

The Brattle Group

Midwest ISO's Resource Adequacy Construct

An Evaluation of Market Design Elements

January 19, 2010

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Prepared for

Midwest Independent System Operator

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I. EXECUTIVE SUMMARY

The Midwest Independent System Operator (MISO) has commissioned *The Brattle Group* to conduct an independent assessment of its resource adequacy construct. This assessment evaluates the progress MISO has made in developing and implementing its resource adequacy construct, including the extent to which MISO has met the goals set forth in its year 2009 Incentive Plan. It also evaluates the merits of the market design and identifies opportunities for improvement.

I.A. SUCCESSES AND AREAS FOR IMPROVEMENT

We have identified several major successes with MISO's resource adequacy construct, both as a whole and with individual elements:

- MISO has successfully implemented a comprehensive resource adequacy (RA) construct, with four major components: (1) a resource adequacy requirement imposed on load-serving entities (LSEs) with financial enforcement provisions; (2) resource qualification and performance requirements that accommodate all resource types, including demand-side resources; (3) a standardized capacity product called "Planning Resource Credits" (PRCs) to support liquidity in trading; and (4) a voluntary capacity auction (VCA) for settling imbalances just before each delivery month.
- The first planning year (PY1) under this construct has proceeded smoothly, although this might be attributed partly to the existing surplus supply conditions.
- MISO has also implemented an industry-leading scarcity pricing mechanism that will help support resource adequacy through the energy and ancillary markets when market conditions become tight.

We have also identified some areas for potential improvement:

- The resource adequacy requirements imposed on LSEs do not include locational sourcing requirements in transmission-constrained zones. Thus, locational resource adequacy may rely on out-of-market mechanisms, except to the extent that locational scarcity prices (for energy and ancillary services) are high enough to attract and retain resources.
- MISO's reliance on LSEs to forecast their own non-coincident peak loads could create incentive problems and accounting gaps. LSEs could be tempted to under-forecast their load when capacity becomes scarce and prices rise. In addition, the use of non-coincident peak loads and *average*

diversity factors to determine capacity requirements does not give LSEs an incentive to improve their diversity factors by managing load away from the system coincident peak. Finally, load migration in retail choice states is not tracked, so migrating customers may temporarily not be included in any LSE's RA requirement.

- The standard "1 day in 10 years" loss of load expectation (LOLE) reliability criterion, which is used as the basis for setting resource adequacy requirements, has not been sufficiently evaluated for economic efficiency by either MISO or the regional reliability entities.

I.B. LONG-TERM VISION

In 2005, MISO presented a vision for implementing an energy-only market in the long term, while possibly relying on an RA requirement in the short term. Some stakeholders have expressed that MISO has not updated its vision, including how the current RA construct fits within that vision. Further, stakeholders are strongly divided about the future direction that the MISO RA construct should take. Some stakeholders support maintaining the current construct, others propose a (mandatory) forward capacity market, and others favor an energy-only market.

We recommend that MISO postpone consideration of transitioning to either a forward capacity market or an energy-only market. The incremental benefits of a forward capacity market would not be available until several years from now when new capacity is needed. When available, these benefits would accrue primarily to retail choice states, and many traditionally regulated states are opposed to the idea. Regarding the energy-only option, MISO should not dispense with the resource adequacy requirement as long as there is insufficient price responsive demand for the market to sort out various levels of non-firm load while maintaining satisfactory reliability for load that prefers more firmness.

In order to maximize economic efficiency and the performance of its capacity, energy, and ancillary services markets, MISO and the states should focus on making the demand side more price-responsive. This means that state regulators should pursue all cost-effective retail-level demand response, while MISO continues to enable wholesale market participation and further develop the price-setting ability of demand response. Increasing the price-responsiveness of demand would enhance market competitiveness while decreasing the amount of generation needed. Less generation could result in relatively high peak energy market prices, which would further promote demand responsiveness. The capacity prices needed to support sufficient capacity investments would then decrease, limiting the impact of administratively determined parameters. Ultimately, increasing demand participation would enable MISO to rely more heavily on market-based energy and ancillary prices without eliminating the reliability standard for the portion of load that does not wish to be curtailed in response to high prices.

I.C. SUMMARY OF RECOMMENDATIONS

MISO should postpone consideration of replacing the current construct with either a forward capacity market or a pure energy-only market. Instead, it should continue to refine the current construct and integrate more price-responsive demand in order to enhance economic efficiency while maintaining a satisfactory level of reliability. We have four specific recommendations for MISO and its stakeholders to consider:

1. **Locational resource adequacy:** assess options for market-based approaches to ensuring locational resource adequacy, including implementing local sourcing requirements. We also recommend incorporating a locational scarcity pricing evaluation into the annual LOLE study which would review scarcity pricing activity in constrained and potentially constrained zones.
2. **Load forecasting:** MISO should develop its own coincident peak load forecasting capability (possibly with input from LSEs) rather than relying solely on LSEs to conduct their own peak load forecasts. The use of a centralized, coincident peak load forecast could avoid adverse incentives and quality problems.
3. **Load tracking:** develop a tracking system that accounts for load migration in retail choice states in a timely manner. It may help to define peak load contributions for customers and to develop a true-up mechanism to account for mid-month load migration.
4. **The reliability target:** (1) conduct an economic efficiency-based assessment to determine an appropriate target; (2) consider adopting a better-defined reliability metric such as expected unserved energy (EUE), which indicates the amount of MWh likely to be curtailed; and (3) work with the North American Electric Reliability Council (NERC) regional entities to consider revising the standards if economic analysis indicates that the current “1-in-10” LOLE standard is inefficient.

We have also identified several additional areas that MISO and stakeholders should monitor over time:

5. **Investment/retirement:** monitor capacity investments and retirements, particularly in retail choice states to ensure that the next round of capital investments will be made when and where needed.
6. **State planning reserve margins:** if a state lowers its planning reserve margin below the MISO-wide requirement, be prepared to evaluate the reliability implications, and plan to refer the issue before the FERC if such a state appears to be leaning on its neighbors for resource adequacy.
7. **VCA performance:** monitor performance by: (1) confirming that prices continue to be consistent with prevailing market conditions of over- or under-supply; and (2) reviewing transaction volumes and soliciting stakeholder feedback (particularly from competitive retail providers) to determine whether the VCA is sufficiently liquid.

8. **Long-term PRCs:** review potential benefits and drawbacks of creating multi-year PRCs as market participants gain more experience as to what value forward PRCs could offer beyond the bilateral contracting options already available.

II. STUDY OBJECTIVES AND APPROACH

II.A. PURPOSE

The Midwest Independent System Operator has commissioned *The Brattle Group* to conduct an independent assessment of its construct for resource adequacy. This evaluation has three objectives. First, to evaluate the progress MISO has made in developing and implementing its resource adequacy construct, including the extent to which MISO has met the goals set forth in its year 2009 Incentive Plan.¹ Second, to evaluate the merits of the market design construct for resource adequacy and to identify opportunities for improvement. And third, to provide MISO and stakeholders with a basis for establishing appropriate goals for the future.

II.B. EVALUATION CRITERIA

The primary evaluation criterion used by *The Brattle Group* authors of this report is economic efficiency. We evaluate the MISO RA construct against a perfectly efficient theoretical ideal in which customers would be able to purchase as much reliability as they desire by paying the incremental resource costs of providing that reliability; no customer would have to pay for “too much” reliability. Similarly, resource suppliers would receive market-based payments that reflect the incremental value of their resources to customers. Payments would support investment in the lowest-cost resources and promote availability at the times and locations where capacity is needed most. This ideal is not yet achievable because, for most customers, technical and regulatory limitations prevent the provision of differentiated levels of reliability.² While recognizing such challenges, we evaluate MISO’s resource adequacy construct based on how close it can come to this ideal.

II.C. APPROACH

We have incorporated extensive stakeholder input and review into this assessment, and have systematically examined each component of MISO’s resource adequacy construct through the following process:

¹ Implementation progress is discussed throughout the report and in particular in Section III.B; evaluation of MISO goals is in Section VI. For Incentive Plan goals, see pp. 8-9, MISO (2009a).

² The exceptions are those customers on traditional interruptible rates or under direct load control programs. These customers are able to achieve a lower level of reliability than the rest of the system and are able to pay a lower overall price for reliability. However, no customer is able to purchase a higher level of reliability than that provided by the system except by installing on-site backup generation because in the case of a system emergency, rolling blackouts would be applied indiscriminately.

- Reviewed MISO's compliance filings with FERC, stakeholder comments, and FERC orders.
- Reviewed current tariff modules, current business practices manuals, historic working group materials, and market results to date.
- Solicited stakeholder input through meetings with the Supply Adequacy Working Group (SAWG), individual focus group meetings with each of the nine stakeholder sector groups, and written comments.
- Compared the MISO market against other RTOs in both best practices and common difficulties.
- Assessed whether the specific goals in the 2009 Incentive Plan have been met as reported in Section VI of this report.
- Evaluated each market design component including progress to date and opportunities for improvement, as reported in the body of this document.
- Presented draft findings to stakeholders in the SAWG and solicited comments on our preliminary findings.

While stakeholder input has been an invaluable source of information and insight, the product of this undertaking represents the findings of *The Brattle Group* authors alone. This report does not attempt to represent stakeholder positions or resolve conflicts among these positions.

III. BACKGROUND

This section of the report begins with an overview of MISO’s resource adequacy construct in comparison with fundamentally different approaches to resource adequacy. The remainder of the section provides a discussion of the MISO’s RA construct including the development and progress, and a description of the current construct.

III.A. GENERAL APPROACHES TO RESOURCE ADEQUACY

MISO’s general approach is to define and financially enforce a resource adequacy requirement placed on load serving entities (LSEs), but without ever procuring resources on behalf of LSEs or requiring LSEs to participate in centrally administered auctions. This approach lies within a spectrum of resource adequacy constructs that have been implemented in the United States and internationally, as summarized in Table 1.³ The top row of Table 1, describes four different approaches for ensuring resource adequacy: mandating capacity procurement by LSEs on a forward basis, mandating capacity procurement by LSEs on an in-year basis, ensuring resource adequacy through administrative capacity payments paid directly to suppliers, and energy-only markets without a resource adequacy requirement.

In constructs where LSEs must meet a resource adequacy requirement, they could be required to procure capacity purely through bilateral contracting or self-supply, or they may have the option to procure capacity through a voluntary or mandatory centralized capacity market, as shown in the leftmost column of Table 1.

³ Table 1 is based on a recent report *The Brattle Group* wrote for PJM. See Pfeifenberger, *et al.* (2009).

Table 1
Spectrum of Approaches to Resource Adequacy⁴

		<i>LSE RA Requirement With Bilateral Capacity Market</i>		<i>Administrative Capacity Payments for RA</i>	<i>No RA Requirement (Energy-Only Market)</i>
		<i>Forward Requirement</i>	<i>Short-Term Requirement</i>		
<i>Type of Residual Capacity Market</i>	<i>No Centralized Capacity Market</i>	CAISO	SPP	Chile, Spain, South Korea	ERCOT, AESO, Australia’s NEM, NordPool, Great Britain
	<i>“Voluntary” Centralized Capacity Market</i>		MISO		
	<i>“Mandatory” Centralized Capacity Market</i>	PJM, ISO-NE, Brazil	NYISO		

III.A.1. Energy-Only Markets

At one extreme of the spectrum are energy-only markets. In a pure energy-only market, there is no guaranteed level of resource adequacy. Instead, the amount of capacity in the system is determined by the aggregate effect of private investment decisions, which are based on the revenues available from the energy and ancillary services markets.^{5,6} Energy-only markets are

⁴ Table 1 refers to the following markets according to their short names: California ISO (CAISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Alberta Electric System Operator (AESO), Australia’s National Electricity Market (NEM), Midwest ISO (MISO), PJM Interconnection (PJM), ISO New England (ISO-NE), and New York Independent System Operator (NYISO).

⁵ For a full discussion of the theoretical basis for pure energy-only markets, see Hogan (2005) and Joskow and Tirole (2004).

⁶ In actual energy-only markets, there often are market interventions through the system operator or government entities in the case of insufficient resources. Out-of-market interventions can take the form of backstop procurement mechanisms, government-built generation, or out-of-market approved rate recovery. These interventions damage the function of the energy-only market by artificially suppressing energy-market prices and tend to be self-perpetuating. A well-functioning energy-only market should not require such interventions. See pp. 19-38, Pfeifenberger, *et al.* (2009).

characterized by moderate energy prices punctuated by occasional severe price spikes. This is because most of the time there will be sufficient available capacity resources, and the competitive market price will reflect the marginal production cost of the most expensive unit dispatched. However, there will also be occasional conditions in which supplies become scarce, and energy prices climb above marginal costs to include a scarcity premium. These occasional price spikes must be large enough and frequent enough to allow the recovery of fixed operations and maintenance and investment costs if capacity resources are to be attracted to and retained in the market.

While price spikes are inherent to the design, they can introduce economic shocks to customers, potentially creating political challenges in maintaining such a design. However, market participants can use financial hedges to limit the impact of this volatility, a practice that is widespread in Australia's National Electricity Market (NEM).⁷

Occasional high scarcity prices motivate demand reductions through price-responsive demand (PRD) reductions and interruptible retail rates. The price during a scarcity event must rise until supply and demand balance. In this case, the scarcity price is (theoretically) an economically efficient and accurate representation of the value customers place on consuming peak power and avoiding interruptions in service. Capacity suppliers, likewise, have an efficient price signal of whether or not to invest in capacity without any administratively-determined resource adequacy standard. The ability to rely on customers to choose their own desired level of reliability through the marketplace, rather than relying on administrative determinations, is the primary advantage of the energy-only market.

However, demand can adequately adjust to balance the system during shortages only if a large enough fraction of the load is exposed to and responsive to market prices. In real-world energy-only markets, there is not yet sufficient price response or interruptible load for the theoretical model of the energy-only market to be workable.⁸ During a scarcity event, the system administrator must enact involuntary load curtailment and set the market price at an administratively-determined level. The most efficient price during rationing events is the estimated price that interrupted customers would have been willing to pay to avoid interruption, or the Value of Lost Load (VOLL).⁹ Such administrative scarcity pricing establishes a maximum-price demand curve for energy.¹⁰ More advanced scarcity pricing schemes gradually increase the price toward the VOLL as the necessity of curtailments became more likely, as is done in MISO and discussed in Section IV.A.4.¹¹

⁷ See Ch. 3, AER (2007).

⁸ See Section V.C for a discussion of how much demand response is needed for a workable energy-only market.

⁹ See Joskow and Tirole (2004) and Hogan (2005).

¹⁰ Note that if there actually *were* significant demand response and interruptibility in the market, the outcome during a scarcity event would be much more efficient because customers would self-select reductions from low-value uses of power. Under involuntary curtailments, high and low value applications for power are indiscriminately interrupted.

¹¹ See Hogan (2005).

III.A.2. Administrative Capacity Payment Systems

Energy markets with administrative capacity payments are similar to energy-only markets, except that energy market prices are typically capped at a level far below the VOLL and do not include a scarcity premium. As a result, suppliers are generally unable to recover their fixed costs from spot energy market revenues, resulting in “missing money” relative to what is needed to attract and retain sufficient capacity. System operators provide the missing money via payments made directly to suppliers of capacity. The system administrator generally recovers the costs associated with these capacity payments via an uplift charged assessed to customers on a pro-rata basis.¹²

There has been great variation in the determination of administrative capacity payments and the designation of eligible suppliers. The most widely-used capacity payment design is similar to the one first implemented in Chile in 1982.¹³ This was an availability-based compensation mechanism under which any supplier bidding in to the energy market would receive a capacity payment whether or not the unit was dispatched. Over the course of the year, these capacity payments would cover the fixed costs of a peaking unit that had demonstrated sufficient availability during months of peak demand or capacity shortage.¹⁴

The major criticism of such capacity payment systems is that they rely on administrative judgment rather than market forces.¹⁵ In a capacity payment system, the system administrator is extensively involved in determining the quantity and type of capacity resources that will be supplied as well as the size of the payments that will be made.

