISO Joint and Common Market. The IURC, however, believes that the evolution to a Joint and Common Market should be cost-effective. As part of this evolutionary process, the IURC agrees with the Joint Board that both RTOs ought to consider the ramifications of adding different functions so that they are compatible with the functions of the other RTO but the IURC is satisfied that price convergence between PJM's and the Midwest ISO's facilitated markets are sufficient indicia that the markets are largely operating as if they were a single market. Therefore, until such time as the technical feasibility is achievable and the net benefits warrant a single dispatch (or other identical functions) the on-going evolution is appropriate.

CONCLUSION

The Joint Board's Report does an excellent job of addressing the issues that the Congress asked the Joint Board to address regarding SCED. However, despite the best intentions of the authors to provide a wide-sweep of information to the Congress, because the Report addresses matters outside of the scope of the EPAct05 without sufficient input by experts or vetting by members of the Joint Board, the Report risks minimizing the importance of a number of critical issues. The several topics and Recommendations that were beyond the scope of the charge to this Joint Board would, more appropriately, be topics for future FERC – State Board dialogue. The IURC is concerned that such issues as the on-going need for RTOs to quantify costs and benefits or for RTOs to demonstrate that additional RTO functions provide net benefits for the reliability and economic efficiency of the wholesale market and, ultimately, retail customers, were not adequately considered. The lack of full consideration of all the issues contained in the Report can not, therefore, be construed as foundations for the Recommendations or for reasoned conclusions.

Attachment B

Dissenting Comments of Montana Commissioner Greg Jergeson to the Joint Board Report, Docket No. AD05-13-000

Like motherhood and apple pie, no one can oppose Security Constrained Economic Dispatch (SCED) of electricity. That is particularly the case if one assumes that the economic dispatch of electricity will yield the lowest possible cost of electricity for the consumer, even considering the security constraint aspects of SCED.

Just as the recipe ultimately determines whether the apple pie is edible, the recipe will determine whether SCED is palatable. In my considered judgment, the recipe for SCED articulated and implied in the document submitted by the PJM/MISO Joint Board does not result in a palatable public policy outcome. Before members of Congress issue ringing press releases that the Joint Board document heralds a new day of reasonably priced electricity for the consumer, they should carefully review and consider the details in the document before they succumb to the inevitable hype.

When this joint board process began, I mistakenly assumed that the definition of SCED as presented in EPAct 2005 was meant to achieve economic benefits for the consumer, i.e. the lowest possible cost electricity. However, the further explanation of the definition contained in the April 28 Joint Board draft, disabused me of that notion. *"The definition of SCED is, such that it takes, as a premise, that SCED will result in the production of energy "at the lowest cost" and that consumers will be "reliably" served."* (emphasis added) I interpret that language to confine consumer benefits to reliability. The economic benefits will accrue to the commercial players in the industry.

That the regime outlined in the Joint Board document will yield 'reliability" benefits to the consumer is, at best, arguable. We're talking about grafting an enormously complex economic management system (SCED and RTOs) on an already complex physical system, the grid. Just look at the hundreds, perhaps thousands of pages in the tariffs that MISO and PJM have filed with, and that have been approved by FERC. Consider that the regime outlined in the Joint Board document will inevitably require hundreds and thousands more pages of tariffs. At some point, the rule that the more complex a system is, the more vulnerable it is to failure applies. From my former life as a farmer, it is not with a whole lot of fondness that I remember the occasions when the failure of a $3.98 bearing hidden behind $15,000 worth of iron, steel, rubber and plastic brought the entire $100,000 machine to a grinding halt.

My suspicions that the economic benefits of SCED are reserved for the commercial interests in the electricity sector, not the consumers, was most aroused by the Joint Board document discussions relating to "Single Clearing Price vs. Pay-as Bid Approach which occur in several places in the document. The document clearly comes down on the side of "Single Clearing Price" wherein all sellers will receive the highest clearing price that fills the load even if they have bid in at a lower price. The buyers (ultimately the consumers) will pay that higher price for all load purchased. To find economic benefit for consumers, i.e. lower prices, in this scenario requires real Orwellian logic. The document discussion goes on to pooh-pooh Pay-As-Bid as too given to game playing in the bidding process by generators and, thus would require (gasp!) too much government regulation to work.

Though I have received numerous assurances that there is no intention to dismantle the vertically integrated, state regulated utilities in those states where that continues to be the model, I fear the virulence of the anti-regulation arguments contained in the Joint Board document will appear as a license for some to attempt the federal imposition of electricity deregulation on those states who have retained the traditional, regulatory model.

I appreciate and applaud the purpose of the market monitor to protect consumers against illegal, anti-competitive, and monopolistic manipulations of the market. However, I fear the task of the market monitor is akin to the challenge facing those charged with stamping out the use of performance enhancing drugs in athletics. Just as the screens are developed to detect the current generation of those drugs, enterprising souls develop a new generation of drugs that are not detected by the latest available screens. And so the cycle goes on.

I have not, in this dissent, attempted a line-by-line critique of the joint board document. That choice is based on my view that the entire paradigm indicated in the document is flawed, and that the document itself will continue to be a moving target up until the very minute it is submitted to the FERC.

Therefore, I respectfully dissent from the document submitted by the PJM/MISO joint board.

Greg Jergeson
Montana Public Service Commission
District 1

Attachment C

Concurring Comments of Joint Board Virginia Representative Howard M. Spinner to the Joint Board Report

Docket No. AD05-13-000

Introduction

By order of September 30, 2005, the Federal Energy Regulatory Commission ("FERC" or "Commission") opened this docket and formed joint federal state boards to, on a regional basis, study "security constrained economic dispatch." FERC Chairman Kelliher set an early May, 2006 date for the submittal of this Joint Board's report to the Commission. These comments specifically address the Bid-Based vs. Cost-Based SCED issue and the Total Revenue Recovered by Generators Through the RTOs' LMP-Based SCED Compared to Aggregate Generator Production Cost issue as set forth in the Board's report. These comments support the position that central issues raised in these two sections are left unanswered due to the complete yet understandable lack of any rigorous analysis undertaken by the Joint Board in this proceeding.

It is certainly understandable that, given the time frame allotted for this Joint Board's work, new, independent and meaningful *quantitative* analysis was not possible. Nevertheless, this lack of analysis necessarily prevents this Board from drawing any conclusions regarding the issues identified in the preceding paragraph. Furthermore, RTO assertions that their operations produce the best possible short-run and long-run outcomes for consumers are nothing more than assertions that have not been verified by independent analysis.

Background

In convening this Joint Board, the FERC acted pursuant to section 1298 of the EPACT of 2005. The MISO/PJM Joint Board is authorized to consider issues relevant to what constitutes "security constrained economic dispatch," how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned, and to make recommendations to the Commission regarding such issues.

For purposes of this proceeding, the FERC has adopted the definition of economic dispatch provided in section 1234(b) of the Energy Policy Act of 2005 as the definition of "security constrained economic dispatch," *i.e.*, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

The position set forth in these comments is that, due to the absence of performance of any independent analysis or the submission of any data by any party or stakeholder, it is impossible for this Joint Board to answer perhaps the most important question placed before it by Congress. That question derives from the EPACT's charge to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned." This key question can be restated simply as "does the current operation of the electric system in the MISO/PJM 'footprint' produce required electrical output in a least-cost manner given the current stock (inventory) of generation and transmission assets?"

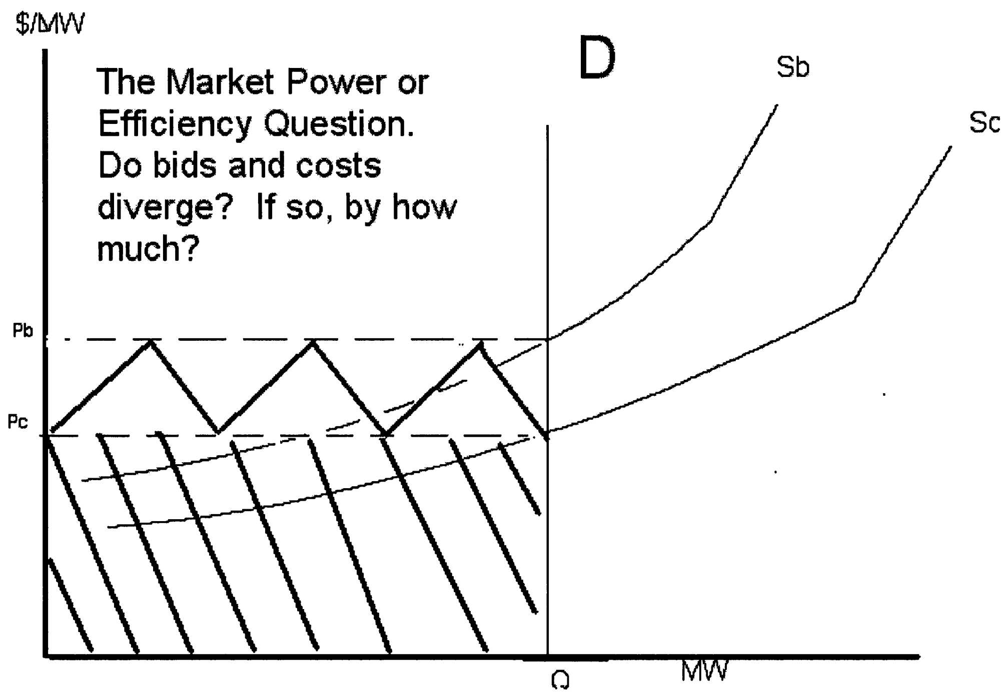
Most relevant to the Board's inquiry is the issue of the cost of electric service ultimately paid by consumers. One important factor that should influence this key metric is the actual resource cost expended to produce a given quantity of electrical output. A concern stated by at least some Joint Board members is that wholesale electric prices may inappropriately diverge from production resource costs. Some members worry that this divergence may ultimately drive up retail electricity prices.

Below these comments address the "bid vs. cost" and the "generator net revenue" issues in turn. The bid vs. cost issue is an efficiency issue. The generator net revenue issue is a fairness or equity issue. Efficiency and fairness issues are related in that if the dispatch is inefficient, that inefficient dispatch can exacerbate unfair market results. For example, if the exercise of market power changes the competitive bid-based dispatch from what would otherwise have been a least (resource cost) dispatch, the bid-based dispatch is inefficient. If this bid-based dispatch causes much higher market clearing prices, some might consider this result unfair as well.

The Issue of Bids vs. Costs. --- The Efficiency Question

During the Board's proceeding, most, but not all of those forwarding comments to the MISO/PJM Joint Board have assumed that MISO/PJM competitive electricity markets function well and that resulting wholesale electricity prices in these markets do not significantly vary from the actual resource cost of electricity production. In other words, generation unit specific offers to sell electricity in these wholesale markets reasonably approximate unit specific short-run marginal cost. As such, it is assumed that the exercise of market power does not adversely impact market outcomes. However, some Joint Board members and stakeholders are not yet ready to make such an assumption regarding the functioning of organized electricity markets absent a rigorous demonstration that the wholesale market operates in a reasonably competitive manner.

The issue boils down to a comparison of bid-based dispatch as currently practiced in competitive organized markets to the dispatch that would have prevailed under the prior regime of cost-based dispatch. Since it is very hard to know what the cost-based dispatch would have been absent industry restructuring, a reasonable starting point for rigorous analysis is a quantification of the cost of the current dispatch based on the best available cost data possessed by the RTOs. Thus, bid-based and cost-based dispatch could be compared. Consider the following diagram:



Here, under a single price auction regime where all generators offer to sell electric energy at marginal cost, customers would pay the lower cross-hatched area (Pc*Q) for energy during the period being examined. Although not explicitly shown on the graph, under cost-of-service regulation, customers would be responsible for paying for energy for this period as determined by the area under the supply curve Sc. Under bid-based competition as currently practiced in organized wholesale electricity markets, customers additionally pay the upper cross-hatched area; the total energy bill for the period under bid-based competition is given by Pb*Q.

The comparison of these alternative payment responsibilities for electric energy is a meaningful exercise. This is true even though, under both pre and post restructuring regimes governing the provision of electric service, other long-run and short-run costs need to be accounted for. The point is that before one forms an opinion regarding the appropriateness of market outcomes, one should have --- as a starting point --- a good handle on the relative sizes of the areas described above and shown in the graph. Unfortunately, up to this point in this proceeding, the RTOs have not provided the data necessary for independent entities to conduct such analysis.

Given any short-run supply curve for electric energy, we would expect the bid-based supply curve to be found up and to the left of the cost-based supply curve. For any given supply curve, movement up and to the left is bad for consumers; it means higher prices for any given level of demand. On the other hand, moving the supply curve out and to the right is good for consumers; it lowers prices, all else held constant. The exercise of market power moves the supply curve up and to the left (the bad direction) while the pressures of a truly competitive market move the supply curve out and to the right (the good direction). The simple question here --- the essence of the bid vs. cost issue --- is which force dominates? Market power or competitive pressure? Where does the supply curve lie relative to where it would have lain in the absence of restructuring. These comments support the proposition that this crucial question is, unfortunately, left unanswered by this Joint Board.

In their paper[188] Uniform Price Auctions in Electricity Markets, Peter Cramton and Steven Stoft clearly state that "Marginal cost bidding has the further benefit of efficient dispatch. Energy is supplied by the least-cost units." The authors go on to explain that "Real markets are not perfectly competitive," and that the profit maximizing behavior of real generators in today's competitive, bid-based RTO administered markets leads to bidding strategies that necessarily deviate from those under perfect competition. The question that the authors do not answer is how those deviations affect market outcomes. The last paragraph of the paper speaks for itself:

> The theory of bidding in uniform-price auctions under conditions of imperfect competition has been developed extensively in the economic literature (Ausubel and Cramton 2002, Klemperer and Meyer 1989). In this theory, each supplier submits a bid function to maximize its profits given its marginal cost curve, its expectations about market demand, and its expectations of the supply curves of the other bidders. The theory has several important implications: (1) so long as there is some probability that the supplier's bid may affect the clearing price, the profit maximizing bid curve exceeds its marginal cost curve; (2) the spread between its optimal bid and marginal cost increases with the quantity that the bidder is supplying; (3) the spread between its optimal bid and marginal cost increases the less responsive the supply of the other bidders is to price; (4) the greater incentive for larger bidders to inflate bids above marginal cost implies a short-run inefficiency—too little of the market is served by the largest bidders; and (5) forward contracts have the effect of mitigating incentives to bid above marginal cost, and indeed, can create incentives to bid below marginal cost.

