**Manual No. 011**

# Business Practices Manual

# RESOURCE ADEQUACY

# Disclaimer

This document is prepared for informational purposes only, to support the application of the provisions of the Tariff and the services provided thereunder. MISO may revise or terminate this document at any time at its discretion without notice. While every effort will be made by MISO to update this document and inform its users of changes as soon as practicable, it is the responsibility of the user to ensure use of the most recent version of this document in conjunction with the Tariff and other applicable documents, including, but not limited to, the applicable NERC Standards. Nothing in this document shall be interpreted to contradict, amend, or supersede the Tariff. MISO is not responsible for any reliance on this document by others, or for any errors or omissions or misleading information contained herein. In the event of a conflict between this document, including any definitions, and either the Tariff, NERC Standards, or NERC Glossary, the Tariff, NERC Standards, or NERC Glossary shall prevail. In the event of a conflict between the Tariff and the NERC Standards, or NERC Glossary, the Tariff shall prevail until or unless the Federal Energy Regulatory Commission ("FERC") orders otherwise. Any perceived conflicts or questions should be directed to the Legal Department.

# Revision History

| Doc Number | Description | Revised by: | Effective Date |
|---|---|---|---|
| BPM-011-r28 | Clarify and add additional context surrounding ZRC replacement and the 31-day outage rule in section 6.4 while ensuring language is consistent with Module E-1 of the MISO Tariff. | N. Przybilla | May-31-2023 |
| BPM-011-r27 | Updates to all sections to facilitate the implementation of seasonal auctions & seasonal accreditation (FERC Docket No. ER22-495). Includes updates from annual BPM review | MISO Staff | October-31-2022 |
| BPM-011 r26 | Replacement of 4.2.12 Battery Storage Accreditation with Electric Storage Resource. Add Electric Storage Resource to section 4.2.8. BTMG Qualification Requirements. Update Appx K. Correct Appendix N – Demand and Energy Forecast Characteristics. | M. Guerriero | AUG-15-2022 |
| BPM-011-r25 | 2021 Annual review complete. Edits include: Hybrid resources, detail added to States establishing PRM, detail for 90/120 day outages, clarification for BTMG wind UCAP, Updated to reference new DSRI tool instead of MCS, updated RAN related LMR accreditation (ER20-1846), new DR Test Deferral process, Battery Storage accreditation, reorganized Appx I XEFORd, added Process Load reporting section, updated App K Timeline. | MISO Staff | JUL-01-2021 |
| BPM-011-r24 | 2020 Annual review complete. Edits include new Appendix W (DR LOLE), Deliverable ICAP (ER20-1942, ER20-2005), GVTC testing clarification, ZDB example, and other minor clarifications. | G. Alexander | DEC-15-2020 |
| BPM-011-r23 | Revisions to address treatment of resources on long term outage which FERC approved under Dock No. ER20-129-000. | T. Bachus | MAR-31-2020 |
| BPM-011-r22 | 2019 Annual Review Complete. Edits include: general clean up, ER19-2559 (PRA Process Timeline) & ER18-2363 (Locational Filing), web links, ER UCAP intermittent qualification, Appx R CONE calculation, removing Att W (ER19-650 RAN Phase 1 LMR filing) by imbedding language into applicable LMR sections. | E. Thoms | OCT-1-2019 |

| | | | |
|---|---|---|---|
| BPM-011-r21 | Added LMR Registration FAQ to address ER19-650-000 | E. Thoms | FEB-20-2019 |
| BPM-011-r20 | Multiple updates. Revisions supporting changes to the out-year transfer study process. Additional revisions to support the Module E-1, Locational Tariff update which created External Resource Zones and several other changes. | M. Sutton | NOV-01-2018 |
| BPM-011-r19 | Revisions to Section 4.2.8 clarifying language when a Qualifying Facility participates as a BTMG. Addition of SER Type II resource. Annual Review completed. | J. Harmon | SEP-28-2018 |
| BPM-011-r18 | Annual Review Complete<br>Includes revisions to Section 4.2.8.5 clarifying deliverability options for BTMG. | J. Harmon | JAN-22-2018 |
| BPM-011-r17 | Annual Review Complete | J. Harmon | AUG-25-2017 |
| BPM-011-r16 | Several updates. Updated Wind UCAP values; added section regarding Solar capacity credit; Revised provisions for Zonal Deliverability Benefit; Inclusion of Suspended resources in the PRA; Retail Choice coincident load forecast reporting process. Annual Review completed. | J. Harmon | JUL-15-2016 |
| BPM-011-r15 | Annual Review completed. Included Inter-zonal replacement, sub regional constraints in PRA, PRMR and LCR relationship, external resource and host BA qualification requirements, GVTC deferral, and refueling versus repowering. Additions to section 5.2.1 for Local Resource Zone reevaluation process and Generation Limited Transfers | J. Milli /<br>M. Sutton /<br>S. Quadri /<br>J. Cole /<br>R. Westphal | SEP-01-2015 |
| BPM-011-r14 | Annual Review completed. Remove netting of Demand Response. Update SFT and Transfer Analysis provisions. | J. Milli | SEP-01-2014 |
| BPM-011-r13 | Updated LRZ map, timeline, and added catastrophic outage provisions | C. Clark | JAN-01-2014 |
| BPM-011-r12 | Annual review and updated to reflect Tariff orders | C. Clark | AUG-01-2013 |
| BPM-011-r11 | Updated to reflect Module E-1-1 Tariff | C. Clark | OCT-01-2012 |
| BPM-011-r10 | Updated GVTC language for Hydro and ROR. | C. Clark | SEP-28-2012 |
| BPM-011-r9 | Annual Review completed and Updated Registration tables and added new section for qualifying PPAs. | C. Clark | APR-15-2012 |
| BPM-011-r8 | MISO Rebranding Changes JUL-19-2011 | G. Krebsbach | JUN-13-2011 |

| | | | |
|---|---|---|---|
| BPM-011-r8 | Annual Review and added Dispatchable Intermittent Resource, minor clarifications | C. Clark | JUN-13-2011 |
| BPM-011-r7 | Updated UCAP calculations for plan year 2011/2012, undated Must-offer provisions, updated External Resources cross-border deliverability provisions, updated minor clarifications | M. Heraeus / C. Clark | Dec-1-2010 |
| BPM-011-r6 | Corrected errors and added "Must-Offer" language and Units with Low Service Hours | M. Heraeus / C. Clark | JUN-1-2010 |
| BPM-011-r5 | Corrected errors and inadvertent omissions | M. Heraeus | MAR-3-2010 |
| BPM-011-r4 | Resource Adequacy Improvements Tariff Filing updates. Changed numbering to BPM -011 | K. Larson | DEC-21-2009 |
| TP-BPM-003-r3 | Removed stakeholder comments from section 6.4 that were provided during drafting of TP-BPM-003-r2. Amended section 4.4.3.14.4.3.1. | T. Hillman | JUN-01-2009 |
| TP-BPM-003-r2 | Revised to reflect the December 28th, 2007 (ER08-394) filing and subsequent Commission required compliance filings through May 2009 to revise Module E-1 to comprehensively address long-term Resource Adequacy Requirements | T. Hillman | JUN-01-2009 |
| TP-BPM-003-r1 | Revised to reflect Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement. | J Moser | JAN-06-2009 |
| TP-BPM-003 | Updated template | J. Moser | APR-01-2008 |
| N/A | Section 3.2.1 Determination of Requirements – Non-valid statements were removed.<br>Section 3.2.3 Default Requirements – Minor revisions were made for clarification.<br>Section 3.2.4 Compliance with the Midwest ISO Requirements – Paragraph on after-the-fact ECAR "must offer" compliance was removed.<br>Section 4.1 Commercial Pricing Node Load Forecast – Minor revisions were made for clarification.<br>Section 5.2.1 Procedure for Designating a Network Resource for Resource Adequacy Purposes – LD Contracts bullet updated to reflect FERC Order 890. | | DEC-12-2007 |

| | | | |
|---|---|---|---|
| | Section 5.2.3 Designating Network Resources External to the Midwest ISO – The second bullet point was revised for clarification.<br>Section 5.3 Determination of Compliance with Network Resource Requirements – This section was deleted.<br>Section 5.4 (5.3) Network Resource Must Offer Requirement – Paragraph on after-the-fact ECAR “must offer” compliance was removed.<br>Section 5.5 Financial Transmission Rights – This section was deleted.<br>Section 5.6 (5.4) Updating Network Resource Designations – RE references have been updated to reflect the current NERC Regions.<br>Section 6.1.3 Liquidated Damage and Similar Contracts – Entire section updated to reflect FERC Order 890.<br>Section 6.1.4 Hubbing Transactions – This section was deleted.<br>Section 8 Data Requirements – Entire section updated to reflect FERC order 890 | | |

## Contents

# 1. Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM)* for Resource Adequacy Requirements includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about the MISO BPMs. The second section (Section 1.2) is an introduction to this BPM. The third section (Section 1.3) identifies other documents in addition to the BPMs, which can be used by the reader as references when reading this BPM.

## 1.1. Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website.

## 1.2. Purpose of this Business Practices Manual

This Resource Adequacy Business Practices Manual describes MISO's and other entities' roles and responsibilities related to maintaining Resource Adequacy, which is ensuring that Load Serving Entities (LSE) serving Load in the MISO Region have sufficient Planning Resources to meet their anticipated peak demand requirements plus an appropriate reserve margin.

The Resource Adequacy BPM will conform and comply with MISO's Energy Markets Tariff, NERC operating policies, and the applicable Regional Entity (RE) reliability principles, guidelines, and standards to facilitate administration of efficient Energy Markets.

This document benefits readers who want answers to the following questions regarding the Resource Adequacy Requirements (RAR).

- How is Resource Adequacy determined?
- How do the multiple state jurisdictions relate regarding Resource Adequacy Requirements (RAR)?
- What are the responsibilities of the different entities regarding Resource Adequacy?
- How are specific resources identified and qualified, including contracted resources, for Resource Adequacy purposes?
- What is a Zonal Resource Credit (ZRC) and how can it be used to comply with RAR?
- What are the deliverability requirements for Planning Resources?

- How are Demand Response Resources (DRR Type I and Type II) incorporated in the Resource Adequacy process?
- How does an LSE comply with its obligations under the changes to Module E-1 of the Tariff?
- What are the procedures for participating in Planning Resource Auctions?
- What are the settlement provisions for the Planning Resource Auctions?
- What are the procedures for tracking and settling retail and wholesale customer switches?

This document provides the necessary detail to aid a MISO Market Participant's (MP) understanding of its primary responsibilities and obligations to the reliable operation of MISO's Balancing Authority Footprint, as a result of MISO's Resource Adequacy Requirements.

## 1.3. References

Other reference information related to this document includes:

- MISO BPMs
- MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff
- NERC – Resource and Transmission Adequacy Recommendations, dated June 15, 2004
- Federal Energy Regulatory Commission (FERC) Order Nos. 890, Order 890 - A, and Order 890 -B.
- Module E Capacity Tracking (MECT) tool Users Guide
- LOLE Study Reports
- Wind & Solar Capacity Credit Report
- PowerGADS User's Manual
- CIL/CEL Study Reports

# 2. Overview of Resource Adequacy

Achieving reliability in bulk electric systems requires, among other things, that the amount of resources exceeds customer demand by an adequate margin. The margins necessary to promote Resource Adequacy needs to be assessed on both a near-term operational basis and on a longer-term planning basis.

The focus of Resource Adequacy is on the longer-term planning margins that are used to provide sufficient resources to reliably serve Load on a forward-looking basis. In the real-time operational environment, resources committed through the Resource Adequacy Requirements have a capacity obligation to be available to meet real-time customer demand and contingencies. Therefore, Planning Reserve Margins (PRMs) must be sufficient to cover:

- Planned maintenance
- Unplanned or forced outages of generating equipment
- Deratings in the capability of Generation Resources and Demand Response Resources
- System effects due to reasonably anticipated variations in weather
- Load Forecast Uncertainty

## 2.1. Planning Reserve Margin Requirement Overview

Each LSE's total obligation will be referred to as the Planning Reserve Margin Requirement (PRMR). Forecasted Coincident Peak Demands are submitted by LSE's using a 50%-50% forecast (50% probability the forecast will be over, and 50% probability the forecast will be under, the actual peak demand) which will include distribution losses. An LSE's PRMR is described in Section 3.1 of this BPM.

## 2.2. Planning Resources Overview

The resources used to achieve long-term Resource Adequacy are called Planning Resources, and consist of Capacity Resources, Load Modifying Resources and Energy Efficiency Resources. The relationships and key attributes of the Planning Resource types are as follows:

- Capacity Resources consist of electrical generating units, stations known as Generation Resources, External Resources (if located outside of the MISO Balancing Authority Area), Stored Energy Resource Type II, Hybrid Resources, and resources that can be dispatched to reduce demand known as Demand Response Resources that participate in the Energy and Operating Reserves Market and are available during Emergencies. Thermal Generation Resources are accredited based on the methodology described in Appendix Y. Intermittent generation resources will be accredited based on historical performance during the critical hours within each season where new resources will receive the class average for that resource type until enough historical data is accrued. The rest of the Capacity Resources are quantified by applying seasonal forced outage rates to Installed Capacity values (ICAP) to calculate the Seasonal Accredited Capacity (SAC) for the resource.

- Load Modifying Resources (LMR) include Behind-the-Meter Generation (BTMG) and Demand Resources (DR) which are available during capacity and transmission Emergencies declared by MISO if used to meet Module E-1 requirements.
- Energy Efficiency Resources include installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

A Market Participant (MP) can use Capacity Resources, LMRs, and Energy Efficiency Resources, up to their SAC values, to comply with their Resource Adequacy Requirements via a Fixed Resource Adequacy Plan as described in Section 5.3 of this BPM, or through self-scheduling their Zonal Resource Credits in the Planning Resource Auction(s) (PRA) as detailed in Section 5.5.6 of this BPM. A Market Participant can also sell the SAC values from Capacity Resources, LMRs, and Energy Efficiency Resources, either bilaterally before the Planning Resource Auction(s) or in the Planning Resource Auction(s) as described in Section 5.5 of this BPM.

MISO will determine Seasonal Accredited Capacity (SAC) values for all qualified Capacity Resources, Load Modifying Resources and for all Energy Efficiency Resources for each season within the Planning Year.

## 2.3. Resource Adequacy Requirements Overview

Planning Resources that clear Planning Resource Auction(s) (PRA) or that are designated in a Fixed Resource Adequacy Plan (FRAP) will be obligated to provide capacity for each season cleared within the Planning Year unless replaced by another Planning Resource, as per Module E-1 Section 69A.3.1.h. Replacement non-compliance charges may be applicable as per module E-1 Section 69A.3.1h paragraph b. LSEs that serve Load during the Planning Year will be obligated to pay for capacity from such Planning Resources pursuant to the relevant Auction Clearing Price (ACP) for the LRZ where the Load is located unless the Planning Resource was designated in a FRAP.

LSEs that have a Planning Reserve Margin Requirement (PRMR) will be obligated to procure capacity equal to their Planning Reserve Margin Requirement pursuant to the relevant Auction Clearing Price (ACP) for the Local Resource Zone where they have PRMR unless, and to the extent that the LSE meets its PRMR via a Fixed Resource Adequacy Plan (FRAP) per Section 5.3 of this BPM, or unless and to extent that the LSE chooses to reduce its PRMR that is cleared in a given auction(s) by electing to pay the Capacity Deficiency Charge per section 5.6 of this BPM.

## 2.4. Settlements/Performance Requirements Overview

The seasonal Planning Reserve Margin Requirement (PRMR) obligations of LSEs will be fixed for each season of the Planning Year and will be settled based upon the applicable Planning Resource Auction(s) (PRA) clearing price for an LSE’s Planning Reserve Margin Requirement, unless covered by a Fixed Resource Adequacy Plan (FRAP) or unless the LSE elects to pay the Capacity Deficiency Charge. Once each planning period begins, LSEs and MPs will have the corresponding charges and credits from each applicable PRA included on their daily settlements statements for all loads and Planning Resources cleared in a PRA as documented in further detail in the Market Settlements BPM.

LMRs with ZRCs that either cleared the PRA or were used in a FRAP will have a performance obligation to be available during system Emergencies refer to section 4.2.7 in this BPM.

# 3. Establishing Seasonal Planning Reserve Margin Requirements

## 3.1. Overview

The seasonal Planning Reserve Margin Requirement (PRMR) is the number of MWs in ZRCs required to meet an LSE's Resource Adequacy Requirements (RAR). The RAR is established to ensure that LSEs have enough Planning Resources to reliably serve load for the applicable seasons.

The seasonal PRMR is expressed in the following equation per Load Serving Entity per Local Resource Zone (LRZ):

$$PRMR_{LRZ} = \sum_{LBA} [(CPDf \quad - FRP \quad + FRS \quad ) \times (1 + TL\% \quad ) \times (1 + PRM_{RTO})]$$

Where attributes are seasonal for the following:
$PRMR_{LRZ}$ = Planning Reserve Margin Requirement per LRZ
CPDf = Coincident Peak Demand forecast per LBA
FRP = Full Responsibility Purchase per LBA
FRS = Full Responsibility Sale per LBA
TL% = Transmission Loss Percentage of LBA
$PRM_{RTO}$ = Planning Reserve Margin in Unforced Capacity set by LOLE Studies

### 3.1.1. Agency Contracts Supporting Resource Adequacy Requirements

An LSE may contract with other entities to comply with RAR. The contracted entity would perform functions on behalf of the applicable LSE including, but not limited to, submitting the LSE's forecasted CPD forecast or share of CPD forecast.

Each individual LSE is ultimately responsible for conformance with the RAR, even if it enters into a contract with a third party acting on its behalf. If requested by MISO, each LSE that contracts with another entity to comply with any part of the Resource Adequacy Requirements must notify MISO of the arrangement. The LSE must provide MISO with the name of the organization representing them, primary and alternate contact information for the individuals representing them, and the scope of responsibilities the contracted entity will provide.