III.A.3. LSE Resource Adequacy Requirements

The approach to resource adequacy used in MISO and almost all of the other RTO markets in the United States is based on resource adequacy requirements imposed on LSEs. Under this design, the system administrator determines the amount of capacity that will be required in the system to ensure resource adequacy. Each LSE must show that it has procured enough capacity to meet its own customers’ peak load plus required reserves.

¹² See pp. 336-337, Adib, *et al.* (2008).

¹³ See p. 4547, Batlle (2007); Larsen (2004); Rudnick (2002).

¹⁴ In Chile, the peak demand months are May-September; in Colombia, the payments are made during the dry season of December-April when hydro capacity is limited. See Rudnick (2002), p. 161. Sometimes the capacity payments are differentiated depending on the type of resource, for example, in order to incent investments in thermal capacity after a period of draught and associated electric shortages, Colombia introduced increased capacity payments for thermal units. However, the units would have to make at least some energy margins to be profitable overall. See Larsen, (2004).

¹⁵ For example, both the South Korean and Colombian systems have been criticized for lack of transparency and predictability. See pp. 5821-22, Park (2007); p. 1772, Larsen, et al. (2004).

As shown in Table 1, PJM, ISO-NE, and CAISO require LSEs to demonstrate sufficient capacity on a forward basis, whereas MISO, SPP, and NYISO require LSEs to demonstrate sufficient capacity immediately prior to the delivery period.

Another key difference among these markets is whether the system operator administers a centralized capacity market. While the creation of a resource adequacy requirement always creates a bilateral market for capacity, centralized capacity markets have not been established in all RTOs. For example, in SPP which lacks a centralized capacity market, LSEs procure capacity only through self-supply or bilateral contracting.¹⁶ MISO operates in largely the same way, but it also administers a Voluntary Capacity Auction (VCA) through which market participants can buy or sell capacity on a voluntary basis.¹⁷ In both MISO and SPP, the LSE is entirely responsible for full procurement of its requirement and the system operator does not procure capacity to fill deficiencies. This is unlike CAISO, which will bilaterally procure capacity when needed to fill deficiencies, and unlike PJM, NYISO, and ISO-NE, which will procure capacity deficit through their centralized capacity auctions.

Participation in the centralized market for procuring residual capacity is mandatory in PJM, NYISO and ISO-NE.¹⁸ Under these designs, LSEs have the option to procure capacity through self-supply or bilateral contracting, but the RTO will procure any residual needed supply through the mandatory centralized auction and assign responsibility for payment to LSEs. Similarly, any existing capacity that has not already been designated toward the resource adequacy requirement must be offered into the mandatory auction.

III.B. MISO'S RESOURCE ADEQUACY DEVELOPMENT TIMELINE

In November 2005, MISO published a whitepaper on its vision of moving to an energy-only market, including a discussion of the conceptual underpinnings of such a construct and key market design elements.¹⁹ In particular, the report envisioned that the energy-only market would be supported by an advanced scarcity pricing mechanism and that states would have to play a significant role in developing demand-side participation. This energy-only proposal represented a departure from the traditional resource adequacy programs overseen and enforced by the states. This report was put out in the midst of MISO's proceeding before the FERC, on how it proposed to transition from an interim resource adequacy construct to a long-term resource adequacy construct.

Since that time, MISO has implemented a comprehensive resource adequacy construct, which is seen by some stakeholders as a step toward an energy-only market. However, stakeholders are divided about how the construct should develop over the long-term, as discussed in Section V.

¹⁶ Member utilities in SPP are mandated to fulfill the 12% capacity margin. The RTO oversees but does not enforce this provision, with overall resource adequacy and enforcement handled by state regulators. See p. 222, NERC (2008a); pp. 2.2-2.4, SPP (2009).

¹⁷ See MISO (2009b).

¹⁸ See PJM (2009a); NYISO (2009a).

¹⁹ See MISO (2005).

Rules governing the current MISO resource adequacy construct are set out in the RA Business Practices Manual, which is the implementation of the MISO Tariff's Module E on resource adequacy as approved by the FERC.²⁰ The rest of this section reviews the progress that MISO has made in developing and revising Module E before the FERC as well as the progress made in the stakeholder process during the first planning year.

III.B.1. Development of Module E of the MISO Tariff

The first version of Module E was approved by the FERC on August 6, 2004 as an interim resource adequacy plan for a transition period until MISO implemented a long-term resource adequacy construct.²¹ The current long-term resource adequacy construct was initially filed with the FERC in December 2007 and refined over a series of compliance filings that have continued to present as detailed below.²² In response to each of MISO's refinements to Module E listed below, the FERC has conditionally accepted the changes and required additional compliance filings.

*December 28, 2007*²³ - MISO filed changes to Module E to implement its long-term resource adequacy construct, including the overall structure of ensuring resource adequacy through a voluntary system enforced by "financial settlements" for non-compliance. Although not all details had been worked out, MISO requested approval of the overall structure to help narrow the focus of the stakeholder process.

*May 27, 2008*²⁴ - MISO submitted a compliance filing covering a large number of issues including: states' authority to change the planning reserve margin (PRM), application of the PRM to LSEs, load forecasting, resource plan requirements, zone definition, and qualification and accounting of capacity resources.

*June 25, 2008*²⁵ - MISO submitted a compliance filing that established the major financial settlement provisions of the RA construct, including LSE deficiency charges and provisions regarding the VCA.

*November 19, 2008*²⁶ - MISO and the independent market monitor (IMM) submitted four separate compliance filings on a large number of issues including: monitoring and mitigation of the VCA, annual capacity testing requirements, treatment of Load Modifying Resources (LMRs) as Local PRCs (LPRCs), must offer requirement on installed capacity (ICAP) rather than unforced capacity (UCAP), submission of LSE data to retail regulatory authorities, accounting of full-responsibility purchase and sales, treatment of external resources, deliverability testing, LMR accreditation, support for the

²⁰ See MISO (2009b) and (2009c).

²¹ See pp. 1-2, MISO (2007a).

²² These proceedings before the FERC are in the sub-dockets under ER08-394, among the proceedings are 13 filings or compliance filings submitted by MISO and 7 substantive orders issued by the FERC.

²³ See MISO (2007a).

²⁴ See MISO (2008a).

²⁵ See MISO (2008b).

²⁶ See MISO (2008c-e) and Potomac Economics (2008a).

\$80/kW-year Cost of New Entry (CONE) calculation for the initial planning year, and removal of the provision for backstop capacity procurement using deficiency penalties.

*December 19, 2008*²⁷ - MISO submitted minor alterations to Module E regarding consistent use of MW and MWh units.

*March 23, 2009*²⁸ - MISO submitted two compliance filings regarding: treatment of LMRs in peak load forecasts, submission of LSE peak load and capacity procurement data to states with jurisdiction, zone definition, full responsibility purchase and sales agreements, and acceptance of redacted versions of power purchase agreements (PPAs) for confirming bilateral capacity arrangements.

*June 17, 2009*²⁹ - MISO submitted a compliance filing regarding: revisions and additional detail on IMM approach to monitoring the VCA, the LSE deficiency penalty schedule, and an interim proposal for addressing the deliverability of LMRs.

*July 31, 2009*³⁰ - MISO submitted a new revised CONE calculation for the second planning year at \$90/kW-year.

*August 18, 2009*³¹ - MISO submitted a required compliance filing on deliverability referring to the many recent updates, but did not make further changes to Module E.

*October 20, 2009*³² - MISO submitted a resource adequacy improvement filing to Module E clarifying a large number of implementation issues without making fundamental changes to the construct. The most substantive change was the integration of Planning Resource Credits (PRC) into Module E, which had previously only been discussed within the RA BPM. Several other implementation issues related to resource qualification and capacity testing were either clarified or rewritten to refer to the BPM.

*November 18, 2009*³³ - MISO revised Module E language clarifying how demand resources (DR) will be netted against LSE peak load forecast.

*December 1, 2009*³⁴ - MISO submitted information regarding behind-the-meter-generation (BTMG) resource activity during PY1. The filing included arguments supporting the current method of treating BTMG like other capacity resources rather than subtracting it directly from load like DR.

There are no further outstanding compliance filings required in order to update Module E, but MISO plans to make at least one additional filing relating to the deliverability of LMRs early in 2010. Furthermore, the most recent MISO filing that FERC has ordered on was from March,

²⁷ See MISO (2008f).

²⁸ See MISO (2009d-e).

²⁹ See MISO (2009f).

³⁰ See MISO (2009g).

³¹ See MISO (2009h).

³² See MISO (2009o).

³³ See MISO (2009y).

³⁴ See MISO (2009z).

2009, with six more recent filings that have not yet been accepted. It is likely that the FERC will issue another order soon, and possibly require additional compliance filings from MISO.³⁵

III.B.2. BPM Implementation Progress during Planning Year 1

Implementation details of Module E are contained in the resource adequacy BPM. The first BPM became effective in June, 2009 at the beginning of PY1. That version contained a large number of interim rules regarding capacity resource qualification, testing, and UCAP rating determination in order to allow all resource types to participate in PY1. These provisions are summarized in Table 2.³⁶ Since that time, the MISO and its stakeholders have addressed a large number of these issues through the SAWG. Many of these final implementation issues have been resolved for PY2 as shown in Table 2, with the version of the BPM applicable for PY2 BPM having been made effective in December.³⁷

³⁵ See FERC (2009a).

³⁶ *The Brattle Group* determined the status of each implementation issue based on discussions with MISO staff and review of the PY1 RA BPM, the current PY2 RA BPM draft, and the current SAWG “Issues List” from December 2009. See MISO (2009b); MISO (2009aa); MISO (2009p).

³⁷ See MISO (2009aa).

Table 2
Status of Implementation Procedures

	By Planning Year 1		By Planning Year 2	
	Internal Resources	External Resources	Internal Resources	External Resources
Qualification Procedures				
Large Generation > 10 MW	In Place	In Place	In Place	In Place
Small Generation <10 MW	In Place	In Place	In Place	In Place
Intermittent Generation	In Place	In Place	In Place	In Place
Use-Limited Generation	In Place	In Place	In Place	In Place
DRR	Transitional	Not Allowed	In Place	Not Allowed
DR	Transitional	Not Allowed	In Place	Not Allowed
Large BTMG > 10 MW	Transitional	Not Allowed	In Place	Not Allowed
Small BTMG < 10 MW	Transitional	Not Allowed	In Place	Not Allowed
Deliverability Testing¹				
Large Generation > 10 MW	In Place	In Place	In Place	In Place
Small Generation <10 MW	In Place	In Place	In Place	In Place
Intermittent Generation	In Place	In Place	In Place	In Place
Use-Limited Generation	In Place	In Place	In Place	In Place
DRR	Transitional	Not Allowed	Filed by Q1 2010	Not Allowed
DR	Transitional	Not Allowed	Filed by Q1 2010	Not Allowed
Large BTMG > 10 MW	Transitional	Not Allowed	Filed by Q1 2010	Not Allowed
Small BTMG < 10 MW	Transitional	Not Allowed	Filed by Q1 2010	Not Allowed
Annual Capacity Test²				
Large Generation > 10 MW	Transitional	Transitional	RE Standard	RE Standard
Small Generation <10 MW	Transitional	Transitional	RE Standard	RE Standard
Intermittent Generation	Transitional	Transitional	RE Standard	RE Standard
Use-Limited Generation	Transitional	Transitional	RE Standard	RE Standard
DRR	Transitional	Not Allowed	Transitional	Not Allowed
DR	Transitional	Not Allowed	Resolved	Not Allowed
Large BTMG > 10 MW	Transitional	Not Allowed	RE Standard	Not Allowed
Small BTMG < 10 MW	Transitional	Not Allowed	RE Standard	Not Allowed
Annual XEFOR_d Rating				
Large Generation > 10 MW	Transitional	Transitional	In Place	In Place
Small Generation <10 MW	Transitional	Transitional	In Place	In Place
Intermittent Generation ³	20% Capacity	20% Capacity	8% Capacity	8% Capacity
Use-Limited Generation	Transitional	Transitional	In Place	In Place
DRR	0% XEFOR _d	Not Allowed	0% XEFOR _d	Not Allowed
DR	0% XEFOR _d	Not Allowed	0% XEFOR _d	Not Allowed
Large BTMG > 10 MW	Transitional	Not Allowed	In Place	Not Allowed
Small BTMG < 10 MW	Transitional	Not Allowed	In Place	Not Allowed
Must Offer Compliance Assessment⁴				
Large Generation > 10 MW	Not Monitored	Not Monitored	Monitored	Monitored
Small Generation <10 MW	Not Monitored	Not Monitored	Monitored	Monitored
Intermittent Generation	Not Monitored	Not Monitored	Monitored	Monitored
Use-Limited Generation	Not Monitored	Not Monitored	Monitored	Monitored
DRR	N/A	Not Allowed	N/A	Not Allowed
DR	N/A	Not Allowed	N/A	Not Allowed
Large BTMG > 10 MW	N/A	Not Allowed	N/A	Not Allowed
Small BTMG < 10 MW	N/A	Not Allowed	N/A	Not Allowed

¹⁻⁴ Numbers correspond to the list on the following page.

Resolved = Agreed upon by stakeholders but not yet codified.

Transitional = Interim procedure is used, but long-term solution not resolved.

N/A = Obligation does not apply to this resource type.

The items identified in Table 2 represented significant progress toward comparable treatment of all planning resources. We discuss here resolved issues that represented major holes in the PY1 BPM.

1. MISO uses system impact studies to determine the aggregate deliverability of generation resources, however it has not established a similar method for assessing the aggregate deliverability of LMRs. The FERC has required MISO to develop such a procedure.³⁸ Recently, MISO has proposed extending its generator deliverability methodology to LMRs.³⁹ MISO plans to file its proposed permanent solution to LMR deliverability studies with the FERC by early 2010.
2. Module E requires that planning resources verify installed capacity by submitting an annual capacity test to MISO. However, the North American Electric Reliability (NERC) Regional Entities (RE) already require annual capacity tests, the rules of which differ among the three regions: Midwest Reliability Organization (MRO), ReliabilityFirst Corporation (RFC), and SERC Reliability Corporation (SERC). MISO's task has been to coordinate among the three standards to make a reasonably comparable standard across MISO. For PY1, MISO did not require generators to submit test results; for PY2, resources will submit the results of its RE test to MISO; for PY3, resources will have to test according to MISO standards.⁴⁰
3. For PY1, all wind resources were assigned a UCAP rating of 20% installed capacity. For PY2, MISO has determined a value of 8% by studying the effective load carrying capability (ELCC) of wind resources over the past five years. Wind resources were examined in aggregate, and the capacity value of each resource will not be evaluated separately.⁴¹
4. Although the must-offer requirement has been in place over the current planning year, compliance has not been assessed or enforced. MISO has recently proposed assessment standards specifying the minimum derate sizes that would have to be reported to the outage coordinator, called the Control Room Operations Window (CROW), in order to prove compliance with must-offer.⁴² If a unit does not offer its entire capacity value into the energy market, but the quantity not offered corresponds to a small temporary capacity rating below the derate threshold, the unit will be considered compliant. No enforcement or penalty system for non-compliance has been proposed.

³⁸ As an interim solution, MISO has allowed the sale of all LMRs into the VCA as Aggregate PRCs, but only if the LSE with the obligation to serve the retail customers underlying the LMR asset has a track record of having more than enough APRCs to offset any LMRs sold, see Sheet Nos. 1490L-1490N, MISO (2009o).