On January 27, 2006, FERC State Outreach circulated a "draft report" presenting a brief discussion of security constrained economic dispatch, how dispatch is done in the region, and a summary of the issues and recommendations made on the record up to that point in time. As noted in the body of this Joint Board report, the "draft report" listed three recommendations from the DOE November 7, 2005, report titled "*The Value of Economic Dispatch, A Report to Congress pursuant to Section 1234 of the EPACT of 2005.*" However, the draft report omitted the following recommendation:

> One industry observer proposes a study of areas that perform bid-based economic dispatch within real-time markets, to compare the market-clearing price outcomes and total costs against the true production costs of the actual units dispatched. This study would presumably examine two questions: how NUG bids in regulated utility dispatch (and utility-owned generator bids in centralized markets) compare to actual production costs, and how total electricity costs in centralized markets compare to total costs in the *(sic)* of the same production priced at its actual production cost. Such a study would require significant data or assumptions, incorporating energy costs and line losses within economic dispatch. It would

188 This paper was submitted on March 22, 2006, to this Joint Board in this matter by PJM in response to the Joint Board's March 8, 2006 data request. See page 16

> have to recognize that a significant amount of the total energy consumed within a region comes from utility-owned generation and bilateral contracts that are not priced at the MCP. In addition, the study would need to incorporate ratepayer charges for capacity for utility rate-based plants and stranded cost recovery, any payments made under a market-capacity-revenue scheme, and acknowledge any savings that might accrue to ratepayers for NUG capital costs left unrecovered from an energy-only revenue stream. (DOE Report to Congress Pursuant to Section 1234 of the EPACT of 2005, November 7, 2005; pages 51 and 52)

The above paragraph describes an approach to studying the "bid vs. cost" issue. Such a study was not conducted pursuant to this proceeding. As such, it seems reasonable that before this Board draws any conclusions regarding the "affordability of service to consumers in the region" as it relates to the functioning of security constrained economic dispatch in the PJM/MISO region, a study along the lines as set forth above should be undertaken.

As noted in the omitted recommendation, such a study would not be a simple affair. The formulation of required assumptions would potentially be controversial. In fact, when FERC staff participant and presumed draft report writer William Meroney was asked why the above recommendation was omitted from the January 27, 2006, draft report, Mr. Meroney replied:

> I think if we left that one out it was probably largely -- it seemed not so much outside of the scope in terms of being technically relevant, but just that doing that study itself seemed beyond the scope of what the Board could accomplish in the time allotted.[189]

At this point Commissioner Brownell added:

> And, Mr. Spinner, I think it gets back to the point I think that Chairman Hardy made and others made. To the extent that the charge here and the record here does not lead you to answer all of the questions you have about the marketplace the Board can if they wish include recommendations for further study, as can the FERC itself. So I think that's an option.
>
> You have certainly made clear what your preference is, and that's subject to further conversation with the Board.[190]

These comments seek to better ensure that further conversations surrounding the affordability of electric service to consumers that result from bid-based SCED in organized markets in the PJM/MISO region does indeed take place. In an effort to collect data from PJM that would allow for independent analysis of the efficacy of PJM market outcomes, the Staff of the Virginia State Corporation Commission ("Staff") has long sought data from PJM that would allow for an unbiased assessment of this crucial aspect of the ultimate impact of PJM operations. Specifically, by letter of September 26, 2005, PJM was requested to provide the following data:

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[189] Tr. February 12, 2006, at p. 44.

[190] Tr. February 12, 2006, at pp. 44-45.

For any given sub-footprint in PJM and starting with the entire PJM footprint, I am interested in the relationship, through time, between day-ahead LMP for any given hour and the actual cost of producing the energy consumed in that hour on both an "as-bid" basis and an as "cost" basis. The cost basis is that developed by generator supplied cost data in PJM's possession. Note that I am not seeking cost data on any particular generating unit, nor am I seeking information that could allow one to decipher cost information regarding any particular generating unit operating in PJM.

In summary, I am requesting that PJM produce hourly calculations for the entire PJM footprint for, say, 2005 year-to-date of:

(1) The "energy bill" for a particular hour equal to the hourly PJM load multiplied by the hourly PJM day-ahead total RTO LMP for that hour;

(2) The cost of supplying energy for that hour (as-bid) calculated as the area under a PJM total RTO supply curve developed from generator bids into the PJM day-ahead energy market; and;

(3) The cost of supplying energy for that hour calculated as the area under a PJM total RTO supply curve developed from generator cost data supplied to PJM by and for generators bidding into the PJM day-ahead energy market.

PJM's response to this request was that such data was not currently available, that PJM was "in the middle of a long-term project[191] to calculate net revenues of every unit for every hour," such data would be made available when the long-term project is complete and that data already available could be used to *estimate* the answer to the question posed. This data has yet to be provided.

The requested information would allow for the development and comparison of the areas represented in the graph described earlier in this comments. Analysis of this data is consistent with the Joint Board's charge to study what constitutes "security constrained economic dispatch," how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned, and to make recommendations to the Commission regarding such issues. The requested data provides a starting point for independent analysis that should shed light on whether competitive wholesale electricity markets continue to deliver the benefits of security constrained economic dispatch that were captured by this industry and delivered to customers prior to restructuring. The requested data should be publicly available. Varied analysis of that data by stakeholders should allow for a free exchange of ideas that can only help this industry move forward in the long-run.

The Generator Net Revenue Issue --- The Fairness Question

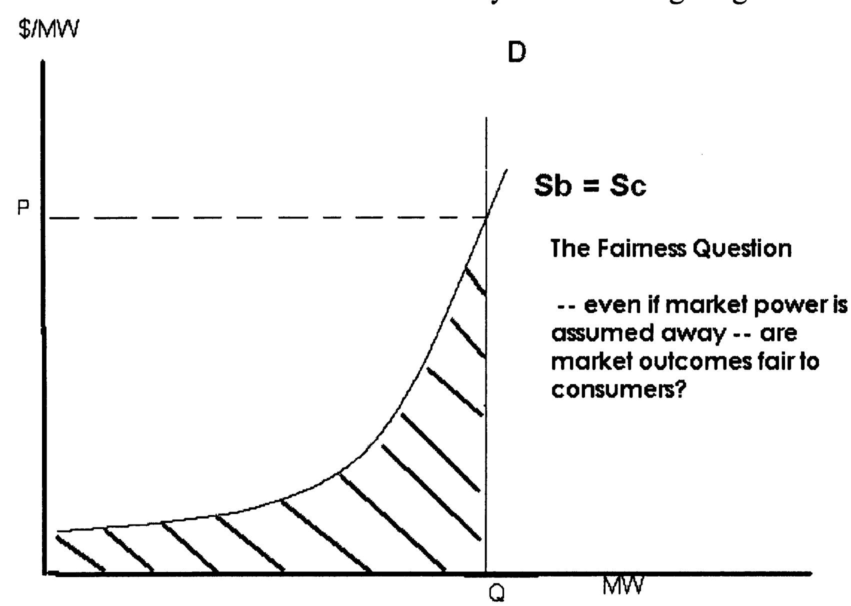
[191] On or about November 11, 2005, PJM stated that such data would be available in the first quarter of 2006. Note that such unit specific data would likely be deemed competitively sensitive. However, such data could be summed by hour. This would answer Staff's question without divulging producer specific information.

On March 22, 2006, PJM responded to a data request of this Joint Board. That data request was propounded to PJM on or about March 8, 2006. While this data request did not specifically ask for the data requested in the September 26, 2005, letter as set forth above, the March 8, 2006 data request asked both PJM and MISO to:

> Please explain whether you share Mr. Spinner's concern about potential divergence between aggregate wholesale electric market prices that result from RTO-managed SCED and aggregate generator production costs. Please provide the relevant data referred to on page 46 of the February 12 Joint Board Transcript.[192]

PJM's March 22, 2006, answer to question #2 includes phrases such as "Mr. Spinner's concerns are not well founded" and "Again, the evidence on net revenues does not support Mr. Spinner's assertions." It bears repeating that while question #2 of the March 8, 2006, data request purports to be somehow related to the above specified data request to PJM contained in the VA SCC staff letter of September 26, 2006, question #2 is not the question that was posed in September. The VA SCC question sought specific data on point to this Board's most important task; question #2 of the March 8, 2006, data request asks the ISOs whether they share the concern of a specific Board member and asks the RTOs to provide any "relevant data" to this issue as it was discussed by the Board. In the case of PJM, that RTO does not appear to share the Board member's concerns nor did it provide any data.[193]

The fairness issue can be illustrated by the following diagram.



Here, market power concerns are assumed away as all offers to sell electric energy into the

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[192] Data Requests from the PJM/MISO SCED Joint Board, March 8, 2006, question #2.

[193] In fact, PJM's March 22, 2006 response for question #2 provides no data at all. PJM's response provides assertions and calculations; the data and assumptions necessary to independently judge those assertions or replicate the calculations was not provided by PJM in their March 22, 2006 response.

competitive market are assumed to be at marginal cost. The graph simply illustrates the result that, when relatively higher marginal cost units set the market price in the single price auction, the actual resource costs to produce electric energy for a particular time period may be small (the cross hatched area) relative to the total bill for electric energy for the time period (P*Q). The point here is, again, that these areas need quantification before key conclusions are drawn as to the efficacy of market outcomes post industry restructuring. PJM has not as yet responded to requests for the information necessary to calculate these areas by supplying the required data as set forth in the VA SCC staff request by letter of September 26, 2005.

Many stakeholders have serious concerns regarding the efficiency and fairness of organized wholesale electric market outcomes and how those outcomes impact consumers. It is possible to posses and express these concerns without asserting that market outcomes are not just and reasonable. The point is that, given the paucity of data available to independent analysts and the corresponding lack of independent studies that purport to show that organized market outcomes in the PJM/MISO region are just and reasonable, this Board cannot make any finding that organized markets in the PJM/MISO region are, in fact, producing results for consumers that optimize customer affordability of electric power. In other words, a reasonable position is that one may express concerns about market outcomes yet assert nothing more than it has thus far been impossible for independent analysts to obtain the data and information necessary to verify RTOs claims that RTO administered markets in the PJM/MISO region produce outcomes that are just, reasonable and consistent with the public interest.

Comment Conclusion

In this matter, the Joint Board is charged with investigating how the operation of the electric energy system affects or enhances the reliability and affordability of service to customers in the PJM/MISO region, and to make recommendations to the Federal Energy Regulatory Commission regarding such issues. Given the lack of data and independent analysis regarding the efficacy and fairness of market outcomes, the Board cannot find that the results of organized wholesale electricity markets practicing security constrained economic dispatch within the PJM/MISO region produce results that are just, reasonable and in the public interest absent further analysis. While further analysis may be deemed beyond the scope of the Board's work or otherwise impossible to complete before the completion of this report, such analysis should be undertaken as soon as practicable. The first step of such analysis ought to be the dissemination of required information to those who seek to study this important question.

Until requested data is produced and subjected to rigorous independent analysis, the Joint Board on Security Constrained Economic Dispatch for the PJM/MISO region should make no finding regarding the how such a mode of operating an electric energy system affects or enhances the affordability of service to customers in the region concerned.

Attachment D

Concurring Comments of Missouri Representative Jeff Davis to the MISO-PJM Regional Joint Board Report

Docket No. AD05-13-000

In response to dissenting comments submitted by Montana Commissioner Greg Jergeson and concurring comments submitted by Virginia Commissioner Howard M. Spinner, the Missouri Public Service Commission submits the following comments on the issue of the ability of the bid-based, uniform clearing price constructs used by the Midwest ISO and PJM in their regional Security-Constrained Economic Dispatch (SCED) to provide benefits (lower energy costs) to consumers. The following summary highlights these comments.

- With respect to lower energy costs for consumers, regional SCED energy markets should be compared to bilateral energy markets in which buyers and sellers make short-term arrangements for off-system energy transactions.
- In both bilateral energy markets and regional SCED markets, absent transmission constraints and transactions costs, perfectly competitive energy markets would exist with resulting uniform clearing prices. However, levels of imperfect competition exist in both bilateral energy markets and regional SCED energy markets primarily due to transmission constraints.
- The comparison between bilateral energy markets and regional SCED energy markets should focus on the costs of implementing and the savings from regional SCED energy markets as measured by the reduction in transactions costs associated with bilateral energy markets coming from first-come, first-served transmission service and requiring bilateral transactions to be at least one-hour transactions.
- The exercise of market power should not be confused with the concept of bidding higher than incremental variable cost. However, the difference between bids and incremental variable costs is an appropriate measure of the degree of imperfect competition that is applicable to both bilateral energy markets and regional SCED energy markets.

1. Putting Concerns of SCED Related Bid-Based, Uniform Clearing Price Constructs in the Proper Context: Wholesale Energy Markets for Off-System Transactions

An issue was raised in the Joint Board for the MISO-PJM regions use of SCED as to whether or not a bid-based system in which a uniform clearing price construct is applied truly results in least cost to consumers. There were two concerns expressed: 1) whether or not generators bid incremental variable energy costs; and 2) whether paying all bidders the marginal bid that clears the market results in consumers over paying for electricity.

These questions are appropriate, but need to be put into the proper context. Specifically, regional SCED energy markets do not determine the price that consumers pay for electricity. They were not designed to do this, but instead were designed to determine the price at which utilities would exchange off-system transactions of energy in a wholesale market. As such, regional SCED energy markets should be compared to bilateral energy markets in which buyers and sellers make short-term arrangements for these same types of transactions.[194]

2. Describing the Alternative to Regional SCED Energy Markets: Off-System Transactions in Bilateral Energy Markets

An off-system transaction in bilateral energy markets can be described as a situation in which two utilities have evaluated (prior to real-time dispatch) the incremental variable cost of serving their load from their own resources, and if these incremental variable costs are different, one being higher than the other, overall costs can be reduced by substituting incremental energy from the lower cost alternative to replace incremental energy from the higher cost alternative. Such incremental substitutions of energy will result in generation cost savings up to the point where the incremental variable cost of energy is equalized between the two utilities. However, this does not describe how the price at which such a transaction will take place is determined.

a. Bid and Offer Strategies in Bilateral Energy Markets

In a bilateral energy market, potential sellers may take the position that there is no value to their ultimate consumers from selling the energy from the generation units that are devoted to serving those consumers unless the price is above the incremental cost of the energy used to make the sale. Why would potential sellers, even an independent generator, be willing to run additional generation if by doing, all that is received is the variable costs of their incremental energy with zero profit? On the other hand, if potential buyers can save any money by substituting lower cost incremental energy for their own higher cost incremental energy, they are very likely to enter into such a transaction.