### 3.1.2. Validation of Firm Transmission Service for Load

Each LSE shall document, as described in Module B – Transmission Service, to MISO that the LSE has obtained sufficient firm Transmission Service to serve its load for each season in the

Planning Year. Load not served by Network Integrated Transmission Service (NITS) must have Firm Point-to-Point Transmission Service or a firm Grandfathered Agreement (GFA), when applicable—however, demand does not require firm MISO Transmission Service when the LSE meets its PRMR using its own Behind-the-Meter Generation (BTMGs), Demand Resources (DRs) and Energy Efficiency Resources (EE Resources), and does not use the MISO Transmission System to serve such demand.

## 3.2. Demand and Energy Forecasts

MISO collects a variety of load forecasts for Resource Adequacy and other planning processes via the MECT tool. This section describes each of these forecasts and what entity is responsible for providing them. Please See Appendix O for the list of parties responsible for reporting Demand and Energy forecasts.

Demand and Energy forecasts that are not subject to retail choice load switching should be reported by the respective LSE. Demand and Energy forecasts that are subject to retail choice load switching should be reported by the respective Electric Distribution Company (EDC). The EDC calculates a Peak Load Contribution (PLC) MW value for each retail choice LSE that represents each LSE's share of the EDC's PRMR. If an LSE disagrees with their PLC value calculated by their EDC, the LSE will work with its EDC to revise the PLC prior to the final EDC forecast submission deadline.

All Demand (Energy) forecasts shall reflect a 50% probability that the Demand (Energy) will not exceed the forecasted Demand (Energy) for the relevant time period. Any manual or ex-post adjustments to the forecasts derived from the LSE's chosen forecasting method that are offered due to catastrophic event impacts (such as COVID-19) must be supported analytically and quantitatively.

For a detailed description of each forecast's characteristics refer to Appendix N.

### 3.2.1. Non-Coincident Peak Demand and Energy for Load Forecasts

Non-Coincident Peak Demand and Energy for Load forecasts are collected for the purposes of facilitating FERC Form 714 and NERC Modeling Data and Analysis (MOD) Standards reporting along with other planning processes at MISO.

The MISO FTR Administration team uses the Non-Coincident Peak Forecast value for the upcoming planning year in the annual Auction Revenue Rights (ARR) allocation process. This forecast should not include transmission losses or Grandfathered Agreements (GFAs) but should include Demand Resources and Behind-The-Meter-Generation (BTMG). Load served by GFAs is reported separately via the same MECT section.

Please refer to NERC's Reliability MOD Standards for a complete definition for the non-Coincident Peak Demand forecast and FERC's Form 714 for the Energy for Load forecast. Below are general guidelines; if a conflict should arise between the guidelines below and the respective NERC standards documents, defer to the latter.

The Non-Coincident Peak Demand and Energy for Load forecasts are reported on a monthly basis for forecast years 1 and 2 and on a seasonal basis for forecast years 3 through 10.

Seasons for the purposes of these forecasts are defined as shown below:

Summer: June through August
Fall: September through November
Winter: December through February
Spring: March through May

For seasonal reporting of the Non-Coincident Peak Demand forecast, the single highest peak hour during the season should be reported in MW. For Energy for Load forecasts, the summation of each month's energy for load (GWh) should be reported.

For all forecasts submitted, each LSE shall ensure that it counts its customer demand once and only once.

For a detailed description of each forecast's characteristics refer to Appendix N.

### 3.2.2. Coincident Peak Demand Forecast

The seasonal Coincident Peak Demand forecasts (CPD forecast) are used as the basis for determining each LSE's seasonal Planning Reserve Margin Requirement (PRMR). The CPD forecasts shall be based upon considerations including, but not limited to, average historical weather conditions, economic conditions and expected Load changes (addition or subtraction of demand).

For a detailed description of each forecast's characteristics refer to Appendix N.

A document describing in detail the desired approach to be used by LSEs in preparing the CPD forecasts, the information required in each annual filing, and the process used in reviewing the CPD forecasts can be found on MISO's website: Peak Forecasting Methodology Review Whitepaper.

The seasonal CPD forecasts must be provided for each Asset Owner/LBA combination. Providing the CPD forecasts by Asset Owner is required by MISO's settlements process. Reporting by LBA allows MISO to apply the appropriate seasonal Transmission Losses towards the PRMR calculation. Seasonal Transmission Losses will be made available on the public website by MISO for each LBA for the seasonal MISO peak hour.

The CPD forecasts must be reported via the MECT tool by 11:59 EST on November 1 prior to the Planning Year.

The CPD forecasts are reported differently in non-retail choice and retail choice areas as described in the following subsections.

### 3.2.3. Forecast Reporting

LSEs with demand and energy that is not subject to retail choice load switching are required to provide MISO with demand and energy forecasts no later than 11:59 p.m. EST on November 1 each year, for the following Planning Year. The CPD forecasts must be reported for each Asset Owner by LBA.

LSEs with demand and energy that is subject to retail choice load switching are not required to provide MISO with demand and energy forecasts. Electric Distribution Companies (EDCs) are responsible for submitting forecasts in areas that have demand and energy that is subject to retail choice load switching.

EDCs are defined as the company that distributes electricity to retail customers through distribution substations and/or lines owned by the company. The EDC of a retail choice area provides MISO with a seasonal peak forecasted Demand coincident with MISO's seasonal peak and must provide this data no later than 11:59 p.m. EST on November 1 prior to the Planning Year.

EDCs must provide both MISO and the respective retail choice LSEs with each retail customer's initial seasonal Peak Load Contribution (PLC) in the EDC's service territory by no later than 11:59 p.m. on December 15th prior to the Planning Year.

All new EDCs are required to work with the MISO Client Services and Readiness department (register@misoenergy.org), to set up access to the MECT tool and the relationships between the EDC and the LSEs in the EDC area. The MISO Client Services and Readiness team will provide the new EDC with the required registration forms. Once the EDC setup is completed, all MPs with commercial pricing nodes participating in the retail choice load switching program are required to provide the name of the EDC where the commercial pricing node is located.

#### 3.2.3.1. Provider of Last Resort

The Provider of Last Resort (POLR) will be responsible for meeting any PRMR from demand left unclaimed by LSEs in the EDC service territory. The Transmission Provider will work with the POLR and EDC to ensure that the POLR will serve any remaining demand that is not allocated to LSEs.

### 3.2.4. Wholesale Load Customers

To ensure wholesale customers are accounted for, LSEs serving wholesale customers during the prompt Planning Year must include the demand and energy attributed to those wholesale customers in their demand and energy forecasts by November 1st prior to the Planning Year via the MECT tool.

An LSE that has previously served a wholesale customer and does not intend on serving that customer for the prompt Planning Year may or may not be required to report that customer in their forecasts.

**Case 1**: LSE knows the entity that will serve the wholesale customer next Planning Year:
In this case the existing LSE is not responsible for submitting the energy or demand attributed to the wholesale customer in their forecasts. However, they must state the entity responsible for serving the customer in their supporting documentation.

**Case 2**: LSE does not know who will serve the wholesale customer next Planning Year:
In this case the existing LSE is responsible for submitting the energy or demand attributed to the wholesale customer in their forecasts.

MISO will work with the wholesale customer regarding their forecasts and contact the wholesale customer to determine who the responsible LSE is. Once the responsible LSE is identified, MISO will transfer the demand from the old LSE to the new LSE prior to the Planning Resource Auction.

### 3.2.5. Review of CPD Forecasts

Starting November 1st, MISO will begin reviewing all forecasts and a randomly chosen set of supporting documentation submitted by LSEs and EDCs in order to give all parties adequate time to resolve any identified forecasting issues with MISO. The review will focus on whether or not the forecast methodology adequately and reasonably forecasts peak demand, energy, and/or demand reduction capability of the submitting entity. The forecast review process will be completed no later than March 1st of each year prior to the annual PRA. If necessary, MISO may develop the required seasonal CPD forecasts for any Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity or other Market Participants that do not submit CPD forecasts and supporting documentation by the November 1st deadline.

## 3.3. Placeholder

## 3.4. Full Responsibility Transactions

Full responsibility transactions (FRT) are referenced differently depending on which side of the transaction is being addressed. The sale side of an FRT is called a Full Responsibility Sale (FRS) and the purchase side is called a Full Responsibility Purchase (FRP). Both the FRS and FRP are a transfer of demand. As a result, the seasonal PRMR calculation will reflect the associated transfer of transmission losses and PRM. FRTs may only be entered for demand that is not subject to retail choice load switching.

The FRS results in an increase in demand and FRP results in a decrease in demand. This can be interpreted as the purchaser paying the seller to take on demand and its associated seasonal PRMR. This transfer of demand also results in a transfer of the associated transmission losses and PRM.

- The seller of an FRS is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load. With Full Responsibility Service to an LSE within MISO's Region, sellers are responsible for all of that LSE's PRMR associated with the sale.

**Example:**

Asset Owner MM1:
Seasonal CPDf = 10 MW
Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner MM1 is the Buyer of the FRT for the total amount of 5 MW
MM1's PRMR = (10 – 5) * (1 + 0.062) * (1 + 0.02) = 5.4 MW

Asset Owner SS2:
Seasonal CPDf = 20 MW
Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner SS2 is the Seller of the FRT for the total amount of 10 MW
SS2's PRMR = (20 + 10) * (1 + 0.062) * (1 + 0.02) = 32.5 MW

Asset Owner BB3:
Seasonal CPDf = 50 MW
Seasonal PRM = 6.2%
Seasonal Transmission Loss % = 2%
Asset Owner BB3 is the Buyer of the FRT for the total amount of 5 MW
Asset Owner BB3 is the Seller of the FRT for the total amount of 10 MW
BB3's PRMR = (50 – 5 + 10) * (1 + 0.062) * (1 + 0.02) = 59.6 MW

The LSE (purchaser) may contract with other entities (sellers) to be responsible for capacity payments based upon the ACP for all or part of its load delivered to the purchaser through an FRP/FRS agreement. Each purchaser and seller must agree on which of their transactions are to be reported as an FRP/FRS. If the purchaser and seller cannot agree upon whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in the Tariff. FRP/FRS agreements are treated effectively like a transfer of forecasted Demand and the associated PRMR from one LSE to another. An LSE with an FRP agreement is required to input the forecasted CPD information for the transferred Demand into the MECT. A MP with an FRS agreement is required to meet the RAR obligation derived from the Demand as though it was their load, as described in Section 3. If the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of MISO, then the purchaser under an FRP/FRS agreement will remain responsible for any capacity payments associated with the FRP/FRS agreement.

If the seller under an FRS/FRP agreement is not an LSE under the jurisdiction of MISO, then the purchaser who is responsible for any RAR deficiencies may coordinate with the non-jurisdictional party to ensure that any RAR obligations associated with transferred Demand are met. Such a purchaser may request that the seller communicate the proper validations and confirmations to the purchaser or confirm validation of RAR obligations in the MECT to the purchaser. Such purchaser also can request that MISO coordinate with the non-jurisdictional party to intermediate the exchange of information from the seller to the purchaser. Such coordination will not relieve the purchaser from responsibilities for any RAR deficiencies associated with the FRP/FRS agreement.

The LSE with the FRS is responsible for compliance with LSE requirements. The obligation to serve the load is shifted but the obligation to forecast the Demand remains with the original LSE (purchaser).The purchasing and selling parties will be required to enter and verify the FRP/FRS transaction into the MECT Full Responsibility Transaction screen. The parties must enter an FRP/FRS transaction into the MECT to enable MISO to track the load and capacity obligations shift. This must be done prior to the closing of the PRA window and the settlement will be between LSEs for all FRP/FRS transactions. The PRMR cannot be a negative number as a result of the FRT.

## 3.5. Planning Reserve Margin

This section describes the Loss of Load Expectation (LOLE) study process and the process used by MISO to establish the seasonal Planning Reserve Margin (PRM) for each season in the MISO Planning Year. A MISO Planning Year runs from June 1 through May 31 of the following year.

### 3.5.1. Determination of Seasonal Planning Reserve Margin

MISO will perform a technical analysis annually to establish the seasonal PRMs and seasonal Local Reliability Requirements for Local Resource Zones for the MISO Region, recognizing internal transmission limitations, and will publish the results by November 1st preceding the applicable Planning Year.

The LOLE study shall be consistent with Good Utility Practice, the reliability requirements of the Regional Entities (RE), and applicable states in the MISO Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources (LMR) and EE Resources, load forecast uncertainty, and the Transmission System's import and export capability with external systems. The PRM that is calculated in the LOLE study software is determined on an ICAP basis. This $PRMR_{ICAP}$ value is the sum of the ICAP ratings of the resources utilized in the simulation to achieve the reliability criteria. Similarly, the sum of the SAC ratings of these same resources utilized in the simulation to achieve the reliability criteria is the total SAC rated MW needed, or the $PRMR_{SAC}$.

MISO will calculate and publish on its website the estimated seasonal PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements.

See MISO's website for current and previous LOLE Study reports.

### 3.5.2. LOLE Analysis

MISO will determine the appropriate PRM for the applicable Planning Year based upon the probabilistic analysis of being able to reliably serve MISO's seasonal Coincident Peak Demand. This probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

MISO's annual LOLE study will calculate the seasonal PRMs such that the summation of seasonal LOLE across the year is one (1) day in ten (10) years, or 0.1 day per year. The minimum PRM requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative unit or adding Planning Resources until a 0.1 day per year solution is reached.

The LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. This is comparable to adding coincident peak demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

An LOLE target of 0.01 will be used to calculate the PRM in seasons with less than 0.01 LOLE risk.

MISO will also determine the Local Resource Requirement for each LRZ consistent with the LOLE achieving 0.1 day per year for each LRZ. The minimum amount of capacity above seasonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the system wide PRM. The minimum amount of capacity above the

Zonal seasonal Coincident Peak Demand required to meet the reliability criteria of a 0.1 day per year LOLE value will be utilized to establish the seasonal Local Reliability Requirement (LRR) for each Local Resource Zone.

### 3.5.3. Loss of Load Expectation (LOLE) Working Group

MISO has established an Unforced Capacity requirement based on the LOLE analysis conducted by the LOLE Working Group (LOLEWG) for the purpose of coordinating PRM study work with stakeholders. The duties of the working group are to help guide MISO in implementing the study methods outlined in the following sections. The LOLEWG will work with MISO staff to perform the LOLE analysis that calculates the PRM requirements for each LSE within MISO. This analysis will conform to the Electric Reliability Organization (ERO) standards, including those established by applicable REs for reliability and resource adequacy. The LOLEWG will also review and provide recommendations to MISO on the methodology and input assumptions to be used in performing the LOLE analysis, as well as reviewing the results of the LOLE analysis and related sensitivity cases. The LOLEWG will use this information as the basis for providing recommendations on the PRM and LRRs to MISO.

### 3.5.4. Probabilistic Analysis LOLE Study

The probabilistic study will use an LOLE model capable of sequential Monte Carlo simulation. Primary inputs are the generation data submitted to MISO through the PowerGADS tool and forecasted Demands provided as described in Section 3. Aside from the generation outage performance that has statistical parameters, the LOLE model requires information to model sub-areas or zones in the Energy and Operating Reserves market and also to model transmission capability among such zones. LSEs are obligated to report GADS data for Generation Resources and External Resources through the PowerGADS tool in the MISO Market Portal. Planned outages and the specific $EFOR_d$ outage parameter is developed from this data and together with the capacity of each Resource are the key generator inputs to the LOLE model. Seasonal $EFOR_d$ outage parameters for the LOLE study are established using the past five (5) calendar years' worth of seasonal data. The $EFOR_d$ metric are more fully described below. The zones to be modeled in the LOLE model are discussed in Section 5.2 Local Resource Zones.

The LOLE study will account for all system wide forced outage causes captured in the $EFOR_d$ metric. The $EFOR_d$ term is defined as:

Equivalent demand Forced Outage Rate ($EFOR_d$): A measure of the probability that a generating unit will not be available for the applicable season due to forced outages or forced deratings when there is demand on the unit to generate.

Outside Management Codes (OMC) Codes for use in the MISO LOLE study are listed in Appendix B.

### 3.5.5. State authority to set PRM

The only entity other than MISO that may establish a PRM for any season during the Planning Year is a state regulatory authority regarding those regulated entities under their jurisdiction. If a state regulatory authority establishes a minimum seasonal PRM for the LSEs under their jurisdiction, then that state-set seasonal PRM would be adopted by MISO for jurisdictional LSEs in such state. Other entities, such as reserve sharing groups or NERC regional entities, do not have the authority to establish a seasonal PRM under Module E-1. MISO will translate any state-set seasonal PRM into the same terms as MISO's seasonal PRM (e.g., utilizing a SAC basis) to facilitate comparison and compliance with PRMR.

MISO will perform the Loss of Load Expectation (LOLE) Study to establish the seasonal PRM and publish the results by November 1 preceding the planning year. State regulatory authorities choosing to set seasonal PRM must notify MISO in writing by December 31 for the upcoming PRA. The notice shall be from an authorized representative of the state regulatory authority and include the seasonal PRM, a list of those LSEs to which the seasonal PRM applies, and a statement that the entities to which the seasonal PRM applies have been duly notified.

Any disputes regarding the applicability of the seasonal PRM information submitted by a state regulatory authority and an affected entity shall be resolved in accordance with applicable dispute resolution measures established by the state regulatory authority. If the state regulatory authority makes any changes to information initially submitted to MISO as a result of such a dispute, the changed information shall be submitted to MISO by the state regulatory authority on or before January 31. If no such changes are submitted, the original information submitted by the state regulatory authority will be used by MISO.

MISO shall update the MECT with the state set seasonal PRM by January 31.

# 4. Qualifying and Quantifying Planning Resources

## 4.1. Overview

This section identifies the qualification requirements for each type of Planning Resource.

All Planning Resources that qualify will have a SAC value determined by MISO. The benefits of SAC include:

- Fair recognition of the contribution each unit provides towards Resource Adequacy;
- Market signals that will promote generating unit availability performance; and in turn, the improved system availability will promote improved regional Resource Adequacy; and
- Supporting bilateral trades by recognizing the SAC value of each resource, while shifting the resource performance risk to owners of Planning Resources, where such risk more properly belongs.

Planning Resources consist of Capacity Resources, Load Modifying Resources, and Energy Efficiency Resources. Capacity Resources consist of Generation Resources, Stored Energy Resources Type II, External Resources, and Demand Response Resources. Load Modifying Resources consist of Behind the Meter Generation and Demand Resources. Energy Efficiency Resources are resources registered with MISO that permanently reduce electricity demand. A Hybrid Resource may also qualify as a Planning Resource to the extent that such Hybrid Resource is a Generation Resource or Capacity Resource.

