COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF DUKE ENERGY KENTUCKY, INC. FROM NOVEMBER 1, 2013 THROUGH APRIL 30, 2014	))))	Case No. 2014-00229

PETITION FOR REHEARING

Comes now Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), by counsel, and petitions the Kentucky Public Service Commission (Commission) for rehearing, pursuant to KRS 278.400, of the Commission's Order entered herein on January 30, 2015 (Order). Duke Energy Kentucky seeks rehearing and clarification on the issue of the fuel adjustment clause (FAC) recovery of energy purchases made within the context of the Company's participation in the Day-Ahead and Real-Time Energy Markets administered by PJM Interconnection, L.L.C. (PJM). The Order does not address a number of issues raised by the Company in this proceeding and is inconsistent with both the intent and plain language of 807 KAR 5:056 (FAC Regulation). As a result, the Order unfairly denies recovery of reasonable, unavoidable energy purchases made as a function and obligation of day-to-day operation in a regional transmission organization (RTO). For these reasons, the Company requests that the Commission reconsider its Order and permit rehearing of the relevant issues.

I. INTRODUCTION

The Commission's Order limits recovery of purchased energy to the cost of Duke Energy Kentucky's highest-cost generating unit available to be dispatched to serve native load during an expense reporting month.[1] The Commission's Order too narrowly construes the FAC Regulation as it pertains to energy purchases made in an RTO construct. While the Commission's interpretation of its precedent, specifically what constitutes economy and non-economy energy, may be appropriate for a stand-alone utility acting as its own balancing authority, this directive simply does not reconcile with the day-to-day operations in an RTO acting as a centrally dispatched power pool such as PJM. The Order results in situations whereby the Company's necessary energy purchases, which are made as a result of PJM's economic dispatch decisions (over which the Company has limited dispatch discretion and no ability to refuse energy purchases), are unrecoverable in the FAC. In an RTO, every mega-watt hour (MWH) of energy used to serve Duke Energy Kentucky's customers is derived from a purchase made in the Real-Time Energy Market. Likewise, every MWH of energy available to be generated by Duke Energy Kentucky's fleet is offered for sale in both the Day-Ahead and Real-Time Energy Market. In the Company's case, it is PJM alone that determines how to most efficiently and reliably serve customers in its multi-jurisdictional footprint. Duke Energy Kentucky's customers benefit significantly from this centrally dispatched construct. PJM dispatches generation in broad consideration of total RTO cost minimization, the benefits of which are directly passed to customers in the form of energy alternatives to owned generation.

The Commission's Order unnecessarily: (1) creates risk for the Company when it operates in the PJM Day-Ahead and Real-Time Energy Markets, which it is required to do as a member of PJM; and (2) imposes additional processes and costs on the Company relating to the new requirement for making after-the-fact calculations to determine whether its generation may not have been picked-up by PJM each and every month. The Order ignores that all energy

[1] Order at 8. Duke Energy Kentucky does not take issue with the qualification for the exclusion of forced outages as required under 807 KAR 5:056 Section 1(3)(a) and (4).

purchases made in response to PJM's security constrained economic dispatch processes are no different than fuel costs that are necessary to serve native customers. The Order thereby exposes the Company to unhedgible financial risks in the wholesale energy market simply because the Company adheres to PJM's energy market tariff that has been approved and is monitored by the Federal Energy Regulatory Commission (FERC). Energy purchases made daily within PJM under the security constrained economic dispatch construct are economic by their very nature and should be recoverable through the Company's FAC mechanism. The Commission's Order should be reconsidered.

II. ARGUMENT

A. The Order Ignores the Fact that PJM's Energy Markets are Operated on an Economic Dispatch Basis

1. The Commission's Order Does Not Address What it Means to Purchase Energy "on an Economic Dispatch Basis"

In its Order, the Commission inappropriately narrowed its review of Duke Energy Kentucky's purchased power costs to whether they were "non-economy energy" costs. The Order is premised upon the language of a prior Commission Order that predates the advent of RTO wholesale markets and participation therein by Kentucky's utilities and not the actual text of the FAC Regulation. Correspondingly, the Order does not address the Company's contention that the FAC Regulation's express terms must be utilized to determine whether energy purchases made on an economic dispatch basis may be recovered.