These bidding strategies do not mean that sellers have "market power" over buyers.[195] Moreover, if there are several potential sellers in the market, buyers can negotiate to get the best price below their incremental variable costs. Equivalently, if there are several potential buyers in the market, sellers can negotiate to get the best price above their incremental variable costs. In essence, the degree of competition in the bilateral energy market determines the level of the profit margins over incremental variable costs that sellers are able to earn.

b. Bilateral Energy Transactions Under Perfect Competition

If there are many buyers and many sellers, no transmission constraints, and enough time for

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[194] In his comments, Commissioner Jergesen states: "The buyers (ultimately the consumers) will pay that higher price for all load purchased." This simply is not the case. Instead the buyer will pay the SCED price for generation purchased as a substitute for own generation to serve load. The comparison that must be made is how this differs from the price paid under a system of bilateral transactions for the same energy.

[195] Market power for a seller over a buyer occurs when that buyer has only a limited number of alternative sellers from which to choose and these few sellers have a large number of buyers to which they can sell.

full discovery of what buyers are willing to pay and sellers are willing to take, the results would be a uniform clearing price. To explain this result, consider a buyer that has perfect information about all potential sellers' minimum take prices. This buyer would go to the potential seller with the lowest minimum take price and attempt to enter into a deal at that price with the potential seller. But, also assuming that seller has perfect information about all buyers' maximum pay price, there would be no deal because the seller would go to the buyer with the highest maximum pay price and attempt to enter into a deal at that price. In the end, after all buyers and sellers have negotiated sufficiently to obtain complete information of the market, the result in a world of perfect competition would converge to a uniform clearing price. The definition of a uniform clearing price is where potential sellers whose minimum take price is above this uniform clearing price would not receive offers from buyers, as buyers can get a better deal at the uniform clearing price, and potential buyers whose maximum pay price is below this uniform clearing price would not receive offers from sellers, as sellers can get a better deal at the uniform clearing price. In basic economics, the uniform clearing price in a perfectly competitive world is where supply equals demand. However, actual bilateral energy markets never meet the ideal conditions of perfect competition.

c. Bilateral Energy Transactions Under Imperfect Competition

In actual practice, the number of buyers and sellers may be limited by both transmission constraints as well as by the amount of time to discover what buyers are willing to pay and sellers are willing to take.

1) Limited Numbers of Buyers or Sellers: In many instances, transactions are limited to a handful of sellers for a given buyer, or a handful of buyers for a given seller. In such cases, individual transactions are based on the buyer's and the seller's perception of the best price they can negotiate. Economists characterize this market imperfection of few buyers and few sellers as one in which game theory determines the sets of trades and prices, rather than one where a uniform, market clearing price is determined by supply and demand. In such gaming situations it would be rare to find either sellers revealing to buyers their true incremental variable costs for own generation not needed to serve their load or buyers revealing to sellers their true incremental variable costs for own generation needed to serve their load.

In any event, there is no expectation of a uniform market-clearing price across all bilateral transactions. One reason for this is that scarce transmission capacity limits the set of buyers available to a given seller as well as the set of sellers available to a given buyer. In addition scarce transmission capacity results in these limits being unique to each buyer and seller.[196]

2) Limited Time for Price Discovery: Bilateral transactions associated with physical transmission rights are limited to being at least an hour in duration, and many transactions will cover multiple hours of the day. In addition, transactions are limited by available transmission service that is sold to market participants on a first-come, first served basis. Economists characterize these market imperfections as "transactions costs," and the impact is that market

[196] This lack of price uniformity in imperfectly competitive bilateral energy markets may be comparable to the locational aspect of SCED determined locational marginal prices (LMPs).

participants have limited time for price discovery. Because of these transactions costs, there is no expectation in bilateral markets of a uniform clearing price, even when such transactions take place at a trading hub. Trading hubs were designed to help provide a way for buyers and sellers to more quickly discover prices, but still allow for individual (bilateral) transactions.[197] But even with improved price discovery through such trading hubs, bilateral energy markets transactions require physical transmission service, which when sold to market participants on a first-come, first-served basis puts additional time pressure on market participants to make their deal and reserve the transmission service as quickly as possible. When choices are limited on a non-economic basis (i.e., first-come, first-served), the result will not be a uniform clearing price.

3. Comparing Regional SCED Markets to Bilateral Energy Markets

It is important to point out that the Federal Energy Regulatory Commission moved away from cost-based transactions (e.g., marginal cost plus 10% adder) to market-based transactions for utilities that could demonstrate a lack of market power, and this change exists for bilateral markets as well as for regional SCED markets. Thus, while a comparison of cost-based transactions to bid-based transactions may provide some measure of the degree of market imperfections, such a metric would beequally applicable to both bilateral and regional SCED markets, but is not reasonable as a measure of comparison between the two types of markets unless it is measure for both.[198]

a. Regional SCED Markets Are Designed to Eliminate The Transaction Costs Found In Bilateral Energy Markets

Since SCED markets allow bids and offers to be submitted by potential buyers and sellers, it would be unrealistic to assume that such markets are designed to eliminate the market imperfections that occur in bilateral markets where buyers and sellers also have the freedom to submit bids and offers. Thus, the issue of lowering costs to consumers related to SCED markets is the extent to which such markets reduce transaction costs.

b. Potential Savings in Transactions Costs from Regional SCED Markets

With the focus of regional SCED being the elimination of market transaction costs, there are potentially two forms of potential savings for consumers. First, instead of limiting potential sellers available to a buyer by the available physical transmission capacity sold on a first-come, first-served basis, SCED puts all buyers and sellers on an equal footing and allocates scarce transmission on the basis of bids and offers submitted. Notice, whether a market participant is a buyer or a seller is determined on the basis of generation bids submitted. In this context, a buyer is a market participant whose own generation that is either scheduled or sold into the market is

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[197] Trading hubs deal in multiple hour products such as a fixed megawatt level over the on-peak hours.

[198] Commissioner Spinner's comments indicate that comparing bids to incremental costs is a "meaningful exercise" because bids higher than incremental costs mean higher costs to consumers, but higher costs in comparison to what? Certainly not in comparison to bilateral markets where similar bidding and offer strategies occur.

less than its load, and a seller is a market participant whose own generation that is either scheduled or sold into the market is greater than its load.[199] By eliminating the time constraint of the first-come, first-served construct of physical transmission reservations, SCED increases the number of transactions of utilities with higher incremental energy costs buying from utilities with lower incremental energy costs; at least to the extent that the transmission system is able to deliver the lower incremental cost energy to the buyers. Which potential sellers get to use the limited capabilities of the transmission system depends on location of the generation and having the lowest bids, not on who is able to submit a request for transmission service at the earliest time.

Second, instead of limiting transactions to being no shorter than one-hour in duration, both MISO and PJM have five-minute dispatches. This allows for a greater level of granularity in decisions about adding the lowest bid generation when load is increasing throughout the hour, or cutting back on the highest bid generation when load is decreasing throughout the hour. With a minimum time frame of one-hour on bilateral transactions, increases or decreases of generation within the hour will not capture the within hour savings available from a five-minute dispatch.

These savings that result from reducing transactions cost do not necessarily mean that regional SCED markets are cost beneficial. Regional SCED markets are expense to operate and these costs should be compared to the benefits that are likely to result from reducing the transactions costs associated with bilateral energy markets. However, the focus should be on proper measurements of the costs and the savings that result from reducing transactions costs and not on the degree of imperfect competition that exists in both types of energy markets.

4. Comparisons of Market Power and Levels of Imperfect Competition

First, it should be pointed out that while the level of bids above incremental cost is a measure of market imperfection (due to transmission constraints), it is not necessarily a synonym for what FERC defines as market power.

a. Measures of Market Power

Market power is the ability of a market participant to influence the price through either economic or physical withholding of generation from the market. Economic withholding is not solely the ability of a seller to offer a price higher than its incremental variable cost in an effort to make a profit when its sells into the market. Instead, economic withholding applies when a market participant expects that a certain block of energy will set the price at which other lower incremental cost energy from that same market participant are likely to sell. The strategy for economic withholding is to offer a price on this marginal block of energy high enough that it is excluded from the market, resulting in the market price being set at a higher price that is then paid to other energy being sold by that same market participant into the wholesale market. Thus, economic withholding is both a question of bid above incremental variable cost as well as the

[199] Of course, generators without contracts to serve load would always be sellers. But to the extent that a load-serving entity has generation resources adequate to cover its load and operating reserves, it could be either a buyer or a seller, and this would only be on the margin.

placement of the bid with respect to market conditions.

The extent to which market power exists is difficult to discover in a bilateral transactions market where bids are confidential. Because of this, FERC has used safe-harbor tests as a method to screen out instances where the potential to exercise market power is very unlikely. If a market participant does not pass this screen in a specified market area, then it must either provide detailed pricing information to prove its lack of market power or submit to mitigating its market power through some form of cost-based pricing.

For regional SCED energy markets, FERC has approved Independent Market Monitors (IMMs) to have access to bids submitted by generators. Clearly, IMMs can estimate the degree to which these bids vary from incremental cost and the market conditions under which such bids are submitted, and this can be used to help detect the exercise of market power. Thus, SCED energy markets may provide some additional disincentives for market participants to exercise market power. However, it is important to note that this hypothesis of additional disincentives would be difficult to verify empirically as data on bids and offers from bilateral energy markets are not available and probably, do not exist. Without empirical verification, it is not correct to assume that market power is reduced simply by the existence of a regional SCED market.

b. Measuring Imperfect Competition: Bids Above Incremental Variable Cost

The degrees to which bids exceed incremental variable costs are an appropriate measure of market imperfections. For example, if bids only exceed incremental variable costs in the range of up to 10% (the old FERC standard for cost-based pricing of off-system sales), it could be argued that the regional SCED energy markets are highly competitive. This high of a level of competition is not likely to occur because of the limitations of transmission constraints. It is worth repeating that the limitations of transmission constraints exist in both bilateral energy markets and regional SCED energy markets. While it might be argued that by reducing transactions costs, regional SCED energy markets also have some impact in reducing the level of imperfect competition by expanding the level of overall transactions, this hypothesis would be difficult to prove empirically.

c. Correcting Imperfect Competition: Expanding Transmission

Beyond using the difference between bids and incremental variable costs as a measure of the degree of imperfect competition due to transmission constraints, the MISO and PJM should addressed the reduction in the difference between bids and incremental variable costs that can be achieved through the expansion of the existing transmission system.[200]

[200] Currently, the Midwest ISO's method for measuring the benefits from transmission expansion focus on the savings that result from expanding the volume of transactions and the decreases that occur in LMPs. Moreover, the bidding behaviors of market participants assumed is that market participants always bid their incremental variable costs. Competitive benefits from expanding transmission could be estimated by comparing the relationship between bids and incremental variable costs in sub-regions and hours where transmission constraints do not result in transmission congestion to sub-regions and hours where transmission constraints result in transmission congestion.

Appendix E: South Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	**Docket No. AD05-13-000**

Study and Recommendations Regarding Security Constrained Economic Dispatch

By

The Joint Board for the South Region

July 11, 2006

I. Overview

The South Joint Board for the Study of Security Constrained Economic Dispatch is one of four joint boards designated by the Federal Energy Regulatory Commission ("Commission" or "FERC") under EPAct2005, Section 1298, Economic Dispatch. The members of the South Joint Board are:

> Chairman Joseph T. Kelliher, Federal Energy Regulatory Commission, Chair of the Joint Board
> Commissioner Sam J. Ervin, IV, North Carolina Utilities Commission, Vice Chair of the Joint Board
> President Jim Sullivan, Alabama Public Service Commission
> Chairman Sandra L. Hochstetter, Arkansas Public Service Commission
> Commissioner J. Terry Deason, Florida Public Service Commission
> Ms. Pandora Epps, Internal Consultant, Georgia Public Service Commission
> Chair Brian J. Moline, Kansas Corporation Commission
> Commissioner James M. Field, Louisiana Public Service Commission
> Dr. Christopher Garbacz, Director, Economics and Planning Division, Mississippi Public Utilities Staff, representing the Mississippi Public Service Commission
> Commissioner Steve Gaw, Missouri Public Service Commission
> Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
> Chairman Jeff Cloud, Oklahoma Corporation Commission
> Vice Chairman G. O'Neal Hamilton, South Carolina Public Service Commission
> Mr. Pat Miller, Director, Tennessee Regulatory Authority
> Commissioner Julie Caruthers Parsley, Public Utility Commission of Texas

The South Joint Board met in public session on November 13, 2005 in Indian Wells, California and on February 12, 2006 in Washington D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1) "to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report is divided into four sections. The first, Security Co nstrained Economic Dispatch: the Basics, provides a description of the basic concept of Security Constrained Economic Dispatch used in the study; the second, Economic Dispatch in the South, describes dispatch procedures in the South; the third summarizes the issues raised and considered by the board, including any recommendations made by individual board members or other parties to address these issues; and the fourth section discusses the recommendations of this Joint Board. The principal sources for these sections are presentations to the board and written comments submitted to the board, discussions among the Joint Board members, the Department of Energy (DOE) report under EPAct 2005, section 1234, and the responses to the DOE survey of economic dispatch.

II. Security Constrained Economic Dispatch: the Basics

For purposes of the joint boards' studies, the FERC adopted the following definition of Security Constrained Economic Dispatch (SCED): "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[1] This definition describes the basic way all utilities in the region dispatch their own and purchased resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and season; the costs of generation from different types of units vary greatly; and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. Security constrained economic dispatch is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and the minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and the cost of environmental compliance.

In addition, forecast conditions that can affect the transmission grid must be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal

[1] September 30, 2005 order at P14.

economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace cheaper units.[2] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail, while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints and in some cases even the network model might vary in economic dispatch software. Generally, however, advances in hardware and software (e.g., the use of mixed integer programming for unit commitment) now make it technologically feasible to undertake security constrained economic dispatch over large regions.