Generation Resources, Stored Energy Resources Type II, and Demand Response Resources backed by behind the meter generation in the Commercial Model that have met all requirements to supply capacity in the MISO Resource Adequacy construct will have SAC MWs calculated based on data submitted by the Asset Owner, as described in the Appendix H of this document. BTMG, DR, Energy Efficiency Resources, and External Resources must follow the registration procedures documented in the applicable subsections of this document to be eligible to supply capacity in the MISO Resource Adequacy construct.

Generation Resources, Stored Energy Resources Type II, and Demand Response Resources backed by behind the meter generation that have not provided at least one season of historical performance data will have their SAC calculated for them after they are registered in MISO's Commercial Model, provided that the Resource meets the Capacity Resource Module E-1 requirements. Planning Resources that are pseudo-tied between MISO Local Balancing Areas will be modeled in the Local Resource Zone based on the LBA in which they are physically located in. The following Table outlines the relationship and key attributes of the Planning Resource types that are committed to providing capacity.

| | Planning Resource | | | | |
|---|---|---|---|---|---|
| | Capacity Resource | | Load Modifying Resource | | Energy Efficiency Resource |
| | Generation, SER Type II, ESR and External | Demand Response Resources | BTMG | Demand Resource | |
| Capacity Verification | X | X | X | X | X |
| Must Offer | X | X | | | |
| GADS Data Entry | X | X | X | | |
| Must Respond to Emergency Operating Procedures | X | X | X | X | |

## 4.2. Planning Resources

### 4.2.1. Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation

#### 4.2.1.1. Qualification Requirements

Generation Resources may qualify as Capacity Resources provided that:

- They are registered with MISO as documented in the Market Registration BPM.
- Generation Resources must be deliverable to Load within MISO's Region. The deliverability of Generation Resources to Network Load within MISO's Region shall be determined by System Impact Studies pursuant to the Tariff that are conducted by MISO, which consider, among other factors, the deliverability of aggregate resources of Network Customers to the aggregate of Network Load. Generation Resources that pass the deliverability test receive Network Resource Interconnection Service.
- Generation Resources that do not pass the deliverability test may procure firm Transmission Service (or utilize a GFA) in conjunction with Energy Resource Interconnection Service (ERIS) to meet the deliverability requirements.

  - Firm Transmission Service must either be a Firm Point-to-Point (PTP) Transmission Service Request (TSR) or a Firm Network Integration Transmission Service (NITS) Scheduling Right (SR).
    - NITS SRs should reference the OASIS NITS Application number and Resource Name used in the SR.
  - Firm transmission service (PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in total or in aggregate and submitted in the MECT.
- Generation Resources with ERIS may participate in MISO's Interim Deliverability Study process as described in BPM-015. The following generic parameters apply for the Interim Deliverability Study:
  - MISO may grant conditional NRIS applicable for the next Planning Year
  - MISO may grant conditional ERIS applicable for the next Planning Year
  - MISO may grant conditional External-NRIS (E-NRIS) applicable for the next Planning Year.
  - MISO may implement a Quarterly Operating Limit (QOL) on a portion of a Generation Resource due to transmission study overloads. MW amount subject to QOL can qualify as capacity in the PRA. The MW amount subject to QOL is not required to procure replacement capacity if the QOL is reduced in a subsequent MISO quarterly study.
- Generation Resources with a Provisional Interconnection Agreement are not qualified to participate in the PRA.
- Generation Resources that were accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date are considered as deliverable.
  - This may include Generation Resources that were issued 'local' NRIS through a Generator Interconnection Agreement consistent with Module E-1 Section 69.3.1.g paragraph v. In such instances, 'local' NRIS is processed in similar fashion as ERIS for the purposes of demonstrating deliverability for participation in the Planning Resource Auction. As with resources with ERIS, firm Transmission Service must be demonstrated to cover the entire Planning Year for the level of participation desired in order to qualify for participation in the PRA.

- Internal purchase power agreements (PPAs) will not be qualified by MISO.

- Generation Resources greater than or equal to 10 MW (based on Generation Verification Tested Capacity (GVTC)) must submit their Generator Availability Data System (GADS) data (including, but not limited to, NERC GADS) into the MISO PowerGADS database through the MISO Market Portal.
- Generation Resources less than 10 MW based upon GVTC are not required to report their GADS data.
- Generation Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report GADS data each Planning Year.
- The seasonal XEFORd for new Generation Resources in service less than one full season will be the seasonal EFORd class average for the resource type. A Generation Resource will use the class average value until 3 consecutive seasonal months of data is available. Forced outage rates are used for the capacity accreditation of non-Schedule 53 Generation Resources.
- Generation Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- Generation Resources that are in approved “Suspension” status qualify as a Planning Resource through the ICAP Deferral process.
- If Generation Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date. Generation Resources with approved “Suspension” status must participate as a Planning Resource in the next Planning Year subject to provisions regarding physical withholding in Module D of the Tariff.
- Generation Resources that plan to retire during the Planning Year will be subject to test for Physical Withholding.
- Generation Resources that are or plan to be suspended will be subject to test for Physical Withholding.
- Generation Resources that have been designated as a System Support Resource (SSR) may participate in the PRA.
- Generation Resources must demonstrate capability on an annual basis as described below.

Generation Resources undergoing conversion to natural gas are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource’s rolling XEFORd.

**When to Perform and Submit a Generation Verification Test Capacity (GVTC)**

- Generation Resources, External Resources, SER Type II, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation (BTMG) that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be completed by completing a real power test or based on operational data. The GVTC must be completed during the test period of September 1st through August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and a revised GVTC should be submitted to MISO no later than March 1st prior to the Planning Year. The initial GVTC, even if a Planning Resource is unable to test and the GVTC is 0, should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a suspended state and the GVTC must be submitted to MISO. A real power test is required when any unit returns to service in MISO after an absence (including but not limited to, catastrophic events, or a period during which it was not qualified as a Planning Resource under Module E-1).
- A real power test is required for Planning Resources in an approved "Suspension" status. If a Planning Resource is unable to complete a real power test, the MP responsible for that Planning Resource must include this item, including timing and cost requirements, when requesting a facility specific reference level.
- The GVTC for a new or returning Non-Intermittent Generation resource is due by March 1st prior to the Planning Year unless the GVTC has been deferred via the ICAP Deferral process as described in Section 4.5. See Appendix J for links to MISO's GVTC Manual and processes.

Reporting is accomplished through MISO's PowerGADS reporting system as described in the Net Capability Verification Test User Manual.

#### 4.2.1.2. SAC Determination

The SAC values for a Generation Resource are based on an evaluation of the type and volume of interconnection service, GVTC values, any applicable forced outage rate adjustment penalties, the $XEFOR_d$ value of non-Schedule 53 Generation Resources as described in Appendix H-I, and SAC value for Schedule 53 Resources as applicable and described in Appendix X.

Generation Resources relying either fully or in part on Energy Resource Interconnection Service (ERIS) coupled with firm Transmission Service to demonstrate deliverability must procure firm Transmission Service up to the Resource's ICAP level in order to receive their full SAC allocation.

If a Generation Resource's procured firm Transmission Service coupled with ERIS is less than the Generation Resource's ICAP value, the SAC allocation would be pro-rated based on Tariff Module E-1 Section 69A.4.5.

The SAC methodology is implemented to address the fact that not all Generation Resources contribute equally to Resource Adequacy. By adjusting the capacity rating of a unit based on its availability, SAC provides a means to recognize the relative contribution that each resource makes towards Resource Adequacy. When the PRM requirement is similarly adjusted by the weighted average $EFOR_d$ of all the pooled resources, the generating units with better than average availability will reflect higher values than units with below average availability.

In order for a Generation Resource to convert its entire calculated Total SAC into Zonal Resource Credits, the Generation Resource must be fully deliverable up to its ICAP. Deliverability is determined by any combination as outlined in Module E-1 Section 69A.3.1.g of the Tariff.

If a Generation Resource is not fully deliverable up to its ICAP, the resource will be eligible to convert a value less than the Total SAC into Zonal Resource Credits as outlined in Appendix H.

#### 4.2.1.3. Intermittent Generation and Dispatchable Intermittent Resources - Qualification Requirements

Intermittent Generation and Dispatchable Intermittent Resources are subclasses of Generation Resources and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1 and the alternate GADS reporting procedure as described below:

> Intermittent Generation and Dispatchable Intermittent Resources (example: run-of-river hydro, solar) must supply MISO with the three most recent consecutive years for each month for the applicable season, for a total of 9 months considered for each seasonal lookback period, of hourly net output (in MW) during critical hours, where the critical hours are hours ending 15, 16, and 17 EST for the spring, summer, and fall seasons, and hours ending 8, 9, 19, and 20 EST for the winter season. For resources on qualified extended

outage where data does not exist for some or all of the previous 9 historical seasonal months, a minimum of 30 consecutive days' worth of historical data during the relevant spring, summer or fall months for the hours ending 15, 16, and 17 EST, and hours ending 8, 9, 19, and 20 EST for the winter months must be provided prior to participating in the PRA. New intermittent resources that do not have a minimum of 30 consecutive days' worth of seasonal historical data during the hours ending 15, 16, and 17 EST in the spring, summer or fall and hours ending 8, 9, 19, and 20 EST in the winter may participate in the PRA if the resource will be in operation by the start of a season.

#### 4.2.1.4. Dispatchable Intermittent Resources & Intermittent Generation Resource - SAC Determination

The Seasonal Accredited Capacity (SAC) for Intermittent Generation Resources or Dispatchable Intermittent Resources will be determined by MISO based on historical performance, availability, and type and volume of interconnection service. Examples of SAC calculations for these resources can be found in Appendix V.

Intermittent Generation and Dispatchable Intermittent Resources that are powered solely by wind will have their SAC values determined based on interconnection service volumes and their respective wind capacity credit established via a seasonal Effective Load Carry Capacity (ELCC) study as described in Appendix A.

BTMG wind will have their SAC values determined based on their historical performance during periods of MISO system peak demand for the three years prior and their respective wind capacity credit established via a seasonal Effective Load Carrying Capability (ELCC) study.

The portion of SAC eligible to be converted into Zonal Resource Credits for an Intermittent Generation Resource or Dispatchable Intermittent Resource shall be determined utilizing the Deliverability Adjusted Capacity Factor method as outlined in the applicable appendices (A - Wind Capacity Credit, H - Seasonal Accredited Capacity (SAC) Calculations for Planning Resources, and V - Solar and Run-of-River Hydro Capacity Credit).

#### 4.2.1.5. Wind & Solar Capacity Credit

MISO uses historical wind availability information to calculate a seasonal Effective Load Carrying Capability (ELCC) to determine a wind capacity credit. MISO's Wind & Solar Capacity Credit

Report by the LOLEWG reports the wind capacity results for each Planning Year. Appendix A of this BPM explains the methodology for calculating wind capacity credit. See MISO's website (misoenergy.org / Planning / Resource Adequacy / PRA Documents / select the appropriate Planning Year) and find the Wind Capacity Credit report. See Appendix H for details on the determination of Convertible SAC using the Deliverability Adjusted Capacity Factor.

#### 4.2.1.5.1 Wind Capacity Credit

MISO calculates specific wind capacity credit (%) for each wind resource and applies it to its registered maximum capability (MW) in the Commercial Model or its registered Capacity (MW) through the LMR or External Resource registration process. Wind capacity credits are determined for each wind resource based on its average capacity factor during MISO's top eight (8) coincident peaks that occurred during the season for the previous three years.

A wind resource with no commercial operation history during the season  will receive a wind capacity credit equivalent to the MISO system wide wind capacity credit from the seasonal ELCC study for their initial Planning Year, and thereafter metered data will be used in order to calculate its future wind resource specific wind capacity credit.

If a wind resource has been operable for the season but no metered data is available, then the wind resource with receive a capacity credit of 0%.

#### 4.2.1.5.2 Solar Capacity Credit

Solar photovoltaic (PV) resources will have their SAC values determined based on the three (3) year historical average output (with curtailments added to the actual real-time output) of the resource for hours ending 15, 16, and 17 EST for the most recent spring, summer and fall months and hours ending 8, 9, 19, 20 EST for the most recent winter months.

Market Participants will need to supply this historical data to MISO by October 31 of each year to have their SAC values determined. Market Participants will use the template found on the MISO website (Planning > Resource Adequacy (Module E) > Planning Resource Auction) to submit the 3-year historical output data.

Solar PV resources that have been upgraded or returning from extended outages shall submit all operating data for the prior season with a minimum of 30 consecutive days to have their capacity registered with MISO.

Resources with less than 30 days of metered values would receive the seasonal class average for its Initial Planning Year. The seasonal class average for a new solar resource for summer, fall, and spring is 50% and 5% for winter. Refer to Appendix V for additional examples and determination of Convertible SAC using the Deliverability Adjusted Capacity Factor.

#### 4.2.1.6. Run-of-River Hydro Capacity Credit

Run-of-River hydro will have their SAC values determined based on the median hourly integrated net output from the three most recent consecutive years for each month for the applicable season, for a total of 9 months considered for each seasonal lookback period, of hourly net output (in MW) during critical hours, where the critical hours are hours ending 15, 16, and 17 EST for the spring, summer, and fall seasons, and hours ending 8, 9, 19, and 20 EST for the winter season up to the most recent 15 years data in each specific season. Market Participants will need to supply this historical data to MISO by October 31 of each year to have their SAC values determined for the upcoming Planning Year. Market Participants will use the template found on the MISO website (Planning > Resource Adequacy (Module E) > Planning Resource Auction) to submit historical output data.

If 15 years of historic data is not available for this period when the 15-year time period is chosen, or is no longer relevant due to environmental, operational, regulatory, or other restrictions, all available relevant data shall be used and accumulated until the 15-year requirement is met.

Resources with less than 30 days of metered values would receive the appropriate class average capacity credit for its Initial Planning Year. Refer to Appendix V for additional examples and determination of Convertible SAC using the Deliverability Adjusted Capacity Factor.

The number of years and methodology used by a Market Participant and submitted as GVTC requirements will be the same number of years submitted in future GVTC data collection.

#### 4.2.1.7. Other Intermittent Generation and Dispatchable Intermittent Resources

All other Intermittent Generation and Dispatchable Intermittent Resources (e.g. biomass) will have their SAC values determined based on the three (3) year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent spring, summer and fall and hours ending

8, 9, 19 and 20 EST for the most recent winter season. . Market Participants will need to supply this historical data to MISO by October 31 of each year to have their SAC values determined.

Intermittent Generation and Dispatchable Intermittent Resources that are new, upgraded or returning from extended outages and that do not have 30 consecutive days of operation data will have their SAC values determined based on class-average capacity credit. After 30 consecutive days of operation, actual unit performance will be used for calculating their SAC values. An example of a qualified extended outage is a resource that does not have a transmission path due to a planned or forced transmission outage.

Resources that experience changing characteristics during the historical period due to changing nameplate capability will have the historical data adjusted by a ratio of the current nameplate rating divided by the nameplate rating in effect at the time the data was collected. For resources that experience partial outages not related to the supply of fuel (e.g., water conditions), regular maintenance, or shutdowns due to safety concerns (e.g., high water), the historical data may be prorated upward to reflect the expected value as if all units had been online. For units that experience reduced output due to reasons outside of management control data from these periods may be excluded from the calculation of SAC . MISO will consider reasons outside management control based on the OMC codes entered in GADS for resources that report data. The SAC will be the three-year average output value after the adjustments as described above have been made.

An increase in unit capability for Intermittent Generation and Dispatchable Intermittent Resources that are solely powered by wind after the SAC values have been established will require written notification from the Market Participant to a member of the Resource Adequacy Team to update the values. This notification is due by March 1st prior to the Planning Year.

SAC options for units with derates prior to the GVTC test date are further explained in Appendix J.4.

### 4.2.2. Use Limited Resources

#### 4.2.2.1. Use Limited Resources – Qualification Requirements

Use Limited Resources are defined as Generation Resources or External Resource(s), that due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or for other non-economic reasons, are unable to operate continuously, but are able to operate for a minimum set of consecutive operating Hours. A Capacity Resource may be defined as a Use Limited Resource if it:

- Is capable of providing the Energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across MISO's peak;
- Notifies MISO of any outage (including partial outages) and the expected return date from the outage;
- Demonstrates GVTC and submits the results to MISO;
- Is a dispatchable resource(s) in which the unit(s) have physical limitations;
- Identifies the resource as use limited when registering the asset, subject to MISO approval.
    - MISO will review the conditions of the asset or PPA to determine if the resource qualifies as a Use Limited Resource.

Use Limited Resources are a subclass of Generation Resource and may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1.

- MISO may qualify a resource classified as a Diversity Contract as a Use Limited Resource seasonally provided the resource meets all of the requirements of both an External and Use Limited Resource.
- Use Limited Resources must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1. See Appendix J for additional details.
- Use Limited Resources with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5.

#### 4.2.2.2. Use Limited Resources – SAC Determination

The SAC values for a Use Limited Resource are based on an evaluation of the type and volume of interconnection service, GVTC value and $XEFOR_d$ value of such Use Limited Resource as described in Appendix H.

In addition, a Use Limited Resource with contract provisions that prevent the resource from meeting its Must Offer requirement will have a decrease in the SAC calculation to the extent that the contract provisions are less than the required Must Offer requirement of 4 hours across the peak for each day during the Planning Year. Use Limited Resources unable to meet the Must Offer requirements will have their SAC prorated relative to the percentage of hours meeting the Must Offer requirement relative to the must offer hours for the season.

### 4.2.3. External Resources

MPs may register an External Resource by providing the information listed below to MISO to qualify such resources as Capacity Resources. External Resources are registered through the MECT tool for the upcoming Planning Year. An MP that owns External Resources or contracts for an External Resource via a power purchase agreement (PPA) may register its External Resources. An MP shall notify MISO if the External Resource being registered is an Intermittent Generation or Use Limited Resource. External Resources that are also Use Limited Resources must meet all requirements in section 4.2.4 and be approved by MISO.