The Commission's interpretation of the FAC Regulation does not follow basic precepts of statutory construction insofar as it does not give effect to the plain meaning of words.[2] According to the Kentucky Supreme Court,

> An agency must be bound by the regulations it promulgates. Further, the regulations adopted by an agency have the force and effect of law. An agency's interpretation of a regulation is valid, however, only if the interpretation complies with the actual language of the regulation. KRS 13A.130 prohibits an administrative body from modifying an administrative regulation by internal policy or another form of action.[3]

As stated in Duke Energy Kentucky's post-hearing Brief, whether the net energy cost of any particular energy purchase is recoverable through the FAC Regulation turns exclusively on whether "such energy is purchased on an *economic dispatch basis*."[4] Although the Order is focused entirely on precedent construing "economy energy purchases" and "non-economy energy purchases," that issue is ancillary to the issue of whether the subject purchase conforms to the plain language of the FAC Regulation, which itself does not define non-economy energy. The Order improperly limits consideration of the phrase used in the FAC Regulation, "economic dispatch basis," to one particular concept adopted in prior precedent and under different facts, ignoring all others.

The plain terms of the FAC Regulation do not support this conclusion; instead, the permissive and illustrative nature of the second sentence of 807 KAR 5:056 Section 1(3)(c)

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[2] *See SmithKline Beecham Corp. v. Revenue Cabinet*, 40 S.W.3d 883, 885 (Ky. App. 2001) ("A court may not interpret a statute at variance with its stated language."); KRS 446.080(4) ("All words and phrases shall be construed according to the common and approved usage of language, but technical words and phrases, and such others as may have acquired a peculiar and appropriate meaning in the law, shall be construed according to such meaning."); *see also Revenue Cabinet v. Gaba*, Ky. App., 885 S.W.2d 706, 707 (Ky. App. 1994) ("[I]n the construction and interpretation of administrative regulations, the same rules apply that would be applicable to statutory construction and interpretation.") (Citation omitted).

[3] *Hagan v. Farris*, 807 S.W.2d 488 (Ky. 1991) (citations omitted).

[4] FAC Regulation, Section 1(3)(c) (emphasis added).

underscores the fact that an economy energy purchase is but one type of purchase made on an economic dispatch basis. This interpretation is bolstered by the similar terms employed in 807 KAR 5:056 Section 1(3)(d). Pursuant to that provision, fossil fuel costs recovered through inter-system sales, "including the fuel costs related to economy energy sales *and other energy sold on an economic dispatch basis*," are disallowed for recovery through the FAC.[5] If "economy energy sales" and "energy sold on an economic dispatch basis" were equivalent, the inclusion of both phrases in Section 1(3)(d) would be unnecessary and superfluous. Thus, "economy energy sales/purchases" and "energy sold/purchased on an economic dispatch basis" must mean different things. Notably, it appears that the Commission attempts to define all energy purchases made under Section 1(3)(c) by that provision's concluding clause - "all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy." However, a careful examination of the full Section 1(3)(c) reveals that this emphasis is misplaced. Section 1(3)(c) clearly states that "charges as a result of scheduled outage" may be included in the net energy cost of energy purchased on an economic dispatch basis, and are thus recoverable. However, energy purchased due to a scheduled outage is not done "to substitute for [a buyer's] own higher cost energy;" in fact, relative cost has no bearing whatsoever on the scheduled-outage situation, and yet "charges as a result of scheduled outage" are recoverable. The Commission's Order, which broadly holds that FAC-recovery of energy purchases is limited to the fuel cost of a utility's highest-cost generating unit available to be dispatched to serve native load, cannot be reconciled with the FAC Regulation.