Aside from differences in the models used in economic dispatch software, questions have been raised about the extent to which all available resources are appropriately considered in the dispatch process. It has been alleged by some, but certainly not all, of the participants in the Joint Board process that various factors, including perceived limitations in utility open access transmission tariffs, have made it more difficult to ensure that all available resources are appropriately included in the dispatch process.

III. Economic Dispatch in the South

The practice of economic dispatch in the South varies by utility and region. In most of the South, economic dispatch is performed on a system-by-system basis. In Texas it is performed on a regional basis through replacement of utility control areas with a central

[2] This is known as "out of merit" dispatch.

market operator, and the Southwest Power Pool is proposing its own form of a regional economic dispatch in the form of a balancing market. Even though the South utilizes the same basic concept of next day unit commitment and real-time security constrained economic dispatch processes described in the prior section, there are variations in the implementation details as described below.

In addition to day-ahead unit commitment, Duke performs resource commitment studies over a seven-day period because of a large concentration of pumped storage generation in its portfolio.[3] Due to the nature of pumped storage generation, Duke needs to look not just at the forecasted conditions for the next day but also the expected conditions over the next week to determine the most effective way to operate those units. Duke also includes third party resources in its commitment and dispatching processes through its bulk power marketing function that is responsible for purchasing economic power.[4] In addition, Duke is implementing an Independent Entity for performing certain Open Access Transmission Tariff functions and an Independent Monitor for monitoring its transmission.

Entergy performs economic dispatch for its footprint in Arkansas, Louisiana, Mississippi, and Texas with a diverse generation resource portfolio and bilateral contracts for power purchases from non-utility generators. In addition to next day unit commitment, Entergy has broadened its use of market purchases in its commitment and dispatching processes through a Weekly Procurement Process to include independent power producers and other utilities.[5]

Southern Companies perform economic dispatch under a pooling arrangement for the generating resources controlled by its operating companies in Alabama, Georgia, Mississippi and Florida.[6] Each operating company makes its generating resources exclusively available for economic dispatch by the pool. The generation portfolio consists of diverse fuel type generation, and purchase power agreements with non-utility generators and other market participants through Southern term traders. [7]

Members of the Southwest Power Pool are considering implementing an Energy Imbalance Market within the SPP footprint. SPP will perform a real-time security constrained economic dispatch of the entire market footprint without respect to control areas. Currently, however, economic dispatch is performed individually by multiple control areas located in the SPP footprint. Each owner of generation performs its own economic dispatch for its portfolio of resources including generation, transactions, and

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[3] Mr. Scott Henry – Duke, Transcript of Nov. 13, 2005 Board meeting, tr at 22.
[4] Id. at 26.
[5] Mr. Hurstell – Entergy, tr at 28.
[6] Alabama Power Co., Georgia Power Co., Gulf Power Co., Mississippi Power Co., and Southern Power Co.
[7] Mr. Graham, Jr. - Southern Companies filing comments, page 6.

demand side management.[8]

Economic dispatch in the Florida Reliability Coordinating Council is performed by eleven Balancing Authorities, (formerly referred to as control areas) through their own economic dispatch energy management system. This optimizes production costs for the balancing authority resources that are supplemented with wholesale "market" sales and purchases through bilateral transaction activity, including both utility and non-utility generation. One balancing authority in the region also acts as a "power pool" for its members.[9]

ERCOT is the only organized market currently operating in the South region. It was organized out of 10 control areas. In ERCOT there are two entities responsible for the dispatch of the system: qualified scheduling entities (QSEs) and ERCOT.[10] QSEs perform commitment and dispatch processes by both taking into account their portfolios and any other offers on the bilateral markets. ERCOT will then modify or supplement that dispatch to meet total system load, maintain system frequency and manage transmission congestion if necessary.

ERCOT meets its system needs by using ancillary service capacity and running a balancing energy market every 15 minutes, allowing all generation, regardless of ownership, to bid and provide balancing energy. ERCOT manages transmission congestion with zonal and intra-zonal type arrangements. ERCOT is moving toward nodal pricing, which will allow it to perform centralized day ahead commitment and economic dispatch processes based on bid prices.

IV. Issues

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues suggested in the record. This section also discusses the recommendations from the DOE report to Congress on the value of economic dispatch.

Below are the issues raised by utilities, independent power producers, market participants and transmission dependent utilities:

- Inclusion of non-utility generation in the dispatch
- Coordination of economic dispatch for all loads
- Independence of dispatcher
- Transparency of dispatch information and processes

[8] SPP: Stakeholder Panel - South filing comments, page 1.
[9] Florida Reliability Coordinating Council responses to DOE survey.
[10] Mr. Saathoff - ERCOT, tr at 63.

- o Market liquidity
- o Transmission constraints
- o Regional transmission planning and expansion

Inclusion of non-utility generation in the dispatch.

In general, the majority of vertically integrated utilities in the region state that the current unit commitment and real–time economic dispatch processes are working fine and benefiting ratepayers in their areas.[11] Their unit commitment processes provide opportunity for third-party generation resources to participate through bilateral contracts in block offers to the extent that those resources elect to be included.

Independent power producers, market participants and transmission dependent utilities state that not all generation resources within vertically integrated utilities' footprints are included in the economic dispatch process. Non-utility generators say that dispatching only generation resources owned by one entity and purchasing power through bilateral contracts does not suggest that the system as a whole is economically dispatched nor does it suggest that the consumers are receiving energy at the least possible cost.[12] If the commitment and dispatch processes do not include all generation resources in a region, then load cannot have access to the most economic power and use of the transmission system will not be optimized. They suggest that including all generation resources regardless of ownership within each utility's footprint and in a broader region would be beneficial to consumers in the entire region.

Some observers say that a reason third-party generation resources are not included in the near real-time economic dispatch is because those resources are incapable of providing sufficient operational flexibility for regulation.[13] In addition, one utility argues that including all generators, regardless of ownership, into the economic dispatch would strip the states of their power to control whether their retail customers received the lowest cost energy and could decrease reliability because some of those generators probably would not be creditworthy.[14]

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[11] Mr. Scott Henry – Duke, tr at 26.
Mr. Hurstell - Entergy, tr. at 32.
Mr. Graham, Jr. – Southern Companies filing comments, page 20.

[12] Mr. O'Connell – Williams, filing comments, page 3.
Ms. Turner - Union Power, filing comments page 2.
Mr. Sam Henry – SUEZ filing comments, page 1.

[13] Mr. Scott Henry - Duke, tr at 27.
Mr. Hurstell - Entergy, tr at 29.
Mr. Graham, Jr. – Southern Companies filing comments, page 16.

[14] Id., page 16.

Coordination of economic dispatch for all loads.

Transmission dependent utilities[15] in the South are concerned that there is no coordinated economic dispatch that covers all loads within a utility's footprint. With Entergy's Weekly Procurement Process, the dispatching utility can take advantage of independent resources of its choosing to serve its own load, but the transmission dependent utility's network customers do not benefit from the process. Furthermore, during the Weekly Procurement Process, the available flowgate capacity determination process for other transmission customers is closed down for about half a day, while the optimization analysis is being performed for the dispatching utility. Other transmission customers seeking alternative resources cannot have transmission reservation requests processed during this "blackout" period, and are able to use only available flowgate capacity that is left after the dispatching utility completes its resource selection.[16] This makes it difficult, especially for entities that are transmission dependent, to efficiently utilize their own resources and prevents them from taking advantage of efficiencies in a broader wholesale market.

Independence of dispatcher.

In addition to suggesting that all generation resources should be included in the economic dispatch process in order to improve benefits to consumers, non-utility generators further recommend that an independent organization should be responsible for implementing and operating the commitment and dispatch processes. An independent administrator will utilize the most efficient resources available regardless of ownership and optimize transmission capacity by sharing real-time information between the dispatcher and the market participants. It also eliminates any suspicion that transmission owners favor their own resources over those of other stakeholders.[17] One utility argues that this Joint Board is not the forum to discuss whether an independent entity should regionally operate the transmission in the South.[18]

Transparency of dispatch information and processes.

One utility argues that there is significant transparency in the transmission information posted on Open Access Same Time Information System ("OASIS"), including information pertaining to Total Transfer Capacity, Available Transfer Capacity, and

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[15] Mr. Priest – MDEA (Mississippi Delta Energy Agency), tr. at 34.
Mr. Beam – NCEMC (North Carolina Electric Membership Corp), tr at 38.

[16] Mr. Priest – MDEA, tr at 36.

[17] Mr. O'Connell – Williams, filing comments, page 4.
Ms. Turner - Union Power, filing comments, page 7.
Mr. Sam Henry – SUEZ filing comments, page 2.

[18] Mr. Graham, Jr. - Southern Companies, filing comments, page 20.

transmission studies.[19] However, independent power producers argue that an independent administrator will provide transparency of prices, allocation of transmission capacity and transmission congestion management through published business rules, interpretations and curtailment events.[20] The lack of visibility into transmission loading events hampers their ability to respond because they do not know whether making a certain adjustment will result in helping or hindering the particular problem that the dispatching utility is addressing. The other issue that hampers them in performing economic dispatch is that their plants do not get access to the control signals necessary to perform certain functions, such as regulation.[21]

Market liquidity.

One transmission dependent utility contends that the South region has a very illiquid market for economic transactions.[22] Utilities still rely on phone calls for potential trading because there is no central clearinghouse, making it an inefficient system for optimizing resources at the lowest cost. One independent power producer argues that trading hubs in the South are less liquid than other hubs because they lack transparency regarding transmission congestion management, transmission system operation, and price information. Limitation on transmission capacity is also a contributing factor.[23]

Transmission constraints.

Because of transmission limitations in the South, transmission dependent utilities and the Southwest Power Pool[24] say that the biggest impediment to economic dispatch is constraints on the transmission system. Transmission constraints can prevent efficient generation resources from being dispatched. These parties say they are frequently unable to access economic sources because of transmission limitations and often forgo economic transactions because of a concern that the transaction could be curtailed.

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[19] Mr. Graham, Jr. – Southern Companies, filing comments, page 12.
[20] Mr. O'Connell – Williams, filing comments, page 4.
Mr. Sam Henry – SUEZ, tr at 45, 46.
[21] Mr. O'Connell – Williams, tr at 52, 53.
[22] Mr. Beam – NCEM, filing comments, page 2.
[23] Mr. O'Connell – Williams, tr at 77,78.
[24] Mr. Beam – NCEMC, tr at 40.
Mr. Monroe – SPP, filing comments, page 2.
Mr. Sam Henry – SUEZ, filing comments page 2.

Regional transmission planning and expansion.

Transmission dependent utilities suggest that transmission infrastructure in the South should be strengthened. One transmission dependent utility[25] states that regional planning and operation of the electric system beyond traditional control area boundaries are necessary to resolve many of these problems without mandating an RTO structure. For example, load-serving entities in North Carolina, in cooperation with the North Carolina Utilities Commission, recently established a collaborative transmission planning process to jointly plan the transmission system for network customers. The Southwest Power Pool also states that, without adequate regional transmission planning to expand and upgrade the capacity of transmission grid, economic dispatch cannot fully sustain its promised benefit.[26] Although members of the South Joint Board did not reach unanimity as to the desirability or importance of independent review of transmission projects, some members of the South Joint Board contend that having an independent entity review transmission projects helps to ensure that regional transmission plans are developed in a non-discriminatory manner so as to optimize security constrained economic dispatch.

One utility argues that without participant funding or direct assignment of costs, expanding the transmission system so that all generators within the system can be incorporated into economic dispatch would be prohibitively expensive and place an undue burden on retail customers.[27]

V. Recommendations of the Joint Board

The members of the South Joint Board agree, consistent with the conclusions reached in the Department of Energy survey, that there is no single appropriate method for performing economic dispatch and that the nature of economic dispatch can appropriately vary from region to region across the country depending upon variations in local conditions, including, but not limited to, the degree to which the industry remains vertically integrated, the presence or absence of bid-based organized markets, the manner in which retail rates are established, and similar factors. For example, dispatch is performed differently in the ERCOT region of Texas than it is in those portions of the region not served by an organized market, but the mere existence of those differences does not establish that either portion of the region fails to engage in security constrained economic dispatch.

The members of the South Joint Board unanimously agree that utilities operating in the region should engage in security constrained economic dispatch. However, economic dispatch is performed differently in ERCOT than in the remainder of the South, where

[25] Mr. Beam – NCEMC, tr at 41.
[26] Mr. Monroe – SPP, filing comments, page 3.
[27] Mr. Graham, Jr. – Southern Companies filing comments, page 12.

generation is dispatched on an individual system basis at the present time. The members of the South Joint Board conclude that utilities in the South are engaging in security constrained economic dispatch to the extent that they operate consistently with the procedures that the utilities described to the Joint Board. Some members of the South Joint Board are concerned about the efficacy of the results that occur when dispatch is performed by the utility outside the context of an organized market or in situations not including an independent operator due to a perceived lack of transparency. The members of the South Joint Board agree that state regulatory oversight of utilities helps to ensure that such utilities do, in fact, perform security constrained economic dispatch. In addition, the members of the South Joint Board conclude that the work of the Joint Board is limited to examining issues relating to "security constrained economic dispatch" and that other forms of dispatch, such as environmental or efficient dispatch, are beyond the scope of the Joint Boards' assignment.

Some members of the South Joint Board believe that, in areas that lack organized wholesale markets, it becomes difficult to determine whether or not all available resources are appropriately included and dispatched and therefore, that cost effective markets can contribute to the operation of generation facilities to produce energy at the lowest cost. Other members of the South Joint Board believe that there are legitimate questions as to the cost-effectiveness of organized wholesale markets, the extent to which transactions in such markets are priced appropriately, the extent to which bid-based pricing of the type characteristic of such organized markets results in the dispatch of the lowest cost generation to meet customer load and the difficulty of overseeing the appropriateness of dispatch in the absence of such markets. As a result, the South Joint Board did not reach a conclusion on the value of organized wholesale markets in ensuring that the lowest cost available resources are actually being dispatched to serve end-user customers.

Although the members of the South Joint Board conclude that security constrained economic dispatch is performed across the region in varying ways, the Joint Board recognizes that a number of different issues were raised during the initial meeting of the Joint Board and in the comments submitted to the Joint Board that are worthy of further discussion. One of the principal tasks committed to the membership of the regional FERC/State Joint Boards is to make recommendations to the Commission concerning possible improvements to economic dispatch in each region. The suggestions made during the initial South Joint Board meeting and in the comments submitted following that meeting were intended to assist the members of the South Joint Board in developing such recommendations. The members of the South Joint Board appreciate the time and effort that went into the presentations made by all participants during the initial Joint Board meeting and the comments that have been submitted to the Joint Board since that time. These presentations and comments raise a number of issues which the members of the South Joint Board have carefully considered in the formulation of our conclusions and recommendations.