An MP will submit the completed applicable registration form for existing resources via the MECT by February 1st prior to the Planning Year. New External Resource registrations or existing registrations with increased capacity are to be completed in the MECT by March 1st prior to the Planning Year. Existing registrations with increased capacity are still required to submit the original GVTC by October 31st prior to the Planning Year. The registration form will require the MP to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resources are not being registered by another party. MISO will notify the MP within 15 days after a completed registration form is received regarding accreditation of the External Resource. MISO will review the External Resource registration form for completeness and accuracy, and will notify the MP when it is determined whether or not the External Resource has been accredited, or whether there are any deficiencies.

#### 4.2.3.1. External Balancing Authority Qualification Options

MISO's objective is to ensure that the resources it relies on for its reserve calculations, including External Resources, will, in fact, be available if called upon in a MISO-declared Emergency. In order to do this, MISO has established host/external Balancing Authority qualification criteria. These criteria apply to Balancing Authorities that impact energy schedules associated with potentially qualifying External Resources. The Balancing Authority qualification criteria ensure that energy schedules corresponding to the qualifying External Resource will only be interrupted in a manner that provides consistency, transparency, and reliability in meriting the objective stated above.

A PPA executed or external resource owned prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA or ownership of the resource if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011 A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011 between June 1st and September 30th.

Resources or PPAs that are being submitted to MISO for qualification as an External Resources must have their corresponding energy schedules flow through host/external Balancing Authorities that comply with one of the three options outlined below to qualify.

**A. Scheduled Interruption is Linked to Performance of a Specific Generator in the External Balancing Authority.**

In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced or plannedoutage.

This type of External Resource would be treated similarly to internal generation because those internal resources constitute Capacity Resources, even when they can be interrupted for forced or planned outages. The key to this provision is that the generator delivering the energy in support of the PPA can be specifically identified.

**B. Slice-of-System Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures.**

PPA or external resource fleets in this category will qualify as Planning Resources so long as the associated capacity schedule only will be curtailed pro-rata along with load in the source Balancing Authority and only when the source Balancing Authority is operating under Emergency Procedures.

Under this situation, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

**C. Slice-of-System in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority.**

In addition to the slice-of-system treatment noted in category (B), above, slice-of-system PPA or external resource fleet can qualify as External Resources under this category, and MISO and the external Balancing Authority will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met. This qualification category has several requirements for the host Balancing Authority:

1. It must be in MISO's Reliability Coordination Area
2. It must share Operating Reserves with the MISO Balancing Authority
3. It must have a Seams Operating Agreement with MISO containing several features. The Seams Operating Agreement must:
    a. Ensure that the host Balancing Authority has established planning reserve processes and criteria similar to MISO's
    b. Specify the actions that will be taken by both entities – MISO and the host Balancing Authority – during Emergency Procedures prior to implementing Load Shedding
    c. Specify that the host Balancing Authority will submit load estimates to MISO in a similar manner as submitted by other Load entities under Module E-1, provide generator testing data for all resources used to serve firm requirements of the host Balancing Authority, and provide transparency to such resource plans in the form of a Fixed Resource Adequacy Plan, pursuant to Module E-1.

With these requirements in place, when both Balancing Authorities have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

For example, if the load of an external Balancing Authority in capacity emergency is 3,000 MW, and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

### 4.2.3.2. External Resources - Qualification Requirements

The following information will be required to register an External Resource:

- Demonstrates that there is firm Transmission Service from the External Resource to the border of MISO's Region, and that;
- Firm Transmission Service has been obtained within MISO to deliver the Capacity Resource MWs seeking to be qualified from the External Resource(s) to the CPNode within MISO. The CPNode will be interpreted as the Local Balancing Authority (LBA) that MISO's OASIS reservation sinks in for Network Customers, or either;
    - The External Resource has Network Resource Interconnection Service under Attachment X
    - The External Resource was accepted by the Transmission Provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that Transmission Owner's integration date
- External Resources may procure Firm transmission service (or utilize a GFA) to meet the deliverability requirements.
    - Firm Transmission Service must either be Firm Point to Point (PTP) Transmission Service (TSR) or Firm Network Integration Transmission Service (NITS) Scheduling Rights (SR).
        - NITS SRs should reference the OASIS NITS Application number and Resource Name of the Scheduling Right.
    - Firm transmission service(PTP TSR or NITS SR) must cover the entire applicable Season within the Planning Year in aggregate and be submitted in the MECT.
- Demonstrates that any External Resources or portions of External Resources being registered as Capacity Resources to serve the Load of the LSE are not otherwise being used as capacity resources in any other RTO/ISO or in another state resource adequacy program; is available in the event of an Emergency; and performs an annual GVTC test and reports data via GADS.
- External Resources that have been retired prior to the Planning Year will not qualify as a Planning Resource.
- If External Resources used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.

- External Resources greater than or equal to 10 MW based on GVTC must submit generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal. This 10 MW threshold applies to individual generator sizes and not to contracted capacity values in PPAs nor does it apply to Intermittent Resources or Intermittent Generation.
- External Resources less than 10 MW based upon GVTC that begin reporting GADS data must continue to report such information.
- Border External Resources and Coordinating Owner External Resources will be modeled, for LOLE and PRA purposes, in the LRZ where their firm transmission service crosses the MISO border. All remaining External Resources will be modeled in an External Resource Zone based on their associated External Balancing Authority.
- A PPA must be valid for the entire Season if being used as a Planning Resource. PPAs that do not cover the entire Season will not qualify as a Planning Resource. If an amended PPA or interim operating plan exists for the Season in which the MP seeks capacity credit, this will be used in calculating the capacity value provided the PPA or interim operating plan contains a capacity amount.
- For a PPA to qualify as a Capacity Resource, it must demonstrate that it complies with the requirements found in Section 69A.3.1.c of the Tariff.
- External Resources that are in service and registering as a Planning Resource for the first time must submit GVTC, and if greater than or equal to 10 MW based on GVTC must submit GADS prior to being approved as a Capacity Resource.
- The seasonal $XEFOR_d$ for new External Resources in service less than one full season will be the class average seasonal EFORd for the resource type. An External Resource will use the class average value until 3 consecutive seasonal months of data is available and a new Planning Year has occurred.
- All External Resources being used as a Planning Resource are required to perform a real power test according to MISO's Generator Test Requirements and submit the GVTC data to MISO's PowerGADS no later than October 31$^{st}$ to qualify as a Planning Resource. The test shall be performed between September 1 and August 31 of the prior Planning Year and corrected to the average temperature of the date and times of MISO's coincident seasonal peaks, measured at or near the generator's location, for the last 5 years, or provide past operational data that meets these requirements to determine its GVTC and submit its GVTC data to MISO's PowerGADS.

External Resources undergoing gas conversion are not required to submit GVTC prior to returning. Changes in performance will be reflected in the resource's rolling XEFORd.

**When to Perform and Submit a Generation Verification Test Capacity (GVTC)**

- External Resources that qualified as Planning Resources for the current Planning Year shall submit their GVTC data no later than October 31st in order to qualify as a Planning Resource for the upcoming Planning Year. GVTC can be met by a real power test or past operational data must be provided during the test period between September 1st and August 31st prior to the upcoming Planning Year.
- A real power test is required to demonstrate a modification that increases the rated capacity of a unit, and then submit the revised GVTC to MISO by March 1st. The initial GVTC should be submitted by October 31st prior to the Planning Year.
- A real power test is required when returning from a suspended state and the results of the GVTC should be submitted to MISO via the PowerGADS system.
- A real power test is required when any unit returns to MISO after an absence (including but not limited to, catastrophic events, or not qualified as a Planning Resource under Module E-1) or being qualified as a Planning Resource for the first time, and must be submitted to MISO no later than March 1st prior to the Planning Year.
- The GVTC for a new External Resource is due before a Market Participant registers the new External Resource in the MECT and must be submitted by March 1st prior to the upcoming Planning Year.
- See Appendix J of this BPM for links to MISO's GVTC Manual and processes.
- External Resources with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5.
- Reporting is accomplished through MISO's PowerGADS reporting system as described in MISO's Capacity Verification Manual, which is located on MISO's Resource Adequacy webpage.

#### 4.2.3.3. Submission of new External Resource Registrations

A Market Participant must register their new External Resource via the Registration screen in the MECT by March 1st prior to the Planning Year. To guarantee new Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. The registering entity must be a Market Participant prior to registering an External Resource. Any entity that is not a Market Participant, but desires to register an External Resource, must contact the Client Services and Readiness team at register@misoenergy.org to become a Market Participant. The information registered in the Registration screen will require the Market Participant to certify that the registration information is accurate, complete, and that the qualified MWs from the External Resource are not being registered by another party or used in another Balancing Area for capacity purposes. Appendix F contains the information that must be submitted by an MP through the MECT External Resource registration screen. MISO will review the External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for External Resources. MISO will notify the Market Participant within 15 days after the registration form was submitted as to whether the resource has been accredited as an External Resource, or whether there are any deficiencies that must be corrected. If the resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT for use by the MP.

#### 4.2.3.4. Termination of Resources Accredited as External Resources

Because External Resources need to be accredited annually, the “Effective Stop Date” will default to the last day of the applicable Planning Year.

#### 4.2.3.5. Amendments to Accredited External Resource Registration Data

The Market Participant can amend the registration for an External Resource for an upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the deadline.

If a Market Participant needs to modify any of the non-end date information submitted in the registration, which may affect the External Resource’s qualification, including, but not limited to, a change in operation or either an increase or decrease in its MW capability, then the Market Participant shall amend registration information in the Registration screen by March 1st prior to a Planning Year in order for MISO to determine whether the resource still qualifies as an External Resource.

#### 4.2.3.6. Renewal of External Resource for Subsequent Planning Years

Each External Resource must be reviewed for accreditation as an External Resource on an annual basis. Renewal of External Resources must be requested by February 1st prior to the Planning Year. MISO will review the renewed External Resource registration information for completeness and accuracy and ensure it complies with the qualification requirements for an External Resource. MISO will endeavor to notify the Market Participant within 15 days after the renewed registration form was submitted whether the External Resource has been accredited as an External Resource, or whether there are any deficiencies that must be corrected. If the External Resource is accredited as an External Resource, it will be given a unique name for tracking purposes and made available in the MECT for use by the MP during the applicable Planning Year.

#### 4.2.3.7. Review of Power Purchase Agreements

Market Participants that have entered into power purchase agreement(s) for future Planning Years may request MISO to review the pertinent provisions of the agreements in order to make a preliminary determination of whether the agreement(s) would qualify as External Resources from power purchase agreement(s) as set forth in sections 69A.3.1.c.(i) through 69A.3.1.c.(v) of the Tariff. PPAs meeting these requirements are considered “conforming”. Market Participants must submit a written request for review of such power purchase agreements to the MISO Manager of Resource Adequacy.

MISO Resource Adequacy and Legal staff will review the submitted agreement(s) and respond within 60 days of receipt of the request. MISO will provide written confirmation as to whether the contract meets the current Tariff requirements. Any such determination is based upon the existing version of the Tariff, which may be modified from time to time subject to the acceptance of such modifications by the Federal Energy Regulatory Commission. The Market Participant requesting an advanced review of their agreements will need to follow the procedures applicable to the planning period for which such External Resource is intended to be relied upon to meet Capacity requirements. This includes the provision of the appropriate GVTC and GADS data and other requirements then in effect for registering an External Resource as set forth in the Tariff and in Section 4.2.5 to have the External Resource modeled in the MECT and qualified as a Capacity Resource. Any subsequent modifications to the PPA will be subject to a new confirmation determined by MISO regarding the portion of the term

PPAs that do not meet the requirements of Section 69A.3.1.c (i) through (v) of the Tariff are considered “non-conforming” and must provide MISO with all the following information in order to qualify as a Capacity Resource:

a) The PPA was executed prior to October 20, 2008;
b) NERC regional entity has accredited the PPA to satisfy resource adequacy requirement provisions;
c) The PPA has provided reliable capacity to the Transmission Provider Region;
d) The supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)’ portfolio of generation assets;
e) Energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions;

f) Either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5;
g) The physical resource(s) backing the PPA are identified by the supplier of the PPA;
h) The portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the MISO Region or as capacity resources in any other region; and
i) If the PPA is renewed, the PPA will be modified to comply with the terms of Section 69A.3.1.c (i) through (v) and (vii).

#### 4.2.3.8. External Resources – SAC Determination

The Seasonal Accredited Capacity (SAC) for External Resources will be accredited based on seasonal GVTC value(s), seasonal transmission service, and seasonal $XEFOR_d$ values of such External Resources based on the methodology documented in Appendix H. MISO will determine SAC values for External Resources that are Intermittent Generation as described in Section 4.2.3. External Resources, from PPAs, with varying monthly Capacity values will be credited with the lowest monthly Capacity value of the contract, unless the resource(s) supporting the PPA can be considered as intermittent generation.

#### 4.2.3.9. Dually Connected Border External Resources

Border External Resources can have interconnection facilities which connect to multiple LRZs. In those instances, these resources would be modeled in a single Zone with which the resource has the greatest connectivity. Connectivity is measured using shift factor analysis that evaluates the generator's impact on flows on the Transmission System. The analysis is performed on the latest models and input files used in support for the upcoming PRA. The study model is created by ramping the resource up and sinking the output to the MISO footprint. Line loadings in the connected LRZs is compared with those of the base model to determine the impact of the unit. The study will include consideration of tie line flow, impact on historical constraints, and impacts on the connected LRZs as a whole. Results of the analysis will be posted on MISO's website prior to the Planning Resource Auction. Details regarding the resource's impact on individual transmission lines will not be published.

#### 4.2.3.10. SAC Determination – Fixed Capacity PPA

Market Participants may register External Resources where the supplier has guaranteed delivery of a fixed MW value of capacity. This type of PPA will specify that the supplier will self-supply planning reserves to ensure guaranteed delivery of capacity. Market Participants should contact the MISO Capacity Market Administration team for review of these types of contracts. Subsequent approval of such contracts by MISO results in an accreditation of XEFORd and the SAC will be set equal to the ICAP of the External Resource registered.

#### 4.2.3.11. SAC Determination – Full Requirements PPA

Market Participants may register External Resources to model a full requirements power purchase agreement with a counterparty. This results in the ICAP of the External Resource being increased for the Planning Reserve Margin, applicable Transmission Losses, and the Forced Outage rating. This adjusted ICAP will be used in the External Resource's SAC and Must Offer calculations beginning with the 2023-2024 Planning Year. Market Participants should contact the MISO Capacity Market Administration team for review of these types of contracts.

$$ICAP_{Adjusted} = \sum_{GADS\ Resources} \left( \frac{ICAP_i \ x \ (1 + PRM_{LRZ}) \ x \ (1 + TL_{LBA})}{(1 - \ XEFORd_i)} \right)$$

Where:
$ICAP_{adjusted}$: PPA Pct. x Resource ICAP or amount owned by MP
$XEFORd_i$: XEFORd of selected GADS resource
$PRM_{LRZ}$: Planning Reserve Margin Requirement for the Local Resource Zone that the External Resource will be serving Load in.
$TL_{LBA}$: Transmission Losses for the LBA that the External Resource will be serving load in.

### 4.2.4. DRR Type I and Type II – Qualification Requirements

Demand Response Resources (DRR) Type I and Type II may qualify as Capacity Resources provided that the following criteria are met. (All references to generation availability and testing in this section pertain to DRRs backed by generation.):

- DRR Type I and Type II backed by behind the meter generation (that are not Intermittent Generation and Dispatchable Intermittent Resources) must submit generator availability data (including, but not limited to, NERC GADS) into the PowerGADS tool through the Market Portal.

- DRR Type I and Type II must demonstrate seasonal capability on an annual basis. Verification of DRR Type I and Type II capability will be in accordance with the guidelines established by the applicable Regional Entity, unless superseded by specific verification guidelines set by the applicable state authorities.
- DRRs may qualify as Capacity Resources if they meet the same qualification requirements in Sec. 4.2.1.1.
- DRRs must demonstrate seasonal corrected GVTC on an annual basis as described in Sec. 4.2.1.1. See Appendix J for additional details.
- DRRs with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5.

#### 4.2.4.1. DRR Type I and Type II – SAC Determination

MISO will determine the SAC value for each Demand Response Resources backed by behind the meter generation based on an evaluation of GVTC value and $XEFOR_d$ values of such generator. If such behind the meter generation facility is interconnected to the Transmission System, MISO will consider the type and volume of the interconnection service when determining the Unforced Capacity. If GADS data is not required to be submitted by the MP, then a class average $EFOR_d$ of the resource type will be used to calculate the forced outage rate (XEFORd) for the resource.

A $XEFOR_d$ value of zero will be applied to all DRR that interrupts or controls load but is not backed by behind the meter generation.

SAC MW options for units with derates prior to the GVTC test date is further explained in Appendix J.4.

### 4.2.5. Load Modifying Resource Obligations and Penalties

Load Modifying Resources (LMRs) consist of Demand Resources (DR) and Behind the Meter Generation (BTMG). A Demand Resource shall mean a resource registered with MISO defined as Interruptible Load or Direct Load Control Management and other resources that result in additional and verifiable reductions in end-use customer demand during an Emergency.

Behind the Meter Generation is defined as a generation resource used to serve wholesale or retail load that is located behind a load CPNode. BTMG is not included in MISO's Setpoint Instructions. An LMR that exclusively relies only on a generator to accomplish the load reduction and remains synchronously connected to the grid, or injects onto the grid, must register as a BTMG. In scenarios where LMRs represent an interruptible program that disconnects the load from the grid and activates a local backup generator to provide power on an asynchronous island, independent from the grid, a DR registration may be used.

BTMG and DR requirements to qualify as an LMR are covered in Sections 4.2.8 and 4.2.9 of this BPM.

