

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security  
Constrained Economic Dispatch

Docket No. AD05-13-000

SUPPLEMENTAL NOTICE OF SECOND PJM/MISO JOINT BOARD MEETING

(February 10, 2006)

On January 6, 2006, the Commission announced that it planned to hold further joint board meetings and that these meetings would take place at the Hyatt Regency on Capitol Hill, 400 New Jersey Avenue, N.W., in Washington D.C. Take notice that the joint board meeting for the PJM/MISO region is scheduled to take place on Sunday, February 12, 2006, from 12:30 p.m. to 3:00 p.m.(EST) in the Yorktown Room.

These meetings are held pursuant to section 1298 of the Energy Policy Act of 2005, Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005). Section 1298 adds section 223 to the Federal Power Act, 16 U.S.C. §§ 824 *et seq.* (2000), requiring the Commission to convene joint boards on a regional basis pursuant to FPA section 209 “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.”

Take further notice that attached are: (1) an agenda for the meeting, (2) a draft study previously circulated to the board members, and (3) recommendations to be considered by the board.

A complete and updated list of board members is available at [www.ferc.gov](http://www.ferc.gov).

For more information about the meeting, please contact Sarah McKinley at 202-502-8004 or [sarah.mckinley@ferc.gov](mailto:sarah.mckinley@ferc.gov).

Magalie R. Salas  
Secretary

Attachment A

**AGENDA FOR THE PJM/MISO JOINT BOARD MEETING  
February 12, 2006**

- Opening remarks
  
- General comments on draft study previously circulated
  
- Recommendations proposed during the course of the Joint Board's activities
  - Recommendations for the Board's consideration are attached to this agenda
  
- Process for subsequent drafts
  
- Next steps and closing remarks

Attachment B: Draft Study

**DRAFT**

**Study of Security Constrained Economic Dispatch  
By  
The Joint Board on Economic Dispatch for the PJM/MISO Region**

**January \_\_, 2006**

## Overview

The PJM/MISO Joint Board is one of four joint boards designated by the Commission under Section 1298 of the Energy Policy Act of 2005.

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.”<sup>1</sup>

In the following sections, this study provides a description of the basic concept of Security Constrained Economic Dispatch used in the study; provides background on economic dispatch in PJM and MISO, summarizes the issues raised and considered by the board, together with any recommendations made by board members or other parties to address these issues; and makes certain recommendations. 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 EAct 2005, Section 1234, and the responses to the DOE survey of economic dispatch under Section 1234.

## 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.”<sup>2</sup> This definition describes the basic way all utilities in the region dispatch their own and purchased resources to meet electricity load. The basics of security constrained economic dispatch 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

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<sup>1</sup> *Joint Boards on Security Constrained Economic Dispatch*, 112 FERC ¶ 61,353 at P 14 (2005) (September 30 Order).

<sup>2</sup> September 30, 2005 Order at P14.

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 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 environmental limits on annual unit output, 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, 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 generators may have to replace cheaper units.<sup>3</sup> 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

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<sup>3</sup> This is known as "out of merit" dispatch.

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.

### **Economic Dispatch in PJM and MISO**

The PJM and MISO consider all resources owned by market participants and then evaluate the market participants' bids as a single resource pool. The broader regional resources available to the RTOs results in a dispatch stack containing generators from all generating-owning members of the RTOs and some generation resources outside the RTOs. The results of the dispatch provide transparent prices. During the operating day, resources are called on based upon their economics reflected in their offers. The RTOs strive to dispatch the lowest cost combination of power plants on-line at any given moment, subject to operational constraints. Generally, however, the most expensive unit operating becomes the market-clearing price for energy. All sellers receive this price and all buyers pay this price.

RTOs have the specific dispatch (balancing and economic dispatch) functions as well as

“security constrained dispatch” (SCED).<sup>4</sup> SCED expressly recognizes transmission limits and other constraints that restrict the dispatch choices available to the system operator. Many of the constraints depend on possible contingencies and the dispatch must be set so that power flows would still be feasible in the event of the contingency. This requires calculation and central coordination.