Among the suggestions for improving economic dispatch in the South were that a trading hub with a day ahead market, an energy broker system such as that previously used in Florida, or an automated interchange matching system similar to the one that existed during the 1990s be established in the region. In view of the manner in which economic dispatch is performed in the portion of Texas served by ERCOT, the members of the South Joint Board assume that this recommendation applies exclusively to the portion of the region outside ERCOT. As the members of the South Joint Board understood these proposals, the proposed improved trading hub, energy broker system, or automated interchange matching system would be voluntarily established and open to any market participant that wished to purchase or sell power using the facilities made available by these arrangements. The purpose of such trading hubs would be to improve the liquidity and price transparency associated with bilateral transactions in certain portions of the region. The members of the South Joint Board agree that there might be some benefit to the establishment of such an expanded trading hub, energy broker system, automated interchange matching system, or some similar mechanism as long as market participants have confidence in the transparency and evenhandedness with which such an institution was operated (whether through independent management or some other mechanism) and as long as such an institution produces cost-effective purchase and sales opportunities without creating additional reliability or congestion issues. Subject to those caveats, the members of the South Joint Board encourage market participants to give further consideration to the development of such arrangements.

In addition to proposing the establishment of an improved trading hub or similar processes, participants in the Joint Board process also suggested that the scope of economic dispatch be expanded. As a result of the approach to economic dispatch employed in the ERCOT portion of Texas, and the energy imbalance market scheduled for operation in SPP in the fall of 2006, members of the South Joint Board believe that this recommendation is applicable to that portion of the region outside ERCOT and SPP. Although the nature and extent of the proposals for expanding the scope of economic dispatch in the region advanced to the Joint Board were not described in detail, some members of the Board believe that the adoption of such proposals could, depending upon the manner in which they were implemented, fundamentally alter the manner in which electric service is provided in some parts of the South, disturb settled customer expectations, and result in significant shifts in jurisdiction and customer costs. Other members of the South Joint Board believe that the implementation of such an expanded dispatch could result in lowering overall generation costs and produce savings for retail customers. In order to implement such a proposal, it would appear to the members of the Joint Board that a Regional Transmission Organization (RTO) or some independent third party dispatch operator would be required. Some members of the South Joint Board are concerned that the institution of an RTO or similar institutions in their states would result in a loss of State jurisdiction and could increase customer costs. Some members of the South Joint Board believe that RTO or independent third-party dispatch creates greater wholesale price transparency and could result in lower customer costs. The FERC's belief (which is shared by many State members) is that such institutions should only be established on a voluntary basis. The State members of the South Joint Board believe that existing law requires that the implementation of such proposals be subject to State review and approval in order to ensure their cost-effectiveness. As a result, the members of the South Joint Board do not recommend that an expanded regional dispatch be involuntarily implemented in the South at this time. As is always the case, however, the members of the South Joint Board encourage market participants and others to continue to investigate alternatives that would reduce the cost and improve the reliability of electric service for customers within the region.

Certain participants in the Joint Board process recommended that additional transparency be created with respect to the operation of the transmission system and transmission congestion management in the region and that the capacity of the existing transmission system be expanded. Although these proposals are interrelated and could apply throughout the region, including the area served by ERCOT and the Southwest Power Pool, the members of the South Joint Board will address them individually, given that these proposals raise several different issues and could be resolved in differing ways.

The members of the South Joint Board favor appropriate, cost-effective, improvements in the transparency with which the regional transmission system is planned and operated and the manner in which transmission congestion is managed. The efficacy of existing economic dispatch procedures in the region, which rely heavily on bilateral transactions, rests on the assumption that load serving entities have non-discriminatory access to potential suppliers. Users of the transmission system for the purpose of participating in wholesale transactions should receive non-discriminatory transmission service in a manner consistent with the Open Access Transmission Tariff (OATT) and existing market rules. However, issues have been raised about the adequacy of the manner in which the OATT has been implemented and enforced in many parts of the country. For that reason, some of the State members of the South Joint Board have expressed support for the Commission's decision to reexamine the existing OATT in order to ensure that any needed improvements are made and any important issues are addressed. The members of the South Joint Board assume that OATT-related issues will be appropriately addressed in the ongoing Commission proceeding relating to the revision of Order 888 and see no need to further comment on those issues as part of the activities of this Joint Board. Furthermore, the nature of the proposed improvements in the manner in which the transmission system in the region is planned and operated and the manner in which transmission congestion is resolved were sometimes not clearly stated. In the event that the proponents of these improvements in transmission system operation contemplate the creation of an RTO or a non-RTO independent entity or process, the members of the South Joint Board conclude that such a step may or may not be appropriate depending on the circumstances, that market participants should feel free to explore the creation of such institutions or alternative approaches, and that proposals for the creation of such institutions should be handled consistently with federal and state law to assure that they are cost-effective and serve the public interest.

As the members of the South Joint Board understand the term, the issue of transmission system expansion may or may not go beyond the scope of an examination of security constrained economic dispatch of the type contemplated by Congress. On the one hand, some members of the Joint Board believe that the inquiry contemplated by Congress takes the capacity of the existing transmission system as a given and proposes an examination of how available generating units should be dispatched in the most economic manner possible given these system limitations. Other members of the South Joint Board believe that issues relating to the expansion of the system are well within the Joint Board's purview as described by Congress. The members of the South Joint Board were not able to achieve unanimity with respect to this legal issue. Regardless of the conclusion which individual members of the South Joint Board reach with respect to this issue, the adequacy of the transmission system in the region clearly affects the ability of load serving entities to utilize or procure energy from certain suppliers and is, for that reason, related to system dispatch issues on a longer-term basis. The members of the South Joint Board further agree that it would be beneficial to obtain improved information about actual expansion of the regional transmission system, including the size, location, and purpose of proposed expansions. In addition, the members of the South Joint Board agree that the obligation imposed upon all regulated utilities to provide adequate service includes appropriately planning for the cost-effective expansion of the transmission system to meet the needs of end user customers in the most reasonably-priced and equitable manner possible. Finally, the members of the South Joint Board believe that issues relating to the expansion of the transmission system should be resolved in a manner that is equitable and cost-effective and that respects appropriate jurisdictional boundaries as is required by existing federal and state law.

Various participants in the Joint Board process recommended the establishment of independent transmission coordinators or similar entities to optimize transmission planning for both reliability-related and economic expansions, to monitor market conditions and behavior, and to oversee system operations. As a result of the role in planning and system operation played by ERCOT and SPP, the members of the South Joint Board assume that these proposals relate primarily to the portion of the region not served by the two existing RTOs. Most areas in the South region outside ERCOT and SPP rely upon traditionally-regulated, vertically integrated utilities with a statutory obligation to provide service in defined service territories. The primary duty that these utilities are required to perform is providing reliable service at just and reasonable rates to native load customers. Although these utilities are solely responsible for planning and operating their own systems, they are interconnected with adjoining utilities and work with their regional neighbors to some degree in order to plan and operate the transmission system. The coordination of planning and operations among such utilities is becoming more formal and interdependent through voluntary action on the part of the affected utilities.

A considerable amount of work on proposals for improving the planning and operation of the transmission system is currently occurring within the region. These initiatives make transmission planning and operation more independent from the utility company owning the transmission. For example, the Commission has recently approved Entergy's ICT proposal and Duke Power's Independent Entity proposal. Similarly, the load serving entities in North Carolina have agreed upon a joint planning process that they hope will lead to improvements in transmission planning there. Some members of the South Joint Board believe that an independent transmission planning process is required to assure that transmission upgrades and other improvements occur on a non-discriminatory basis. In addition, some members of the South Joint Board believe that specific proposals for independent transmission planning should be subject to State review for cost-effectiveness as a precondition for their implementation. Although the members of the South Joint Board disagree on the need for or desirability of an independent transmission planning process, they do agree that interested parties should continue to explore such alternatives on a voluntary basis and to seek appropriate regulatory redress in the event that they possess evidence of inappropriate conduct by any market participant. The members of the South Joint Board also conclude that the formation of such entities should be encouraged where their activities would be cost effective, beneficial to customers, and not diminish reliability and that their formation should be voluntary rather than mandatory and subject to any applicable state rules, regulations, and statutes.

Among the recommendations advanced in the study of economic dispatch issues performed by the United States Department of Energy was the suggestion that the Joint Board review selected dispatch entities, including some investor-owned utilities, in order to determine exactly how they conduct economic dispatch. According to the DOE study, such reviews could document the reasons for any departures from pure least-cost dispatch so that one could ascertain whether such deviations resulted from entity-specific or regional business rules, on the one hand, or reliability, regulatory, and environmental constraints, on the other. The members of the South Joint Board believe that conducting such a study in a dispassionate, fact-based manner might resolve some of the issues that were raised by various participants in the Joint Board process and would tend to be supportive of the performance of such a study. However, it is not clear to the members of the South Joint Board how much data would need to be obtained in order to conduct such a review, how much time and expense would be involved in the review process, and how such a study would be paid for. As a result, the members of the South Joint Board conclude that such a review should be undertaken by an appropriate body in the event that the cost of such a review is determined to be reasonable, the funding source is clearly identified, the necessary data is readily available in filings with state or federal agencies, and the purpose and scope of the review is agreed upon by all parties at the beginning of the review process.

Furthermore, the DOE recommended that the Joint Boards explore various proposals for more standardized contract terms associated with wholesale power transactions and engage in further study of current economic dispatch technology tools. The members of the South Joint Board believe that further exploration of these issues could be helpful. However, any such exploration should be undertaken with the understanding that adequate flexibility in wholesale contracting should be preserved in the interests of assuring the most economical service for customers, that the data necessary to undertake these explorations should be reasonably available before such a study is undertaken, that the costs of these reviews should be reasonable, and that any review of such standardized contract terms and dispatch technology tools should have a specific, widely-accepted scope and set of specific objectives sought to be accomplished.

CODA

The record contains expressions of concern about the extent of the willingness of vertically integrated utilities to purchase power from unaffiliated generators even when it is economically appropriate to do. The vertically integrated utilities argue in response that they do not hesitate to purchase power from any available source that can supply power on an economic basis. The Joint Board process created by Congress does not allow the members of the South Joint Board to resolve this apparent factual dispute since it does not involve the use of formal hearing procedures. The members of the South Joint Board note that, in many States where vertically integrated utilities continue to exist and are subject to state regulation, State commissions or State commission staff have the authority to oversee utility dispatch decisions and to disallow costs incurred as the result of a failure to purchase the most economical power. However, the information on potential bilateral energy transactions available to state commissions may be subject to certain limitations. Specifically, data on potential transactions not pursued by the utility may not be routinely retained in the absence of an order to the contrary. In addition, under certain circumstances, claims alleging undue or unreasonable discrimination by regulated utilities can be presented to either the FERC or a State commission. The members of the South Joint Board conclude that there is some degree of recourse available to entities that believe that security constrained economic dispatch is not being performed in an appropriate manner and that entities with evidence that security constrained economic dispatch is not being performed properly should not hesitate to bring such claims to the appropriate regulatory body for redress in accordance with law. Some members of the South Joint Board believe that it may be difficult for a regulatory body to determine whether actionable discrimination has occurred in the absence of the transparency that they believe to be inherent in organized markets or the use of an independent operator. However, as has been noted above, the members of the South Joint Board have differing opinions as to the value of such institutions. Those Joint Board members that are supportive of cost effective organized markets and similar institutions believe that they improve the ability of regulators to evaluate the credibility of such allegations. Those Joint Board members that are not convinced of the value of such institutions are skeptical of the usefulness of any information that is allegedly available in such markets given limitations on available resources and do not believe that organized markets or similar institutions are necessary to permit a determination as to whether actionable discrimination has occurred.

Appendix F: West Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	**Docket No. AD05-13-000**

Study and Recommendations Regarding Security Constrained Economic Dispatch

By

The Joint Board for the West Region

May 12, 2006

Executive Summary:
Recommendations of the Federal/State
Joint Board on Economic Dispatch for the West Region

On September 10, 2005, the Federal Energy Regulatory Commission (the Commission) issued its Order Convening Joint Boards Pursuant to Section 223 of the Federal Power Act "to study the issue of security constrained economic dispatch for the various market regions," "to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating . . . affects or enhances the reliability and affordability of service," and "to make recommendations to the Commission."[1]

The West Joint Board consists of the Federal Energy Regulatory Commission and the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming.[2]

Our analysis of security constrained economic dispatch (SCED) began with the Commission's definition in the Order: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." In the Report, we discuss the basics of SCED and how it functions in the Western Interconnection. Below are short summaries of the major issues considered by the Board and our recommendations to the Commission in this Report.[3] We also address three recommendations made to the Joint Boards by the DOE in The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005.

1. Independence of dispatcher.

The Board examined the suggestion that independent transmission dispatch was needed to ensure fairness and the full integration of the all generation facilities into the dispatch without regard to ownership of those facilities.

Recommendation:
We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is deemed

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[1] The Order was issued in Docket No. AD05-13-000, Joint Boards on Security Constrained Economic Dispatch.

[2] These states are within the Western Interconnection,with the exceptions of South Dakota and Texas, only portions of which are served from within the interconnection.

[3] Texas's recommendations diverge from the majority, and are contained in the *Texas Perspective on Security Constrained Economic Dispatch*, filed separately in Docket No. AD05-13-000.

warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

2. Utility dispatch of third party power through contracts.

The Board examined the question of whether the relationship between dispatching utilities and IPPs should be governed by contract to ensure the high level of reliability and responsiveness needed for the dependable dispatch of contract units as fully functional integrated grid resources.

Recommendation:

We encourage, but do not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing reliability, dispatchability and other issues. The Joint Board recommends the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with an LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

3. Transparency of dispatch information and processes.

The Board examined the question of whether a central entity, dispatching all of the resources in a region, that had more timely access to high quality information could function more efficiently and better realize the value of SCED. For competitive reasons, some entities are reticent about sharing confidential dispatch and load information with a non-independent dispatching entity.