As discussed in the Company's post-hearing Brief and below, all energy purchased through PJM (exclusive of those purchases made as a result of forced outages) is energy

[5] FAC Regulation, Section 1(3)(d) (emphasis added).

purchased on an economic dispatch basis and thus recoverable under Section 1(3)(c) of the FAC Regulation. Importantly, for the Commission to hold otherwise, it must also determine that PJM is not operating in accordance with economic dispatch principles. Such a conclusion not only misconstrues the very nature of PJM's system-wide dispatch methodology, but directly conflicts with both Congress' and the FERC's understanding of the energy market.[6]

2. PJM's Energy Markets Operate on a Security Constrained Economic Dispatch Basis

The Company must abide by the rules of PJM's markets as a Commission-approved PJM member.[7] As a member of PJM, the Company must purchase 100 percent of the energy and ancillary services required to service its load from PJM's wholesale energy markets and must offer to sell 100 percent of its available generation into those same markets. Thus, while Duke Energy Kentucky maintains the responsibility to ensure its customers have adequate resources to meet energy needs, the actual determination as to how those needs are met on a daily and even hourly basis rests solely with PJM. Such is the very nature and purpose of an RTO.

In order to determine which available generation units should be dispatched for a given hour, PJM employs a security constrained economic dispatch process. This process takes into account the various, unique challenges faced by RTOs in supplying power across their regional footprints. Specifically, the production of electricity "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

[6] *See* the Company's post-hearing Brief in this matter, at fn. 8.

[7] *See In the Matter of Application of Duke Energy Kentucky, Inc., for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment,* Order, Case No. 2010-00203 (Ky. P.S.C. Dec. 22, 2010.)

reliably."[8] Because of these challenges, PJM's dispatch process "is designed to be an optimization process…so that a reliable supply of electricity at the lowest cost possible under the conditions prevailing in each dispatch time interval can be delivered."[9]

Importantly, PJM's decisions as to which generating units should be dispatched are not made exclusively based on the individual unit's cost.[10] Although the price of energy at a generating unit is certainly important, PJM's dispatch process must take into account a number of factors, including system-wide reliability, transmission grid congestion and losses, and operational conditions. Consequently, there are a host of reasons why the Company can and does have energy purchases that cost more than one of its available, but not utilized, generation assets. As it pertains to Duke Energy Kentucky, these factors include, but are not limited to: (1) the overall volatility of locational marginal prices (LMP);[11] (2) the inability to predict future hourly and intra-hourly movement of wholesale energy prices in relation to amortization of costs

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[8] *See* Attachment 1, *F.E.R.C Docket AD05-13-000, Report on Security Constrained Economic Dispatch By the Joint Board of the PJM/MISO Region*, at page 5 (May 24, 2006).

[9] *Id.*

[10] Referencing the Company's Response to Item 2(b) of the Commission Staff's Second Request for Information in this matter, the Commission stated in its Order that "limiting recovery through the FAC to Duke Kentucky's highest cost unit is not problematic, as any power purchased from PJM would be less than Duke Kentucky's highest-cost unit and, therefore, would fall below the limit for recovery through the FAC." Order at 6. The Commission's characterization of the Company's Response is not entirely accurate and unfortunately does fully reflect the Company's statements regarding the issue. As described on page 4 of the Company's Response to Item 2(b), PJM performs a security-constrained economic commitment and economic dispatch process for all generation in its footprint, including the Company's. While, in a general sense, PJM does call upon the most economic generation available to it, the fact that a particular unit does not get called upon may not necessarily mean that specific unit costs more to run. As described herein and in the Company's Response to Item 2(a)(1) of Commission Staff's Third Request for Information (filed Oct. 20, 2014), PJM maintains the flexibility to overlook a unit that might be less expensive when, for reliability reasons, there is a more efficient and effective way to move power. Additionally, there are times even within an hour where a unit may not be dispatched by PJM due to its offer price, but then due to the inherent volatility in LMP, the unit may, after the fact, appear to have been less expensive than the energy purchased based upon the settlement of the final hourly LMP.

[11] Once PJM makes its decision to dispatch a generating unit, energy prices continue to move and therefore a unit that was not economic at the time of the decision, may after-the-fact have become economic.

of a units start-up;[12] (3) fuel availability;[13] (4) prior PJM unit commitment for ancillary services making the unit not available to provide energy in the same Real-Time energy market; (5) unit operating constraints (*e.g.*, minimum run-times, start-up, staffing) or (6) inability to self-commit a generator at times due to reliability. Thus, it is reasonable that PJM's dispatch process may, after the fact, result in a utility paying more for energy in a particular hour than it could produce from one of its owned, non-dispatched units.[14] However, each utility and the PJM system-at-large benefit over the long-term due to PJM's reliable, efficient, and fundamentally economic dispatch process.