The primary means of relieving congestion constraints is by changing the output of generation at different locations on the grid. This re-dispatch can be implemented through non-market procedures (Transmission-Line Loading Relief or TLRs) or market-based procedures. The market-based approach used by both the MISO and PJM relieves the constraint by sending price signals to owners of generating facilities. These price signals, called Locational Marginal Cost Pricing (“LMP”), consider both the impact of specific generators on the constrained facility and the cost to change (re-dispatch) the generation output.

The MISO and the PJM coordinate both Real-Time and Day-Ahead spot markets for energy.<sup>5</sup> This coordination is evident in the substantial price convergence in the PJM and MISO’s real-time markets.

The Real-Time market functions as a real-time “balancing market.” This market is based on voluntary supply offers to sell power and bids to purchase power (demand) submitted to the RTO by market participants. The RTOs use the voluntary offers and bids to arrange a security-constrained, economic dispatch for each market interval. For the MISO the market interval for the Day-Ahead Energy Market is one hour; while the Real-Time market dispatch interval is five minutes. PJM’s real-time market dispatch interval is also five minutes.

Once the MISO and the PJM define a security-constrained economic dispatch for a given market/dispatch interval, the RTOs determine market clearing prices in each market,

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<sup>4</sup> A reliability analysis to ensure that sufficient generation will be available in real time to meet the forecast demand. Any supplemental commitments made in this analysis are done on the basis of minimizing the cost of providing reserves. PJM refers to their dispatch program as Unit Dispatch System.

<sup>5</sup> **Day-Ahead Energy Market** – The Day-Ahead Market calculates hourly clearing prices for each hour of the next day. The Day-Ahead Market is cleared using Security-Constrained Unit Commitment and Security-Constrained Economic Dispatch computer programs that satisfy energy demand bids requirements and supply requirements. **Real-Time Energy Market** – The Real-Time Energy Market is a “balancing” market in which the LMPs are calculated every five minutes. Generators that are available but not selected in the Day-Ahead Energy Market may alter their Offers for use in the Real-Time Energy Market.

using the principles of LMP. LMP defines the marginal cost of serving the next increment (1 MW) of load at each location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. Under LMP, the market-clearing prices used for settlements will 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.

The MISO and the PJM schedule and dispatch generation in their regions using a security constrained dispatch methodology based on the prices and operating characteristics offered by generation owners in the region. This methodology results in the most economic use of resources at any given moment for the entire region, taking into account all transmission constraints, while ensuring that sufficient generation is dispatched to meet the energy requirements of the region.

Uncoordinated and separate dispatches by different utility companies in response to constraints will not be the same as a region-wide dispatch coordinated by the MISO or PJM. 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. Separate dispatches will inevitably result in higher costs.

MISO and PJM are working together to develop complementary system operations and one robust, non-discriminatory wholesale electricity market to meet the needs of all customers and stakeholders in 23 states, the District of Columbia and the Canadian province of Manitoba. The market is being developed through an open stakeholder process and is being designed to serve residents regardless of whether they reside in states with bundled or unbundled retail rates.

## **Issues**

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing those issues suggested in the record. Generally, the speakers at the Joint Board meeting and the commenters endorsed SCED as a mechanism that provides reliable energy at lower cost to consumers. Based on the discussion on the initial meeting and subsequent comments, there appeared to be a consensus that enhancements to the transmission infrastructure and the mitigation of seams between PJM and MISO would optimize the benefits of SCED. This section also discusses the recommendations from the DOE report to Congress on the value of economic dispatch.

## A. Observations

A number of issues have been raised about the nature of economic dispatch, its scope and uses, and implications for affordable and reliable service to electricity consumers. Some of these issues concerned general features of an economic dispatch that should be included in a report discussion, rather than specific issues for additional study. These general issues included:

- Efficient dispatch versus economic dispatch
- Quantifying the benefits of SCED

*Efficient Dispatch Versus Economic Dispatch.* Some entities 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.<sup>6</sup> Another state commissioner suggested that this issue and how SCED affects fuel diversity should be addressed in the Board's study.<sup>7</sup> One utility argued that efficient dispatch only considers how well a generator converts the input fuel source into electricity as measured by its heat rate, while economic dispatch improves an efficient dispatch by taking into consideration not only the heat rate but also cost of fuel delivered to the plant, the variable cost of operation and maintenance, transmission losses, transmission constraints, etc.<sup>8</sup> Neither PJM nor MISO distinguished between these concepts.<sup>9</sup>

*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.<sup>10</sup> 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 because it was flawed and

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<sup>6</sup> Letter from Chairman Schriber, Public Utilities Commission of Ohio, January 4, 2006, at 1 (Chairman Schriber at 1), and Chairman Schriber, Tr. at 25.