Recommendation:

Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. We recommend that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

4. Consolidation of control areas in a region.

The Board looked at the question of whether consolidation of control areas might yield better information which might, in turn, enable more efficient dispatch than would be the case if several control areas simply shared information. The benefits of larger control areas for renewable technologies such as wind were discussed as was the range of information available from WECC and otherwise to smaller control areas.

Recommendation:
We recommend that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. Any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and we recommend that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

5. Import/export schedule changes within an hour.

The Board learned that large changes in load and large amounts of imported power make it difficult to schedule efficiently for the hour in some markets. Slow ramp rates can cause imbalances when scheduling for the hour.

Recommendation:
We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the hour.

6. Some practical limitations on economic dispatch.

The Board recognizes that the physical makeup of the grid, the demands placed on it and the available generation resources sometimes impose cost, reliability and other limitations on economic dispatch to assure that the needs of the public are accommodated. Various state and regional policies also emphasize goals that go beyond "pure" economic dispatch.

Recommendation:
We recommend that the definition of security constrained economic dispatch be flexible and broadened to include other public policies, values and physical and operational constraints as well as costs.

7. First DOE Recommendation: review dispatch practices.

The DOE recommends that the Joint Boards review selected dispatching entities to determine how they conduct economic dispatch and document the rationale for deviations from "pure" least-cost economic dispatch.

Recommendation:
The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing

much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

8. Second DOE Recommendation: standardize dispatch contract terms.

The DOE recommends that it and FERC encourage stakeholders to develop more standard contract terms concerning price stability, dispatchability, reliability, and penalties for not meeting performance standards.

Recommendation:
We recommend that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

9. Third DOE Recommendation: review dispatch tools.

Existing economic dispatch technology, including software and data used and the underlying algorithms and assumptions, deserve scrutiny.

Recommendation:
We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.

I. Introduction

This Report of the West Joint Board on Economic Dispatch presents the results of the Joint Board's study of security constrained economic dispatch (SCED) issues, and provides recommendations to the FERC. The West Joint Board is one of four joint boards designated by the Commission under EPAct2005, Section 1298, Economic Dispatch. The members of the West Joint Board are:

Commissioner Suedeen Kelly, Federal Energy Regulatory Commission, Chair of the West Joint Board
Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the West Joint Board
Commissioner Marc L. Spitzer, Arizona Corporation Commission
Commissioner Dian M. Grueneich, California Public Utilities Commission
Chairman Gregory Sopkin, Colorado Public Utilities Commission
Commissioner Thomas J. Schneider, Montana Public Service Commission
Mr. Richard L. Hinckley, General Counsel, Public Utilities Commission of Nevada
Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
Chairman Lee Beyer, Oregon Public Utility Commission
Commissioner Dustin Johnson, South Dakota Public Utilities Commission
Commissioner Barry Smitherman, Public Utility Commission of Texas
Chairman Ric Campbell, Utah Public Service Commission
Chairman Mark Sidran, Washington Utilities and Transportation Commission
Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission

The West Joint Board met in public session on November 13, 2005 in Indian Wells, California and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1)"to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report contains four sections in addition to this introduction: Section II provides a description of the basic concept of SCED used in the study; Section III provides background on the variations in dispatch procedures in the west; and Section IV gives a summary of the issues raised and considered by the Joint Board, together with recommendations to address these issues. The principal source material for this Report include [i] presentations to the Joint Board, [ii] written comments submitted to the Joint

Board, [iii] discussions among the Joint Board members at Board meetings and otherwise, [iv] the DOE report under EPAct 2005, Section 1234[4], and [v] the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: the Basics

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch:

> "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[5]

This definition describes the basic way all utilities in the region endeavor to dispatch their own and purchased resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and seasons; the costs of generation from different units and different types of units vary greatly; and scheduled and unplanned outages in a generator fleet and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating

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[4] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005.

[5] September 30, 2005, Order at ¶14.

characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance.

Operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as required environmental limits on annual unit output, and non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

In addition, conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, transmission path congestion (line capacities as affected by loading levels and flow direction), inadvertent loop flow and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive but better situated generators may have to replace cheaper units.[6] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized while the necessary level of service is maintained. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure that they stay within reliability limits and voltage stays within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes. The Western Electricity Coordinating Council (WECC) provides reliability related service throughout the Western Interconnection and closely monitors the condition of the network.

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[6] This is known as "out of merit" dispatch.

III. Economic Dispatch in the West

The practice of economic dispatch in the West varies by area. For purposes of this report, we will organize the discussion around the four areas used by WECC. These subregions[7] are shown in Figure 1 and are as follows:

- Northwest Power Pool Area (Northwest)
- California-Mexico Power Area (California)
- Arizona-New Mexico-Southern Nevada Power Area (Southwest)
- Rocky Mountain Power Area (Rockies)

The overall pattern of dispatch in the West depends to a large extent on differences between the resources and loads in each area. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in the north to peak loads in the south, while power in the winter flow from south to north to meet the peak loads in the northwest. The north-south transmission system has developed to support this pattern, and provides for overall economic utilization of generation resources when water conditions permit. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west, in California and the Pacific Northwest. The electric transmission systems reflect the need to move power west from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power comes from baseload plants that run year round.

The CAISO is the one multi-utility area market in the west that is centrally organized and dispatched. The remainder of the areas in the west perform economic dispatch on a cooperative but decentralized basis, with a form of control area or utility dispatch similar to the basic dispatch described in the previous section. However, there is considerable variation in individual practices in each area that distinguish the way economic dispatch is practiced. The variations in regional practice are discussed briefly below.

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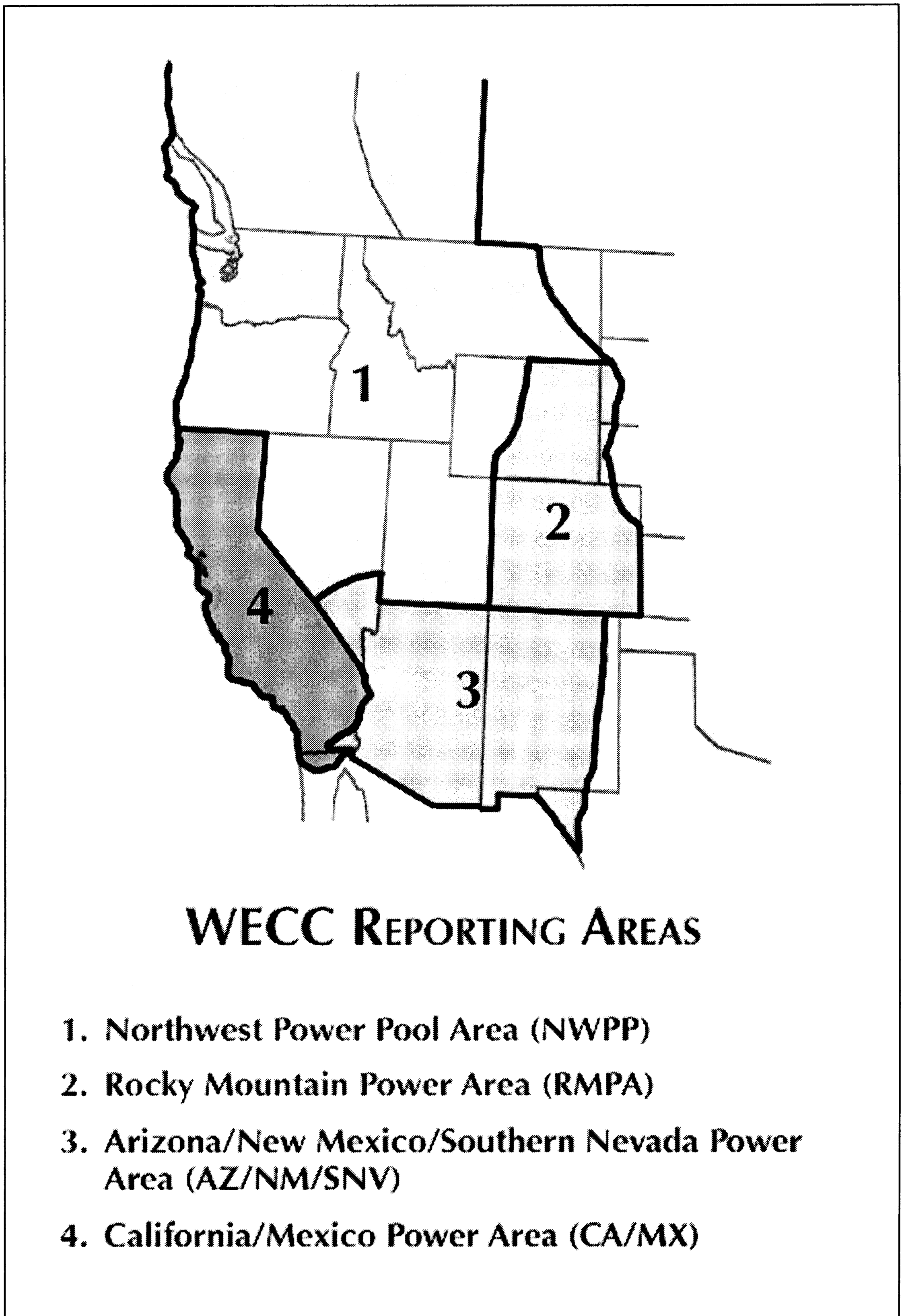
[7] Because the Western Interconnection is coextensive with the area being studied by the West Joint Board, Commissioner Smith recommended using the term "subregion" when referring to less than the entire Western Interconnection region. Transcript of February 13, 2006, meeting of West Joint Board, hereinafter Tr. 2, pp. 49-50.

Figure 1. Western Regions for Economic Dispatch Discussion



A. Northwest

Although significant hydropower resources exist throughout the west, they dominate power generation in the Northwest. Fifty eight percent of capacity in the Northwest is conventional hydropower; seventy nine percent of the total western hydropower resources occur in the Northwest.[8] In the west as a whole, hydropower accounts for thirty four percent of the total capacity.[9] This level of hydropower resources alters the way economic dispatch is performed in the Northwest and in the entire west, making western dispatch issues significantly different from those in the Eastern Interconnection and ERCOT.

Several characteristics of hydropower have direct implications for dispatch in the Northwest:

- Economic dispatch needs to consider the overall optimization of hydropower and thermal resources, making the problem of resource optimization much more difficult than it is in a power system based exclusively or primarily on thermal resource capacity.
- Hydropower generation resources in the Northwest are highly interdependent, so that they need to be dispatched as a coordinated system for power generation, rather than as separate, independent power sources.
- Conventional hydropower is generally limited by the total available energy stored in the water behind the dams, not by the total generating capacity of the resource.
- Hydropower can generally be dispatched very quickly when available, providing an abundance of low cost, rapidly dispatchable capacity to an extent not present in the other North American interconnections.

These characteristics have led to a long history of coordination in the Northwest, beginning around 40 years ago with the Columbia River Treaty with Canada and the Pacific Northwest Coordination Agreement (PNCA), and including the Mid-Columbia Hourly Coordination Agreement (MCHA). The PNCA enables both Federal and Non-Federal projects to operate as a single utility owner to optimize power and nonpower river demands, while the MCHA optimizes the hydraulic operation of seven dams on the Columbia River. The MCHA permits hydropower resources to provide load following for much of the Northwest load, and hydropower resources also provide regulation and reserves at a low cost.

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[8] WECC, 2005 Information Summary, Total Existing and Planned Generation, p. 6.

[9] *Id.*

Another factor affecting Northwest dispatch is operation of BPA's transmission assets, which are closely connected to the operation of hydropower resources. Historically, the coordinated operation of the system of dams meant that all power was treated equally regardless of location on the system, so that a megawatt had the same value at any location. Until relatively recently, there were few constraints on the BPA transmission system, so there was sufficient transmission capacity to ensure that coordination would work successfully. In the last few years, there have been an increasing number of internal constraints; and BPA is now moving toward a power flow based methodology to more accurately capture transmission effects in dispatch.[10]

The coordination of power and non-power uses leads to determining the optimum power operation *within* the non-power constraints. This optimum operation is distinct from the objective of minimizing short term operating costs. The valuation of hydropower resources for short term dispatch presents unique challenges when such a high percentage of resource is low cost in the short term and potentially high (and uncertain) in value over the longer term.

Although the presence of hydropower in the Northwest significantly affects the overall operation and dispatch of the power system, the basic dispatch remains decentralized and economic dispatch is conducted on a utility by utility basis rather than being coordinated centrally. Plans for the development of a RTO in the Northwest are not being actively considered; but Columbia Grid has recently begun efforts to form a grid organization in the Pacific Northwest.

Based on the responses to the DOE survey and the utility presentations at the initial meeting of the West Joint Board, utility dispatch in the Northwest is similar to the basic model described in the Section II, once operations are adjusted for the presence and limitations of hydropower. The main difference is less emphasis on day-ahead unit commitment of thermal resources to provide load following and reserves, because hydropower is generally the lowest cost alternative for these functions and will be used when available. Utilities report dispatching a mix of their own generation, independent generation committed under contract, and wholesale spot market purchases, combined to achieve the lowest cost from the resources available. These dispatch decisions are generally made before the operating day, either in the day ahead planning or earlier, and take into account factors other than strict operating costs, such as environmental limits, fuel contract terms, opportunity cost of company-owned hydropower, and similar factors.

[10] BPA, Economic Dispatch in the Pacific Northwest, presentation to the meeting of the West Joint Board for the Study of Economic Dispatch, Palm Springs, CA, November 13, 2005. (FERC Docket No. AD05-13-000)

Although planning for dispatch may take into account a wider range of sources, hourly or real time adjustments are often restricted to company owned resources or resources under contract that permit the utility sufficient flexibility in the terms of the dispatch.

B. California

The California ISO (CAISO) performs an economic dispatch covering most of California, with the exception of some control areas.[11] Formed in 1998, the CAISO dispatches a single control area, corresponding to the former control areas of California's three largest Investor Owned Utilities. Prior to the formation of the CAISO, each of the three control areas performed single utility economic dispatch, by dispatching their own resources and other resources under their control. This dispatch was similar to the basic dispatch process described in Section II, using the costs of the generation resources to establish the order of the dispatch and running the lowest cost resources available, given the security constraints of the system.