PJM's security constrained economic dispatch process satisfies the nationally recognized definition of "economic dispatch." Although not addressed in the Order, the Company noted in its post-hearing Brief that federal law and FERC have defined "economic dispatch" to mean "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."[15] Clearly, the notion of "economic dispatch" includes more than just a consideration of cost, and the Commission should not undermine or erode the numerous benefits of RTO participation by

[12] Similarly, the Company must factor in its operating expenses for a unit and amortize those start-up costs as part of its unit offer into the energy markets without knowing how an LMP may change over time.

[13] *See In the Matter of An Investigation of Duke Energy Kentucky, Inc's Accounting Sale of Natural Gas not Used in its Combustion Turbines*, Order, Case No. 2014-00078 (Ky. P.S.C. Nov. 25, 2014).

[14] The security constrained economic dispatch process that PJM uses is no different than any single utility would use in the situation where it is its own balancing authority. Local transmission line outages or constraints could also force such a utility to dispatch its generation out of economic order in order to provide reliable service to customers. The Commission would not disallow the utility's costs of fuel in such an event, but the Order has precisely that effect when applied to Duke Energy Kentucky operating within PJM.

[15] *See* the Company's post-hearing Brief in this matter, at fn. 8.

holding otherwise.[16] PJM's economic dispatch model is presumptively reasonable,[17] and nothing in the Order suggests to the contrary. Moreover, the Commission should not reinterpret the phrase "economic dispatch" in variance with the well-established meaning given to that term by Congress, the FERC and the electric power industry as a whole.

The Order too narrowly construes the FAC Regulation as it pertains to energy purchases made in an RTO construct. While the Commission's interpretation of the FAC Regulation may track well with a stand-alone utility acting as its own balancing authority, it simply does not comport with the day-to-day operations in a RTO such as PJM that employs a system-wide security constrained economic dispatch methodology for supplying electricity. PJM has access to complete information regarding the operation of its Day-Ahead and Real-Time Energy Markets in making the determination to commit and dispatch a unit.[18] Because of the efficient and informed nature of PJM's dispatch methodology, a utility's energy purchases in PJM's Day-Ahead and Real-Time Energy Markets are the most economic means available to satisfy customer load at that moment in time.[19] The Company lacks PJM's system-wide scope of data

[16] Notably, even in general, everyday usage, the term "economic" does not usually equate to "least expensive" or "cheapest." For example, an individual may wish to purchase a vehicle and is presented with two options—the first vehicle costs $5,000, and the second $10,000. Though the first vehicle may be less expensive when viewed at a particular moment in time, purchasing it may not be the most economic decision, as the second vehicle may require less maintenance, have better gas mileage, or perform more reliably (thus avoiding the need to obtain incrementally more expensive secondary transportation, such as by taxi). The FAC Regulation's reference to "economic dispatch" should be interpreted in a similar fashion; although PJM's security constrained economic dispatch process may not result in the least expensive available energy at every particular moment in time, its overall benefits (including, but not limited to, monetary benefits realized over a more extended term) render the Company's Commission-approved participation therein truly economic and in the best interests of customers.

[17] *See Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 954 (1986) ("[A] utility's cost based upon a FERC-filed rate must be treated as a reasonably incurred operating expense for the purpose of setting an appropriate retail rate.").

[18] *See* Duke Energy Kentucky's Response to Commission Staff's Third Request for Information, Request No. 2(a)(1) (filed Oct. 20, 2014).

[19] *See* Duke Energy Kentucky's Response to Commission Staff's Second Request for Information, Request No. 2(b).

for managing reliability across its entire transmission grid footprint and the Commission's Order effectively penalizes the Company for not second guessing PJM's dispatch decisions.

The Commission's Order results in a miscorrelation between a LMP and generator's cost and presumes a direct relationship where one does not exist. One is not a proxy of the other. A LMP consists of three distinct components: energy, congestion, and losses. Duke Energy Kentucky pays a LMP at the Duke Energy Kentucky load zone to serve its native load. That LMP is based on a reference bus energy price that equates to the cost or benefit to the PJM system of any transmission congestion required to deliver energy to the load zone, plus the cost or benefit to the PJM system of thermal losses incurred on PJM's transmission system to serve the Company's load. Therefore, the LMP is a bundled product.