<sup>7</sup> Commissioner Kevin Wright, Illinois Commerce Commission, submittal to the record, January 18, 2006.

<sup>8</sup> AEP at 5.

<sup>9</sup> Mr. Harris, Tr. at 57-58 and Mr. Torgerson, Tr. at 61.

<sup>10</sup> Mr. Harris, Tr. at 43-58 and Mr. Torgerson, Tr. at 58-69.

suggested developing more accurate studies.<sup>11</sup> A state commissioner also cautioned that the studies alleging net benefits due to the implementation of regional markets by MISO and PJM were offered in macro, region wide format, often based on economic modeling rather than actual experiences.<sup>12</sup> His concern was that these studies failed to disclose the distribution of benefits and costs, both geographically and demographically.<sup>13</sup> 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, understand the current market conditions and improve market performance.<sup>14</sup> A state regulator 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.<sup>15</sup>

## **B. Specific Dispatch Issues**

The specific dispatch issues that were raised at the initial meeting or in the DOE survey comments varied by market segment, with different issues raised by utilities, independent power producers, independent transmission companies, grid operators and state regulators. These specific issues raised are listed below, and discussed in the remainder of this section.

- Importance of adequate transmission and ways of getting it built
  - Sufficient transmission infrastructure is needed to realize the full potential of SCED
  - Transmission planning process
  - Cost recovery for transmission investments/transmission pricing/cost allocation
  - Value of independent transmission companies
- Mitigating seams between RTOs is needed to optimize the benefits of SCED
- Demand-side participation in SCED

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<sup>11</sup> WLSE at 4-5.

<sup>12</sup> Commissioner Jergeson at 2.

<sup>13</sup> *Id.*

<sup>14</sup> WLSE at 4, 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, Tr. at 76-85.

<sup>15</sup> Commissioner Hadley, Tr. at 107-108.

- Improved load forecasting
- Scope of SCED
- Non-utility generation outside of organized markets
- Participation by non-traditional generation in SCED
- Application of SCED

### *Importance of Adequate Transmission and Ways of Getting it Built*

1. *Sufficient Transmission Infrastructure is Needed to Realize the Full Potential of SCED.* Several entities argued that a robust transmission network is the key to optimizing economic dispatch and ensuring a low cost reliable supply of energy.<sup>16</sup> Even in an RTO that enables all generation to bid in to the market, a transmission bottleneck could limit the amount of low-cost energy that flows through to load and the dispatcher will redispatch out of merit (more expensive) energy from a local source to manage the congestion.<sup>17</sup> Therefore, without adequate transmission, lower cost generation will not displace higher cost generation.<sup>18</sup> 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.<sup>19</sup>

Some entities asserted that in order to get transmission built, long-term regional transmission planning was needed, timely investment and cost recovery of those investments was needed, and appropriate cost allocation had to take place. The role of independent transmission companies (ITC) was also discussed.

2. *Transmission Planning Process.* Several commenters argued that a regional and long-term transmission planning process was necessary to build a robust transmission network.<sup>20</sup> One commenter recommended implementing a collaborative and inclusive

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<sup>16</sup> Chairman Schriber at 1 and 3, AEP at 6 and 10, ITC at 2-3, WPSRC at 6, Mr. Tatum at 1 and Tr. at 144, and Mr. Welch, Tr. at 152 and 155.

<sup>17</sup> Mr. Tatum at 1, ITC at 3 and Joint State Commissions 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..

<sup>18</sup> WPSRC at 6, Mr. Tatum, Tr. at 144, and Mr. Welch, Tr. at 152 and 155.

<sup>19</sup> New Jersey Board of Public Utilities (NJBPU) at 2.