³⁹ See MISO (2009r).

⁴⁰ See pp. 2.99, MISO (2009aa).

⁴¹ See MISO (2009bb).

⁴² See MISO (2009t).

The progress in these areas through the Supply Adequacy Working Group (SAWG) has been substantial, and it appears that this progress made in addressing the items on its outstanding issues list will continue for the remainder of PY1 and into PY2.⁴³

III.C. KEY ELEMENTS OF THE MISO CONSTRUCT

The MISO resource adequacy construct is an LSE resource adequacy requirement, as described in Section III.A.3; this Section describes the construct's major elements, while Section IV reports on our evaluation of these elements. The key elements of the construct are: (1) a method for determining the RA requirement; (2) testing and verification procedures for evaluating resources' UCAP values; (3) a voluntary capacity auction; and (4) mechanisms for enforcing the RA requirement.

In setting the resource adequacy requirement, MISO annually conducts a Loss of Load Expectation study to determine the amount of capacity needed to achieve an LOLE of 1-day-in-10-years.⁴⁴ The resulting RA requirement is expressed as a Planning Reserve Margin (PRM) in excess of the forecasted system coincident peak load.⁴⁵ The PRM is then adjusted downward by a historic diversity factor in order to determine the PRM required in excess of the non-coincident peaks of individual LSEs. Finally, the number is reduced further based on a fleet-wide forced outage rate in order to determine the PRM requirement (PRMR) on a UCAP basis.^{46,47}

The unforced, non-coincident peak reserve margin required for the upcoming planning year is announced to market participants by November 1 prior to the planning year that begins the following June.⁴⁸ By March 1, shortly prior to the planning year, each LSE must submit its Annual Resource Plan, which includes preliminary monthly submissions for: (1) non-coincident peak load forecast for each of the LSE's commercial pricing nodes (CPNodes) excluding any full responsibility purchases (FRPs) and including any full responsibility sales (FRS), which are purchase or sales obligations that are handled as native load; and (2) the designation of planning

⁴³ For the most recent SAWG issues list as of December 2009, see MISO (2009p).

⁴⁴ The Year 2009-2010 study concluded that a 15.4% installed reserve margin was required to meet the 1-in-10 LOLE reliability target. See pp. 1, 31, MISO (2009i).

⁴⁵ However, if any state regulatory authority has determined a different PRM, then that state's PRM will be used for LSEs under that state's jurisdiction, no matter whether it would require a higher or lower reserve margin; the implications of such a change are discussed in Section IV.C.1. See Original Sheet No. 810.01, MISO (2009c).

⁴⁶ There are two forced outage rate metrics used in the resource adequacy construct: the Effective Forced Outage Rate (EFOR_d) which includes all outage causes, and the XEFOR_d which excludes all events Outside Management Control (OMC). The XEFOR_d is the number used to determine suppliers' UCAP ratings. See pp. 3.9-3.11, MISO (2009b).

⁴⁷ The Year 2009-2010 LOLE study determined a diversity factor of 2.34% based on the lowest historic annual diversity factors among Local Balancing Authorities (LBA) over 2005-2008. The overall XEFOR_d rate was 6.51%. After making these adjustments, individual LSEs' non-coincident, unforced PRM requirement was calculated at 5.35%. See pp. 17-19, MISO (2009i)

⁴⁸ Planning years are June 1-May 31. For planning year one MISO had to post the PRMR only five months in advance of the planning year. See Original Sheet No. 810A, MISO (2009c); p. 8, MISO (2009o).

resource credits (PRCs) that will be used to meet its PRMR for that month.⁴⁹ Submission of this annual plan is required, although the plan is preliminary and capacity deficiencies are not subject to enforcement or penalty. The LSEs then have until the 1st of the month prior to each delivery month to update their monthly resource plans by adjusting their peak load forecasts and designating sufficient PRCs.⁵⁰

Each LSE submits its own forecast of non-coincident monthly peak load, to which the PRMR is applied to determine the total monthly planning resources required to fulfill the LSE's obligation. This forecast is the LSE's best estimate of peak load including any changes that might occur over the month due to retail load migration, as well as anticipated transmission losses.⁵¹ The LSE must also submit additional information related to its calculation of peak load, including sufficient information to calculate a standard deviation around the peak load forecast, which can depend on price and weather variables.⁵² After the delivery month has passed, MISO does an after-the-fact demand assessment to determine whether an LSE has under-forecasted its peak load.⁵³ If identified for potential under-forecasting, the LSE has the opportunity to show evidence of an unanticipated event including any increases in retail customers. If a determination of under-forecasting is made in three consecutive months or in any month during the summer period from June to September, MISO will report the LSE to the state authority.⁵⁴

The PRCs that LSEs must use to fulfill their monthly resource plans represent capacity, which can be converted at the rate of 1 PRC to 1 MW of UCAP.⁵⁵ All types of planning resources can be designated toward an LSE's resource plan, with the special characteristics of the various resource types accommodated by different treatment as summarized in Table 3. Planning resources fall into two major categories. First are "Capacity Resources," including internal generation, external generation, demand response resources (DRR) Type I and Type II, which are subject to must-offer obligations. Second are "Load Modifying Resources" (LMRs), which include demand resources and behind-the-meter generation (BTMG). The main difference between capacity resources and LMRs is that LMRs have the obligation to respond only during emergencies and are not obliged to offer energy into the MISO energy markets. Although both LMRs and DRRs are demand-side resources, they are treated differently in the energy market

⁴⁹ A description of PRCs follows in the text. See pp. 5.63-5.65, MISO (2009b).

⁵⁰ Id.

⁵¹ See pp. 4.22-4.23, MISO (2009b).

⁵² There is no one method prescribed for determining peak load or standard deviation based on these variables or specifying exactly what supporting information must be supplied. However, the information must be sufficient so that MISO can determine a standard deviation around forecasted peak load before and after any weather and price normalizations. See pp. 5.67-6.71, MISO (2009b).

⁵³ The assessment consists of a series of checks for statistically significant under-forecasting with the null hypothesis that actual load will be no more than one standard deviation above forecasted load (2.5% p-value, one-tail, normal distribution). Significance tests are done both before and after normalizing for price and weather. The LSE must fail all of these tests to be deemed under-forecasting. Id.

⁵⁴ A state authority will be notified only if it has jurisdiction over the under-forecasting LSE, pp. 5.67-6.71, MISO (2009b). While MISO has been conducting these under-forecasting assessments monthly, MISO is not yet reporting results to state authorities to allow time for stakeholders to gain familiarity and address stakeholders' concerns with the process.

⁵⁵ See p. 5.41 MISO (2009b).

because DRRs are dispatched on the supply side of the market like generators; LMRs are allowed to participate as price-responsive demand (PRD) and would be treated on the demand side of the market.

In order to participate in the RA construct, the resource must pass through the qualification process and an annual capacity testing process. The Equivalent Forced Outage Rate (EFOR_d) after excluding events outside of management control (XEFOR_d) of each resource is also updated annually in order to establish the UCAP rating. The UCAP value can then be converted into one of three types of PRCs. If an internal resource, or a portion of it, has been determined to be aggregate deliverable through a system impact study, then the aggregate deliverable portion of the resource can be converted into an aggregate PRC (APRC) and designated at any CPNode in MISO; otherwise it can only be converted into a local PRC (LPRC), which can be designated at any CPNode within the same Local Balancing Area (LBA). External resources can be converted into External PRCs (EPRC) and can be designated at any CPNode within the LBA into which it has firm transmission service.⁵⁶

⁵⁶ For planning year one, some LPRCs and EPRCs have been allowed to be designated at any CPNode within the LBA. For future planning years, the EPRC can only be used at the CPNode where the firm transmission rights sink. See pp. 4.34, 5.42-5.43, MISO (2009b).

Table 3
Categorization and Requirements by Resource Type⁵⁷

	Planning Resources				
	Capacity Resources			Load Modifying Resources	
	Generation Resources	External Resources	Demand Response Resources	Behind-the-Meter Generation	Demand Resources
Capacity Verification	Yes	Yes	Yes	Yes	Yes
Energy Market Must Offer Requirement	Yes	Yes	Yes	No	No
GADS Data Entry	Yes	Yes	No	Yes	No
Required Emergency Response	Yes	Yes	Yes	Yes	Yes
Eligible to be Deducted Directly from PRMR ⁵⁸	No	No	No	No	Yes

An LSE can procure the PRCs to meet its RA obligation through self-supply, traditional bilateral contracts, bilateral purchases of PRCs, or purchases through the VCA.⁵⁹ The VCA is a monthly auction held five business days prior to the resource plan deadline, within which market participants have the option of transacting APRCs.⁶⁰ The VCA is intended to provide only a residual balancing market for capacity right before the deadline, with most transactions occurring

⁵⁷ See p. 2.3 and other sections, MISO (2009b); pp. 2.99, MISO (2009aa).

⁵⁸ Demand Resources can either be converted into LPRCs, or subtracted directly from the PRMR, but not both. See p. 4.25, MISO (2009b).

⁵⁹ Traditional bilateral contracts and power purchase agreements (PPA) can be used to contribute toward the resource plan of an LSE. However, these agreements must be fulfilled through the transfer of PRCs that have been converted from a planning resource through MISO's process; the PPA by itself cannot be used. Bilateral contracts that are non-resource specific and can be met from any of a range of resources are held to the same standard and must be fulfilled through the transfer of PRCs in order to demonstrate that no resource has been double-counted toward different LSEs' resource plans. See p. 5.53, MISO (2009b); Revised Sheet Nos. 818B-820, MISO (2009c).

⁶⁰ There are some limitations to the voluntary nature of the VCA, as the market is subject to IMM oversight. While the specific measures that the IMM will take to monitor the market have not yet been approved by the FERC in Module D of the Tariff, the IMM has proposed to monitor for: 1) physical withholding of more than 500 MW of planning resources from the VCA by any individual LSE or resource owner (including through capacity exports to external markets at less than 50% of the capacity price in MISO), and 2) economic withholding via APRC offer prices inflated above going-forward costs by more than 10% of CONE. See Attachment with proposed revised sheets to Module D, MISO (2009f).

bilaterally. If the LSE has not nominated sufficient PRCs to meet its obligation by the monthly resource plan deadline, the LSE will be assessed a deficiency penalty, which is a multiple of the gross annualized CONE for capacity resources depending on the number and timing of the deficiency months.^{61,62}

⁶¹ Each year MISO must update its estimate of CONE in a filing with the FERC. Planning years 1 and 2 have CONE values of \$80/kW-year and \$90/kW-year respectively. See MISO (2009g).

⁶² The penalty schedule assessed on any deficient MW is 100% of the annual CONE value for the first deficient month, 25% of CONE for each subsequent deficient month in Dec-Feb or Jun-Aug, and 8.3% of CONE for each subsequent deficiency in any other month. See pp. 6.78-6.79, MISO (2009b).

IV. EVALUATION OF MISO'S RESOURCE ADEQUACY CONSTRUCT

This section presents the results of our review of all aspects of the MISO resource adequacy construct. While each aspect of the construct was analyzed, not every aspect is discussed here. The discussion in this section focuses on: (1) the most noteworthy successfully implemented components; (2) the most important opportunities for improving the construct; and (3) components of the construct that are potentially problematic, but for which there is currently insufficient evidence to evaluate fully. This analysis is the result of a systematic review of available market data, regulatory proceedings, governing documents, historic stakeholder meeting materials, and current stakeholder comments. We have gathered stakeholder input on these topics through focus groups with each stakeholder sector group as well as through feedback on drafts of this report. While the inputs of stakeholders and MISO staff have been invaluable sources of information and insight, the conclusions presented here represent the findings of the authors alone and do not attempt to represent all positions or arguments.

IV.A. MAJOR SUCCESSES

This section presents the most notable successful components of the MISO resource adequacy construct.

IV.A.1. Coherent Construct with Major Components in Place

The major components required in a complete resource adequacy construct are in place and have been implemented in MISO, as discussed in Sections III.B and III.C. This is a substantial achievement because MISO has both traditional utility and retail choice states in its territory, as well as three NERC regional entities, and no common history in a tight power pool like some other RTOs and ISOs.⁶³ The resource adequacy construct has to be workable under all of these different regimes, making the undertaking more difficult.

As discussed in more detail in subsequent sections, implementation in the first planning year has generally gone smoothly, although some implementation issues are still being addressed, and stakeholders are still gaining familiarity with the process. In summary, over PY1:

- No LSEs have been assessed planning resource deficiency penalties. This is not surprising given the substantial surplus of capacity in the region.

⁶³ The MISO territory spans portions of 13 states and the Canadian province of Manitoba. The three NERC regional entities are the Midwest Reliability Organization (MRO), ReliabilityFirst Corporation (RFC), and SERC Reliability Corporation (SERC). See MISO (2009j); NERC (2009).

- The bilateral market appears to be sufficiently liquid. It has experienced robust trading in PRCs over PY1, with monthly APRC transaction volumes representing 29-44% of summer peak load.⁶⁴
- The VCA exhibited low volumes at less than 1% of summer peak load, but had non-zero cleared volumes each month.
- Prices in the VCA were volatile; they have been low in PY1, which is consistent with current conditions of excess capacity.⁶⁵
- MISO has not monitored capacity resources' compliance with their must-offer obligation over PY1 because the evaluation process had not yet been finalized, although a monitoring structure has been proposed for PY2. No enforcement or penalty structure for non-compliance has yet been proposed, outside of a market participant being in violation of the Tariff, which has the potential to have substantial monetary fines.⁶⁶
- LSEs have over-forecasted annual peak loads. Unexpectedly low peak loads were likely caused by the economic downturn and low summer temperatures, the full effects of which were not anticipated.⁶⁷

Implementing a new RA construct comes with the risk of design flaws that could result in excess costs or reduced reliability, outcomes that MISO has apparently substantially avoided. This smooth transition is a major achievement, and it was likely aided by making the transition under a condition of excess capacity.

IV.A.2. Liquid Bilateral Market Supported by PRCs

A bilateral market for capacity existed long before the introduction of the MISO resource adequacy construct. The prior bilateral market developed because utilities and states established their own resource adequacy requirements, and it was economic for utilities to transact capacity to help meet these requirements. The MISO resource adequacy construct has supplemented and supported this existing bilateral capacity market by introducing PRCs, which represent a standardized capacity product.

By introducing a standard system for measuring, verifying, and accounting for all planning resources, MISO has made capacity a more fungible commodity that can be readily transacted. The introduction of PRCs fits into traditional trading arrangements and provides market

⁶⁴ See Section IV.A.2.

⁶⁵ See Section IV.C.2.

⁶⁶ See Section III.B.2.

⁶⁷ See NOAA (2009). Despite this, 29-45 LSEs were determined to be “under-forecasting” over each of the summer months as discussed further in Section IV.B.3.

participants several advantages over the traditional bilateral contracting options that were available:

- Centralized and standardized capacity evaluation, although still being finalized, allows for an aggregate assessment of overall resource adequacy and verification of LSEs' contribution toward resource adequacy.
- Many transaction costs associated with developing a traditional Power Purchase Agreement (PPA) can be avoided, including verifying the maximum and unforced capacity ratings of the unit, verifying the creditworthiness of the counterparty, and making transmission arrangements. MISO guarantees that each PRC an LSE has purchased will count toward its resource adequacy requirements, allowing LSEs to pool the risks of physical and financial default. However, these advantages only apply to transactions within one year, corresponding to the time period for PRCs.
- Transactions can be made in any size, including small sizes down to one tenth of a megawatt, rather than limiting capacity transactions to the size of whole plants. This allows small LSEs to purchase only the amount of capacity they need, and provides small suppliers with greater ability to sell their capacity. It also allows larger participants the flexibility to make small adjustments to their capacity portfolios.