Similarly, Duke Energy Kentucky sells energy to PJM at the generator bus when its units are dispatched. The LMP at the generator bus represents the marginal cost of one additional MW of energy from the unit, plus or minus the impact on PJM transmission congestion at that bus, plus or minus the impact on PJM system losses at that bus. That relationship between the LMP at the generator bus and the incremental energy offer of that particular unit is critical to whether PJM decides to dispatch the unit. Accordingly, it is inappropriate to characterize the LMP paid by load as comparable to that of the LMP at a generating station. It is not an apples-to-apples relationship. Energy sales from generators serve to completely offset purchases only in the instance where the LMPs are exactly the same. In fact, there are few hours of the year where all three Duke Energy Kentucky generating stations and the Duke Energy Kentucky load LMPs align, and indeed many where there is significant divergence. If the Company were to ignore the LMP and self-commit its generation simply because the load zone price exceeded the "energy only" cost of a particular generator, the Company would regularly incur losses on behalf of customers. In other words, the Company would be incentivized to attempt to self-commit the negatively congested unit, at a significant loss to customers, in order to avoid a regulatory disallowance. This sub-optimal strategy clearly cannot be the intended result of the Commission's Order. For these reasons, the Company's energy purchases made through PJM are made on an economic dispatch basis, and thus its purchases should be recoverable under 807 KAR 5:056 Section 1(3)(c).

3. The Commission's Order Disregards 807 KAR 5:056 Section 1(3)(b)

An energy purchase either falls under Section 1(3)(c), or it does not. The Company contends that all energy purchases made through PJM fall under Section 1(3)(c) (notwithstanding the exclusion provided for in Section 1(4)); however, if the Commission determines that some energy purchases made through PJM do not fall under Section 1(3)(c), then such excluded energy purchases must fall under Section 1(3)(b). The terms of Section 1(3)(b) make this conclusion logically necessary, as the provision refers to any and all energy purchased "for reasons other than identified in [Section 1(3)(c)]." Stated another way, and pursuant to the terms of the FAC Regulation, there are two – and only two – types of energy purchases that a utility can possibly make: those that fall under Section 1(3)(c) and those that fall under Section 1(3)(b).

Importantly, the types of costs that are recoverable under the FAC Regulation varies depending on whether the subject energy purchase falls under Section 1(3)(b) or Section 1(3)(c). As discussed, a utility is entitled to recover the "net energy cost" of any energy purchase that falls under Section 1(3)(c). Conversely, if an energy purchase falls under Section 1(3)(b), a utility is entitled to recover the "actual identifiable fossil and nuclear fuel costs associated" with said purchase. The Order does not differentiate between Section 1(3)(c) purchases and Section 1(3)(b) purchases.

In its Order, the Commission caps recovery of costs for *all* energy purchases "to the fuel cost of [a utility's] highest-cost generating unit available to be dispatched to serve native load."[20] However, the fuel cost of a utility's highest-cost generating unit available to be dispatched to serve native load is entirely irrelevant to a purchase made under Section 1(3)(b). Section 1(3)(b), as written, does not require a cost comparison of any sort, and the over-breadth of the Order must be re-evaluated.

B. The Order is Inconsistent with the Spirit of the FAC Regulation

The Order states that the FAC mechanism "was never meant to allow the utility to recover 100 percent of fuel costs incurred on a monthly basis, as evidenced by the restrictions set out in the regulation."[21] This statement appears to be unprecedented, is not supported, and does not comport with the FAC Regulation (which, as discussed, always allows recovery of at least the "actual identifiable fossil and nuclear fuels cost" associated with an energy purchase under Section 1(3)(b)).

The Order renders actual, prudent and reasonable fuel expenses (including energy purchases) incurred by the Company unrecoverable through the FAC without any legal support. While the Order intimates that these costs may yet be recoverable through base rates, in a practical sense, full recovery is delayed and rendered more expensive. A utility is limited in base rate recovery to those costs incurred during a test year, subject to certain adjustments. Therefore, there will always be a gap, whether positive or negative, between what a utility incurs as a purchased energy expense on a daily basis through economic dispatch principles, and what is budgeted in base rates. By operation of the dynamic PJM markets, utilities are making energy

[20] Order at 8. Duke Energy Kentucky does not take issue with the qualification for the exclusion of forced outages as required under 807 KAR 5:056 Section 1(3)(a) and (4).