LMRs differ from Capacity Resources in that they do not have a must offer requirement, however, they must be available for use with MISO as defined in this BPM during Emergency events (including capacity and transmission events) declared by MISO unless unavailable because of maintenance, Force Majeure or other reasons outlined in this BPM. LMRs communicate to MISO their availability through the Demand Side Response Interface (DSRI). MPs with LMR assets must provide updates to availability specific to each LMR that is listed in the DSRI. The DSRI is populated with the monthly availability data provided at the time of the LMR registration. If the LMR only partially clears the PRA, MISO will grant an opportunity to adjust the monthly MW values to account for the cleared LMR ZRCs. It is critical that LMR availability be current at all times as the Scheduling Instructions (dispatch directives) and ultimately performance and availability review will utilize the information in the DSRI at the time the Scheduling Instruction is issued and how the Market Participant responds to the Scheduling Instruction. If the LMR is on any type of derate, outage or otherwise not available, the LMR availability should be adjusted by decrementing LMR availability in the DSRI by reducing the “MWs available for MISO” for the affected LMR. The following are two examples of a 40MW BTMG LMR derated by 25MWs, and a 25MW DR LMR derated by the full 25MWs and is completely in outage:

^ 40MW BTMG LMR derated by 25MWs — 08/23/2022 11:48 EST (LAST UPDATED) — MISO Test User (UPDATED BY) — ALTE (LBA) — Central Region (MISO REGION)

COPY PREVIOUS DAY

| Hours (EST) | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Notification Timeframe | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 |
| MWs Available for MISO | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Self Scheduled MWs | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| Run Hours | 6 |
|---|---|

SAVE

^ 25MW DR LMR derated by the full 25MWs — 08/23/2022 12:02 EST (LAST UPDATED) — MISO Test User (UPDATED BY) — WEC (LBA) — Central Region (MISO REGION)

COPY PREVIOUS DAY

| Hours (EST) | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Notification Timeframe | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 |
| MWs Available for MISO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Self Scheduled MWs | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| Run Hours | 4 |
|---|---|

SAVE

If a BTMG is scheduled to be deployed by the MP, the “Self Scheduled MWs” section in the DSRI should be increased for LMR MWs that are scheduled to be deployed and the “MWs available for MISO” amount should be reduced to reflect the remaining MWs available for additional MISO deployment. If a DR is scheduled to be deployed by the MP, or it simply has reduced load for the end-use at the facility then the “Self Scheduled MWs” section in the DSRI should be increased for LMR MWs that are scheduled to be deployed or has been already reduced and the “MWs available for MISO” amount should be reduced to reflect the remaining MWs available for additional MISO deployment. Derates and outages that occur where load is not reduced should not be entered as “MWs available for MISO” or “Self-Scheduled MWs”. The following are two examples of a 40MW BTMG LMR coming online for a test between 0600 – 2100, and a 25MW DR LMR available for only 5MWs for MISO because there is reduced load at the facility:

^ 40MW BTMG LMR testing 0600-2100 — 08/23/2022 12:16 EST (LAST UPDATED) — MISO Test User (UPDATED BY) — ALTE (LBA) — Central Region (MISO REGION)

COPY PREVIOUS DAY

| Hours (EST) | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Notification Timeframe | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 | 05:00 |
| MWs Available for MISO | 40.0 | 40.0 | 40.0 | 40.0 | 40.0 | 40.0 | 35.0 | 35.0 | 35.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 20.0 | 20.0 | 30.0 | 30.0 | 35.0 | 35.0 | 40.0 | 40.0 | 40.0 |
| Self Scheduled MWs | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 5.0 | 5.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 20.0 | 20.0 | 10.0 | 10.0 | 5.0 | 5.0 | 0.0 | 0.0 | 0.0 |

| Run Hours | 6 |
|---|---|

SAVE

^ 25MW DR LMR available for only 5MWs (With 20MWs of reduced load not related to an outage) — 08/23/2022 12:17 EST (LAST UPDATED) — MISO Test User (UPDATED BY) — WEC (LBA) — Central Region (MISO REGION)

COPY PREVIOUS DAY

| Hours (EST) | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Notification Timeframe | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 | 02:30 |
| MWs Available for MISO | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| Self Scheduled MWs | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |

| Run Hours | 4 |
|---|---|

SAVE

For specifics on DSRI functionality, please see the MP LMR Users Guide located in the Learning Center.

If an Emergency is declared by MISO that requires LMR deployment, MISO will issue Scheduling Instructions in the DSRI using the LMR availability information (“MWs available for MISO” and “Self Scheduled MWs”) provided by MPs. Self Scheduled MWs are included in a Scheduling Instruction to ensure that the MW deployed voluntarily by a MP continue to be deployed if required during an Emergency. The LBA and the MP will receive a notification of the Scheduling Instructions via an MISO Communications System (MCS) message. Market Participants with LMRs must have personnel operating on a 24x7 basis that are capable of receiving and responding to MCS messages. The MP will need to acknowledge receipt of the Scheduling Instruction and update the remaining availability, if any, of the LMR(s) being used to meet the Scheduling Instruction in DSRI/MCS to reflect the MW amount available in the specified time(s). This update and acknowledgement should be done within one (1) hour of receiving the Scheduling Instruction from MISO. Also, before the Emergency deployment, the MP that registered the LMR(s) should submit the specific designation of LMRs and associated MWs used to meet the total MWs contained in the Scheduling Instruction via the Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI.

MPs that report LMR availability (including self-scheduled MWs) in the DSRI that is less than the performance obligation based on the MW value that is being used to meet RAR, may be requested to provide documentation and/or metering data to MISO for the dates and hours that MISO declared an Emergency. Meter data for the LMRs used to meet the MWs requested in the Scheduling Instruction should be uploaded in the Demand Response Tool within 53 days of the Emergency event or as requested by MISO.

MISO will not violate registration parameters (e.g., notification time) and real time availability updates provided by MPs when issuing a Scheduling Instruction. MISO does, however, rely on real time availability updates provided by MPs when issuing a Scheduling Instruction.

#### 4.2.5.1. LMRs with Dual Registration

LMRs have the opportunity to register in the energy market as Emergency Demand Resources and Demand Response Resources.

LMRs that have some capability registered as Emergency Demand Response (EDR) or Demand Response Resource (DRR) should adjust their availability in DSRI to reflect net LMR MWs available to MISO (e.g. decrement total LMR capability by EDR offer amount and DRR cleared Day Ahead or pending Real Time offer). It is the responsibility of the Market Participant to ensure no double counting of MWs offered across the dual registration types. Double counted MWs may be subject to underperformance penalties.

#### 4.2.1.5.3 LMRs Also Registered as Demand Response Resource (DRR)

DRR Type I and Type II that have converted SAC to ZRCs which were used to meet seasonal Resource Adequacy Requirements (RAR) are categorized as Capacity Resources under Module E-1 (Section 69A.3.1.b) and therefore are not LMRs. However, a DRR that does not convert all its associated SAC may also register the remaining SAC of the resource as an LMR. In this case, the UCAP converted and used to meet RAR under the LMR designation would follow the respective LMR requirements and likewise the DRR SAC if converted and used to meet RAR would carry the must offer requirement. The combined SAC converted to ZRCs between the DRR designation and the LMR designation cannot exceed the assigned SAC value of the singular resource.

#### 4.2.1.5.4 LMRs Also Registered as an Emergency Demand Resource (EDR)

A resource may qualify as an Emergency Demand Response (EDR) under Schedule 30 to participate in the energy market regardless of whether it qualifies as an LMR under Module E-1. An LMR may also dually register and qualify as an EDR. In the case of a dual LMR / EDR registration, the resource may be dispatched as an EDR when there is a pending EDR offer (EDR offers are made daily). If the resource is not dispatched as an EDR, it maintains its LMR obligations, and its performance will be evaluated as such. Being dual registered requires the resource to meet the most stringent of the two designations' requirements. Also, the tolerance band allowed for an EDR does not apply when dual registered. MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff.

For more information regarding the dual registration of LMRs as EDRs, please see Section 6.4 of BPM-026 Demand Response.

#### 4.2.7.2. LMR Performance Obligations

The registered capacity of accredited LMRs that has been converted to ZRCs and has cleared in the PRA must be available as outlined above for use in the event of an Emergency declared by MISO. MISO will populate LMR Availability in the DSRI with the monthly availability submitted for the LMR at the time of registration as the default values. MPs should keep these values up to date to ensure the availability is accurate as Scheduling Instructions will be based on the LMR Availability in the DSRI. The Available MWs for MISO should be consistent with the availability indicated in the LMR's registration. A Market Participant utilizing LMRs to meet Resource Adequacy Requirements will be subject to the penalties described in Section 69A.3.9 of the Tariff if the LMR is included in the Market Participant's response to Scheduling Instructions and the LMR fails to respond.

A Demand Resource (DR) must respond with an amount greater than or equal to the target level of load reduction or reduce demand to at or below the registered firm service level. A BTMG must provide the target level of generation increase as indicated on the Market Participant's Resource Deployment tab of the LMR Scheduling Instruction Event in the DSRI when responding to Scheduling Instructions Combined, the Market Participant's DR and BTMG responses must meet the total MWs contained in their Scheduling Instruction.

This "target" level MW is indicated by the MP via the DSRI's Resource Deployment tab of the LMR Scheduling Instruction Event which outlines which LMRs were utilized and the associated MW levels to meet the total MWs contained in the Market Participant's Scheduling Instruction. An LSE shall be assessed the costs that were otherwise incurred to replace the energy deficiency at the time the LMR was dispatched.

MISO will not assign LMR penalties to Emergency Demand Response (EDR) resources that have already been assessed penalties under Schedule 30 of the Tariff. LMR values entered in the DSRI availability will also be considered when evaluating whether target levels of generation increase or Load reduction have been met. For more information regarding the performance assessment of an LMR, please see BPM-026 Section 6.2.

The operators of LMRs that improperly report to MISO that an LMR is unavailable in the DSRI prior to receiving a Scheduling Instruction or the LMR does not respond when included in a Market Participant's response to Scheduling Instructions will have an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. A penalty will not be assessed for any portion of the target level of Load reduction for a DR, or target level of generation increase for a BTMG, which had already been accomplished for other reasons (*i.e.*, for economic considerations, self-scheduling at or above the amount of BTMG committed in a Planning Resource Auction, or local reliability concerns) and properly reflected in the hourly availability in the DSRI for each resource. Likewise, for certain LMRs that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the target level of Load reduction or target level of generation increase may be adjusted and the hourly availability in the DSRI should be updated to properly reflect the anticipated capability of the resource.

#### 4.2.6. BTMG Qualification Requirements

MPs with BTMGs can qualify as LMRs by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Intermittent BTMG (e.g., solar, wind, run-of-river hydro, etc.) are exempt from submitting the additional documentation for monthly availability and notification time as they are not dispatched via the DSRI/MCS.
- Confirming through the registration process such BTMG can be available to provide energy with no more than 12 Hours advance notice from MISO or the LBA and sustain energy production for a minimum of four (4) consecutive Hours for 5 emergency events.

- Confirming through the registration process that the BTMG is capable of being interrupted and available at least the first (5) times as needed during the Summer and Winter and at least the first (3) times as needed during the Spring and Fall by MISO or the LBA for emergency event purposes, consistent with the registration information of the physical capability of the BTMG.
- Confirming that the BTMG is equal to or greater than 100 kW (an aggregation of smaller resources that can produce energy may qualify in meeting this requirement if located in the same LRZ).
- Behind the Meter Generation must demonstrate GVTC on an annual basis as described in Sec. 4.2.1.1. See Appendix J for additional details.
- Behind the Meter Generation with any new or untested additional capacity are eligible for the ICAP Deferral Process as described in Sec. 4.5.
- Submitting generator availability data (including, but not limited to, NERC GADS) into a database through the Market Portal for non-intermittent BTMG greater than or equal to 10 MW based on GVTC. Non-intermittent BTMG less than 10 MW based upon GVTC that begin reporting generator availability data must continue to report such information. Behind the Meter Generation that is an intermittent resource must submit information in accordance with Section 4.2.3.
- For wind resources being registered as BTMG, the following information is required:
    - Resources with commercial operation history of metered values during at least one Season would submit metered values in MW terms for all Hours in the test period.
    - Resources with no commercial operation history of metered values during the Season would receive class average for each Season within the Initial Planning Year.
- For solar resources being registered as BTMG, the following information is required:
    - Resources with at least 30 consecutive days of metered values for that Season would submit metered values in MW terms for all hours in the test period.
    - Resources with less than 30 consecutive seasonal days of metered values would receive class average for the Seasons within the Initial Planning Year.
- For non-GADS reporting electric storage resources (including but not limited to, batteries, flywheels, compressed air, and pumped storage) being registered as BTMG, the following information is required:

    - Resources with commercial operation history of metered values during no less than 30 consecutive days in a specific season days would submit unforced availability values in MW terms for all Hours in the test period.
    - Resources with less than 30 consecutive days of metered values during the Summer would receive class average for the Initial Planning Year.
- Internal purchase power agreements (PPAs) will not be qualified by MISO.
- BTMGs that have been retired prior to the Season will not qualify as a Planning Resource.
- If BTMGs used to meet Resource Adequacy Requirements retire or suspend during the Planning Year, they must be replaced effective with their change of status date.
- A BTMG with a notification time requirement greater than 6 hours but less than or equal to 12 hours and a minimum of 10 interruptions allowed during the Planning Year will receive 50% credit as a Planning Resource for the 2022/2023 Planning Year. For the 2022/2023 Planning Year, BTMG with notification time requirements greater than 6 hours but less than or equal to 12 hours with less than 10 interruptions allowed will receive no credit. Beginning in the 2023/2024 Planning Year, a BTMG must have a notification time requirement less than or equal to 6 hours to receive credit as a Planning Resource.

#### 4.2.6.1. Submission of New BTMG Registrations

A MP will register its new BTMG via the Registration screen in the MECT by March 1st prior to the Planning Year. The registering entity must be a MP prior to registering a BTMG. In order to guarantee new Resources can be used in an LSE’s FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. An entity that is not a MP, but desires to register a BTMG, must contact the Customer Registration team at register@misoenergy.org to become a MP. During the registration process the MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the BTMG are not being registered by another party. Appendix E contains the information that must be submitted by an MP through the MECT registration screen. MISO will review the BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to notify the MP within 15 days after the registration form was submitted regarding whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

#### 4.2.6.2. Termination of BTMG Accredited as LMR

Because BTMGs need to be accredited seasonally, the “Effective Stop Date” will default to the last day of the applicable Season.

#### 4.2.6.3. Amendments to Accredited BTMG Registration Data

The Market Participant can amend the registration for a BTMG for an upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the February 1st due date.

The Market Participant may modify any of the non-end date information submitted in the registration, which may affect the BTMG’s qualification, including, but not limited to, a change in operation or has either an increase or decrease in MW capability. The Market Participant shall submit new or amended registration information in the MECT by March 1st prior to a Planning Year for MISO to determine whether the resource still qualifies as a BTMG. The Market Participant will still need to provide MISO with a GVTC by the original test date as outlined in the BPM. Any modifications in the capability of an existing BTMG must have updated test and registration information submitted to MISO via the MECT by March 1st.

*Renewal of BTMG for subsequent Planning Years*

BTMG must be reviewed for accreditation as an LMR on an annual basis. A MP can request renewal of BTMG accreditation for subsequent Planning Years through the MECT registration screens. Renewal of BTMG must be requested by February 1sr prior to the Planning Year. NOTE: BTMGs must submit GVTC and/or operational data by the October 31 deadline, per Section 4.3, in order to have SAC values determined. MISO will review the revised BTMG registration information for completeness and accuracy and ensure it complies with the qualification requirements for BTMG. MISO will endeavor to review the registration for approval within 15 days after the revised registration form was submitted to determine whether the BTMG has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the BTMG is accredited as an LMR, then it will be given a unique name for tracking purposes and be made available in the MECT screens for use by the MP during the applicable Planning Year.

#### 4.2.6.4. Behind the Meter Generation (BTMG) – SAC Determination

The SAC value for a BTMG is based on an evaluation of the applicable type and volume of interconnection service, GVTC (or historical output at peak if intermittent), line losses if not interconnected to MISO, and $XEFOR_d$ value of such BTMG.

BTMG that are intermittent resources will have their SAC determined consistent with the methodology described for similar resource fuel types as described in Section 4.2.3.2 through 4.2.3.4.

#### 4.2.6.5. BTMG Deliverability

Each BTMG must demonstrate deliverability to qualify as an LMR type Planning Resource for participation in the PRA. Majority of BTMG is interconnected at distribution level voltage; however, it is possible for BTMG to be interconnected at transmission level voltage. Additionally, MPs with BTMG must coordinate with their LSE, Distribution Provider (DP), and Transmission Owner (TO) to determine eligibility to participate in the PRA. This section will outline the roles and responsibilities of an LSE, DP, TO, and MISO for an individual BTMG to participate in the PRA including specific methodologies available to the BTMG MP to demonstrate deliverability. Responsibilities of an entity may differ depending if the Point of Interconnection is on the distribution system or transmission system and will be noted.

#### 4.2.1.5.5 Roles and Responsibilities to Determine Eligibility for PRA Participation

Additional descriptions of the role and responsibility of each entity is below. The MP owning a BTMG is responsible for providing an attestation to MISO that proper coordination has occurred with each entity.

Load Serving Entity (LSE): Collaborate with BTMG MP to establish eligibility for a BTMG to participate in the wholesale market (e.g., PRA) in accordance with the relevant state regulatory framework.

Distribution Provider (DP): Ensure reliability of distribution system and assess access to the transmission system. Typically, the DP completes an interconnection study to assess the reliability impacts on the distribution system. The DP is responsible for determining engineering studies, facility upgrades, and/or agreements required to permit access of a BTMG to the transmission system.

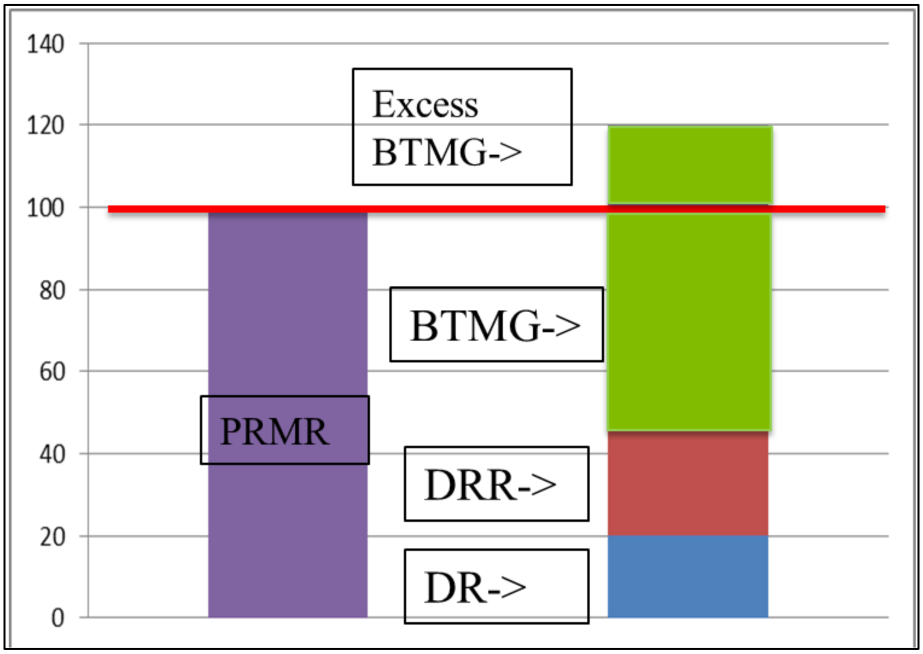
Transmission Owner (TO): Determine when the transmission system is utilized by a BTMG to serve load and coordinate with the DP and MISO on engineering and facility studies as appropriate. The TO typically ensures studies are completed, per their direction, to ensure transmission facilities (including other interconnected generators) are not impacted by an additional injection of energy from a BTMG onto the transmission system. Studies will vary depending on the specific Point of Interconnection.