These advantages of a standard capacity product have been recognized in other markets where similar mechanisms have been instituted.⁶⁸ Table 4 is a summary of the bilateral PRC transactions that have taken place in MISO since PRCs were introduced. While it is not possible to compare the liquidity of the current bilateral market to what existed prior to the introduction of PRCs, it is clear from Table 4 that APRCs are liquid and are transacted widely, with 29%-44% of peak summer demand being transacted for each delivery month. It is also likely that a large portion of these APRC transactions represent pre-existing bilateral contracts, including any long-term contracts. The significant variability in these transactions indicates that a large portion also represents short-term or seasonal bilateral procurement, much of which would likely have occurred even without PRCs.

LPRC transaction volumes are much lower, partly because LPRCs making up a small fraction of the overall resource base, and partly because of limitations on where they can be designated toward an LSE's PRMR. No transactions of EPRCs have been recorded, also likely a result of the lower contribution to resource mix and designation limitations.

⁶⁸ Each of the RTOs with centralized capacity auctions, ISO-NE, PJM, and NYISO, has standardized the methods for evaluating the capacity value of various resources. Recently, CAISO has also gained FERC acceptance for its Standard Capacity Product, which the RTO has deemed to be a valuable addition to the design even without a centralized auction. See FERC (2009b).

Table 4
Summary of Bilateral PRC Transactions⁶⁹

Planning Month	Total APRC Transactions			Total LPRC Transactions			Number of Market Participants Transacting
	Number	MW	% of Summer Peak	Number	MW	% of Summer Peak	
Jun-09	287	27,528	28.9%	18	763	0.8%	97
Jul-09	370	42,272	44.4%	23	889	0.9%	104
Aug-09	393	36,676	38.5%	23	867	0.9%	105
Sep-09	328	30,460	32.0%	22	799	0.8%	107
Oct-09	319	28,677	30.1%	23	828	0.9%	107
Nov-09	316	28,661	30.1%	24	842	0.9%	107

IV.A.3. Integration of All Resource Types Including Demand Resources

Since its inception, Module E has allowed all types of resources to help meet resource adequacy requirements, including generation, external resources, DRRs, BTMG, and DR. This has maximized the potential pool of resources that can participate, which should increase efficiency and decrease the overall costs of resource adequacy. Table 5 and Table 6 summarize the qualified UCAP rating of each planning resource type for the expected peak month of July, 2009. Table 5 shows the qualified resources of each type of PRC as well as breaking out the LMR and DRR contributions separately; Table 6 shows internal capacity resources by fuel type.

⁶⁹ PRC data provided by MISO, (2009k). Summer peak load of 95,186 MW from June 2009, see MISO, (2009l).

Table 5
Qualified Planning Resources by PRC Category
During the Expected Peak Month of July, 2009⁷⁰

Resource Type	UCAP, MW	Fraction of Resource Mix
DRR	78	0.1%
DR (LMR)	3,620	2.9%
BTMG (LMR)	4,818	3.9%
LPRC (Non-LMR)	7,390	5.9%
APRC (Non-DRR)	103,180	82.7%
EPRC	5,696	4.6%
LMRs and DRRs	8,515	6.8%
Total	124,781	100%

Notes: Mutually exclusive resource categories.
Totals not adjusted for DR gross-up value caused by direct subtraction from peak load forecast.

Table 6
Qualified Local and Aggregate Capacity Resources by Fuel Type
during the Expected Peak Month of July, 2009⁷⁰

Fuel Type	UCAP, MW	Fraction of Resource Mix
Coal	60,022	48.1%
Coal/Gas	307	0.2%
Gas	26,458	21.2%
DRR	78	0.1%
Nuclear	9,800	7.9%
Oil	2,867	2.3%
Oil/Gas	7,212	5.8%
Other	57	0.0%
Pet Coke	179	0.1%
Waste	139	0.1%
Water	2,821	2.3%
Wind	707	0.6%
Total	110,648	88.7%

Note: EPRC, DR, and BTMG resources not represented.

The successful integration of demand resources in resource adequacy is highlighted in Table 5 which shows that DR, BTMG, and DRR contributed more than 8,500 MW of UCAP during the expected peak month of July, 2008, making up **6.8%** of all planning resources. The share of demand-side resources in MISO's capacity resource mix is comparable to that in other RTOs. For the 2012/13 planning year, demand response and energy efficiency represented 5.9% of the

⁷⁰ Data provided by MISO (2009dd).

total committed capacity in PJM and 7.8% in ISO New England.^{71,72} The share of capacity from the demand side in NYISO was 6.4% for the summer of 2009.⁷³

Of note in interpreting MISO's share of resources from LMRs and DRRs however, is the small UCAP contribution of DRRs; the 78 MW of DRR planning resources is much less than the 2,410 MW of DRRs eligible to participate in the energy and ancillary markets.⁷⁴ This low participation of DRRs in the RA construct could be related to the must-offer requirement imposed when DRRs participate as planning resources.⁷⁵ However, if MISO's filing regarding Aggregators of Retail Customers (ARC) is approved by the FERC, then ARCs will be enabled to bring additional DRRs to market, subject to the approval of the retail regulators.⁷⁶

Energy efficiency is one type of resource that has not been included on the supply side, as it has been in forward capacity markets such as PJM and ISO-NE.⁷⁷ PJM and ISO-NE count energy efficiency as supply resources on a forward basis for two reasons. First, doing so allows third-party providers of energy efficiency services to capture the peak-reducing value of their projects.⁷⁸ Second, it ensures that the peak-reducing value of the measure is recognized in a timely manner, rather than waiting to observe the effects on load then incorporating the effects in the following forward auction for delivery three years later. There is no threat of such lags in MISO, where the RA requirement is month-ahead, not three-years ahead.

IV.A.4. Complementary Scarcity Pricing Mechanism

The scarcity pricing mechanism that MISO has implemented within its energy and operating reserves markets is better designed than that in other RTOs, and it complements the resource adequacy construct. As introduced in Section III.A.1 as part of the discussion of energy-only markets, scarcity pricing allows energy market prices to rise above marginal costs of supply

⁷¹ In the Base Residual Auction held for the 2012/13 delivery year, 7,047 MW of demand resources and an additional 569 MW of energy efficiency resources cleared, of the total 136,144 cleared UCAP MW, see PJM (2009c).

⁷² For the 2012/13 planning year, 36,995 MW of capacity cleared, of which approximately 7.8% was from demand resources, see ISO-NE (2009b-c).

⁷³ In the summer of 2009, Special Case Resources represented 2,138 MW, which was 6.4% of the peak load forecast of 33,452 MW, see NYISO (2009b).

⁷⁴ See p. 3, MISO (2009ee).

⁷⁵ A full discussion of demand response integration in MISO is contained in Newell, et al. (2009b).

⁷⁶ See MISO (2009v).

⁷⁷ Energy efficiency could be accounted for either by reducing the peak load obligation of the LSE or allowing a market participant to submit energy efficiency on the supply side. PJM and ISO-NE have allowed supply-side participation, which allows the resource to capture capacity value (even if it is developed by an aggregator rather than an LSE) and fits more easily into their existing constructs. See Section III.13.1.4, ISO-NE (2009a); pp. 35-37, PJM (2009a).

⁷⁸ However, early evidence from ISO-NE suggested that third-party suppliers provide less energy efficiency resources to the capacity market than they do other demand-side resources. In the 2008 auction for delivery year 2010-11, merchant suppliers provided 79% of the 980 MW of cleared real-time demand response and load reductions, but only 9% of the 650 MW of cleared energy-efficiency capacity resources. See p. 6, ISO-NE (2008).

under scarcity conditions when the system is short of operating reserves or must enact involuntary load shedding.

The theoretically efficient price level during emergency conditions when load must be shed is the VOLL for the average interrupted customer.⁷⁹ If the price during such conditions is set accurately, the average customer would be indifferent between experiencing an interruption in service and paying a very high price for delivered power. These very high prices also give strong incentives for demand reductions and supply performance exactly when they are needed most. MISO is the only US market in which the price cap is explicitly tied to the VOLL, putting MISO ahead of other U.S. markets in this respect.⁸⁰

The VOLL that MISO uses is \$3,500/MWh, based on a meta-analysis of various studies conducted between 1989 and 2002, using MISO-specific values for the independent variables.⁸¹ Those studies show that VOLL varies widely depending on customer class, business sector, duration of outage, and advanced warning of the outage. For a 1-hour outage, the MISO review found VOLL ranges of \$730-\$2,510/MWh for residential customers, \$15,000-\$50,000/MWh for small commercial and industrial (“C&I”) customers, and \$16,000-\$78,000/MWh for large C&I customers.⁸² The range in estimates shows the range across industries, where, for example the mining and refining sector has a much larger VOLL than the services sector. MISO’s \$3,500 estimate of VOLL is lower than an average across all sectors because, as stated in MISO’s FERC filing on scarcity pricing, it “represents an estimate for the market segment that values uninterrupted electrical service the least.”⁸³ This value is also substantially lower than the VOLL used in the Australian National Energy Market (NEM), which is currently \$9,150/MWh, soon to increase to \$11,440/MWh as shown in Table 7.

This VOLL estimate would be inappropriate to use if MISO were to transition into an energy-only market, because it understates the value to the *average* interrupted customer, if interruptions were done indiscriminately without regard to the value customers place on energy. It may, however, be appropriate if load shed occurred in an order based on customers’ VOLL. In an energy-only construct, using this low VOLL value would result in inefficiently low prices during scarcity events and an inefficiently low level of reliability in the long run. However, because MISO is not an energy-only market, this low VOLL estimate and consequently low scarcity prices will not result in reliability concerns because the RA requirement ensures that sufficient planning resources will be procured.

⁷⁹ See pp. 9-11, Hogan (2005); p. 14, Joskow and Tirole (2004).

⁸⁰ Australia’s NEM also has a price cap tied to the VOLL. The NEM estimate for the VOLL is many times higher than the MISO estimate.

⁸¹ See pp. 69-71, Testimony of Roy Jones, MISO (2007b).

⁸² See MISO (2006).

⁸³ Median VOLL values were taken by customer class from each of the studies reviewed. Weights of 0.18 and 0.15 were then applied to the residential and small C&I classes’ median VOLL values respectively to determine the \$3,500. See pp. 69-71, Testimony of Roy Jones, MISO (2007b). Further, the VOLL was determined in 2005 dollars.

In implementing scarcity pricing, the market administrator must also determine how to set the price during times of scarcity when the system is approaching the need to shed load. There are a variety of approaches, as summarized in Table 7. One approach is to increase the scarcity price to a fixed level if a certain operating reserve threshold cannot be met. For example, in NordPool the day-ahead price is set to the price ceiling if the system operator must dispatch capacity reserves.⁸⁴

The MISO approach is more gradual, using “demand curves” for operating reserves by reserve zone.⁸⁵ This “demand curve” for operating reserves allows MISO to schedule a slightly lower level of operating reserves if the marginal cost of those reserves is very high. If the availability of operating reserves becomes more scarce, the demand curve for reserves will increase the LMP to scarcity levels (above suppliers’ offer cap) and finally to the VOLL if operating reserves are so scarce that load shedding must be enacted. The largest drawback to the administrative demand curve is that it is not market-based, but instead is determined by the market administrator. A demand curve based on the bids of actual market participants would be a more efficient alternative if there were sufficient active demand-side participants.

In using an administrative demand curve rather than relying on high supply offers during scarcity events, MISO has avoided one of the common pitfalls in other markets’ scarcity pricing designs. Scarcity pricing that depends on high supplier bids can be problematic because: (1) market monitors can not necessarily distinguish between scarcity and market power; and (2) the price level does not necessarily correspond with the severity of the scarcity event. For example, ERCOT’s scarcity pricing mechanism allows small suppliers, who are deemed not to have market power, to bid above their marginal costs. According to the market monitor, this approach has been unreliable in that it has resulted in widely varying prices under identical scarcity conditions.⁸⁶

⁸⁴ See Nordel (2007).

⁸⁵ MISO has separate “demand curves” for regulating reserves and two types of contingency reserves: spinning and supplemental. Both types of operating reserves demand curves are determined both for the entire market and by reserve zone. Individually, the maximum prices in these demand curves are lower than the VOLL, but they are additive in that in the case of extreme shortage when load must be shed, they contribute to a total LMP which is equal to the VOLL. See Section 5.2, MISO (2009w).

⁸⁶ See pp. xxxv and 46-52, Potomac Economics (2008b).

Table 7
Comparison of Scarcity Pricing Mechanisms

Market	Resource Adequacy Construct	Maximum Energy Price	Is the Maximum Price at VOLL?	How Scarcity Prices are Set
NordPool ⁸⁷	Energy-Only	\$2,980/MWh (€2,000/MWh) ⁸⁸	No	Day-ahead price goes to the maximum level if operators must dispatch capacity reserves. Intra-day and balancing prices must be as high or higher. ⁸⁹
Australia's NEM ⁹⁰	Energy-Only	\$9,150/MWh (\$10,000 AUD) ⁹¹	Yes	Suppliers bid above their marginal costs.
MISO	Voluntary Capacity Market	\$3,500/MWh ⁹²	Yes	Price rises gradually to VOLL as operating reserves dwindle and load shedding becomes more likely. ⁹²
PJM	Forward Capacity Market	\$1000/MWh ⁹³	No	Supply bids above marginal costs are not mitigated during scarcity events. ⁹³
ISO-NE	Forward Capacity Market	\$1000/MWh ⁹⁴	No	Price is increased by a Reserve Constraint Penalty Factor (RCPF) up to \$850/MWh if target operating reserve level is not met. ⁹⁵
ERCOT	Energy-Only	\$2,250/MWh ⁹⁶	No	Supply bids above marginal costs from small suppliers without market power. ⁹⁷

⁸⁷ Nordpool is the Scandinavian power market.

⁸⁸ Only the day-ahead price is capped, the intra-day and balancing markets are not capped. Nordpool (2008). Currency conversion of 1.489 \$/€ from FRB (2009).

⁸⁹ See Nordel (2007).

⁹⁰ The National Electricity Market is Australia's largest electric system and is not physically or administratively interconnected with Australia's other electric systems. See pp. 59, 204, AER (2007).

⁹¹ The value will be increased to \$11,440/MWh (\$12,500 AUD) in 2010. See p. 43, AER (2007); AEMC (2009). Currency conversion of 0.915 \$/AUD from FRB (2009).

⁹² See pp. 5.9-5.33, MISO (2009m); Revised Sheet No. 2226, MISO (2009n).

⁹³ See pp. 68-70, PJM (2009b).

⁹⁴ See Revised Sheet No. 7088, ISO-NE (2009a).

⁹⁵ The RCPF is set at different administratively-determined levels for each type of reserve: \$50/MWh for both ten-minute spinning reserves and local 30-minute reserves, \$100/MWh for system-wide 30-minute reserves, and \$850/MWh for system-wide 10-minute reserves. Prices for these different types of reserves cannot exceed the RCPF. See Revised Sheet No. 7149D-E, ISO-NE (2009a).

⁹⁶ The price cap will be increased to \$3,000/MWh after the transition to nodal pricing. See ERCOT (2008); p. vi, Potomac Economics (2008b).

⁹⁷ See pp. xxxv, 46-52, Potomac Economics (2008b).

In an energy-only market such as ERCOT or Australia's NEM, efficiently constructing the scarcity pricing mechanism is critical. This is because the size and frequency of these scarcity events will determine the willingness of suppliers to enter the market when new capacity is needed. If scarcity prices are too low in an energy-only market, customers will experience lower reliability than they really want; if scarcity prices are too high, customers will experience high reliability but at an inefficiently high cost.