[21] Order at 7.

purchases, and sales, on an hourly basis in response to such real-time factors as demand and transmission constraints. Unless the utility is able to track and recover these costs through its FAC or the Commission is willing to allow the Company to create a monthly regulatory asset for any incremental purchases, the practical effect is reasonable and necessary fuel costs to serve customers are not recovered or are over-recovered. Additionally, this regulatory lag induced by limiting recovery through base rates can quite easily result in higher rates for customers. High purchase power recovery costs that are solely incorporated in a base rate test year would continue in rates until revised in a subsequent base rate case. This could span several years. The purpose of the FAC Regulation is to eliminate the need for recurring base rate cases to constantly readjust the amount of fuel expenses that are recovered through base rates.

Yet, the Order actually creates perverse incentives for a utility that is a member of an RTO to have more expensive generation, rather than to seek opportunities to minimize costs or maximize efficiency of generation. As previously discussed, utilities in RTOs, like PJM, are required to offer to sell all of their supply (*i.e.,* generation) and to buy all of their energy needed to serve load through the Day-Ahead and Real-Time Energy Markets. If the non-economy energy limitation to the utility's own highest cost unit must be applied to each and every MWH of energy that is purchased, then the only way to ensure the utility's fuel costs are recovered is for its owned available generation to always be more expensive than the energy it must purchase in the RTO. Such a strategy ensures recovery for a utility and complies with the Commission's interpretation of the FAC Regulation, but is likely to result in unnecessarily higher costs for customers. Moreover, under the Order, if the utility were presented with an opportunity to reduce its costs or improve the efficiency of its owned generating assets, then the ceiling for recovering purchased energy is also lowered, thereby increasing the likelihood that the cost of purchased energy needed to meet its load obligations becomes stranded and not recoverable. Such a result was never the intent of the FAC Regulation. There are clear distinctions between utilities that are participating in a RTO and those that are not, and the application of the FAC Regulation should not be so rigid as to completely ignore, erode or undermine the benefits of participation in an RTO.

III. CONCLUSION

Duke Energy Kentucky contends that the plain language of 807 KAR 5:056 Section 1(3)(c) controls the issue presented in this matter. Because energy acquired through PJM is purchased on an economic dispatch basis, the net energy cost of all the Company's energy purchases is recoverable under the FAC Regulation. Yet even if the Commission disagreed, and its judgment affirmed, then the fuel costs at issue herein would still be subject to recovery under Section 1(3)(b), which the Order does not address. Regardless, the Order has the practical impact of diminishing the value of participating in PJM and creates operational incentives and costs, which are unlikely to have been intended.

WHEREFORE, on the basis of the forgoing, Duke Energy Kentucky respectfully requests that the Commission grant its Petition for Rehearing and reopen this matter for additional proceedings.

Dated this 19 day of February, 2015.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing filing was served on the following via electronic mail, this 19th day of February, 2015:

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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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DISSENTING AND CONCURRING COMMENTS OF THE INDIANA UTILITY REGULATORY COMMISSION TO THE JOINT BOARD REPORT 1

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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

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[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 <u>unit dispatch</u> 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

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

[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

[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

[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

[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:

[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]

[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. SCED Scope

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

[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. <u>Effects of SCED on Generators</u>

1. Participation by Non-Traditional Generation in SCED

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

[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

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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

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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. SCED Benefits

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.

[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.

[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

[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. <u>Transmission Infrastructure</u>

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

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[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]

[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.

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

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[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?"