<sup>20</sup> Joint State Commissions at 10, NJBPU at 2 and 6, Mr. Torgerson, Tr. at 98-99,

transmission planning process for local transmission owners and wholesale transmission customers for reliability-based upgrades and economic upgrades.<sup>21</sup> Another contended that a properly executed consistent regional transmission planning process over a large footprint, including siting and appropriate cost allocation for needed upgrades to the transmission system, is needed.<sup>22</sup> 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/LMP markets.<sup>23</sup> According to one commenter, both RTOs conduct separate planning, and in fact, 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.<sup>24</sup> MISO admitted that it needs to develop long-term transmission planning and procedures.<sup>25</sup> 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.<sup>26</sup> A state commissioner recommended that regional transmission planning and SCED should be addressed by the Board's study.<sup>27</sup>

*3. Cost Recovery for Transmission Investments/Transmission Pricing/Cost allocation.*

In order to build transmission infrastructure, timely investments in the transmission grid

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Mr. Tatum, Tr. at 145, and Mr. Naumann, Tr. at 166.

<sup>21</sup> Mr. Tatum at 2 and Tr. at 145.

<sup>22</sup> Joint State Commissions at 10.

<sup>23</sup> Joint State Commissions at 10, WPSRC at 2 and 6, Chairman Schriber at 3, Mr. Torgerson, Tr. at 98-99, Mr. Tatum, Tr. at 144 and Mr. Welch, Tr. at 152.

<sup>24</sup> WPSRC at 6.

<sup>25</sup> Mr. Torgerson, Tr. at 98.

<sup>26</sup> NJBPU 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 dispatched after a less expensive plant such as a coal-fired plant without advanced pollution controls. NJBPU at 4.

<sup>27</sup> Commissioner Wright submittal.

are needed.<sup>28</sup> Market participants expect more assurance with respect to cost recovery and cost allocation to provide new facilities.<sup>29</sup> One commenter argued that the existing MISO transmission pricing proposals discourage generation and transmission construction, thus hampering the optimization of SCED.<sup>30</sup> It was 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.<sup>31</sup> Others proposed flow-based pricing, but that may require considerable study and testing and so in the meantime FERC should consider a distance pricing mechanisms to replace license plate rates to more closely reflect the nature of the commerce being conducted on the interstate system.<sup>32</sup> Another commenter asserted that using postage stamp rates would provide incentives for generation and transmission investment.<sup>33</sup>

A state regulator suggested that if non-incumbent merchant transmission owners built transmission additions, they should be allowed to recover their costs recovery in the RTO's tariff on the same non-discriminatory basis as provided to generation-owning transmission companies.<sup>34</sup> Another state commissioner suggests that cost allocation and the associated federal-state jurisdictional ratemaking issues be addressed by the Board.<sup>35</sup>

*4. Value of Independent Transmission Companies.* Some observers suggest that

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<sup>28</sup> Joint State Commissions at 9, Mr. Tatum at 2, ITC at 4 and AEP at 6 and 10. 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. *See also* WPSRC at 5-6, Mr. Harris, Tr. at 105, Mr. Welch, Tr. at 169 and 173.

<sup>29</sup> Mr. Harris, Tr. at 103-104, Mr. Welch, Tr. at 153 and 167-173.

<sup>30</sup> WPSRC at 6.

<sup>31</sup> Mr. Tatum at 2 and Tr. at 146, Mr. Welch, Tr. at 170, and ITC at 4. *See also* Mr. Harris, Tr. at 104.

<sup>32</sup> Chairman Schriber at 4.

<sup>33</sup> WPSRC at 6.

<sup>34</sup> Chairman Schriber at 2-3.

<sup>35</sup> Commissioner Wright submittal.

independent transmission companies (transcos) could help achieve the objectives of economic dispatch and that the value of for-profit transcos needed to be recognized in the joint planning efforts by MISO and PJM.<sup>36</sup> However, 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 constraints resulted in intra-market price differentials.<sup>37</sup> Commenters 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.<sup>38</sup>

*Mitigating Seams Between RTOs is Needed to Optimize Benefits of SCED.* Some state regulators are concerned that if FERC allows PJM and MISO to continue down divergent paths on certain issues, it will create difficulty for market participants seeking to operate in both PJM and MISO and perpetuate seams issues that negatively impact the market.<sup>39</sup> They recommended that any initiatives pursued by PJM or MISO should contribute to the development of the 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.<sup>40</sup> Several commenters stated that a number of issues needed to be addressed in the PJM and MISO footprints in order to optimize SCED.<sup>41</sup> 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; allocation of Firm Transmission Rights; the development of ancillary service markets; and identifying differences in algorithms between PJM and MISO markets.<sup>42</sup> 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.<sup>43</sup>

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<sup>36</sup> ITC at 1 and Chairman Schriber at 2-3.