Because MISO is *not* an energy only market, it is not as critical that the scarcity pricing mechanism exactly reflects the average VOLL. For example, if scarcity prices are slightly low overall because the VOLL estimate is low, then reliability will still be maintained through the resource adequacy requirement. However, scarcity prices will still provide some level of incentive for generation to be available and for demand reductions to activate precisely at the times and places where they are needed most. A well-constructed scarcity pricing system also increases suppliers' energy margins and therefore will decrease capacity market prices as discussed in Section V.C.

IV.B. SHORTCOMINGS

In this section, we discuss the most significant current shortcomings of the resource adequacy construct, which should be given primary attention in future revisions to the resource adequacy construct. The four key shortcomings that we have identified are: (1) the 1-in-10 reliability standard, while traditional, has not been examined for economic efficiency; (2) the construct will rely on out-of-market mechanisms should locational resource adequacy needs arise; (3) the decentralized peak load forecasting arrangement has introduced a variety of problematic incentives and potential accuracy problems; and (4) the construct lacks an accounting and settlement process for addressing customer migration in retail choice states. Of these, we recommend that MISO place initial focus on the first and third items, which we believe have the greatest potential for causing problematic market outcomes.

IV.B.1. Standard, But Unexamined, Reliability Target

The MISO resource adequacy construct is designed to meet the 1-day-in-10-years LOLE standard, which is the standard in two of the three regional entities in MISO.⁹⁸ This same reliability standard is used by most NERC regional entities, and has historically been used by many vertically integrated utilities.⁹⁹ Despite the fact that this standard has been widely used historically, it is not necessarily an efficient standard (with benefits commensurate to the costs). An economically efficient resource adequacy requirement would balance the tradeoff between

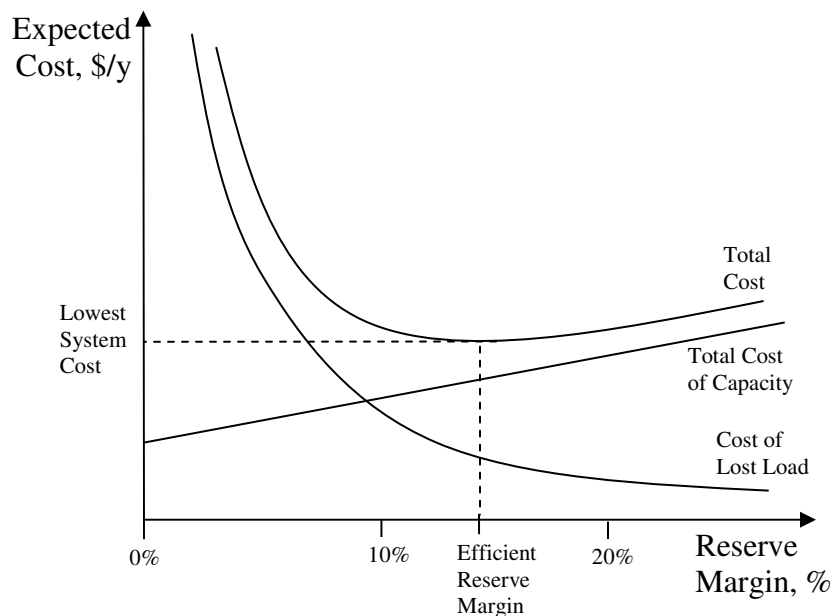
⁹⁸ This is the standard of MRO and RFC; SERC does not have a resource adequacy standard, with planning studies having been conducted by its member utilities, see NERC (2008b).

⁹⁹ For a comparison of the resource adequacy assessments and standards of each regional entity, see NERC (2008b).

the incremental cost of developing or retaining capacity resources against the incremental value of avoided interruptions.

As shown in Figure 1, increasing the target reserve margin reduces the expected costs of outages to customers by decreasing the expected unserved energy (EUE), and it also increases the costs of achieving the RA target by requiring more resources in the system. The efficient reserve margin minimizes the combined costs of providing capacity resources and suffering adequacy-related outages. This value-of-service (VOS) based approach to resource adequacy planning has a long history as an alternative approach to determining reliability standards, although it has been used only in limited circumstances.¹⁰⁰

Figure 1
Efficient Resource Adequacy Target



It is unclear whether the current standard of 1-in-10 results in efficient reserve margin requirements because it has not been examined. Further, LOLE itself is an awkward concept from both economic and engineering perspectives. It measures only the expected percentage of time that an outage will occur, without considering the expected size of such outages. This means that a 1-in-10 LOLE can mean widely different levels of reliability, for example the 1-in-10 event can be the size of a single customer or an entire state. For the same reason, the same LOLE could imply a higher level of reliability when applied to a larger system area like MISO than it does when applied to a smaller system like a constrained zone or a traditional utility's

¹⁰⁰ For example, a 1992 study of this type for PG&E compared the traditional 1-in-10 standard against a VOS approach, showing that the traditional standard required a reserve margin of 22.5% while the VOS approach indicated an efficient reserve margin of 16.2%. See pp. 824, 826, Keane, et al. (1992). See also, p. 21, Poland (1988); pp. 5-7, 12-13, Munasinghe (1988).

territory depending on how load shedding is conducted.¹⁰¹ We note that no other RTO has evaluated their legacy RA criteria to date.

We recommend that MISO periodically conduct an economic efficiency-based assessment to determine an appropriate target. MISO has already developed the capability for most of the components required for such an assessment, including estimating VOLL and CONE, and determining the relationship between reserve margins and reliability metrics. We also recommend that MISO consider moving to a more meaningful reliability metric, such as EUE, which has the same reliability meaning independent of the severity of the expected outages.¹⁰² If an economic analysis indicates that the current standard is inefficient, MISO should work with the NERC regional entities to consider revising their standards.

IV.B.2. Out-of-Market Mechanisms for Local Resource Adequacy

The scarcity pricing mechanism at the reserve zone level can help attract and retain capacity where needed. However, these locational scarcity pricing signals may not provide sufficient signals for locational adequacy for two reasons. First, the scarcity pricing construct is not sufficient to maintain resource adequacy overall. Because the VOLL used in MISO is lower than the actual average value as discussed in Section IV.A.4, the energy and ancillary services markets alone would maintain insufficient capacity. Second, the reserve zones within which scarcity pricing is determined must be consistent with load pockets. While it is likely that these reserve zones, which are re-determined quarterly based on expected transmission constraints, will tend to coincide with load pockets, we do not have evidence that this is always the case.¹⁰³

To the extent that energy and ancillary services prices do not fully provide for local resource adequacy, MISO plans to rely on out-of-market mechanisms if its recent filing on deliverability is approved by the FERC.¹⁰⁴ The annual LOLE study identifies import constrained zones on a current and forward basis, and refers them to the MISO Transmission Expansion Planning (MTEP) process for further study.^{105,106} MISO also reserves the option (which has not been

¹⁰¹ If one loss of load event is experienced in all of MISO every ten years, this is a much higher reliability than if one event of the same size is experienced in each subsystem every ten years. This understanding and implementation of the LOLE within the GE-MARS software that MISO uses for its LOLE study has been confirmed via personal communication with the software vendor. See pp. 14-16, MISO (2009i); GE (2009).

¹⁰² While 1-in-10 is the adequacy standard in MRO, the regional entity does allow for the option of using an EUE metric, stating “Expected Unserved Energy may be performed as the method to meet [the standard] provided the results of such an assessment is compared with [a loss of load probability] LOLP analysis and the comparison is documented.” See MRO (2007).

¹⁰³ See Section 3.3.1-2, MISO (2009m).

¹⁰⁴ See MISO (2009h).

¹⁰⁵ See pp. 5-6 MISO (2009h).

¹⁰⁶ MISO screens for candidate zones using a filtering process based on the Marginal Congestion Component (MCC) of the LMP over all hours of the simulated upcoming delivery year, after narrowing down to a peak period. Co-located busses with the highest MCC values are identified as candidate import-

used) to engage in out-of-market System Support Resource (SSR) contracts with generators who might otherwise retire.¹⁰⁷

MISO's RA construct does not include any local sourcing requirement provisions requiring LSEs within import-constrained zones to procure a portion of their capacity locally. In contrast, ISO-NE, NYISO, PJM, and CAISO do impose local sourcing requirements (or locational capacity pricing), which creates a demand reduction incentive and provides price signals to attract and retain capacity where needed.¹⁰⁸ Furthermore, both NYISO and PJM have developed mechanisms for merchant transmission projects into constrained zones to receive capacity transfer rights and compete with generation to capture the value of these rights.¹⁰⁹

Relying on out-of-market mechanisms can undermine the market-based resource adequacy construct as well as locational energy and ancillary services market price signals. Administrative processes such as MTEP help ensure reliability, but they are inevitably subject to error or inefficiency. If a particular combination of transmission upgrades is falsely identified as the least-cost alternative for local adequacy, MISO will approve transmission development, which can pre-empt development of alternatives such as demand response or new generation. Transmission upgrades are approved primarily based on reliability assessments. Approved projects are also evaluated for economic benefits and compared to generic non-transmission alternatives to some extent, but any of these non-transmission alternatives would *not* be approved through the MTEP process.¹¹⁰

It should be noted that even in markets that do incorporate local sourcing requirements and locational capacity pricing, resource adequacy auctions or deadlines generally occur after the non-merchant transmission planning has occurred. Therefore the same pre-emptive market intervention takes place through the planning process, particularly in NYISO and CAISO, whose RA constructs do not have the long time horizons of the PJM and ISO-NE forward capacity markets.

constrained zones, if the zones have at least 2,000 MW of load they are kept for further reliability study. See Sheet Nos. 810.01-810E, MISO (2009c); pp. 10-12, MISO (2009i).

¹⁰⁷ Id.

¹⁰⁸ See Sections VII.B.3, VIII.B, Pfeifenberger, et al. (2009); Sections III.13.2.3.4, III.13.2.7.8, ISO-NE (2009a).

¹⁰⁹ In the NYISO construct, an LSE in a locally constrained zone can use either local capacity or else capacity outside the zone along with Unforced Capacity Deliverability Rights (UDR) which represent transmission into the zone meet its capacity obligation. See Section 4.14, NYISO (2009a). In PJM, payments for Capacity Transfer Rights (CTR) that a transmission provider receives for upgrading transmission into a Locational Deliverability Area (LDA) are determined through the capacity auctions based on the capacity price differential between LDAs and will be decreased if new local capacity enters. See Section 6, PJM (2009a).

¹¹⁰ The Value Based Planning Process is currently under revision and will be primary means by which transmission upgrade combinations are compared for overall customer cost impact including generation and transmission costs under various future scenarios. See Section 1.4, MISO

We recommend that MISO review its options for developing market-based approaches to local resource adequacy. The three general options available for modifying the construct for locational resource adequacy are:

1. Impose a local sourcing requirement (LSR) for any quantity of capacity that cannot be imported to a constrained zone.
2. Develop locational capacity prices by applying transmission constraints to the VCA, which could also translate back into the bilateral market. This option would be unlikely to work well however, unless VCA volumes increased significantly or the option were combined with a bilateral mechanism for purchasing capacity import rights similar to the one in place in NYISO. A challenge with this option and the previous option is that annually changing planning zones could introduce mixed market signals to market participants.
3. Transitioning to an energy-only construct by relying on scarcity pricing for resource adequacy in load pockets. This would require increasing the VOLL to the actual average value in MISO and ensuring that these load pockets are accurately represented within the reserve zones for scarcity pricing. As discussed in Section V.C however, there is no guarantee that the energy-only construct would result in the same 1-in-10 level of reliability required for MISO as a whole.

Finally, regardless of the approach MISO takes for locational resource adequacy, we recommend incorporating a locational scarcity pricing evaluation into the annual LOLE study. The study would assess the consistency between the import-constrained zones identified in the LOLE and the scarcity pricing reserve zones. Further, the study would review the level of scarcity pricing activity in any import-constrained zone identified through the LOLE process, to determine the extent to which scarcity pricing has been providing a market incentive for locational resource adequacy by increasing suppliers' profitability in those locations.¹¹¹

IV.B.3. Decentralized Peak Load Forecasting

The monthly peak load forecasting upon which LSEs' resource adequacy obligation is based is conducted by individual LSEs.¹¹² This decentralized approach has introduced potential incentive, equity, and accuracy problems, which are of concern to many stakeholders, and we recommend transitioning to a centralized, coincident peak load accounting system.

A non-coincident peak load method requires a means of accounting for load diversity, i.e., the extent to which peak loads at individual CPNodes occur at different times. The sum of individual LSEs' non-coincident peak loads is higher than the MISO system-wide coincident peak load because LSEs' non-coincident peak loads occur at different times. The percent

¹¹¹ For example, this could include an analysis similar to the Net Revenue Analysis that the IMM conducts for the market each year. See pp. 9-11, Potomac Economics (2009).

¹¹² See 5.63-5.64, MISO (2009b).

difference between these non-coincident and coincident peak load numbers is the diversity factor. The coincident peak load number is the value relevant to system-wide resource adequacy because conditions of insufficient supply are related to system-wide coincident load, not the load of any individual LSE.

As of now, MISO does not have a robust method for determining accurate diversity factors. The diversity factor of 2.34% used in the first planning year was selected based on the lowest diversity factor observed at the LBA level over the years 2005-2008.¹¹³ This diversity factor was used because it was conservatively low, which does not conform to the objective of determining a reserve margin for meeting the expected peak load and maintaining the target level of reliability. In fact, this diversity factor was much lower than the actual peak month diversity factor at the CPNode level, which was 5.76% in 2008/09 as shown in Table 8. The effect of having a low diversity factor is to inflate the effective RA requirement.

The LBA-level diversity factors used as the basis for PRMR accounting is an indicator of CPNode level diversity, but diversity over these larger areas is lower than diversity at the more granular CPNode level. The diversity factor at the CPNode level is the value relevant to the MISO construct because this is the level of granularity at which LSEs actually make their non-coincident peak load forecasts upon which the PRMR is determined.

Table 8
Historic Diversity Factors for Historic System Peak Months¹¹⁴

Planning Year	Diversity Factor	
	LBA Level	CPNode Level
2005-06	3.84%	4.05%
2006-07	2.35%	3.18%
2007-08	5.66%	6.80%
2008-09	5.78%	5.78%
2009-10	n/a	5.76%

Using non-coincident peak load accounting can also create incentive and equity problems by not recognizing the value of peak load diversity. An LSE whose coincident peak load is low, even if its non-coincident peak load is high, should not require as many capacity resources for reliability as an LSE with a high coincident peak load. Not recognizing this fact creates an equity problem in that LSEs that are highly non-coincident are required to pay for more than their share of required planning resources. Table 9 illustrates this point, although the public dataset used to compile the table is incomplete, representing only 27 different utilities accounting for 40% of

¹¹³ See pp. 17-19, MISO (2009i).

¹¹⁴ The shown LBA diversity factor is an *annual*; the CPNode diversity factor is diversity during the *system peak month*. The CPNode diversity during the system peak month is the relevant metric to use because it matches the LSE PRM requirement mechanism. See pp. 17-19, MISO (2009i); MISO (2009k).

MISO's summer peak load.¹¹⁵ Although the diversity factor among these utilities was only 3.3% during the peak month in 2006, individual utilities had diversity factors ranging from 0% to 22.6% during the month. Under the current non-coincident peak accounting system, a utility with a very low diversity factor of 0% would pay less than its fair share of resource costs, and a utility with a very high diversity factor of 22.6% would pay much more than its fair share. In fact, the LSE with the very high diversity factor of 22.6% would be required to procure about 26% more than its fair share of planning resources.¹¹⁶

Because a generic diversity factor is applied to all LSEs regardless of its customers' loadshapes, there is no incentive for LSEs to help manage their customers' loads away from the coincident peak. If LSEs were accountable only for their coincident peak, they might find it worth implementing rate structures or programs that would increase system diversity and reduce the overall need for planning resources.