The CAISO consolidated the dispatch of the three utilities into a single dispatch for approximately 45,000 MW of California peak load, by balancing generation and load every 10 minutes based on market bids from generation resources. This balancing market was similar to the previous control area balancing function in that lower cost generation resources were dispatched before higher cost resources; however, the traditional utility costs were replaced by bids to the CAISO. This change altered the economic dispatch process in two fundamental ways: [i] all resources capable of being dispatched were eligible to submit bids on an equal basis, and [ii] the market bids that replaced the utility production cost estimates were no longer required to be tied to actual production costs of the utility.

In October 2004, the CAISO began the Real Time Market Application (RTMA), a new market application that plans a 5 minute dispatch for 2 hours in the future, dispatches online resources on a 5 minute basis in real time, and starts "fast start" resources on a 15 minute interval. A Market Redesign and Technology Upgrade (MRTU), planned for late 2007, will include the use of market bidding for day ahead planning and unit commitment, and greater detail in representation of the transmission grid for more accurate representation of the security constraints in the economic dispatch decision. These changes will enhance the dispatch processes of the CAISO, but will not change the basic differences between the CAISO dispatch and dispatch in the rest of the west: CAISO will continue to perform the only centralized, multiple-utility, market-bid-based

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[11] Examples of control areas inside California, but not included in the CAISO dispatch are the Los Angeles Department of Water and Power in Southern California, Sacramento Municipal Utility District in Northern California, and a few others throughout the state.

economic dispatch in the west. Although the CAISO is the only area in the West with this type of dispatch, its operation has significant effects on dispatch in the rest of the west because the total load in California is large (approximately thirty percent of the summer peak load for the west)[12] and California relies on significant imports from the rest of the west. Because California is so closely dependent on imports from the rest of the west, and because long distance power transactions are an important factor in overall power flow, the centralized dispatch in the CAISO has greater direct impact on other areas in the WECC than comparably-sized centralized dispatch in the Eastern Interconnection has on other areas in the east.

The CAISO dispatch includes all resources needed to serve the load, both those that can be dispatched on a 5-minute basis and those that are not capable of responding to 5-minute dispatch signals. The non-dispatchable resources include generating plants that must be run for longer time periods, such as nuclear plants, as well as imports into the CAISO control area. These imports follow scheduling procedures set for the WECC as a whole, and must conform to fixed hourly schedules for exchanging power between control areas. Although imports are eligible to bid into the CAISO market for dispatch in real time, they must do so on an hourly basis and cannot be varied in the real time dispatch.

The CAISO is still evaluating the current implementation of real time dispatch, the RTMA, but notes two changes from the previous economic dispatch.[13] First, prices have become more volatile and the fluctuation of the dispatch has increased. This result is consistent with the change in the design of the dispatch, which was intended to promote more frequent balancing of generation and load and produce market prices that more closely mirrored that balance. Second, RTMA has improved the handling of "start up" problems, including improved pricing of import/export bids. Coordination of the balance of hourly exports/imports and 5-minute generation dispatch continues to be a challenge, however, particularly when load is rapidly fluctuating.

C. Southwest and the Rockies

Although the Southwest and Rockies are separate areas, they have a single reliability coordinator, located at the WECC Rocky Mountain/Desert Southwest Reliability Center (RDRC) in Colorado. Both areas rely principally on thermal resources, but face somewhat different issues in performing economic dispatch. The Southwest has a larger amount of hydropower capacity in the generation mix, and has a significantly greater

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[12] Based on a summer peak load of 141,100 in 2004, *WECC, 2005 Information Summary*, p. 2.

[13] *Assessment of Economic Dispatch Practices at the CAISO*, initial Meeting of the West Joint Board on Economic Dispatch, November 13, 2005, p. 18.

level of trade with California.

Natural gas is the largest single source of generation in the Southwest, followed by coal and nuclear. Hydropower also plays a significant role, with slightly over ten percent of the total area capacity. Dispatch throughout the area is by individual utilities that perform unit commitment and economic dispatch of the own resources, supplemented by resources controlled by contract and purchases from the spot market. Generally, the large base load plants are located near fuel sources that are remote, and in some cases hundreds of miles away from the load centers. These base load units may be jointly owned, each with its own dedicated capacity that needs to be dispatched. Consequently, the availability of transmission facilities is a factor that must be taken into account in the economic dispatch. This general pattern of utility dispatch is followed by large investor owned utilities such as Arizona Public Service, large projects such as the Salt River Project, and smaller cooperatives and public power entities. Thus the Southwest dispatch is similar to the basic model described in the Section II, and does not have the extensive procedures needed to coordinate the dispatch of the hydropower resources of the Northwest, nor has it adopted the centralized dispatch procedures used in the CAISO. Active spot markets exist at the Palo Verde, Four Corners and Mead hubs, providing a basis for price discovery in the Southwest and points of reference for including wholesale purchases in the economic dispatch.[14]

El Paso Electric (EPE), the only Texas electric provider in the Western Interconnection, is a small part of that grid, and is in a particularly constrained area to the extent that, in the short run, moving to a broader regional dispatch may have little impact for EPE. However, Texas believes there are longer-term regional and national benefits that could be obtained from a more coordinated dispatch through more efficient fuel use and the development of the competitive wholesale electricity market in the western region.[15]

Like the Southwest, the Rockies generation resources are largely thermal, with coal being the largest generation resource, followed by natural gas, and dispatch follows the single utility approach, together with use of resources under contract and spot market purchases. The utilities serving this area utilize WECC's services in coordinating and promoting electric system reliability on the Western Interconnection. WECC supports efficient competitive power markets, open and non-discriminatory transmission access among members (including, e.g., BPA, CAISO, LADWP, and many privately and cooperatively held utilities serving throughout the West), provides a forum for resolving transmission access disputes, and fosters coordination of the operating and planning activities of its members.

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[14] *See,* DOE survey comments of APS, Salt River Project and Arizona Electric Power Cooperative on the use of wholesale spot purchases in the dispatch.

[15] *Texas Perspective on Security Constrained Economic Dispatch*, p1.

D. Western Systems Power Pool

Trading between utilities and between sub-regions of the West improves the dispatch of resources. Such trade is enhanced by the Western Systems Power Pool (WSPP). As discussed above, there is a long history in the West of both seasonal (north-south) and resources-to-load (east-west) power movement. For these reasons, there has been an active wholesale electricity market in the West for decades. This market became more formalized in 1987, when FERC approved the WSPP. The WSPP has provided a platform for short-term transactions throughout the Western Interconnection for economy energy, unit commitment, and firm sales or exchange services. With over 220 WSPP members (virtually all market participants), the WSPP agreements are the most widely used standardized power sales contracts in the electric industry.

As a result, this readily available platform for day-ahead and real-time transactions adds an important dimension to SCED in the West. (Even entities within the CAISO, many of which are WSPP members, can use the WSPP agreements to import power if the transmission capability exists.) It allows Western electricity market participants to use risk management strategies more effectively in order to meet their load service obligations at the lowest cost practicable and in a reliable manner. These wholesale activities provide enhanced operational flexibility, particularly when water available for hydroelectric generation is subnormal, unplanned generation or transmission outages occur or transmission constraints exist. They also provide economic flexibility based on how wholesale prices compare with marginal generation costs. Thus, the ability to trade electricity on a West-wide basis greatly influences the process of economic dispatch.

This has led to the development of numerous robust wholesale trading hubs in the Western Interconnection, such as Mid-Columbia, Palo Verde, California-Oregon Border, North Path 15, and South Path 15, where numerous wholesale electricity purchases and sales occur on a daily basis. Sales volumes and prices at these hubs are reported on a voluntary basis to ICE (IntercontinentalExchange Inc.), Dow Jones, and other reporting services, aggregated by hub, and made public daily. Sales by jurisdictional utilities are also reported to FERC in Electronic Quarterly Reports.

IV. Issues and Recommendations

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues..

The Joint Board makes two general observations regarding any approach to issues relating to SCED. First, Joint Board members generally believed that there should not be a "one size fits all" approach to the use of SCED. Differences among the areas in the west, and often differences within each area, are too large to warrant recommending a single form of SCED for all areas or utilities. Second, the focus of changes from current practices should be at the state or local level. Regional or subregional changes should be based on collaborative efforts among utilities, other market participants and states, rather than on legislative or regulatory initiatives at the federal level.

Recommendations from the DOE report to Congress on the value of economic dispatch are discussed at the end of this section.

A. Observations

Introduction

A number of general issues have been raised about the nature of economic dispatch, its scope and uses, and implications for affordable and reliable service to electricity consumers. These general issues include:

- Relative importance of hourly dispatch costs
- Least cost production may not be lowest cost for the ratepayer
- The broad choice between cost-based and bid-based dispatch

Relative importance of economic dispatch.

Some board members and market participants expressed the desire to put the implications of economic dispatch in an overall cost perspective. In terms of total overall cost, economic dispatch, when framed in terms of daily and hourly dispatch, was felt to be relatively unimportant compared to long term investment in generation and transmission.[16]

Least cost production may not be lowest cost for the ratepayer.[17]

This issue was raised by several board members, in reference to environmental costs, the nonpower issues of hydropower scheduling, and other considerations. The concern was that many factors are considered in the unit dispatch decision that cannot be easily translated into short term monetary terms, so that exclusive emphasis on minimizing daily or hourly production costs could prove to be more expensive to the ratepayer in the long run.

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[16] Commissioner Schneider,Transcript of first West Joint Board meeting (Tr.) at 116.

[17] Commissioner Beyer, Tr. at 114.

Choice of cost based or bid based dispatch.

This issue focused on the idea that economic dispatch often arose in the context of choice between two different systems of dispatch. The cost-based system referred to the basic single utility dispatch where a utility dispatched its own units based on its own generation costs and other factors, and was compared to a system with a separate grid operator that dispatched generation resources based on bids to supply power and then set a market price for the power based on the bids. Each overall approach gave rise to different sets of specific issues regarding the factors to consider for SCED. One board member noted the existence of these different approaches, and proposed that the board not recommend a single approach to this issue.[18]

B. Specific Dispatch Issues

Introduction

The specific dispatch issues raised varied by subregion, with different issues raised in each of the areas of the west, and by market segment within regions, and with different issues raised by utilities, independent power producers, grid operators and state regulators. These specific issues are listed below and discussed in the remainder of this section.

- Independence of dispatcher
- Utility dispatch of third party power through contracts
- Transparency of dispatch information and processes
- Consolidation of control areas
- Regional scope benefits
- Import/export schedule changes within an hour

Independence of dispatcher.

A representative from the independent power producers (IPPs) recommended that some type of independent transmission dispatch was needed so that independent power producer resources could be fully integrated in the hour-to-hour operation of the dispatch.[19] In discussion, the IPP representative stated that dispatcher independence was

[18] Commissioner Campbell, Tr. at 110
[19] Mr. Kahn, Tr. at 91.

a prerequisite for merit order dispatch.[20]

Board discussion:
There are three dispatch models employed in the Western Interconnection: [i] the California Independent System Operator (CAISO), [ii] individual utilities performing economic dispatch within their control areas, and [iii] public and private utilities cooperating to dispatch the Northwest's multi-owner hydroelectric system.[21] All three models may be assisted by the WSPP. Faced with a variety of different operating scenarios and the issues they raise, including those concerned with the performance of independent operators, states should be allowed to deal with these issues themselves. Texas states that "having an independent grid coordinator with access to comprehensive regional information can significantly enhance reliability and market operations."[22] However, there is little enthusiasm among other Joint Board Members for creating new independent dispatchers where the current system is functioning properly; and "joining or not joining a regional dispatch entity should be up to each utility and the negotiation with their regulatory body."[23] Decisions on dispatcher independence should be flexible and responsive to the needs of the state [24] Independent entities should not be created for their own sake:

> Where utilities perform dispatch functions and do so fairly and efficiently, they should not be supplanted with an independent dispatcher simply for the sake of having one. Utilities operating in such a manner should be involved with the development of independent dispatching entities.[25]

In addition to a general caution regarding significant changes to existing dispatch practices, two recommendations were put forward: (1) keep any structural changes flexible and sensitive to the needs of the states; and (2) make changes voluntary wherever possible.[26] Several board members cited this issue in their summary remarks.[27] In addressing the question, regulators should remember that both public and private entities serve load in many areas. All have duties to serve the public but all do not have the same

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[20] Mr. Kahn, in response to a question from Commissioner Grueneich concerning whether a utility would always favor its own generation, Tr. at 94.

[21] Commissioner Campbell, Tr. 2, p. 38; and Commissioner Smith, Tr. 2., p. 38.

[22] *Texas Perspective on Security Constrained Economic Dispatch*, p2.

[23] Mr. Brown, Tr. 2., p37.

[24] Commissioner Sidran, Mr. Brown and Commissioner Grueneich, Tr. 2, pp. 36-39.

[25] *Wyoming Discussion Points*, February 3, 2006, p. 1.

[26] Ms. Edwards, Tr. at 73.

[27] Commissioner Greuneich, Tr. at 111; Commissioner Beyer, Tr. at 115.

level or type of regulatory oversight.[28]

Recommendation:

We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is later deemed warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

Utility dispatch of third party power through contracts.

This issue was cited by both utilities and non-utilities, with utilities sometimes arguing that it was difficult to obtain sufficient performance and reliability from third party contracts. One utility stated the primary difficulty with incorporating non-utility generation in their dispatch was their "inability to complete alternative actions in a swift and economic manner."[29] Independent power producers stated the opposite position, arguing that their generation was flexible and capable of being very responsive, but that they were often denied the ability to dispatch power by utility generation owners who controlled the dispatch, particularly in the case of hourly dispatch and ancillary services.[30]

Board discussion:

This issue describes the ongoing tension among IPPs and incumbent utilities on the subject of IPP integration; and the independent producers should play a constructive and full role in the development of a system capable of accommodating them. IPP integration should be approached as part of a cooperative effort, overseen on a subregional level by appropriate entities or on an interconnection-wide level by WECC through its committee process. Entities should carefully consider the potential reliability and dispatchability impact of the IPP on the Western Interconnection or relevant portions thereof and should make sure that the IPP bears its fair share of the costs of integration with the system, including the up-front cost of creating any independent dispatch capability to accommodate their participation. Thus, consideration of "merit order" dispatch should be done in the context of an overall cooperative effort and not as a goal in and of itself. The ultimate end of the effort is to serve the consumers better and more efficiently, and consideration of when to dispatch will likely have less monetary impact on consumers

[28] Commissioner Sidran, Tr. 2, p. 40.

[29] Portland General Electric response to DOE survey, p. 2.