<sup>37</sup> *Id.* at 2.

<sup>38</sup> Chairman Schriber at 4 and ITC at 3.

<sup>39</sup> Joint State Commissions at 3-5 and 13.

<sup>40</sup> *Id.* at 5.

<sup>41</sup> Joint State Commissions at 5, WPSRC at 4-5, Mr. Torgerson, Tr. at 105, and Mr. Orr, Tr. at 137-138.

<sup>42</sup> *Id.* See also Mr. Meyer, Tr. at 29, and Mr. Orr, Tr. at 130-131.

<sup>43</sup> Chairman Schriber at 1.

One state commissioner asserted that different operational rules and business practices in PJM and MISO has stifled transactions with neighboring utilities across these RTO borders.<sup>44</sup> He recommends that each RTO's operational rules and business practices must be reviewed and amended to recognize and accommodate cross RTO border trading if SCED is to facilitate an open and common market in the combined PJM/MISO region.<sup>45</sup> Also, eliminating the multiple sets of reliability rules for the RTOs and adopting common reliability rules will allow more efficient operations.<sup>46</sup> Another state commissioner suggested that the impact of different SCED algorithms should be addressed by the Board.<sup>47</sup>

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.<sup>48</sup>

*Demand-side Participation in SCED.* Some observers say that organized markets must develop more ways for demand-side response to participate in markets.<sup>49</sup> 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.<sup>50</sup> One state commissioner suggests that the Board should address demand response as a potential competitive factor.<sup>51</sup> MISO noted that it should increase demand side participation in SCED in order to balance the supply side.<sup>52</sup> PJM has played a role in programs that foster demand

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<sup>44</sup> Chairman Schriber at 2.

<sup>45</sup> *Id.* at 2.

<sup>46</sup> Mr. Naumann, Tr. at 132.

<sup>47</sup> Commissioner Wright submittal.

<sup>48</sup> AEP at 9 and Schriber 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.).

<sup>49</sup> Mr. Torgerson, Tr. at 98, Mr. Harris, Tr. at 54 (PJM has seen benefits of demand response) and 104, and Mr. Kruk, Tr. at 149.

<sup>50</sup> Joint State Commissions at 10.

<sup>51</sup> Commissioner Wright submittal.

response and distributed generation.<sup>53</sup>

*Improved Load Forecasting.* It was observed that improved forecasting by RTOs and market participants could bring further operational benefits.<sup>54</sup> One state commissioner suggested that the importance of load forecasting should be addressed in the Board's study.<sup>55</sup>

*Scope of SCED.* The DOE study found that generally economic benefits tend to increase as the geographic scope and electrical diversity of the area under unified dispatch increases.<sup>56</sup> MISO expressed a concern, and PJM concurred, that the costs of eliminating a current system and creating a single dispatch between these two RTOs would outweigh the benefits.<sup>57</sup> A utility 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.<sup>58</sup> It stated that a larger RTO footprint did not eliminate the practical challenges of economic dispatch in a capacity-constrained transmission grid, but a sufficiently robust transmission system would address these challenges.<sup>59</sup> A state commissioner suggested that increasing the scope of SCED application should be addressed by the board.<sup>60</sup>

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<sup>52</sup> Mr. Torgerson, Tr. at 98.

<sup>53</sup> Joint State Commissions noted 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 Commissions at 11. Other programs that identify and factor the environmental value of a particular generator into a buying decision helped states in PJM region to ensure dispatch of cleaner generation. Joint State Commissions at 11.

<sup>54</sup> Mr. Meyer, Tr. at 26, Mr. Kruse, Tr. at 118 (important that day ahead plans mirror real time plans as closely as possible), and Joint State Commissions at 10.

<sup>55</sup> Commissioner Wright submittal.