¹¹⁵ The dataset used to compile the table are the hourly load data from each entity in MISO submitting FERC form 714 data. The diversity factor values were calculated using the following steps: (1) summing the hourly load data from each utility represented to determine the coincident load; (2) identifying the hours of monthly and annual coincident peak load; (3) determining the individual LSEs' coincident peak loads during the identified hours of annual and monthly coincident peak; (4) independently determining the monthly and annual peak loads of each individual LSE; and (5) determining the percentage that the LSE's non-coincident peak load was below the coincident peak load. See FERC (2009c).

¹¹⁶ The calculation of this ratio is $126\% = (100\% - 2.34\%) / (100\% - 22.6\%)$. The numerator represents the coincident peak load assumed under the current MISO construct as a percent of the non-coincident peak load; the denominator represents the actual coincident peak load as a percent of the non-coincident peak load.

Table 9
Diversity Factors among MISO Utilities Reporting FERC 714 Data¹¹⁷

714 Utility Number	Coincident Peak Load		Annual Diversity Factor		Peak Month Diversity Factor	
	2006	2007	2006	2007	2006	2007
1	143	187	5.3%	9.2%	3.4%	9.2%
2	285	522	0.3%	1.7%	0.3%	0.0%
3	297	--	0.0%	--	0.0%	--
4	307	253	0.0%	19.7%	0.0%	12.2%
5	312	--	0.0%	--	0.0%	--
6	376	472	49.6%	40.6%	22.6%	8.5%
7	390	419	19.8%	20.3%	19.8%	10.5%
8	406	345	0.0%	15.3%	0.0%	1.4%
9	412	--	12.9%	--	2.6%	--
10	603	561	11.3%	20.4%	2.7%	5.1%
11	742	682	0.0%	0.3%	0.0%	0.3%
12	767	657	2.7%	14.9%	2.7%	14.9%
13	887	853	0.0%	3.3%	0.0%	3.3%
14	1,011	968	0.1%	0.5%	0.1%	0.0%
15	1,320	1,775	13.9%	17.0%	2.1%	3.9%
16	1,359	1,449	11.0%	13.6%	11.0%	6.4%
17	1,709	1,684	2.4%	3.9%	2.4%	0.5%
18	2,192	2,000	4.1%	9.5%	4.1%	9.2%
19	2,274	2,088	14.9%	16.8%	14.9%	9.9%
20	2,353	2,281	3.0%	1.0%	3.0%	0.0%
21	2,537	2,235	1.0%	10.7%	1.0%	9.7%
22	2,837	2,650	3.5%	0.0%	3.5%	0.0%
23	3,086	--	24.9%	--	5.5%	--
24	3,453	3,467	2.6%	4.4%	2.6%	4.4%
25	4,853	4,731	0.1%	3.8%	0.1%	3.8%
26	--	5,813	--	0.6%	--	0.6%
27	9,015	8,548	0.2%	2.9%	0.2%	2.3%
Overall	43,925	44,639	6.2%	6.5%	3.3%	3.8%

MISO relies on the LSEs to provide their own (non-coincident peak) load forecasts primarily because of their experience forecasting their own load. Even so, the current system is not entirely tailored to the types of load forecasting that LSEs are used to or experienced with. Many LSEs report that they do not have sufficient experience to accurately forecast load at the CPNode level as is currently required, but rather have historically done their forecasting for the entire LSE. For new or growing competitive retailers, the ability to do accurate load forecasting is further hindered because these retailers likely do not have sufficient historic data for all of their customers.¹¹⁸

¹¹⁷ See FERC (2009c).

¹¹⁸ The BPM suggests that these retailers might want to coordinate their load forecasts with the relevant Electric Distribution Company (EDC) or Provider of Last Resort (POLR) which is presumably more experienced at load forecasting, but this coordination is not required. See p. 4.23, MISO (2009b).

Finally, the current self-forecasting process introduces incentives to either over-forecast or under-forecast. The incentive to under-forecast is that the planning resource obligation is based on the LSE's own peak load forecast, meaning that an under-forecast would immediately result in lower costs. This incentive is recognized within the current construct, and in the attempt to prevent LSEs from engaging this behavior, MISO has developed a complex after-the-fact under-forecasting assessment based on LSEs' reported peak load, dependence of peak load on weather and price variables, and reported standard deviation around peak load.¹¹⁹

Overall, LSEs have over-forecasted their peak loads during the first four months of PY1 as shown in Table 10. The overall result was actual resource requirement at 29.4% above actual coincident peak load. This is well above the 15.4% target annual reserve margin.¹²⁰ The over-forecasting observed this year is different from historic years, when LSEs did not over-forecast their non-coincident peak loads by such a large amount. There are several likely contributing factors to the over-forecast, including the economic downturn and the unusually cool summer. Weather and the recession may explain most of the over-forecast since the numbers in Table 10 and Figure 2 are not weather-normalized, however the magnitude of the over-forecast suggests that there may have been other contributing factors, including MISO's understated diversity. The incentive to over-forecast to avoid state reporting may also have influenced LSEs. However, in the future, when capacity prices are higher, the incentive to under-forecast to reduce costs will increase and will likely outweigh any incentives to over-forecast.

Table 10
LSE Forecasts and Actual Peak Load In Planning Year One (Not Weather Normalized)¹²¹

Month	Actual Data		LSE Forecasts		ICAP PRMR [†]
	Coincident Peak Load, MW	Non-Coincident Peak Load, MW	Non-Coincident Peak Load Forecasts	Error in Non-Coincident Peak Load Forecast	Based on LSE Forecast, MW
Jun-2009	94,163	99,915	91,723	-8.2%	103,363
Jul-2009	80,830	86,608	108,149	24.9%	121,873
Aug-2009	88,683	96,094	106,414	10.7%	119,918
Sep-2009	78,587	84,305	97,168	15.3%	109,498
Equivalent Annual ICAP PRMR[‡]					29.4%

[†]PRMR is 12.69% above the LSE forecasted non-coincident peak, see p. 1 MISO (2009i).

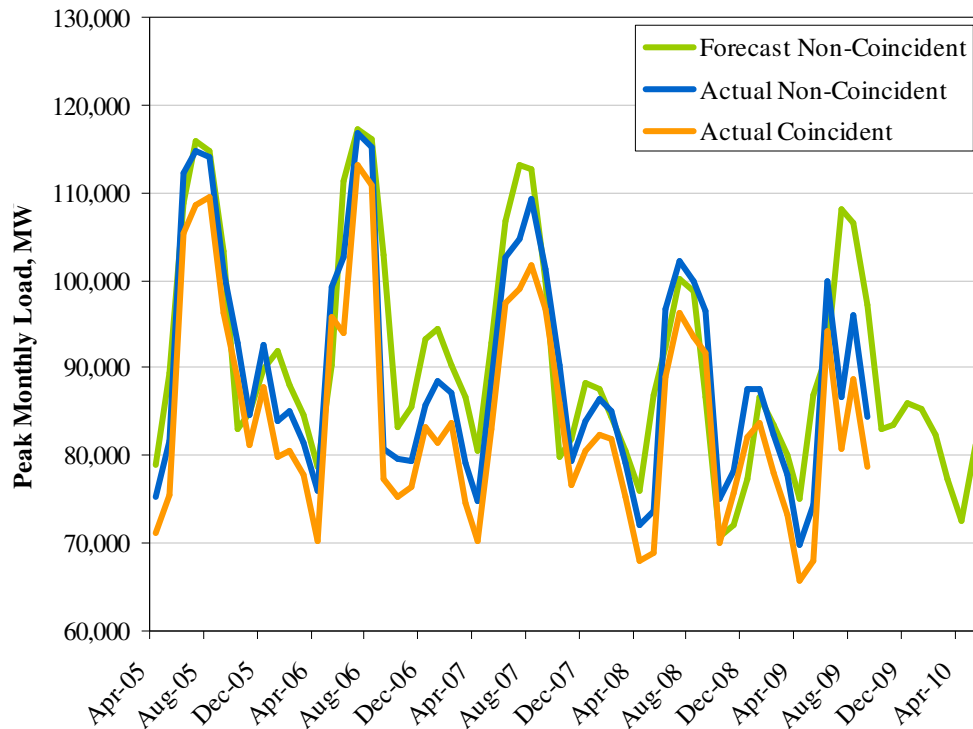
[‡]Peak annual requirement (from July) divided by peak annual load (from June).

¹¹⁹ The cost to an LSE of over-forecasting is low now because the excess capacity can be purchased at low cost; however, as capacity becomes more scarce and expensive this may change.

¹²⁰ See p. 1, MISO (2009i).

¹²¹ Compiled from CPNode-level coincident and non-coincident peak load data obtained from MISO.

Figure 2
Monthly Peak Load Data and Forecasts at the CPNode Level (Not Weather Normalized)¹²²



The level of complexity in the after-the-fact assessment has also created problems. First, because there is not a standardized method for forecasting generally, nor a standard set of weather variables, nor a standard way to calculate standard deviations, the evaluation cannot be applied uniformly across LSEs. For example, an LSE with a more accurate load forecasting method will have a lower standard deviation than a less accurate LSE. As a result, the LSE with a better load forecast could be identified for under-forecasting even when its actual forecast error is smaller than a different LSE that had reported a higher standard deviation. Second, the inherent complexity and non-uniformity could be used by unscrupulous LSEs to obscure an intentional under-forecast, for example by over-stating their standard deviation.

Table 11 shows the results of MISO’s assessment of under-forecasting in PY1. Over the first three months, 13%-31% of all CPNodes were identified for having under-forecasted peak loads, although LSEs in aggregate have *over-forecasted* by a large amount. The identified under-forecasts appear to be driven by the lack of stakeholder familiarity with the process, although it is difficult to tell this from the data. A large number of LSEs failed to report standard deviations, which caused MISO to treat their standard deviations as zero and resulted more under-forecast determinations. Although the under-forecasting assessment and resulting reports to state regulators are the only enforcement mechanism for preventing under-forecasts, these results are

¹²² Id.

yet to be reported to state regulators. This reporting has been delayed in order to allow states to comment on what data they would like to receive and to allow stakeholders an opportunity to become more familiar with the under-forecast process.

Table 11
Results of Under-Forecast Assessment from Planning Year One

Number of LSEs or CPNodes	All MISO		
	June	July	August
Number of LSEs Under-Forecasted	45	29	32
CPNodes Under Forecasted	31.4%	12.9%	17.0%
CPNodes Reporting Standard Deviation	48.1%	60.2%	60.2%
CPNodes Reporting Weather Normalization	1.5%	n/a	n/a

Number of LSEs or CPNodes	Without Retail Choice States		
	June	July	August
Number of LSEs Under-Forecasted	15	5	10
CPNodes Under Forecasted	22.4%	5.2%	8.2%

We have reported here on a variety of incentive, equity, and accuracy problems resulting from the current decentralized process.¹²³ We recommend that MISO develop a centralized, coincident-peak load forecasting system, although we recognize that developing the capability will be a challenge for MISO. MISO may not want to be responsible for any forecasting errors which place financial burdens on LSEs, however, now is a particularly good time for MISO to begin developing its load forecasting capabilities while there is a capacity surplus and the cost of errors is low.

One of the drawbacks of a centralized load forecasting system is that MISO does not have the specialized local knowledge and customer base experience that LSEs have. For this reason, we also recommend that in transitioning to a centralized forecast, MISO should continue to gather forecasting data and input from LSEs and local balancing authorities to inform and improve the system forecast.

IV.B.4. Load Accounting in Retail Choice States

When customers in retail choice states migrate between two LSEs, there is a temporary ambiguity about which LSE is responsible for purchasing sufficient capacity resources on their behalf. MISO's approach is to require each LSE to conduct its monthly peak forecast based on its best estimate of how much load it will gain or lose over the month.¹²⁴ If an LSE has under-

¹²³ Non-coincident peak load is still the appropriate forecast to be used for import-constrained zones.

¹²⁴ See p. 4.23, MISO (2009b).

forecasted its peak load but demonstrates to MISO that this is due to gaining new retail choice customers, MISO will not report the LSE to the state regulator for under-forecasting.¹²⁵

This arrangement provides an incentive for the LSE losing retail customers to accurately predict those losses, and for winners to inaccurately predict no customer gains. The arrangement could temporarily result in an aggregate system deficiency in which no LSE is held responsible for covering migrated load. As long as the level of load migration remains small, this issue may not amount to a significant problem, but the rate of retail migration could increase if market prices shift rapidly. Another challenge for competitive retailers is that if migration levels do become high, it is not clear whether the VCA will have sufficient volumes to support last-minute purchases.¹²⁶

Finally, MISO provides no true-up mechanism to account for mid-month migration, creating an equity problem if, for example, one LSE designates sufficient PRCs but then loses customers at the beginning of the month. Retail choice states could independently develop standards for true-up and PRC responsibility for migrating customers, but as yet have not.

We recommend that in the absence of state standards to perform these functions, MISO adopt a PJM-like system where each customer has a coincident peak load contribution (PLC) and each customer is assigned to an LSE.¹²⁷ Under that mechanism, PJM assigns the peak load obligation of each Electric Distribution Company (EDC) or Provider of Last Resort (POLR). The EDC is responsible for allocating a portion of that peak load to each of its customers by a method negotiated with its retail regulator. Then, if any end-user is currently served by an alternative retail provider or later migrates to one, the PLC of that customer must be acquired by the alternative supplier. Allocation of PLCs to customers would be simplest if done on an annual basis, possibly as a percentage which could scale to the peak load of each month.

Under a PLC system, the equity problem could be solved with the creation of a monthly after-the-fact true-up based on the number of days that customers were with each LSE. The under-designating LSE would be charged; the over-designating LSE would be credited. The true-up price could be the VCA clearing price or could be determined by the state regulator. State regulators may prefer to develop their own true-up price if they feel that the VCA price is too volatile or does not accurately represent underlying fundamentals due to the low volumes. However, we do not believe that a separate state true-up price would be necessary unless the VCA failed to clear. As discussed in Section IV.C.2, it appears that the VCA prices have been consistent with market conditions, and the pattern of prices observed to date could be a result of seasonal demand effects rather than pure volatility.

¹²⁵ See pp. 5.66-6.71, MISO (2009b).

¹²⁶ For example, in the predicted peak month of July, a trivial amount of capacity was offered into the VCA, at only 345 MW or about 0.4% of summer peak load. See Table 12.

¹²⁷ See p. 88, PJM (2009a).

IV.C. ISSUES TO EVALUATE OVER TIME

There are several ways in which the MISO construct has not been fully tested, due primarily to the short length of time for which the construct has been in place. In this section, we discuss aspects of the construct that MISO should continue to evaluate for performance, although we have not observed problematic results to date. The issues of this type that we have identified are: (1) the potential that a state would lean on the reliability provided by its neighbors by setting a lower reserve margin than MISO as a whole; (2) the performance of the VCA in setting prices consistent with market fundamentals; (3) the ability of the short-term construct to result in sufficient investments in retail choice states when needed; and (4) the potential addition of forward-year PRCs as a trading option for market participants.

IV.C.1. Reserve Margin Differences among States

Each state within MISO has the option under Module E to set its own PRM for LSEs under that state's jurisdiction, whether the PRM is higher or lower than the PRM set by MISO for the rest of the system.¹²⁸ This provision has the potential to cause reliability problems, particularly if a state should choose to set a lower PRM than MISO. If one state lowered its PRM to be commensurate with a lower reliability target, it would reduce the reliability for the entire MISO region (unless MISO were prepared to shed load in the lower-PRM state first). The state could thus save money by paying less for planning resources while leaning on the reliability provided by its neighbors.