[30] Mr. Kahn, Tr. at 88.

than will wise choices of what resources to build.[31]

Further progress will require basic contract commitments by IPPs regarding dispatchability and other issues. EPSA and EEI proposals to develop standard contract terms should be encouraged.[32] In summary, Commissioner Kelly cited the following member's observation as the consensus of the Joint Board that it should:

"Encourage contractual commitments by independent producers to provide energy in a manner consistent with the utility's dispatch, but do not require utilities to purchase nonutility power."[33]

Recommendation:
We encourage, but do not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing dispatchability and other issues. The Joint Board recommends the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with the relevant LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

Transparency of dispatch information and processes.

One of the benefits cited for an independent entity dispatching all resources in a region was the ability to provide a transparent process for the dispatch. One utility representative argued that full value economic dispatch would not be fully realized without this transparency.[34] Without the independence condition, sharing sensitive real-time information between a utility transmission provider and third parties can be viewed as an impediment to dispatching economically.[35]

Board discussion:
Transparency of information and process can enhance the dispatch function, but the desire to promote transparency should not drive the decision as to whether or not an independent dispatch entity is needed. Transparency is not an end in itself. It can further some of the goals of economic dispatch, but should not serve as a rationale for creating

[31] See, *Wyoming Discussion Points*, February 3, 2006, pp. 2-4.
[32] See discussion of the Second DOE Recommendation in section C of this document.
[33] Tr. 2, p. 41; and Attachment C to Supplemental Notice of Second West Joint Board Meeting in FERC Docket No. AD05-13-000, p. 1.
[34] Mr. Larson, Tr. at 49.
[35] Discussion between Commissioner Smith and Mr. Larson, Tr. at 53 and 54.

an independent entity to achieve transparency. Furthermore, one board member observed that too much market knowledge can potentially foster collusion which can do damage to the market ostensibly being helped.[36] Transparency of information can be a benefit to a region, but that benefit is not in itself sufficient to support a mandate for regional economic dispatch.[37]

In a related observation, the Department of Energy suggested that there should be further study of the "impact of the accuracy of load forecasting and quality load forecasting on the results of economic dispatch." If the quality of forecasted information is low, the resulting dispatch may be wasteful. DOE suggested the study look at the costs of suboptimal forecasting and "ways to improve the quality of forecasting to improve economic dispatch."[38]

Recommendation:
Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. We recommend that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

Consolidation of control areas in a region.

The current single-utility dispatch means that each utility first determines a dispatch for its own area with only limited knowledge of conditions in other areas. In the Western Interconnection, WECC provides important real time information on the status of the grid which assists dispatchers. However, coordination among control areas may sometimes be based on limited information on generation availability in other areas and constraints on transmission available for imports and exports between control areas, when compared to the information available within each control area. The larger the number of areas, the greater the potential benefit of consolidating control areas, in principle, arising from better information available to the dispatchers and better control over generation and transmission resources. Some presenters recommended that control areas be consolidated, citing the large number in an area like the Northwest.[39] Others argued that there were potential benefits to SCED from consolidation, without taking a position on whether the benefits of consolidation would exceed the costs.[40] Texas cited the ERCOT example of combining ten control areas into one as providing evidence of significant

[36] Commissioner Schneider, Tr. 2, p. 44.
[37] Commissioner Sidran, Tr. 2, p. 42.
[38] Ms. Silverstein, Tr. 2, p. 62.
[39] Mr. Kahn, Tr. at 89.
[40] BPA in comments submitted in the docket.

benefits from control area consolidation and regional dispatch.[41]

Board discussion

Consolidation of control areas should be approached rationally rather than making consolidation an aim in itself. Single utilities do not dispatch in an informational vacuum, but frequently are in contact with relevant control centers and entities throughout the Western Interconnection. Very large control areas encounter problems in dealing with 15-minute import/export exchange to ameliorate problems of scheduling on the hour. However, it is also true that larger control areas can be a positive development if the integration of smaller control areas makes operational sense. This is especially true for wind resources which can benefit from being part of larger and hence more diverse control areas. The focus should be on the technological advisability of consolidation and not on simply reaching the goal of larger and larger control areas.[42] The geography of the West has already helped to create relatively large control areas, which is not always the case in other parts of the nation. We therefore must be careful to examine the costs and usefulness of further consolidation.[43] WECC's three reliability centers which can see the entire Western Interconnection should be an integral part of the analysis of control centers. WECC is now studying its reliability centers to determine both the number of centers needed in the future and what tools are required to see the whole of the Western Interconnection at once and to issue reliability directives. Commissioner Smith cautioned against creating new single-generator control areas.[44]

Increasing the size of the dispatch region, even without consolidating regions into a single control area, can lead, in principle, to a lower cost dispatch through inclusion of more generation and transmission resources. However, there appeared to be no consensus on whether such regional benefits exist in practice. Some cited regional benefit studies that concluded there were positive net benefits; for example, the representative from the Independent Power Producers cited a recent study for Grid West as demonstrating benefits.[45] One utility representative stated that there were potential benefits from regionalization, without citing a specific study. However, at least some board members felt the current system of utility dispatch coupled with spot and short term market purchases worked efficiently. One board member cited the adage, "If it ain't broke, don't fix it."[46]

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[41] *Texas Perspective on Security Constrained Economic Dispatch*, p1.

[42] Commissioner Campbell, Tr. 2, pp. 45-46; and his comment approving *Wyoming Discussion Points*, February 3, 2006, p. 3.

[43] Commissioners King and Johnson, Tr. 2, pp. 47.

[44] Commissioner Smith, Tr. 2, pp. 47-49.

[45] Mr. Kahn, Tr. at 90.

[46] Commissioner Baca, Tr. at 119.

The west should carefully examine the usefulness of creating larger dispatch regions on an individual basis. Participation by major stakeholders should be assured before meaningful consolidation can take place. The west should draw on the well developed grid management experience of institutions such as WECC, and on the wholesale market facilitation and coordination experience of entities such as WSPP, to assist in deciding whether or not to form larger dispatch -- or control -- areas. Case-by-case examination would better fit with the diversity encountered in the Western Interconnection than would a blanket consolidation mandate.[47]

Recommendation:

We recommend that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. Any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and we recommend that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

Import/export schedule changes within an hour.

The CAISO identified large hourly schedule changes as a problem for their dispatch. The source of this problem is that schedules between control areas change at the beginning of each hour and remain constant for the hour. Because the CAISO often has large amounts of imported power at the same time that it has large changes in load over the hour, it becomes difficult to accommodate these large blocks of hourly imports while following a volatile load.[48] To address this issue, CAISO recommended spreading the changes out over the hour to decrease the magnitude of each change.[49] Scheduling could still occur on an hourly basis, but each hourly schedule could increase or decrease on a less than one hour basis, for example, on 15 minute intervals. Because scheduling imports and exports between control areas in the west follows a standard protocol, developing the ability to provide schedule varying on 15 minute intervals would require coordinated development of such a change throughout the west.[50] One board member cited this recommendation positively, but there was no further comment from other board members at the initial meeting.[51]

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[47] Commissioner Lewis, Tr. 2, p. 50.

[48] Mr. Rothleder, Tr. at 38.

[49] Mr. Rothleder, Tr. at 41.

[50] Mr. Rothleder, Tr. at 39.

[51] Commissioner Campbell, Tr. at 110.

Board discussion:

Although this is, at this time, a situation most focused on California and the CAISO as it confronts loads which are more volatile than imports over the hour, the Board in general supported the concept.[52] Oregon's experience shows that hourly scheduling of interchanges between utilities is complicated by relatively slow ramp rates which can cause utilities to experience imbalances. Allowing for ramp rate changes, e.g., 10 minutes before and after the hour, could significantly reduce these imbalances. The Board accepted this addition as an important consideration for further work on the topic.[53]

Recommendation:

We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the top of the hour.

Some practical limitations on economic dispatch.

The heavy and increasing reliance on natural gas as a generator fuel must be included in future studies of economic dispatch. Recognizing that it is subject to substantial price volatility, the ideal might be to dispatch the most efficient natural gas plants to make the best possible use of our natural gas resources. The study of the challenges inherent in the use of natural gas may begin with the distinction between economic dispatch and efficient dispatch. The United States Department of Energy has described the differences between these concepts:

> In a recent hearing of the Senate Energy and Natural Resources Committee*, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will *usually* run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.
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> Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

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[52] Commissioners Grueneich and Kelly, Tr. 2, pp. 51-52.

[53] Mr. Brown and Commissioner Kelly, Tr. 2, pp. 52-53

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs.
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.[54]

* Senate Committee on Energy and Natural Resources, Full Committee Hearing – Hurricane Recovery Efforts, October 27, 2005

Board discussion:

SCED is defined above in Section II of this report sufficiently broadly to include more localized reliability concerns. Therefore, the definition of SCED should not later be so narrowly construed that it makes it impractical or too costly to incorporate such local reliability and other considerations in regional, subregional or state analyses.

California observed, as a practical matter, that it would probably have to keep older and less efficient natural gas-fired plants in operation to deal with more localized issues of reliability and system congestion. This goes to the heart of how we define economic dispatch in the future and means that there must be practical rather than only theoretical assessments of system capabilities and costs. Commissioner Grueneich of California observed that, to accommodate these considerations, either [i] the definition of economic dispatch should be broadened to take such reliability-related issues into account, or [ii] the inquiry should be taken beyond economic dispatch to allow these issues to be considered.

Similarly, California recommends incorporation of renewable generation in the economic dispatch process. In California, economic dispatch also means incorporating the State's policy of encouraging the development of renewable energy sources and the preferred resource loading order. California's "Energy Action Plan II" includes a loading order that identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs followed by renewable generation, combined heat and

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[54] *The Value of Economic Dispatch: A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 11. Text of report found at http://www.electricity.doe.gov/document/value.pdf

power and distributed generation, and traditional fossil resources. Some other states across the country have also adopted renewable portfolio standards in many ways similar to California's but with different regional goals which reflect public policy in those individual states.[55]

Even with overall goals of trying to address natural gas prices and of implementing direct economic dispatch, the local cost and reliability issues will vary to such an extent that each particular situation should be examined closely -- "on a very decentralized basis."[56]

Better service to the people is the primary goal of this inquiry. Issues of reliability and system congestion can have region-wide implications, but they also have a strong local dimension which can keep purely theoretical economic dispatch from being the best or most realistic solution. The best way to deal with such challenges is to make analyses on a case-by-case basis, not ignoring economic dispatch but recognizing that it is not an end in itself and that it should not be promoted with disregard for its local effects.

Recommendation:

We recommend that the definition of security constrained economic dispatch be broadened to include other public policies, values and physical and operational constraints as well as costs.

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, *The Value of Economic Dispatch*, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

First DOE Recommendation: review dispatch practices

FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct Economic Dispatch.[57] These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices

[55] Commissioner Grueneich, Tr. 2, pp. 11-13.

[56] Commissioner Grueneich, Tr. 2, pp. 57-58.

[57] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 52.

from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow IPPs and other resources to compete effectively and serve load.

Board discussion:

The study recommended here was generally seen as being at odds with the general consensus of the Joint Board that economic dispatch has to be a flexible concept, capable of adapting to the varying needs of different states and subregions in the Western Interconnection. The study would take us deeply into variables and deviations from "pure" economic dispatch without providing much value. [58] On the other hand, California, with its substantial unregulated municipal utility presence, could benefit from a better understanding of how these entities make economic dispatch decisions, although jurisdictional and funding issues probably make the issue unripe at this time.[59] The new rules presupposed in this recommendation may be incorrectly assumed necessary. The recommendation is also at odds with the complexity of economic dispatch issues in the Western Interconnection.[60] The Joint Board generally agreed that this recommendation should not be pursued. However, Texas believes that there are potentially significant benefits from SCED that warrant study and disagrees with the recommendation not to pursue further study at this time.[61]

Recommendation:

The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

Second DOE Recommendation: standardize dispatch contract terms

FERC and DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts.[62] Specifically, the EEI has proposed that [i] IPPs should commit to provide energy at specified prices for specified times to meet unit commitment schedules, and [ii] there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

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[58] Commissioner Sidran, Tr. 2, pp. 23-24.

[59] Commissioner Grueneich, Tr. 2, pp. 24-25.

[60] Commissioner Smith, Tr. 2, pp. 25-26; Commissioner Schneider, Tr. 2, p. 26.

[61] Commissioner Smitherman, Tr. at 126-28.

[62] *DOE Report* at p. 51.

Board discussion:

A high level of cooperation already exists in the electric industry and among the non-utility generators regarding contracts.[63]Existing initiatives should be the vehicle for crafting standard language of the kind envisioned in the Recommendation and therefore it should be pursued by industry and the IPPs rather than through duplication by the Joint Board or the federal government. The Recommendation rightly recognizes the value of communication among stakeholders to refine their relationships. The Joint Board recognizes the valuable and ongoing work of the North American Energy Standards Board (NAESB) to promote well crafted standardized contracts to encourage efficiency in the electric and natural gas marketplaces.[64] We also encourage EPSA and EEI to go forward with standard contract language proposals. We believe that these existing initiatives should be monitored and encouraged but not duplicated.[65] Regional differences in some cases may be so pronounced that standard contracts should take them into account. Thus, a Western Interconnection contract might of necessity differ from one employed in the East. We note the difference between on-peak products in the East and the West.[66] Wyoming's comment on this subject summarizes the Joint Board's response to this recommendation: [67]

> We think this recommendation should be pursued on a regional basis rather than on a national basis. The regional variances in grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis. This does not mean that standardized terms are per se are a bad idea or that federal resources such as those of the DOE should not play an important collaborative role.

Recommendation:

We recommend that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

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[63] Mr. Hinckley, Tr. 2, p. 28.

[64] Commissioner Sidran, Tr. 2, p.32

[65] Commissioner Smith, Tr. 2, pp. 31-32.

[66] Commissioner Campbell, Tr. 2, p. 31; and New Mexico Comments of February 13, 2006, p. 3.

[67] Commissioner Lewis, Tr. 2, pp. 28-29; and Commissioner Campbell, Tr. 2, p. 31; and *Wyoming Discussion Points*, February 3, 2006, p. 4.

Third DOE Recommendation: review dispatch tools

Current economic dispatch technology tools deserve scrutiny.[68] These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

Recommendation:

We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.[69]

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[68] DOE Report at p. 53.

[69] Commissioners Smith, Grueneich, and Mr. Hinckley, Tr. 2, pp. 33-34.