MISO: Accountable for ensuring BTMG has demonstrated deliverability for use in the PRA (additional details below) and ensuring the BTMG MP has provided attestation of coordination with the LSE, DP, and TO.

#### 4.2.1.5.6 Definition of "Excess BTMG"

Deliverability of BTMG is established relative to the portfolio of total BTMG assets owned or under contract by an LSE in a singular LBA. A BTMG that utilizes the transmission system or a volume of BTMG exceeding an LSE's "net PRMR" in a singular LBA is considered "Excess BTMG" and will need to demonstrate deliverability utilizing an option described in Sec. 4.2.8.5.3. It is possible for the volume of "Excess BTMG" to be less than the SAC of a singular BTMG. In this instance, the MP is eligible to demonstrate deliverability for a portion of a generator or multiple generators. MISO will collaborate with the BTMG MP to establish the specific point of injection onto the transmission system.

The term "net PRMR" is utilized rather than PRMR because it is possible for an LSE to have a portfolio of ZRCs that include registered Demand Resources (DR) and demand backed Demand Response Resources ($DRR_{demand}$) that reduce the expected peak demand by an LSE and result in a net injection onto the transmission system. Net injection onto the transmission system is "Excess BTMG" as represented by the figure below.




#### 4.2.1.5.7 Options for BTMG to Demonstrate Deliverability

Below are the multiple options for a MP with BTMG to demonstrate deliverability:

Option 1: BTMG utilizing the distribution system to offset PRMR. BTMG used to offset an LSE's load utilizing only the distribution system is considered deliverable up to the volume of "net PRMR" of an LSE in a singular LBA. No additional studies are required.

Option 2: Firm Transmission Service. The MP of the BTMG can apply for Point to Point or Network Integration transmission service using a type of "Monthly" or "Yearly" depending on the Point of Interconnection (POI). A BTMG with a POI on the distribution system can utilize "Yearly" type Firm transmission service to facilitate a system impact study, if required. A BTMG with a POI on the transmission system can use "Monthly" or "Yearly" type of Firm transmission service since an ERIS study would have been completed. A Network Customer may designate a BTMG as a Network Resource on MISO's OASIS utilizing Firm transmission service.

Option 3: Interconnection Service of NRIS or External NRIS (E-NRIS). The MP of the BTMG can enter the Generation Interconnection Queue and apply for NRIS or E-NRIS. An MP can apply for E-NRIS with a BTMG that has a POI on the distribution system. A BTMG with a POI on the transmission system is eligible for NRIS. The BTMG would be part of a MISO Definitive Planning

Phase (DPP) study and required to submit an application and deposits as appropriate. Refer to BPM-015 Generation Interconnection for additional details.

Option 4: Historical determination of deliverability. BTMG used to offset an LSE's PRMR located in the same LBA and historically demonstrated deliverability as accepted by MISO or a Transmission Owner is considered deliverable. Individual BTMGs may have demonstrated deliverability by confirmation by a Network Customer as a designated network resource or completion of a Market Transition Deliverability test prior to an LSE joining MISO.

#### 4.2.6.6. Measurement and Verification of BTMG

See Attachment TT of the Tariff and BPM-026 Demand Response.

### 4.2.7. Demand Resource (DR) – Qualification Requirements

MPs with DR can qualify the DR as an LMR by:

- Submitting monthly availability (in megawatts) and notification time (in hours) for the upcoming Planning Year.
- Registering the reduction capability of the DR, excluding transmission losses and consistent with conditions at MISO's seasonal Coincident Peak.
- Confirming through the registration process such DR can be available to reduce Demand with no more than twelve (12) Hours advance notice from MISO or the LBA and sustain the reduction in Demand for a minimum of four (4) consecutive Hours.
- Confirming through the registration process that the total DR load reduction is not exclusively accomplished and dependent on the dispatch of a BTMG owned or operated by a wholesale or retail customer.
- Confirming through the registration process that the DR is equal to or greater than 100 kW (an aggregation of smaller resources within an LBA that can reduce Demand may qualify in meeting this requirement if they are within the same Load Zone CPNode).
- Confirming through the registration process that the DR is capable of being interrupted at least the first (5) times during the Summer and Winter and at least (3) times as needed during the Spring and Fall as needed by MISO or the LBA for Emergency purposes, consistent with the registration information of the physical capability of the DR.
- Confirming that the Market Participant has the authority to reduce demand using the DR. In the case of an ARC registering a DR, this would include uploading into the MECT registration a copy of the signatory pages between the ARC and the load asset

customers. MISO does not accept an attestation by the ARC as an artifact to demonstrate the Market Participant possesses ownership or equivalent contractual rights in a Demand Resource.

- Documenting in the MECT the DR's capability to reduce demand to a targeted Demand reduction level or firm service level at the MISO seasonal Coincident Peak. All DR owners should demonstrate demand reduction capability of at least 50% of their registered capability via Scheduling Instructions from a MISO Event or conduct a real power test for accreditation and provide a procedure document detailing the steps followed to implement the demand reduction. Additional details regarding the demonstration of demand reduction capability are in section 4.2.9.8 below. If a DR opts not to demonstrate demand reduction capability for accreditation, one of the following options may be used for accreditation:
    - Provide documentation from the state that has jurisdiction accrediting the DR program. Additionally, if not specified in the state documentation, provide documentation supporting the capacity of the DR being registered.
    - Verification from a third-party auditor that is unaffiliated with the MP that documents the DR's ability to reduce to the targeted Demand reduction level or firm service when called upon to perform by MISO or the LBA.
    - If past performance data does not exist to demonstrate demand reduction capability, then a mock test can be provided. The mock test should show:
        - The demand resource's seasonal meter data from the previous planning year. New resources can provide documentation supporting estimated seasonal demand.
        - Documentation showing a mock execution or drill of implementing the demand resource without implementing the demand reduction.
    - Accreditation documentation, including past performance data, mock test, third party audit, or state commission documentation, supporting the MW being registered should be from the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year. Renewed registrations must submit revised documentation on an annual basis for accreditation.
- If the DR opts out of demonstrating demand reduction capability via Scheduling Instruction or a real power test, then the DR will be subject to three (3) times the underperformance penalties during a MISO Emergency event. Specifically, undelivered MWs will be penalized at a rate of LMP times three (3), rather than LMP. The RSG component of the penalty will not be multiplied times three (3), nor will any

capacity penalties or lost capacity revenue. Only a DR with a regulatory restriction will be eligible to waive the penalty.

- Documenting in the MECT the Measurement and Verification (M&V) protocol that will be used to determine if such DR performed when called upon by MISO or the LBA during Emergencies. A DR that is sensitive to temperature changes must identify the extent of such temperature sensitivity with sufficient detail to enable MISO to verify whether the DR would be subject to the penalties set forth in Section 69A.3.9 of the Tariff. Temperature sensitivity must at a minimum include identifying the measure used for temperature changes and elasticity of the LSE's load to weather. An MP that registers a DR as a Planning Resource must confirm that the DR is able to meet all of the requirements in Section 69A.3.5 of the Tariff.
- DR that has been retired prior to the Planning Year will not qualify as a Planning Resource.
- If a DR used to meet Resource Adequacy Requirements obligations retires or suspends during the Planning Year for a season in which they were used for a FRAP or cleared in the PRA, the applicable Seasonal ZRCs must be replaced effective with their change of status date.
- Beginning in the 2023/2024 Planning Year, a Demand Resource must have a notification time requirement less than or equal to 6 hours to receive credit as a Planning Resource.

#### 4.2.7.1. Demand Resource Registration Process

DR can be registered to be used as a Planning Resource and receive SAC MW that can be converted to ZRCs.

**Submission of new DR Registrations**

A MP may register new DR via the Registration screen in the MECT by March 1st prior to the Planning Year. To guarantee new Planning Resources can be used in an LSE's FRAP, registrations should be submitted no later than February 15th prior to the Planning Year. The registering entity must be a MP prior to registering a DR. Any entity that is not a MP, but desires to register a DR, should contact the Customer Registration team at register@misoenergy.org to become a MP. The MP will be required to certify that the registration information is accurate, complete, and that the qualified MWs from the DR are not being registered by another party. Appendix D contains the information that must be submitted by an MP through the MECT registration screen for DR. MISO will review the DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to review the registration within 15 days after the registration was submitted to determine whether or not the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP.

**Submission of ARC LMR Registrations**

The LBA and LSE will verify the following:

- LBA name
- LSE name
- RERRA name
- CPNode name
- End use customer account number
- Meter identification number(s)
- Maximum level of participation (MWs)
- Address of the assets in the ARC registration.

The maximum level of participation for each asset within an LMR resource should be no greater than that asset's load as evaluated by the LBA or LSE.

The assets' load should be calculated as the average load of the assets up to the last three seasonal MISO system peak hours. One or two years of load data may be used if the full three years is not available.

It is the responsibility of the Market Participant to provide an explanation which demonstrates why historical average peak load is not representative of expected future peak load for an asset and propose an alternative method of calculating the maximum level of participation for review and approval by MISO and the LSE.

If during registration review the LBA or LSE is identified to be incorrect for assets in a registration, the registration will be rejected. The Market Participant can submit a new registration once the Market Participant has identified the correct LBA or LSE. This will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Any modification to the assets during the review will restart the review timeline for MISO, the LBA, the LSE, and RERRA.

Instances where the ARC LMR's customer changes LSEs:

- The LSE identified by the ARC LMR should be correct at the time of the ARC LMR's registration submitted to the Module E Capacity Tracking (MECT) tool. Otherwise, the ARC LMR Registration will be rejected.
- If the ARC LMR's LSE changes during the registration process, the ARC LMR registration can be revised. The date the registration was submitted will be sent along to the LSE for their review.
    - It is the responsibility of the ARC LMR's customers and the ARC to identify LSE changes.
    - It is the responsibility of the ARC LMR to notify MISO, the old LSE, and the new LSE when changes to the ARC LMR's customer's LSE occur.

#### 4.2.7.2. Termination of Demand Resource Accredited as LMR

Because DRs need to be accredited annually, the "Effective Stop Date" will default to the last day of the applicable Planning Year.

#### 4.2.7.3. Amendments to Accredited DR Registration Data

The Market Participant can amend the registration for a DR for an existing upcoming Planning Year by providing MISO notification no later than March 1st if the original registration was submitted by the February 1st due date.

The MP may modify any of the non-end date information submitted in the registration, which may affect the DR's qualification, including, but not limited to, a change in operation, number of interruptions, advisory notice period, maximum duration, or accreditation amount as either an increase or decrease in either its targeted MW level or firm service level. The MP shall submit registration information in the MECT registration screen by March 1st prior to the Planning Year in order for MISO to determine whether the resource still qualifies as an LMR.

#### 4.2.7.4. Renewal of DR for subsequent Planning Years

A DR must be reviewed annually for accreditation as an LMR. A MP can request renewal of DR accreditation for subsequent Planning Years through the MECT registration screens. Renewal of DR must be requested by February 1st prior to the Planning Year. MISO will review the renewed DR registration information for completeness and accuracy and ensure it complies with the qualification requirements for DR. MISO will endeavor to notify the MP within 15 days after the renewed registration form was submitted regarding whether or not the DR has been accredited as an LMR, or whether there are any deficiencies that must be corrected. If the DR is accredited as an LMR, it will be given a unique name for tracking purposes and made available in the MECT screens for use by the MP during the applicable Planning Year.

#### 4.2.7.5. Demand Resources – SAC Determination

A Demand Resource must be registered and accredited with MISO and will receive 100 percent of its capacity rating for the Planning Year. Seasonal capacity values for Demand Resources will be based on documentation from the state, third party auditor, past performance, or mock test consistent with their ability at MISO's seasonal Coincident Peak Demand. Since DR is a reduction in demand, SAC is adjusted upward by applying the MISO PRM and transmission loss percentage for the LBA to the capacity rating.

#### 4.2.7.6. Demand Resource Deliverability

The owner of ZRCs converted from DR may use them as part of a FRAP or offer them into the PRA. The DR ZRCs are considered deliverable regardless of the LRZ where the DR physically resides.

#### 4.2.7.7. Measurement and Verification of Demand Resource

See Attachment TT of the Tariff and BPM-026 Demand Response.

#### 4.2.7.8. Demand Resource – Testing Requirements

The testing period for a DR to demonstrate demand reduction capability is the calendar year (January 1 to December 31) immediately preceding the applicable Planning Year. For example, the testing period for the 2020-21 Planning Year will be January 1, 2019 to December 31, 2019. DR shall demonstrate seasonal demand reduction capability for a minimum of 1-hour duration with an attestation that the DR is capable of continuing the reduction for a minimum of 4 consecutive hours. Results should be submitted in accordance with LMR registration deadlines and attached to the LMR registration.

Test results should be adjusted to MISO seasonal Coincident Peak conditions. Adjustments shall not exceed 50% of each DR and may include, but not limited to, factors such as temperature, humidity, and/or other process load variations. Adjustments to test results should be documented and submitted with the test results to support the capacity accreditation for the DR. Adjustments to DR test results are subject to MISO review and approval during the LMR registration process.

DR are required to demonstrate performance of at least 50% of their registered seasonal capability via Scheduling Instructions from a MISO Event or conduct a real power test. If a DR is only able to demonstrate at 50% to 80% of their intended registered MW capability, an attestation from an officer of the Market Participant registering the DR, or from a financially responsible entity, must be provided to MISO during the registration process documenting the reasons for the difference between the registered capability and the demonstrated amount (i.e., industrial process, temperature, etc.). If demonstrating greater than 80% of the registered capability, the DR shall need to provide documentation supporting the adjustments made to normalize the MW capability to seasonal peak conditions.

Results may be uploaded to the accreditations section of the LMR registration and may include: (1) test results including the meter data for the entire day of the tests, (2) historical meter data for 10 days around the MISO seasonal Coincident Peak with the MISO seasonal Coincident Peak as a midpoint, to calculate the capacity baseline, and (3) any other supporting documentation necessary for the LMR capability adjustment. The templates used for submitting the requested meter data may be found on the MISO public website under Markets and Operations > Demand Response.

If a DR is unable to demonstrate performance of at least 50% of the registered MW capability of the DR [only partially performs], the DR must retest the underperforming portion(s) of the DR or create separate registrations for the portions of the DR that did not exceed the 50% performance threshold. If the DR is unable to demonstrate performance of at least 50% of the registered MW capability during the testing period, the DR may still qualify for the PRA by opting out of the testing requirement, provided that the DR will then be subject to the three (3) times penalty provisions for underperformance described in Section 4.2.9.

If a DR underperforms during a MISO Emergency event and that event is chosen by the DR owner to satisfy the testing requirement, the tested portion of the DR will equal the actual reduction achieved during the event. If a DR only partially tests, the entire DR may be registered, however, separate registrations will be required. For example, the tested portion of the DR would be one registration and the untested portion of the DR would be another registration. If a DR is made up of an aggregation of different physical locations, each location can demonstrate performance—or elect not to—separately. Tested locations may be aggregated together and untested locations may be aggregated together in registrations, as long as all locations are within the same Load Zone CP Node. Separate registrations for tested versus untested resources are required in order for MISO to accurately assess penalties for underperformance during a MISO Emergency event, as the untested DR would be subject to the three (3) times penalty, unless the untested DR is not required to test per qualification requirements in 4.2.9.

When testing a DR, accurate availability should be reflected in the DSRI by showing the DR as self-scheduled. If an MP plans to test DR greater than 20 MW, the MP should notify MISO operations two (2) Business Days prior to conducting a test by submitting the DR Testing Notification Template to the MISO ITOC (itoc@misoenergy.org). The DR Testing Notification Template should include: (1) LMR name, (2) MP, (3) Load Zone CP Node, (4) expected MW reduction, (5) expected reduction date and hour(s), (6) notification time, and (7) operator contact information in case MISO Operations has questions. New DR and DR that did not clear the PRA will not be able to update the DSRI, however, these DR should still notify MISO by utilizing the DR Testing Notification Template.

#### 4.2.9.9 Demand Response Test Deferral

The MP must provide written notification to MISO (help@misoenergy.org) of their intention to defer Demand Response testing by February 1st prior to a Seasonal auction within the upcoming Planning Year. This DR Testing Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Name
- Local Balancing Authority (LBA) or External Balancing Authority (BA) where located
- Expected DR test value (MW)
- Estimated completion date of DR test

Once the DR test is completed, information pertaining to it must be submitted via written notification to MISO (help@misoenergy.org).

A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

If the Market Participant submits the real power test results on or before the last business day of the month prior to the season the DR was used in a FRAP or cleared the auction within the

Planning Year that are equal to or greater than the expected DR test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted.

If SAC associated with a Planning Resource for which DR testing has been successfully deferred are unconverted to ZRCs, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred DR value, in which case the Transmission Provider will adjust the Market Participant's DR value and credit requirement within twenty (20) Business Days.