It is unlikely that state regulators would act in bad faith. So far, no state has exercised the option to lower its PRM, and maintaining the provision is primarily a matter of jurisdiction.¹²⁹ However, many stakeholders have commented either to the FERC or during stakeholder discussions that this possibility is of concern to them.¹²⁹ The reality is that the incentive and potential for a state to lean on the system do exist and MISO should be prepared to address this before the FERC if any state does significantly lower its PRM and begin leaning on its neighbors for RA.

IV.C.2. Voluntary Capacity Auction Performance

The VCA design has not previously been tested in other markets, and there are few market results to observe to date. We recommend that the market results continue to be observed

¹²⁸ See Original Sheet No. 810.01, MISO (2009c).

¹²⁹ The FERC has accepted states' role within the resource adequacy construct to set different PRMs, but has maintained that this "cannot undercut [FERC] authority to review resource adequacy and reserve margins that affect matters within our jurisdiction, i.e., provisions that affect our authority under section 201, 205, and 206 of the [Federal Power Act] to ensure that the provisions of the tariff will result in just and reasonable and not unduly discriminatory or preferential rates." See p. 18, FERC (2008a). See also pp. 10-26, FERC (2008a); pp. 10-20, FERC (2008b).

closely for this reason, although it appears that the results to date have been consistent with market fundamentals.

Many stakeholders have expressed a lack of confidence in the VCA market results, which have exhibited low volumes and widely varying prices over the seven months of operation as shown in Table 12. The average cleared volume in the VCA is only 0.7% of the system summer peak, and only 1.9% of the volume of bilateral PRCs traded as presented previously in Table 4.¹³⁰ These low volumes could be because many LSEs prefer to procure most of their seasonal capacity needs several months in advance rather than through the auction right before the planning deadline. Further, low volumes do not necessarily indicate any problems, since MISO is primarily a bilateral market and the VCA was never intended to replace bilateral activity. The VCA was only intended to serve as a balancing market.

Despite this lack of stakeholder confidence, we observe that the prices within the VCA are low compared to the costs of new entry, which is consistent with the current market conditions of over-supply in planning resources. With a gross CONE of \$80/kW-year and expected energy and ancillary margins of approximately \$17/kW-year, a new market entrant would need annual capacity revenues of approximately \$63/kW-year to invest.¹³¹ This translates into a VCA price of \$5,250/MW-month every month of the year, whereas the average VCA price has been well below this at only \$636/MW-month. Alternately, a new entrant would receive sufficient revenue if the VCA had one high price of \$63,000/MW-month in one peak month and a zero price in all other months. A seasonal pattern of VCA prices of this sort may be observed in future years and may already have been partly observed in the results to date, with the highest price observed in the expected peak summer month when planning resources are most scarce, but a low VCA price in many other months when expected peak load is low and planning resources abundant. In either case, the prices observed to date are low and we would not expect these observed VCA outcomes to prompt investments in new planning resources, which is an expected outcome under the current market conditions of over-supply in capacity.

Another potential concern is regarding the observed price volatility in the VCA, which has cleared at low prices close to zero in most months, but at a price as high as \$10,015/MW-month in the expected peak month. The low volumes of cleared capacity could have contributed to this volatility, or the one high clearing price could simply be a seasonal effect as discussed previously. In the worst case, high volatility in a capacity market could increase the investment premiums that potential suppliers will require before they are willing to invest, but we do not believe that the MISO design is likely to result in this outcome for several reasons.¹³² First is that the VCA is a residual market covering only a small fraction of the market, making it unlikely that these prices will have a large impact on the overall investment outcomes. Second,

¹³⁰ System summer peak load of 95,186 MW from June 2009, see MISO, (2009I).

¹³¹ Gross CONE of \$80/kW-year based on the PY1 CONE used by MISO as the basis for deficiency penalties, see MISO (2009g). Approximate energy margins are based on the range of \$14-\$20/kW-year for a reference CT calculated by the IMM for the year 2008, see pp. 9-11, Potomac Economics (2009).

¹³² Note that the volatility premium associated with a capacity market is still likely to be much lower than the volatility premium in an energy-only market, which is characterized by periodic severe price spikes.

the voluntary nature of the market should work to dampen volatility by incorporating a demand curve built from buyers' bids. Finally, the price pattern observed to date is consistent with a seasonal effect that may be a result of market fundamentals rather than pure volatility.

Table 12
VCA Results to Date¹³³

Planning Month	PRC Volumes, MW-Month			Clearing Price, \$/MW-Month
	Offers Submitted	Bids Submitted	Cleared Volume	
Jun-09	7,525	864	864	\$50.00
Jul-09	364	1,217	364	\$10,015.00
Aug-09	3,588	110	110	\$1.00
Sep-09	13,730	300	300	\$0.01
Oct-09	22,313	615	615	\$0.05
Nov-09	22,425	1,039	1,039	\$0.50
Dec-09	19,688	1,226	1,226	\$0.75
Jan-10	19,982	1,281	1,281	\$0.25
Average	13,702	831	725	\$636.12

Unfortunately, we are unable to compare observed VCA prices against prices in the much larger bilateral capacity market, which is less transparent than the VCA or what prices in a mandatory centralized capacity market would be. Some stakeholders have expressed concern that low VCA prices have depressed bilateral market prices. However, it appears likely that the recent VCA prices merely reflect the current market conditions (an excess supply of capacity) and have only made the excess transparent. Although they influence each other, bilateral prices are not likely to converge to the VCA prices because the VCA represents only the current month excess or shortage of capacity, while the bilateral market can represent an outlook of one year or longer.

Stakeholders have expressed mixed reviews of the bilateral market's transparency and a low confidence in the relevance of the VCA price. Many market participants have reported satisfactory transparency in the bilateral market through responses to requests for proposals (RFP) or other bilateral interactions.

A final question related to the VCA is whether it should be made mandatory. Even now, the VCA is not entirely voluntary, given the IMM's authority to monitor and mitigate for physical and economic withholding.¹³⁴ However, a fully mandatory auction would require that any

¹³³ See MISO (2009cc).

¹³⁴ Physical withholding threshold is 500 MW of planning resources kept from the market by any individual LSE or resource owner (including through capacity exports to external markets at less than 50% the capacity price of MISO); economic withholding threshold is a APRC offer price inflated above going-

residual planning resources that an LSE had not procured by the monthly deadline would have to be procured through the auction; similarly, all supply resources would be required to offer all uncommitted resources.

A mandatory auction would create several benefits, including: increased transactions and liquidity, thus greater transparency for supply, demand, and clearing prices; greater ability to monitor and mitigate the market; and a built-in mechanism for backstop capacity procurement, preventing LSE deficiency. The primary drawbacks of a mandatory centralized auction are the greater reliance on administratively determined parameters, and the effect that these centralized market outcomes would have on the bilateral market.¹³⁵ The incremental benefits of a mandatory centralized auction appear to be small in the traditionally regulated states without retail competition, and representatives from those states appear to strongly oppose the idea of a mandatory centralized capacity market. Proponents of a mandatory centralized market are primarily from retail choice states and generally propose the idea in the context of a mandatory forward market, as discussed further in Section V.A.

IV.C.3. Capacity Investments in Retail Choice States

Several stakeholders, particularly merchant generators in retail choice states, have expressed concern that the RA construct was developed primarily to work in traditionally regulated states, and that it does not work as well for retail choice states. The primary issue is in attracting sufficient resources where and when needed (more minor issues related to forecasting and accounting are discussed in Sections IV.B.3 and IV.B.4 respectively).

In retail choice states, the planning and long-term contracting functions of the traditional utility are absent. Only market prices provide signals for new capacity investments, via the energy, ancillary services, and capacity markets. The argument that future “short-term” requirements will work backward into current investment decisions may not work as well in retail choice states because without captive load, retailers risk stranded costs if they sign long-term contracts or acquire generation assets.

State authorities may require long-term contracting, but typically only to a limited extent. For example, the Illinois Power Authority (IPA) administers multi-year contracting for standard offer service providers for terms of up to five years, but even there, the IPA contracting does not extend to competitive retailers for whom stranded costs are still a risk.¹³⁶ This issue has been resolved in PJM and ISO-NE, which have three-year forward capacity procurement on behalf of all load, with responsibility for payment allocated among all LSEs shortly before the delivery year.

forward costs by more than 10% of CONE. See Attachment with proposed revised sheets to Module D, MISO (2009f).

¹³⁵ The VCA is already subject to several administrative parameters, including the withholding thresholds, the value of CONE assessed in penalties, and the IMM-determined going-forward costs of planning resources.

¹³⁶ See 220 ICLS 5/16-111.5, ICLS (2009).

Retail choice states are the minority in MISO, but the construct must work in these states in order to function efficiently overall. Other RTOs have tested short-term RA requirements under retail choice with mixed results. ISO-NE and PJM both abandoned their short-term requirements in favor of long-term requirements, but the primary reason for their redesign was the inability of the original constructs to attract new capacity in constrained areas due to lack of locational price signals. NYISO has found its short-term RA requirement workable under retail choice.¹³⁷

From the market results to date, we cannot confirm that the current MISO construct will incent the next round of capital investments in retail choice states, because it has not yet been tested by foreseen shortages. Our expectation, however, is that needed investments will be made, although possibly at a greater cost, and possibly not where needed, as discussed in Section IV.B.2. The lack of long-term contracting under retail choice places investment risks on suppliers, who will therefore require a higher return on investment. The shift of risk from consumers to suppliers, and the associated risk premium, are inherent in retail restructuring, and it is not MISO's job to undo these state policies. Even so, the RA construct includes an LSE penalty structure that is more than three times higher than the net cost of new resources (particularly if the LSE were to be short for an entire year), creating a large incentive to avoid being caught short and paying the required premium for resources not under long-term contract.¹³⁸ We recommend that these issues be monitored over time, with close attention paid to the outlook for forecasted capacity requirements in comparison with expected available capacity based on planned new investments and expected retirements.

IV.C.4. Forward-Year PRCs for Bilateral Trading

As discussed in Section IV.A.2, there are a large number of advantages associated with the standardized capacity product of PRCs, including reduced transaction costs and increased flexibility. Currently, the MISO construct allows PRCs to be created out of a planning resource only for the current planning year.¹³⁹ While traditional forward bilateral contracting options are open to market participants, the advantages of PRCs cannot be realized for bilateral transactions for future years. Some stakeholders have proposed that a system for the forward creation of PRCs should be developed.¹⁴⁰

The primary disadvantage to allowing the forward creation of PRCs is that neither MISO nor the asset owner knows exactly what the future UCAP value of a particular resource will be. The problematic scenario would be if a planning resource converted its entire expected UCAP value

¹³⁷ For a discussion of NYISO experience under short-term RA requirement, see Newell, et al (2009a).

¹³⁸ If an LSE had been short for the entire year in PY1, the total penalty for being short would be \$220/kW-year (\$80/kW-month for the first month of June, plus \$20/kW-month for the five remaining summer and winter months, plus almost \$7/kW-month for the six shoulder months). Compare with the approximate net cost of new entry of \$63/kW-year estimated in Section IV.C.2. For details on the deficiency penalty schedule, see pp. 6.78-6.79, MISO (2009b).

¹³⁹ Planning resources that have completed all annual capacity verification tests are assigned UCAP ratings by December 1, prior to the planning year.

¹⁴⁰ See, for example, Integrys (2009).

to PRCs and then ended up with a higher XEFOR_d rating than expected, thereby coming up with a deficiency once its final UCAP rating was determined prior to the planning year.

This problematic scenario could be resolved however by allowing the resource owner to make up for any such deficiency by purchasing equivalent PRCs from the market and applying them to the deficiency. Any remaining deficiency that the resource owner did not make up should then be assigned the same CONE-based penalty that a deficient LSE would be subject to.¹⁴¹ Another method for preventing the creation of more-than-necessary forward PRCs would be to allow resource owners to convert only a fraction of their expected UCAP into PRCs for future years, possibly with the fraction decreasing for further out years. Any resource owner that preferred not to take on the risk of becoming PRC deficient could decline to convert its UCAP into PRCs for future years.

Overall, it is not clear how large the benefits of creating forward PRCs would be. However it also is not clear whether this addition would create a significant administrative burden. Therefore, we recommend that MISO and stakeholders continue to evaluate this option as market participants gain more experience as to what need this product would fill.

¹⁴¹ See pp. 6.78-6.79, MISO (2009b).

V. LONG-TERM VISION

In 2005, MISO released a whitepaper proposing its vision for an energy-only market with the possibility of an interim RA requirement.¹⁴² However, some stakeholders have expressed that MISO has not updated its vision, including how the current resource adequacy construct relates to the energy-only vision. Changes to the construct and regulatory uncertainty regarding how long the current RA construct will last impose costs on market participants who must develop operational capability under a changing design. Adding to the difficulty, stakeholders are strongly divided about the best direction to take, with conflicting proposals, including:

- Finalize and improve the current construct without making structural changes
- Transition to a mandatory forward capacity market
- Evolve to an energy-only market

Each of these options has advantages and disadvantages. However, moving to either a forward capacity market or an energy-only market would require substantial changes to the current construct. Whichever of these designs MISO and stakeholders choose in the long term, our recommendations for the short term are the same. We recommend that MISO resolve the existing issues with the resource adequacy construct identified in this report and continue its progress in integrating demand-side resources in order to develop a more dynamic market, as discussed in Section V.C.

V.A. THE MANDATORY FORWARD CAPACITY MARKET OPTION

Several stakeholders have expressed strong support for a move to a mandatory forward capacity market of the kind implemented in PJM and ISO-NE. However, representatives from traditionally-regulated states without retail competition seem strongly opposed to mandatory centralized capacity auctions, including forward auctions.

There are several potential advantages of a mandatory forward capacity market, especially for retail choice states.¹⁴³ A mandatory auction would provide greater transparency, a built-in mechanism for backstop procurement, and greater ability to monitor and mitigate the market. A forward market would align development lead-times with the capacity procurement timeline, and allow potential entrants to compete with existing capacity, while providing more certainty and

¹⁴² See MISO (2005).

¹⁴³ For a more thorough discussion of the advantages and disadvantages of a forward capacity market compared with a short-term capacity market, see two recent *Brattle* reports that review these issues in detail. Newell, et al. (2009a), and Pfeifenberger, et al. (2009).

stability in the market price. This is in contrast to the high volatility and extreme short-term effects of the energy-only market, as discussed in Section V.B.

There are also several disadvantages of a centralized, mandatory forward capacity market. Forward markets have a greater dependence on parameters such as demand curves and price floors, which are subject to errors because they are administratively-determined or the outcome of stakeholder negotiations. One likely source of error is the lower accuracy of peak load forecasts far in the future, which could lead to the inefficient cost burden of over-procurement.¹⁴⁴ The greater complexity of these markets also introduces the risk of market design flaws, particularly during implementation.

Design flaws and errors in administrative parameters would also affect the bilateral markets. Although bilateral agreements can pass through the centralized auction as price takers, both suppliers and buyers of capacity would evaluate bilateral arrangements in comparison with the prices expected in the centralized market. Further, a forward market precludes most bilateral transactions of a shorter term than the forward period. Finally, the market redesign and extension that would be required for a forward market would impose significant costs on both MISO and market participants.

Overall, there is no urgency to redesign the MISO construct for a forward capacity market in the near term, and we recommend that MISO postpone consideration of this redesign for several years. As *The Brattle Group* authors concluded in a recent evaluation for NYISO, the advantages of a forward capacity market will not be available until new capacity is needed.¹⁴⁵ With MISO's current conditions of over-supply in planning resources and the expectation that new resources will not be needed for many years, it appears that a forward market would not benefit the RTO in the near term. Postponing consideration of a forward market will allow MISO more time to observe and learn from the experiences of other forward markets; postpone incurring implementation costs while it resolves existing issues in the construct. In particular, the existing problems related to decentralized load forecasting and load migration should be addressed, as these problems could be exacerbated by a forward market design if they are not resolved.