<sup>56</sup> Mr. Meyer, Tr. at 21.

<sup>57</sup> Mr. Torgerson and Mr. Harris, Tr. at 91-92.

<sup>58</sup> AEP at 2.

<sup>59</sup> *Id.* at 3.

<sup>60</sup> Commissioner Wright submittal.

*Non-utility Generation Outside of Organized Markets.* Independent power producers (IPPs) asserted that in non-RTO regions, the dispatch of electricity generation does not fully take into account the availability of competitive generation due to the lack of transparency and independence.<sup>61</sup> Ensuring that all available and eligible generation, regardless of ownership, is simultaneously considered for merit order economic dispatch can be accomplished by ensuring that regulators foster a bilateral forward market for supply contracts between load serving entities and wholesale suppliers beyond the utility or its affiliate.<sup>62</sup> Further, IPPs contended that regulators need to be clear that utilities will be required to explain their choices if they economically dispatch their own generation when other, cheaper generation supply was available.<sup>63</sup> IPPs also argued that both bilateral contracts in forward markets and spot markets would enable wholesale market development and economic dispatch of nonutility generation.<sup>64</sup>

In its study, DOE concluded that existing rules and practices exclude non-utility generators from the economic dispatch stack, which in turn hampered their ability to receive long-term contracts to sell to load serving entities and secure sufficient transmission capacity to deliver energy.<sup>65</sup> According to certain state commissions, this is not a problem in RTOs like PJM and MISO, but is a problem in other regions.<sup>66</sup> They recommended further studies on these issues.<sup>67</sup>

*Participation by non-traditional generation in SCED.* Certain state commissions also asserted that opportunities for non-traditional resources, such as wind power and demand response, to participate and compete equally with traditional resources such as fossil-fueled generation should be further explored and promoted.<sup>68</sup> They contended that FERC

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<sup>61</sup> EPSA Nov. 11, 2005 Comments.

<sup>62</sup> EPSA Nov. 11, 2005 Comments, Attached Response to DOE Survey at 3.

<sup>63</sup> *Id.*

<sup>64</sup> *Id.*

<sup>65</sup> Joint State Commissions at 11 citing to DOE Study at 6.

<sup>66</sup> Joint State Commissions at 12.

<sup>67</sup> *Id.* at 12.

<sup>68</sup> *Id.* at 12.

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.<sup>69</sup>

*Application of SCED.* The Montana state commissioner cautioned against changing the way Montana Dakota Utilities, the rural electric cooperatives and WAPA serve the customers in eastern Montana.<sup>70</sup> 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.<sup>71</sup>

*Additional issues to be considered by the Joint Board.* One state commissioner suggested that the following additional issues be addressed in the Board's study:<sup>72</sup>

- Effect of ancillary markets for reserves and regulation on SCED.
- Effect of regional SCED on reliability and the effect of reliability rules on regional SCED.
- Effect of multiple control areas within and RTO on RTO-managed SCED.
- RTO-managed SCED and the impact on entities that are not within the RTO's dispatch market.
- MISO's early experience operating a market under SCED.
- Definition of SCED.
- Summary of DOE Report.
- SCED issue needing additional analysis or research
- History of economic dispatch
- SCED in MISO and PJM
- Review of RTO benefit studies
- Treatment of non-utility generators in RTO-managed SCED.
- Effects of SCED on fuel diversity

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<sup>69</sup> *Id.* at 12-13.

<sup>70</sup> Commissioner Jergeson at 1.

<sup>71</sup> *Id.* 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).

<sup>72</sup> Commissioner Wright submittal.

- Relationship between RTO market rules and SCED.

### **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 investor owned utilities, to determine how they conduct economic dispatch.<sup>73</sup> 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 non-utility generators and other resources to compete effectively and serve load.
- FERC and DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts.<sup>74</sup> Specifically, the EEI proposed that non-utility generators 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.<sup>75</sup> These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

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<sup>73</sup> 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 52.

<sup>74</sup> *Id.* at 51.

<sup>75</sup> *Id.* at 53.