A Market Participant that provides a DR Test Deferral Notice and that either (1) has not submitted any real power test result for such DR by the last business day of the month prior to the season the DR was used in a FRAP or cleared the auction within the Planning Year, or (2) has submitted a real power test result by the last business day of the month prior to the season the DR was used in a FRAP or cleared the auction within the Planning Year that demonstrates fewer megawatts are available than the expected DR test value submitted in the DR Test Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency and distributed pursuant to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the DR Test Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

### 4.2.8. Energy Efficiency Resources

Energy Efficiency (EE Resource) Resources are installed measures on retail customer facilities that achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecasts used for the PRA for the Planning Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the season within the Planning Year, without any requirement of notice, dispatch, or operator intervention. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

The reduction in electric energy consumption due to existing EE programs that is reflected in the CPD forecast cannot qualify as an EE Resource. All the requirements to offer or commit an EE Resource in MISO's capacity planning market are detailed in the sections below. One of the major requirements includes the measurement and verification of the EE Resource's Nominated EE Value for season within the Planning Year. The Nominated EE Value is the expected average demand (MW) reduction, excluding transmission losses, during the defined EE Performance Hours in each season of the Planning Year. The EE Performance Hours are between the hour ending 13:00 Eastern Prevailing Time (EPT) and the hour ending 19:00 EPT during all days of the applicable season the EE Resource is seeking capacity accreditation, inclusive, of such Planning Year, that are not a weekend or federal holiday.

A Measurement & Verification (M&V) plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource and confirming that the Nominated EE Value is achieved. The EE Resource provider must submit an initial Measurement & Verification plan for the EE Resource by February 1 prior to the PRA in which the EE Resource is to be initially offered. The EE Resource provider must submit an updated Measurement & Verification plan for the EE Resource by February 1 prior to the next PRA in which the EE Resource is to be subsequently offered. Post-installation of the EE Resource, the EE Resource provider must submit an initial Post-Installation M&V Report for the EE Resource by March 1 prior to the first Planning Year that the EE Resource is committed to PRA. The EE Resource Provider must submit updated Post-Installation M&V Reports by March 1 prior to each subsequent Planning Year that the resource is committed. Failure to submit an updated Post-Installation M&V Report by March 1 prior to a subsequent Planning Year or failure to demonstrate that post-installation

M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a Nominated EE Value equal to zero MWs of seasonal ZRCs for the Planning Year.

The last Post-Installation M&V Report submitted and approved by MISO prior to the Planning Year that the EE Resource is committed will establish the Nominated EE Value that is used to measure PRA commitment compliance during the Planning Year. Details regarding seasonal PRA commitment compliance and the associated penalty for failure to deliver the unforced value of a seasonal PRA capacity commitment are detailed below.

MISO reserves the right to audit the results presented in an initial or updated Post-Installation M&V Report. The M&V Audit may be conducted at any time, including during the defined EE Performance Hours. If the M&V Audit is performed and results finalized prior to the start of a

Planning Year, the Nominated EE Value confirmed by the Audit becomes the Nominated EE Value that is used to measure seasonal PRA commitment compliance during the Planning Year. If the M&V Audit is performed and results are finalized after the start of a Planning Year, the Nominated EE Value confirmed by the M&V Audit becomes the Nominated EE Value prospectively for the remainder of that Planning Year.

Energy Efficiency installations that are installed prior to any given Planning Year are eligible to participate in seasonal PRAs or used in a FRAP for that Planning Year and three subsequent Planning Years. For example, an EE Resource installed and qualified prior to June 1, 2013, could participate in the seasonal PRAs or be used in a FRAP for 2013/14, 2014/15, 2015/16, and 2016/17 Planning Years provided the EE Resource registers and meets the qualification requirements for each Planning Year. After four years, the EE Resource could no longer be used as a Planning Resource but would continue to be included as a reduction in the demand forecast.

#### 4.2.8.1. Energy Efficiency Resource – Measurement and Verification

See Attachment UU of the Tariff.

### 4.2.9. Stored Energy Resource Type II Accreditation

A Stored Energy Resource (SER) Type II can qualify as a Capacity Resource for the Planning Resource Auction provided the resource is able to continuously discharge for a minimum of 4 hours across the expected peak hour each operating day and meet the following criteria.[1]

- A SER Type II must demonstrate seasonal capability on an annual basis. Verification of capability will be in a manner similar to a GVTC.
- A SER Type II must submit resource availability data on an annual basis in a manner similar to GADs data.

#### 4.2.11.1. SER Type II – SAC Determination

MISO will determine the SAC value for each SER Type II based upon an evaluation of its annual demonstrated capability, resource availability, and interconnection service if applicable. SER Type II resources must demonstrate deliverability prior to participating in the PRA. Deliverability will be determined by MISO depending upon the Point of Interconnection of the resource.

Like other resources, SER Type II would use a class average forced outage rate to determine a default UCAP value prior to being in service long enough to calculate a unit specific SAC rating.

[1] A non-Type II Stored Energy Resource cannot qualify as a Capacity Resource

In the absence of enough SER Type II resources to actually calculate an average FOR, a 5% FOR will be assumed until sufficient SER Type II resources exist (30 or more individual units) to come up with an average value.

### 4.2.10. Electric Storage Resource

An Electric Storage Resource (ESR) is a resource capable of receiving electric energy from the grid and storing it for later injection of energy back to the grid. The ESR includes all technologies and/or storage mediums, including but not limited to, batteries, flywheels, compressed air, and pumped storage. The location of an ESR may be at any point of grid interconnection, on either the Transmission System or a local distribution system. An ESR must:

- be capable of injecting a minimum of 0.1 MW;
- be capable of complying with MISO's Setpoint instructions;
- have the appropriate metering equipment installed; and
- be physically located within the MISO Balancing Authority Area.

#### 4.2.10.1. Electric Storage Resource - Qualification Requirements

An ESR may qualify as a Capacity Resource for the Planning Resource Auction (PRA) provided the resource is able to continuously discharge for a minimum of 4 hours across the expected peak hour each Operating Day and meets the following criteria.

- An ESR must demonstrate capability for a time period that aligns with the same PRA time period for which the ESR will be used to meet Resource Adequacy Requirements (RAR). For example:
    - If MISO employs a PRA for an annual time period, then capability must be demonstrated for the Summer peak.
    - If MISO employs seasonal based auctions, then the ESR would need to demonstrate capability during each of the seasonal auctions the ESR will be used to meet RAR.
- Verification of capability will be based on the power (MW) and the energy rating (MWh) via GVTC data submitted in the MECT.
- For an upcoming PRA, the following data for the ESR must be submitted to the MECT by October 31 using the ESR registration template: Generation Verification Test Capacity (GVTC), ESR's Power Rating (MW), and Total Net Energy Rating (MWh) from the GVTC testing (minimum of 1 hour up to 4 hours).
- An ESR must demonstrate deliverability in order to qualify as a Capacity Resource for participating in the PRA. If an ESR is interconnected to the MISO Transmission System, the Resource can either obtain Network Resource Interconnection Service

(NRIS) under Attachment X or procure Firm Transmission Service in conjunction with Energy Resource Interconnection Service (ERIS). If an ESR is interconnected to the Distribution System, the Resource will be subject to coordination with Distribution Provider, Transmission Owner, and MISO Transmission Service. For more information, see section "4.2.8.5.1 - Roles and Responsibilities to Determine Eligibility for PRA Participation."

#### 4.2.10.2. Electric Storage Resource - Installed Capacity Calculation (MW)

The Installed Capacity (MW) of ESR will be calculated as minimum of ESR's Power Rating (MW), Hourly Equivalent Discharge Amount (MW), and Total Interconnection Service (MW). The Hourly Equivalent Discharge Amount (MW) will be calculated as:

$$\frac{Total\ Net\ Energy(MWh)}{Total\ Hours\ tested}$$

where The Total Net Energy Rating (MWh) and the Total Hours tested are based on the GVTC test (see the ESR Data template for details).

#### 4.2.10.3. Reporting Historical Data

Market Participants will use MISO's non-GADS performance template, formerly known as the "Intermittent Data Template" found on the MISO website to submit the appropriate historical data for the upcoming Planning Year. The performance template can be found on the MISO website under Planning > Resource Adequacy. The performance template should be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool.

The reporting is optional if an ESR is less than 10 MW average. If the historical data is not submitted, the default FOR will be used. However, once the historical data is submitted, then the owner must continue to submit the data.

#### 4.2.10.4. ESR Capacity Accredited Value Determination

MISO will determine the capacity accredited value for each ESR based upon an evaluation of its demonstrated capability, resource availability, and interconnection service if applicable. ESRs must demonstrate deliverability prior to participating in the PRA. Deliverability will be demonstrated by the Market Participant and verified by MISO depending upon the Point of Interconnection of the resource. A class-average forced outage rate will be applied to an ESR to determine a default capacity accreditation value prior to being in service long enough to calculate a unit-specific forced outage rate. A 5% forced outage rate will be assumed until sufficient ESRs exist (30 or more individual units) to come up with an average value. Forced outage rate for an ESR with sufficient historical data is the unavailability factor calculated in the ESR template.

The capacity accredited value for an ESR is calculated as Installed Capacity * (1 – forced outage rate).

Note: Class average forced outage rate will be applied in the calculation of capacity accreditation if an ESR has less than 12 months of operational data or is less than 10 MW. Class average forced outage rate will be applied in the 1st Planning Year unless the class average forced outage rate is available. MISO will re-evaluate the class average forced outage rate value annually and modify it as needed.

### 4.2.11. Qualifying Facilities (QF)

Certain generators may be recognized as a Qualifying Facility under PURPA. MISO offers three modeling options that facilitate market participation for QF generators. Each of the options, described below, are reflected differently in the PRA. Each QF should coordinate with its LSE to determine eligibility.[2]

**Gross Modeling**: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's demand forecast submitted to MISO and generation is modeled as a Generation Resource with a CPnode. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.1.

**Hybrid Modeling**: When QF generation exceeds the associated QF load, both load and generation may be modeled as a single Generation Resource CPnode. The expected net injection onto the transmission system (e.g., QF generation – process load served by QF generation) is modeled as the GVTC. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.1.

**BTMG Modeling**: Load and generation associated with a QF are modeled separately in the PRA. Load associated with the QF would be included in the LSE's demand forecast submitted to MISO and generation is modeled as a BTMG. QF generators utilizing this option are required to meet the accreditation requirements for testing and deliverability as described in Section 4.2.8.

[2] Additional details can be found in MISO's Qualifying Facilities White Papers on the MISO website. Markets and Operations-> Markets and Operations-> Whitepapers.

### 4.2.12. Hybrid Resources

Hybrid Resources, as defined in Module A of the MISO Tariff, may register as DIR, SER Type-II or Generation Resource depending on make-up and owner/operator preferences and plans for how the unit will be operated.

For purposes of resource accreditation, Hybrid Resources will be accredited in two phases; Phase I – Sum of Parts accreditation, and Phase II – Availability-based accreditation. Phase I applies in the initial service life of a Hybrid Resource before enough operating history is available. Phase II applies once a Hybrid Resource has been in service long enough to have sufficient operating data. See Appendix X for details.

Hybrid Resources that received Surplus Interconnection Service through the Definitive Planning Phase process may be accredited for capacity. Existing portions of the unit would be accredited through the Phase II process. New portions of the unit derived from the Surplus Interconnection Service would be accredited through the Phase I process.

## 4.3. Confirmation and Conversion of SAC MW

A ZRC represents 1 MW-day of qualified Seasonal Accredited Capacity (SAC)from a Planning Resource for a specific Season of a Planning Year, tracked to the nearest tenth of a MW, pursuant to the applicable ZRC qualification procedures described herein. To create a ZRC, a MP must confirm the SAC MW and then convert SAC MW from each qualified Planning Resource to seasonal ZRCs through the MECT SAC/ZRC conversion screen. SAC confirmation and conversion should be completed prior to the opening of the PRA auction window.

When seasonal ZRCs are converted from SAC by the Asset Owner, the seasonal ZRCs are populated into the available ZRC account for that Asset Owner. MISO will keep track of how many ZRCs the MP has created, and how many remaining SAC MWs for each Planning Resource are available for conversion to ZRCs. Once created, MISO will track ZRCs back to the specific Planning Resources that they were created from to assist with establishing clearing requirements, the auction clearing process and market mitigation monitoring.

## 4.4. ZRC Transactions

### 4.4.1. Transfer of ZRCs

Available ZRCs can be transferred between MPs using the MECT. This is accomplished in the ‘ZRC Transactions’ tab in the MECT. Both the ‘Buyer’ and ‘Seller’ are required to account for a ZRC transaction in the MECT. The ’Seller’ is required to submit the transaction in the MECT and the 'Buyer' is required to confirm the transaction reported. Once the transaction has been submitted and confirmed by both parties, the ZRC transaction volumes will be subtracted from the seller's available ZRC account and added to the buyer's available ZRC account. The Market Participant that registered the Planning Resource is responsible for complying with all Tariff requirements. The MECT allows transactions based the ZRC balance in the Seller's portfolio. ZRC transactions can occur throughout the PRA auction cycle, including during the Offer window. ZRC transactions can also be utilized during the Planning Year to facilitate ZRC replacement transactions.

## 4.5 ICAP Deferral

### 4.5.1 Summary

ICAP Deferrals allow Market Participants (MPs) to participate in the Planning Resource Auction (PRA) using Zonal Resource Credits (ZRCs) that have been credited to the following:

- an untested new Planning Resource;
- an existing Planning Resource that is returning to operation from a catastrophic outage or suspension;
- an existing Planning Resource increasing its capability through increases to GVTC or Interconnection Service (IS);
- a Planning Resource awaiting other miscellaneous resource approvals to achieve commercial operation;
- an existing Planning Resource where the Market Participant's GVTC extension request was denied or the Market Participant missed the GVTC submittal deadline and failed to request an extension; or
- an existing Planning Resource that is currently in an approved "Suspend" status.

### 4.5.2 Requirements and Timeline

The MP must provide written notification to MISO (help@misoenergy.org) of its intention to defer ICAP by February 15$^{th}$ prior to the upcoming Planning Year. This ICAP Deferral Notice should state that the Planning Resource will demonstrate deliverability, demonstrate commercial operation including filing a COD Notification (Appendix E to the GIA) with MISO Resource Integration (ResourceIntegration@misoenergy.org), have Transmission Service in service, and/or perform a real power test to submit its GVTC after March 1$^{st}$, but before the last Business Day, prior to the start of the deferred season. The ICAP Deferral Notice can be found in Appendix T of this BPM. The ICAP Deferral Notice must be from an officer of the company and include the following information:

- Company Name
- NERC ID of Company
- Planning Resource Type
- Planning Resource Name/CPNode Name
- Local Resource Zone (LRZ) or External Resource Zone (ERZ) where Planning Resource is located
- Planning Resource Fuel Type
- Estimated ICAP Value in MW
- Estimated Completion Date of ICAP
- Type of ICAP being deferred
- Season(s) to be deferred
- Generator Interconnection Agreement (GIA) Number (only necessary if deferral includes upgrades to Interconnection Service)
- Expected NRIS and ERIS values
- GVTC
- Commercial Operation Date
- TSR Number
- Other ICAP Type

Once the GVTC test is completed, information pertaining to it must be submitted via written notification to MISO (help@misoenergy.org).

New resources must have (i) an executed GIA or an unexecuted GIA accepted by FERC and (ii) be registered in the June Commercial Model prior to the upcoming Planning Year at the time of the ICAP Deferral request. For modeling SAC in the PRA, it is preferred that the new resource CP Node be modeled in the March model in order to offer into the PRA accordingly.

The MP requesting the ICAP Deferral must post 90 days of credit for the ICAP value of the untested ZRCs no later than March 1st prior to the upcoming Planning Year. The credit will be based on the 90 days of daily CONE for the LRZ in which the resource is located.

MISO will adjust the Market Participant’s credit requirements within ten (10) Business Days of the full ICAP being met and has been validated by MISO or when the MP provides written notification to the Capacity Market Administration team that a Planning Resource replacement has been completed.

### 4.5.3 Uncleared ZRCs

If the untested ZRCs will not be used in a FRAP or will not be offered into the PRA, the MP that registered the resource may provide notice to by March 1 MISO that it wishes to forfeit the deferred ICAP value. MISO will recalculate the resulting Seasonal Accredited Capacity (SAC) value and will adjust the credit requirements within ten (10) Business Days after receiving the notice. Furthermore, if the untested ZRCs do not clear the PRA, MISO will release credit back to the MP that submitted the ICAP Deferral Notice.

### 4.5.4 ICAP Deferral Non-Compliance Charge

The MP that submitted the ICAP Deferral request is responsible for completing ICAP or resource replacement by the last Business Day of prior to a Seasons' start date for all deferred ZRCs that cleared in the PRA or were included as part of a FRAP. Any ICAP not completed or replaced by the last Business Day of prior to a Seasons' start date will be subject to the ICAP Deferral Non-Compliance Charge for each day the ICAP or the Planning Resource replacement is not completed.

The ICAP Deferral Non-Compliance Charge will be based on the sum of the applicable Seasonal Auction Clearing Price (ACP) and daily CONE based on the LRZ or ERZ of the Planning Resource, multiplied by the number of ZRCs that have not been replaced or tested.

The distribution of ICAP Deferral Non-Compliance Charge will be allocated pro-rata based on each LSE's share of the total seasonal Planning Reserve Margin Requirements (PRMR) in MISO.

Please refer to Appendix U for Examples of ICAP Deferrals.

# 5 Resource Adequacy Requirements

## 5.1 Overview

MISO's Resource Adequacy construct ensures that adequate Planning Resources are maintained for each Local Resource Zone (LRZ) to meet the MISO footprint's seasonal Planning Reserve Margin Requirement (PRMR). An LSE can meet its seasonal PRMR by any of the following ways:

1) Self-scheduling of ZRCs
2) Fixed Resource Adequacy Plan (FRAP)
3) Participating in the Planning Resource Auction (PRA)
4) Paying the Capacity Deficiency Charge (CDC)

## 5.2 Local Resource Zones

MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be in the appropriate physical locations within the MISO Region to reliably meet Demand and LOLE requirements. MISO will provide the details of each LRZ no later than September 1st of the year prior to a Planning Year. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of previous LOLE studies; (5) the relative size of LRZs; and (6) market seams compatibility. MISO may re-evaluate the boundaries of LRZs if there are changes within the MISO Region including, but not limited to, any of the preceding factors, significant changes in membership, the Transmission System and/or Resources.