V.B. THE ENERGY-ONLY MARKET OPTION

Some regulators in retail choice states have expressed continued support for MISO's 2005 vision for an energy-only market. However, we conclude that MISO is not ready for this change because there are several critical elements that are needed for a proper energy-only market functioning as discussed in Section III.A.1 that are not yet sufficiently developed in MISO. The move may not immediately result in problems, but design shortcomings in energy-only markets

¹⁴⁴ For example, an independent consultant has recently made several high-profile criticisms of PJM's method and results in calculating its installed reserve margin requirements and peak load forecasts, claiming that the result is approximately 10 GW of excess capacity purchases. See *MegaWatt Daily* (2009).

¹⁴⁵ See Newell, et al. (2009a).

are never apparent until new capacity is needed. For example, Australia's NEM and Great Britain both moved to energy-only markets when they had excess capacity. However these markets have worked off excess capacity and yet private investments have not been developed; to address foreseen supply adequacy problems, both countries have turned to government intervention and publicly financed projects.¹⁴⁶ We recommend that instead of rushing to this end, MISO further develop the critical elements needed in an energy-only market, primarily demand responsiveness, which benefit the wholesale market regardless of whether a decision to move to an energy-only market is made.

As discussed more fully in Section III.A.1, one of the primary advantages of an energy-only market would be its reduced dependence on administratively-determined parameters. Instead an energy-only market would ideally rely entirely on market forces to maintain sufficient capacity. However, few customers have the metering infrastructure or rate structures to enable price responsiveness, and distribution technology does not allow load-serving entities to offer differential levels of reliability. Similarly at the system level, when MISO must implement load shedding, it will do so indiscriminately without considering which customers would be willing to pay more to be interrupted last. We further discuss the issue of how much demand response is needed before an energy-only market should be considered in Section V.C.

Without sufficient demand response or differentiable reliability, energy-only markets are still dependent on administratively-determined scarcity prices when supply runs out. Administratively-set scarcity prices are subject to the same kinds of errors as administratively-set reserve margins. For example, if scarcity prices are capped at an estimated VOLL below customers' true willingness-to-pay, prices would support insufficient capacity to maintain an acceptable level of reliability. As discussed in Section IV.A.4, the current MISO VOLL *is* set below the true average value for all customer segments. The parameter would have to be increased substantially in order to support an efficient level of reliability. An energy-only market with its higher, more volatile prices is also more vulnerable to manipulation through short-term withholding since new resources cannot enter in the short-term.

MISO and its stakeholders would have to accept the consequences of an energy-only market, including potentially severe price spikes and an uncertain, potentially lower level of reliability for customers. The price spikes associated with energy-only markets may also prove politically difficult if the volatility is passed on to customers; however, retail volatility can be muted even in an energy-only market if these rates are supported by financial hedges. Operationally, a lower level of reliability would require MISO to be prepared to act under shortage or emergency conditions more frequently. In short, eliminating the resource adequacy requirement would not necessarily achieve a more efficient outcome, and it would have consequences that might not be politically acceptable.

¹⁴⁶ See Section IV, Pfeifenberger, et al. (2009).

V.C. RECOMMENDATION FOR HYBRID APPROACH WITH A RESOURCE ADEQUACY REQUIREMENT AND SOME FEATURES OF AN ENERGY-ONLY MARKET

While MISO should not attempt to move to an energy-only market in the near term, we agree that there are several advantages of energy-only markets and therefore propose that MISO should adopt a hybrid approach in order to achieve these benefits while maintaining a reliability standard for unresponsive customers. This proposal does not differ substantially from the current RA construct, except that it emphasizes developing a much more active demand side.

We propose that MISO maintain a resource adequacy requirement while expanding the use of market signals and reducing the importance of administrative determinations. This is possible only by making the demand side more responsive to prices through some combination of dynamic pricing and interruptibility. This involves a large role for states, which must invest in Smart Grid (including interval meters and controls that allow individual customers to be interrupted) and provide dynamic retail rates. At the wholesale level, MISO needs to continue incorporating demand response into its planning and operations.¹⁴⁷ Customers will then be able to sort themselves out into firm load and various levels of non-firmness. The non-firm load would choose a lower level of reliability in exchange for lower peak prices or demand charges. The "firm" load would be shed last because it would be subject to a traditional resource adequacy requirement. However, as long as "firm" load is not physically separable from the non-firm load, the resource adequacy requirement would apply to everyone. Customers providing supply-side DRR and LMR planning resources would continue to pay for resource adequacy on one hand but receive a payment for providing load reductions on the other; costumers not selling load reductions but simply planning to buy less during peak periods (supported by a dynamic rate) would also have to buy reserves but based on a reduced peak forecast.

The overall market results within an extremely dynamic market would be quite different from current market outcomes. In the short-run, if the amount of generating capacity online remains unchanged, demand response should decrease energy market prices due to load shifting and peak reductions.¹⁴⁸ In the long run, adding large amounts of dynamic load will reduce the amount of generation that needs to be built and retained. This will reduce total planning resource costs, but it will likely *increase* energy prices in the long run due to high scarcity prices. If most responsive customers reduce load only at high prices (from hundreds to thousands of dollars per MWh), it is comparable to the use of super-peaking generation with low capital costs and high operating costs. If super-peaking demand response displaces investment in generation, energy prices will increase in any hour when the displaced generation would have set the price, including both the super-peak scarcity hours and other moderate hours when displaced inframarginal generation would have set the price.

¹⁴⁷ A full discussion of MISO's progress in integrating demand response is contained in Newell, et al. (2009b).

¹⁴⁸ For example, see two *Brattle* reports quantifying the short-run price impacts from demand response. Newell, et al. (2007).

Generators would benefit from higher energy prices and energy margins, reducing the amount of "missing money" from the energy market that new capacity would need in order to enter and maintain an administratively-determined reserve margin for the "firm" load. This increase in energy margins would reduce both bilateral and centralized capacity prices required to attract and retain capacity. Lower capacity prices would also reduce the costs of administrative error in choosing the resource adequacy requirement and other potential capacity market design flaws. The overall effect of a highly active demand side would be to make the MISO market more like an energy-only market by reducing the value of the capacity market and increasing the value of the energy and ancillary markets.¹⁴⁹

While MISO has been generally successful in integrating demand resources into its RA construct, it appears that there is significant room for increased participation, especially in the energy markets. The efficient level of demand response in an electric market depends on several factors: (1) the net costs of advanced metering (net of potential operating benefits such as meter-reading savings); (2) the level of customer participation and responsiveness; and (3) the value of customer responsiveness within energy, ancillary services, and capacity markets. An estimate for PJM showed that investments in smart meters can be cost-effective for 60%-85% of all customers, representing more than 90% of all load, once new capacity is needed.¹⁵⁰ The cost-effectiveness of advanced metering investments vary by region and by utility, and states will have the primary role in examining and approving these cost-effective smart meter expansions as well as the dynamic retail rate structures needed to achieve the potential benefits.

The related question of how much demand response is needed for a properly-functioning energy-only market is somewhat more speculative. In principle, an energy-only market could function without *any* demand response if administratively-determined scarcity prices are high enough and occur frequently enough to attract capacity when needed. However, in this case investment is driven by administrative determinations; it would be more efficient for high scarcity prices to be set by demand. In its 2005 energy-only market vision paper, MISO proposed a price responsive demand (PRD) target such that 10% of its peak load would be reduced under high price conditions.^{151,152} However, it appears that this proposed target may be modest overall; in a recent study for the FERC, authors from *The Brattle Group*, estimated that full deployment of

¹⁴⁹ However, as discussed in Sections IV.A.4 and V.B, the capacity market price would not be expected to drop to zero if either: 1) the VOLL were set below the actual average value as it is now in MISO and there were insufficient demand participants in the energy market, or 2) the resource adequacy requirement were set inefficiently high.

¹⁵⁰ The 65%-80% of customers cost-effective to cover represent all commercial and industrial customers as well as most residential customers. Anywhere from 4%-12% of peak load reductions would be expected from this level of smart meter deployment depending on how responsive these customers are to peak prices. See Part IV, Spees (2008).

¹⁵¹ See p. 29, MISO (2005).

¹⁵² Note that 10% of peak load corresponded to 135 hours in MISO in 2008; if prices reached roughly \$7,590/MWh on average during that many hours, there would be no missing money for supporting new entry when needed (assuming \$80/kW-year CONE). Load data from MISO (2009ff).

smart meters with dynamic retail rates as the default option for all customers could achieve a 12%-14% reduction in peak loads in the Midwest.¹⁵³

To summarize, making the demand side more dynamic will allow the market to determine the level of reliability for the non-firm customers while reducing the number of dollars riding on administrative determinations in the long run. In addition, resource costs will be lower because less capacity will be needed to support the non-firm load, and there will be less low-value consumption when the cost of energy is very high.

Given these advantages, MISO should continue to make it a priority to accommodate demand resources in its capacity, energy, and ancillary services markets.¹⁵⁴ Even more importantly, the states need to act to develop this resource by developing the infrastructure, dynamic retail rates, and access for aggregators and curtailment service providers.

¹⁵³ See the *Achievable Participation Scenario*, p. 30, Faruqui, et al. (2009).

¹⁵⁴ A full discussion of MISO's progress in integrating demand response is contained in Newell, et al. (2009b).

VI. EVALUATION OF MISO PROGRESS ON RESOURCE ADEQUACY GOALS

We present here the MISO Board goals set forth in its year 2009 Incentive Plan and summarize the progress made on these goals.¹⁵⁵ As Table 13 shows in reference to the relevant documentation in this report, each of the MISO board goals on RA for 2009 has been met.

Table 13
MISO Board Resource Adequacy Goals¹⁵⁶

<i>Goal</i>	<i>How Goal Has or Has Not Been Met</i>
Implementation Tasks as outlined in the FERC Order addressing compliance are complete, including the rehearing on the treatment of LMR (DR & BTMG)	MISO has completed these items and has made several additional follow-on compliance filings as discussed in Section III.B.
Outline and implement stakeholder process to determine modifications required for Planning Year #2 (June 2010 - may 2011) - intermittent capacity factors, planning reserve zones, DR and BTMG analysis are areas of emphasis	MISO has met this goal, as discussed in Section III.B. A large number of issues have been addressed, with Module E amendments made or proposed to the FERC as discussed in Section III.B.1. Further progress has been made through the stakeholder process in modifying the RA BPM for PY2, as discussed in Section III.B.2.
Expand the Midwest ISO Portal Bulletin Board to enable multi-year capacity bids and offers (including Demand Response)	As discussed in the Long-Term Contracting Portion of MISO's 719 compliance filing on April 28, 2009, this bulletin board has been implemented, and the goal has been met. ¹⁵⁷
Draft and distribute a whitepaper on the 1 st Planning Year for Resource Adequacy Requirements (RAR) for the Midwest ISO wholesale region - report will assess the accuracy and completeness of RAR and the further improvements that are required	MISO met this goal through the completion of this report and the prior distribution of preliminary findings to stakeholders and The Board.

¹⁵⁵ For Incentive Plan goals, see pp. 8-9, MISO (2009a).

¹⁵⁶ See p. 8, MISO (2009a).

¹⁵⁷ See

VII. RECOMMENDATIONS

MISO should postpone consideration of replacing the current construct with either a forward capacity market or a pure energy-only market. Instead, it should continue to refine the current construct and integrate more price-responsive demand in order to enhance economic efficiency while maintaining a satisfactory level of reliability. We have four specific recommendations for MISO and its stakeholders to consider:

1. **Locational resource adequacy:** assess options for market-based approaches to ensuring locational resource adequacy, including implementing local sourcing requirements. We also recommend incorporating a locational scarcity pricing evaluation into the annual LOLE study which would review scarcity pricing activity in constrained and potentially constrained zones.
2. **Load forecasting:** MISO should develop its own coincident peak load forecasting capability (possibly with input from LSEs) rather than relying solely on LSEs to conduct their own peak load forecasts. The use of a centralized, coincident peak load forecast could avoid adverse incentives and quality problems.
3. **Load tracking:** develop a tracking system that accounts for load migration in retail choice states in a timely manner. It may help to define peak load contributions for customers and to develop a true-up mechanism to account for mid-month load migration.
4. **The reliability target:** (1) conduct an economic efficiency-based assessment to determine an appropriate target; (2) consider adopting a better-defined reliability metric such as expected unserved energy (EUE), which indicates the amount of MWh likely to be curtailed; and (3) work with the North American Electric Reliability Council (NERC) regional entities to consider revising the standards if economic analysis indicates that the current “1-in-10” LOLE standard is inefficient.

We have also identified several additional areas that MISO and stakeholders should monitor over time:

5. **Investment/retirement:** monitor capacity investments and retirements, particularly in retail choice states to ensure that the next round of capital investments will be made when and where needed.
6. **State planning reserve margins:** if a state lowers its planning reserve margin below the MISO-wide requirement, be prepared to evaluate the reliability implications, and plan to refer the issue before the FERC if such a state appears to be leaning on its neighbors for resource adequacy.
7. **VCA performance:** monitor performance by: (1) confirming that prices continue to be consistent with prevailing market conditions of over- or under-supply; and (2) reviewing

transaction volumes and soliciting stakeholder feedback (particularly from competitive retail providers) to determine whether the VCA is sufficiently liquid.

8. **Long-term PRCs:** review potential benefits and drawbacks of creating multi-year PRCs as market participants gain more experience as to what value forward PRCs could offer beyond the bilateral contracting options already available.

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LIST OF ACRONYMS

AESO	Alberta Electric System Operator
APRC	Aggregate Planning Resource Credit
BPM	Business Practices Manual
BTMG	Behind-the-Meter Generation
C&I	Commercial and Industrial
CAISO	California ISO
CONE	Costs of New Entry
CPNode	Commercial Pricing Node
CROW	Control Room Operations Window
CTR	Capacity Transfer Right
DR	Demand Resource
DRR	Demand Response Resource
DRWG	Demand Response Working Group
EDC	Electric Distribution Company
EFOR _d	Effective Forced Outage Rate Demand
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EOM	Energy-Only Market
EPRC	External Planning Resource Credit
EUE	Expected Unserved Energy
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRP	Full Responsibility Purchases
FRS	Full Responsibility Sales
GADS	Generating Availability Data System
ICAP	Installed Capacity
IPA	Illinois Power Authority
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
LBA	Local Balancing Authority
LMR	Load Modifying Resource
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LOLEWG	Loss of Load Expectation Working Group
LPRC	Local Planning Resource Credit
LSE	Load-Serving Entity
LSR	Local Sourcing Requirement
M&V	Measurement and Verification
MISO	Midwest Independent System Operator
MW	Megawatt

MWh	Megawatt Hour
MRO	Midwest Reliability Organization
MTEP	MISO Transmission Expansion Planning
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NYISO	New York ISO
OMC	Outside Management Control
PJM	PJM Interconnection
PLC	Peak Load Contribution
POLR	Provider of Last Resort
PRC	Planning Resource Credit
PRD	Price-Sensitive Demand
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PY1	Planning Year 1
PY2	Planning Year 2
PY3	Planning Year 3
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RCPF	Reserve Constraint Penalty Factor
RE	Regional Entity
RFC	Reliability <i>First</i> Corporation
RFP	Request for Proposal
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SAWG	Supply Adequacy Working Group
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
SSR	System Support Resource
UCAP	Unforced Capacity
UDR	Unforced Capacity Deliverability Right
VCA	Voluntary Capacity Auction
VOLL	Value of Lost Load
VOS	Value of Service
XEFOR _d	EFOR _d Excluding Events OMC