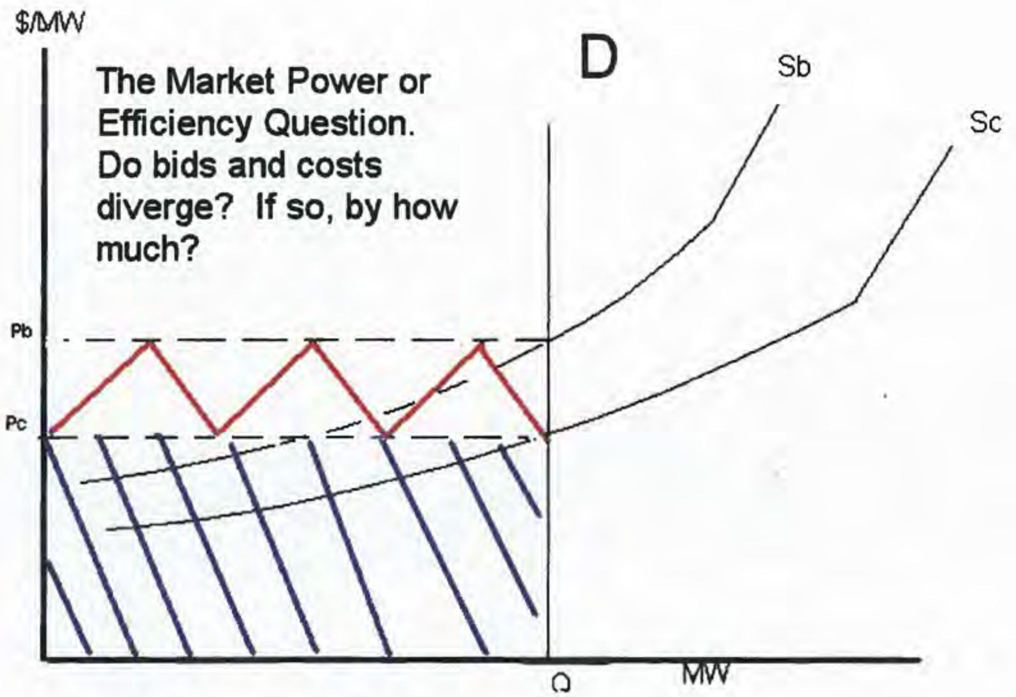
Most relevant to the Board's inquiry is the issue of the cost of electric service ultimately paid by consumers. One important factor that should influence this key metric is the actual resource cost expended to produce a given quantity of electrical output. A concern stated by at least some Joint Board 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.

<u>The Generator Net Revenue Issue --- The Fairness Question</u>

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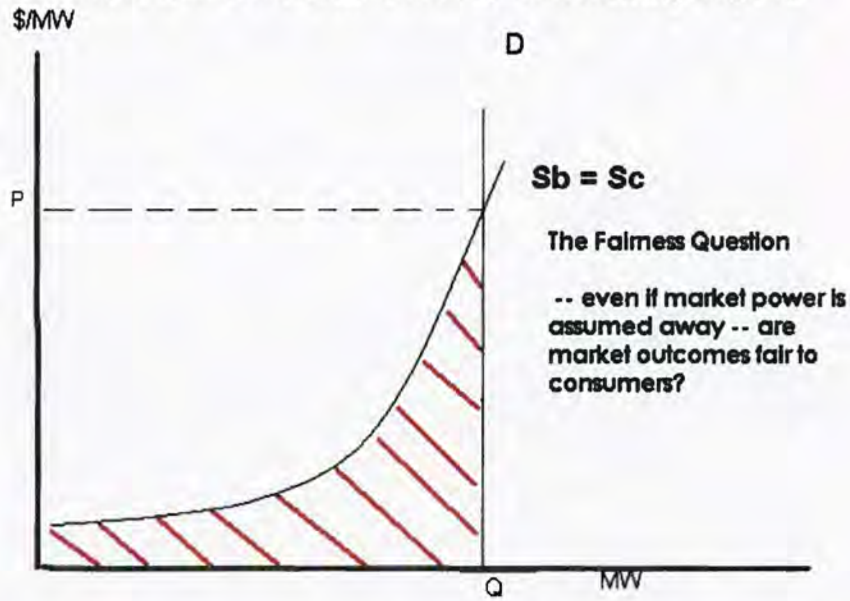
[191] On or about November 11, 2005, PJM stated that such data would be available in the first quarter of 2006. Note that such unit specific data would likely be deemed competitively sensitive. However, such data could be summed by hour. This would answer Staff's question without divulging producer specific 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 <u>not</u> 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

[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

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[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]

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[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.