**Recommendations of the Joint Board for the PJM-MISO Region**

To be completed by the Joint Board

## Attachment C

### **RECOMMENDATIONS FOR CONSIDERATION BY THE PJM/MISO JOINT BOARD**

#### **Recommendations Found in the PJM/MISO Joint Board Record**

This is a list of various recommendations made by individual board member or by participants in the initial board meeting and comment process

- The region should develop a long-term transmission planning process that is collaborative and inclusive and involves Federal and state regulators, RTOs, local transmission owners, wholesale customers, etc.
- Develop an appropriate cost allocation mechanism for both reliability and economic upgrades.
- Adopt a different transmission pricing method, such as formula rates, flow-based rates, or postage stamp rates
- All potential transmission developers (incumbents, merchants and transcos) should be allowed to bid for construction and ownership of transmission projects.
- Non-incumbent transmission owners should be able to recover costs through the RTO tariff.
- PJM and MISO's operational rules and business practices must be reviewed and amended to accommodate trading across these RTOs' borders.
- PJM and MISO should pursue common rules and market design regarding: resource adequacy, long-term transmission planning, allocation of FTRs, ancillary service markets, reliability rules and SCED algorithms.
- PJM and MISO should increase their efforts to encourage demand-side participation in their markets.
- Improvements to RTOs and market participants' load forecasts should be pursued.
- Studies need to be undertaken to determine optimal scope of SCED, while taking into consideration the existing dispatch, benefits and costs, etc.

- Further studies should be conducted on participation of non-utility generators in regions that do not have organized markets.
- In areas not in the footprint of an organized market, regulators should foster inclusion of non-utility generation in the dispatch by fostering bilateral forward markets and question decisions to dispatch relatively expensive generation when cheaper non-utility generation was available.
- Opportunities for non-traditional resources should be explored and promoted.
- The analysis and incorporation of benefits of diverse generation should be encouraged by FERC.
- Limit SCED application to offers for sale of surplus power only after entities have satisfied their native load obligations.
- Review 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, and distinguish entity-specific and regional business practices from regulatory, environmental and reliability-driven constraints. (DOE Report at 52)
- Recommend that FERC and DOE explore Electric Power Supply Association (EPSA) and Edison Electric Institute (EEI) proposals for more standard contract terms and encourage stakeholders to undertake these efforts. (DOE Report at 51)
- Review current economic dispatch technology tools. These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions. (DOE Report at 53)
- The Joint Board's study should address the following major issues:
  - Geographic scope of SCED (larger geographic scope reduces seams; larger geographic scope internalizes more diversity in generators and loads; potential for improved optimization at lower total cost; single combined dispatch issues)
  - Regional Transmission Planning and SCED (transmission cost allocation; transmission expansion obligations; federal/state jurisdictional ratemaking issues)

- Treatment of demand response within RTO-managed SCED (demand response as a potential competitive factor)
- Effect of ancillary markets for reserves and regulation on SCED
- Effect of regional SCED on system reliability/ effect of reliability rules on regional SCED (value of common reliability rules across the combined PJM/MISO footprint)
- Effect of multiple control areas within an RTO on RTO-managed SCED (effect of current configuration on MISO market efficiency)
- RTO-managed SCED and the impact on entities that are not within the RTOs' dispatch market (border entities; non-participants geographically located within the RTO; RTO redispatch vis-à-vis third parties who use TLRs to control congestion).
- MISO's early experience operating a market under SCED (effects on SCED of generating unit offer characteristics; comparison between the flexibility/ dispatchable range within the MISO and PJM generation dispatch)
- The Joint Board's study should address the following additional issues:
  - Definition of SCED (constrained optimization issue)
  - Summary of DOE report
  - SCED issues needing additional study/analysis/research
  - History of economic dispatch (utility-managed SCED; using TLR, rather than LMP)
  - SCED in MISO and PJM (regional; different SCED algorithms; different kinds of generating unit characteristics; independence and transparency)
  - Review of RTO benefit studies
  - Economic dispatch versus efficient dispatch (effect of SCED on fuel diversity)
  - Treatment of non-utility generators in RTO-managed SCED

- Importance of load forecast in SCED
- Effects of SCED on fuel diversity
- Relationship between RTO market rules and SCED

**Additional Recommendations by Joint Board Members**

- The Joint Board should perform a study that compares market-clearing price outcomes and total costs against the true production costs of the actual units dispatched.