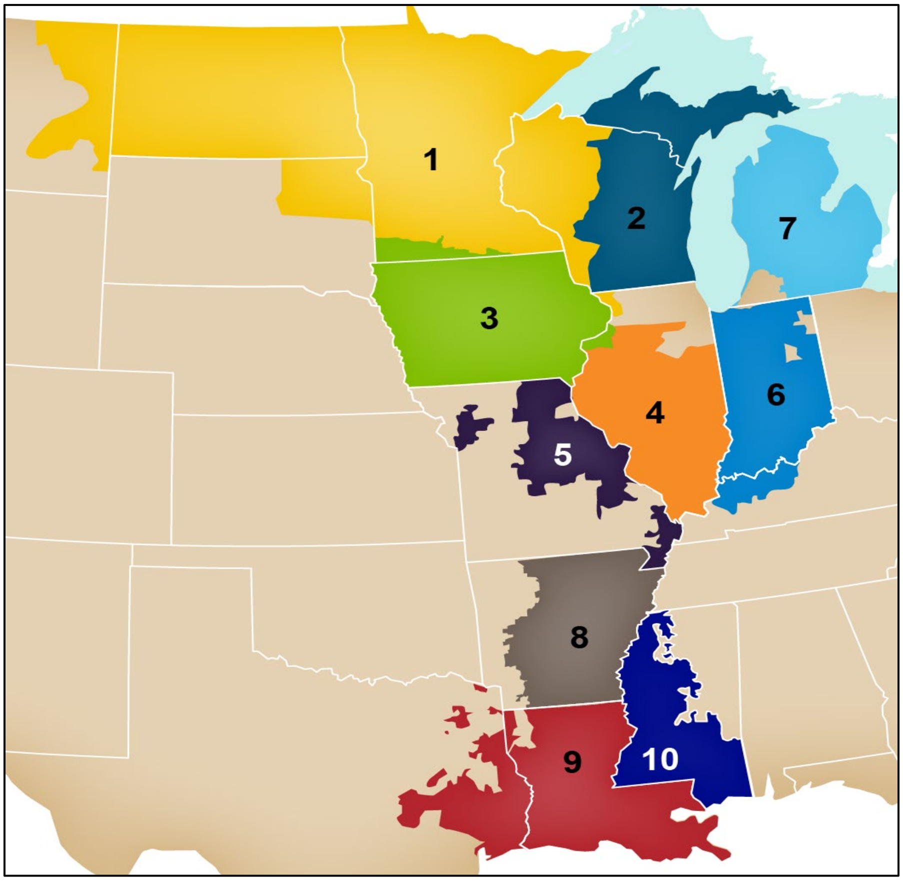



**Figure 5: Local Resource Zones Map**

### 5.2.1 Change in LRZ Configuration

MISO, after working with stakeholders and submitting a Tariff revision to Attachment VV, may change the configuration of the LRZs if a re-evaluation trigger has occurred and after consideration of the criteria outlined for consideration in setting LRZ boundaries. Changes to LRZ configuration will only be applicable to future Planning Years that have not already been cleared through the PRA. MISO will share any re-evaluation triggers and the results of the analysis documenting the impacts of the proposed LRZ boundary changes with stakeholders in an open and transparent manner prior to making any filings to change LRZ boundaries.

Once the boundaries of an LRZ have changed, its boundaries should stay constant for at least three years to provide stable future locational signals.

### 5.2.1.1 Re-evaluation Triggers

The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region. Such changes are called re-evaluation triggers, and they include, but are not limited to, the following:

1) Significant changes in membership:
   Re-evaluation may occur for LRZs where new members join the MISO system or for areas which neighbor the regions where new members join the system. Re-evaluation may occur prior to or in the cycle immediately following the integration of new members into the MISO system.
2) Significant changes in the Transmission System:
   Transmission infrastructure must be on target to be in-service by June 1 of the year which would follow a filing for an LRZ boundary changes (i.e., the transmission must be in-service for the first summer where the zonal changes will go into effect). The changes to the transmission system should impact transmission constraints represented in the MISO Resource Adequacy construct for the zone(s) being reevaluated.
3) Significant changes in Resources:
   Changes to the resource mix may include the addition of significant new generation or the retirement of significant existing generation. The resource changes should be shown to modify the transmission system flows in the zone(s) being studied, impacting transmission constraints represented in the MISO Resource Adequacy construct.

The existence of a trigger will not guarantee that a zonal change will be implemented; the trigger will allow the analysis to proceed and will be considered as part of the final decision on whether or not to change zonal boundaries.

### 5.2.1.2 Re-evaluation Considerations

Once a re-evaluation trigger has been met, the geographic boundaries of the zone or zones may be re-evaluated. This re-evaluation will be based upon an analysis that considers the following factors.

1) Electrical Boundaries of Local Balancing Authorities
2) State boundaries
3) Relative strength of transmission interconnection between Local Balancing Authorities
4) Results of LOLE studies
5) Relative Size of LRZs

6) Natural geographic boundaries such as lakes and rivers

The electric boundaries of Local Balancing Authorities, state boundaries, and natural geographic boundaries will be considered by inspection. Additional information on the process used to analyze the other criteria is below.

**Relative Strength of Transmission Interconnections between Local Balancing Authorities**
Multiple aspects of the transmission system are considered in this portion of the evaluation. These aspects are first investigated individually, and the final assessment considers all of the factors. The assessment includes the following:

- Previously identified LOLE results (Capacity Import and Export Limit constraints)
- Constraint variation(s)
- Transmission projects
- Physical ties including post-contingency connectivity and transmission service

LOLE results identified for Capacity Import and Export Limit analysis before and after the boundary change is applied will be considered. Zonal transfer analysis yields a list of constraints. The most limiting constraint after redispatch determines a zone's limit in the LOLE study. In the re-evaluation analysis, the less limiting constraints are also considered since reconfigurations impact the transfer level at which constraints are limiting. Also, while there can only be one limiting constraint, multiple constraints can be seen at similar transfer levels. For example, assume the most limiting constraint is at a transfer level of 100 MW. There are two additional constraints at 99 MW and one at 90 MW. Since these transfer levels are very close, all four are considered in this evaluation.

Constraint variation is caused by reconfiguration of Local Resource Zones. This variation is caused by changing the generation that is used to create the transfer. Zonal definitions determine which generators are used in the transfer analysis so any change in zonal definition may result in a difference in the impact the transfer has on the constraint. It is possible that a constraint has an impact above the threshold before reconfiguration and less than the threshold afterwards which is considered in this evaluation.

The impact of approved MTEP Appendix A and Target A transmission projects is considered. If a project mitigates a constraint and the project is expected to be in service prior to the Planning Year under consideration, then the impact of the transmission project to the LOLE results is considered.

MISO will consider the number of ties of any reconfigured zone. Generally, a reconfigured zone should have two or more ties with the rest of MISO. Two or more ties between the zones are optimal when planning for contingencies so the zones are still connected post-contingency. Any LBA being added to an existing LRZ should have two or more ties with an LBA in the new LRZ. Any other impacted LRZs should have contiguous LBAs with two or more ties. Further consideration is needed if an LBA leaving an LRZ results in an LRZ with unconnected LBAs. In addition, confirmed transmission service between zones may be considered when evaluating reconfigurations. Confirmed long-term transmission service indicates transmission capacity between the zones has been previously evaluated.

**The Results of LOLE Studies**

LOLE studies will be performed with the LRZ configuration being considered. The results of this analysis will be compared with the prevailing LRZ configuration. This LOLE analysis includes a MISO PRM model analysis (Section 3.5), LRZ LRR determination (Section 5.2.2.2), and capacity import and export limit analysis (Section 5.2.2.1) for the LRZ configuration being considered and for the prevailing LRZ configuration. The results of this analysis and comparison with the prevailing system results will be used as one factor in determining whether LRZ changes are warranted, in conjunction with the other LRZ considerations.

**Relative size of LRZs**

The relative size of an LRZ will contain no less than 2,000 MW of demand.

#### 5.2.1.3 Determination of LRZ Boundaries

Following the determination of an LRZ trigger, the conclusion of all analysis with consideration of stakeholder feedback will determine whether the LRZ boundaries will be changed. This determination will be based upon the benefits and/or risks that the LRZ boundary changes would present on the system. MISO’s final determination will be shared with stakeholders and the changes will be filed with FERC.

#### 5.2.1.4 External Resource Zones

MISO developed External Resource Zones (ERZs) to reflect the physical location of External Resources and establish Auction Clearing Prices for such External Resources (other than Coordinating Owner and Border External Resources). An ERZ will be created for each External Balancing Authority adjacent to MISO with Planning Resources participating in the MISO PRA

#### 5.2.1.5 Establishing Sub-Regional Resource Zones (SRRZ)

MISO will also establish SRRZs applicable for each Planning Year. A SRRZ is a zone, comprised of an LRZ or combination of two or more LRZs, to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Currently, MISO has two SRRZs: MISO South defined as LRZs 8, 9 and 10 and MISO Midwest defined as LRZs 1-7. These SRRZs are a result of the settlement agreement between MISO, SPP, and the other Joint Parties. This agreement established Regional Directional Transfer Limits (RDTL) that limit the amount of total transfer between these two SRRZs in the PRA. The RTDL from South to Midwest is 2,500 MW and the RTDL from the Midwest to South is 3,000 MW.

MISO shall establish the Sub-Regional Export Constraint (SREC) and Sub-Regional Import Constraint (SRIC) by March 1st prior to the Planning Year. The methodology for determining the SREC and SRIC for each SRRZ is described below.

##### 4.2.1.5.8 Determination of Seasonal SREC and SRIC

The following steps describe the steps MISO will utilize to calculate the SREC and SRIC.

1. Begin with the Regional Directional Transfer Limits (RDTL) between the two SRRZs
2. Complete a feasibility analysis to review operational events from the previous seasonal peaks to determine if a further reduction to the Regional Directional Transfer Limit is warranted for reliability.
3. Decrement the initial RDTL (from step 1) based upon completed feasibility analysis
4. Subtract from the net RDTL (from step 3) the sum of Firm Reservations on MISO OASIS that utilize the contract path between South and Midwest and are exporting the MISO BA for the applicable season of the Planning Year. This difference determines the SREC and SRIC to be utilized for that season of the Planning Year.

<u>Example from the 2016-2017 Planning Year</u>

1. The RDTL from South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.
2. MISO's feasibility analysis for the 2016-2017 Planning Year determined that no additional reduction of the RDTL was required; 0 MW.
3. The net RDTL for 2016-2017 is equal to the initial RDTL; South to Midwest is 2,500 MW and from Midwest to South is 3,000 MW.

4. The MISO OASIS Reservations, in each direction, that exported from the MISO BA for the 2016-2017 Planning Year were summed:
   South to Midwest Direction: 1,624 MW
   Midwest to South Direction: 206 MW

Final SREC and SRIC applied for the 2016-2017 Planning Year:
   South SRRZ SREC: 876 MW
   South SRRZ SRIC: 2,794 MW
   North SRRZ SREC: 2,794 MW
   North SRRZ SRIC: 876 MW

#### 4.2.1.5.9 Regional Directional Transfer Limit Feasibility Analysis

On an annual basis, prior to administrating the PRA, MISO will review operational data from the previous Seasonal peaks to determine if operational events experienced in the past and forecasted expected conditions for the applicable Planning Year season warrant a reduction in the initial RDTL between the MISO South and Midwest Regions. MISO will review the results of the feasibility analysis with stakeholders prior to implementing in a PRA.

The following data sources are considered for the feasibility analysis:

- Studies that assess MISO transfer capability between Regions
- Studies that assess load diversity between Balancing Authorities
- Transmission system constraints
- Congestion history on relevant transmission constraints
- Capacity or Transmission Emergency alerts, warnings, or events

### 5.2.2 Local Requirements and Transfer Capability

#### 5.2.2.1 Calculation of Transfer Limits for the Planning Resource Auction(s)

MISO will determine the seasonal import and export limits for each LRZ by performing a transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values which represent a zone's ability to import and export capacity in every season, respectively. The seasonal ZIA and ZEA values are adjusted by the amount of exports to non-MISO load from the zone to determine a zone's seasonal CIL and CEL. Seasonal CIL and CEL determine the maximum amount of ZRCs that can be imported or exported respectively to/from that zone in that season. The seasonal ZIA is an input to the calculation of the seasonal Local

Clearing Requirement (LCR) for each LRZ, as described in Section 5.2.2.3. Seasonal LCR, CEL, and CIL are inputs to the Planning Resource Auction clearing process.

Transfer analysis is not required to calculate an ERZ CEL; instead, MISO will determine the seasonal CEL of each ERZ by determining the volume of SAC for External Resources within that zone. The seasonal CEL will be set to the MW SAC in the ERZ no later than eight (8) business days before the last business day in March.

Transfer analysis will be performed on seasonal model's appropriate for the upcoming Planning Year. Additionally, out-year analysis will be performed on models representing a time frame beyond the current Planning Year. Out-year analysis primarily differs from Planning Year analysis because it focuses on LRZs with the potential to bind in the future. The next section details the out-year process. The considered time frame of the out-year analysis will depend on several variables, which might include:

- Regulations (passed or anticipated)
- System changes (generation or transmission)
- Stakeholder needs

**Out-Year Analysis**

These efforts will focus on LRZs identified to have potential risk of binding on transmission limits or LCR. Available PRA(s) and OMS-MISO survey data will be used to identify the zones at risk. The LRZs in the scope of the study will include the following:

1) LRZs with potential capacity levels from the survey exceeding previously identified CELs
2) LRZs that bound on imports in the most recent PRA(s), or were within a reasonable margin of binding
3) LRZs potentially short of local requirements based on LRZ capacity projections from the survey and an estimation of out-year LCR

LRZs meeting the requirements in number 1 will be included in the initial scope for out-year CEL. LRZs meeting the requirements in numbers 2 and 3 above will be included in the initial study scope for out-year CIL. The scope will be further refined by two additional steps. First, LRZs in the initial scope that were previously evaluated in the out-year will be identified. If prior analyses address the concern from the initial scope, further out-year analysis is not required. Additionally, if there aren't significant modeling differences since the last out-year analysis, further analysis is not required. Second, analysis is not required for LRZs that are potentially long beyond CEL and are not expected to export in the PRA. Out Year CIL and CEL analysis will be conducted on an annual basis using the 22-23PY and 2022 OMS Survey data. After 23-24PY and 2023 OMS survey are completed seasonally the Out Year CIL CEL analysis will also be conducted seasonally.

The primary difference between the Planning Year transfer analysis and out-year transfer analysis is the power flow model. Changes in generation from the OMS-MISO survey found to potentially impact LRZs at risk will be considered for out-year modeling. An additional step in the reporting of results will be to note MTEP Appendix B projects near constraints identified in the out-year analysis if the risk of binding is not addressed by generation and topology changes in the out-year model. These potential solutions might be useful while reviewing results.

**Transfer Analysis**

Transfer capability is the measure of the ability of interconnected electric systems to reliably transfer power from one area to another under certain system conditions. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. First Contingency Total Transfer Capability (FCTTC) indicates the total amount of power able to be transferred before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability.

$$Total\ Transfer\ Capability\ (TTC) = Base\ Power\ Transfer + \ FCITC$$

Linear FCITC analysis will identify limiting constraints with a minimum Distribution Factor (DF) cutoff of 3%, meaning the transfer and contingency must increase the loading on the overloaded element by 3% or more. In addition, facilities must have loadings 100% or more of the normal rating for system-intact conditions and loadings 100% or more of the emergency rating for N-1 contingencies.

Export and import capabilities of subsystems will be respected and machine limits are enforced. Exporting an LRZ's available capacity will include offline units. A pro-rata dispatch is used which ensures all available generators will reach their max dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base dispatch from its maximum dispatch, which reflects the available capacity of the unit. Refer to Table 2 and the equation below for an example of how one unit's dispatch is set, given all machine data for the source subsystem.

| Machine | Base Model Unit Dispatch (MW) | Minimum Unit Dispatch (MW) | Maximum Unit Dispatch (MW) | Reserve MW (Max dispatch – Unit Dispatch) |
|---|---|---|---|---|
| 1 | 20 | 20 | 100 | 80 |
| 2 | 50 | 10 | 150 | 100 |
| 3 | 20 | 20 | 100 | 80 |
| 4 | 450 | 0 | 500 | 50 |
| 5 | 500 | 100 | 500 | 0 |
| | | | Total Reserve | 310 |

**Table 2: Example Subsystem**

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{(Machine\ 1\ Reserve\ MW)}{(Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$Machine\ 1\ Post\ Transfer\ Dispatch$ = 25.8

**General Assumptions**

Power flow models and input files are required to determine the import and export limits of each LRZ in each season. Input files (subsystem and contingency) from MTEP studies built for timeframes matching the effective period of the transfer limit study will be used. Single-element contingencies in MISO and seam areas are evaluated. Other than the power flow model, all other input files will be the same across all seasons within the Planning Year.

Subsystem files will be modified to include required source and sink definitions, details are provided in the next two sections (Import and Export Limit Determination Sections). The monitored file will include all facilities under MISO functional control and Seam facilities 100 kV and above.

Power flow models will contain approved MISO MTEP Appendix A and Target A projects with effective dates on or before the effective date of the study model. Planning Resources, internal and external to MISO will be dispatched in the base model according to the Generator Modeling and Transactions/Interchanges sections of the Transmission Planning Business Practices

Manual, or BPM-020. The following generators are excluded from the incremental transfer analysis dispatch:

- Nuclear
- Generators with negative dispatch
- Hydro
- Wind
- Solar

Wind and solar will be ramped down for transfers and will not be ramped up. Maximum wind output will be limited to base dispatch in the power flow model which is set by the wind capacity credit. MISO and external area interchange in the base case will be set to the net of the expected firm transactions with its neighbors.

**Seasonal Zonal Import Ability (ZIA) and Seasonal Capacity Import Limit (CIL) Determination**

To determine an LRZ's seasonal limits, a generation to generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is determined for the sink subsystem. Import limits are found by increasing MISO generation resources in adjacent Local Balancing Authorities (LBAs) while decreasing generation inside the LRZ under study. LBAs that are interconnected with the LRZ under study are considered adjacent. Tiers are used to define the generation pool used for import studies and are comprised of the adjacent systems of the zone being studied.

- Tier 1 – Generation in the MISO LBAs adjacent to the LRZ under study
- Tier 2 – Tier 1 plus generation in MISO LBAs adjacent to Tier 1

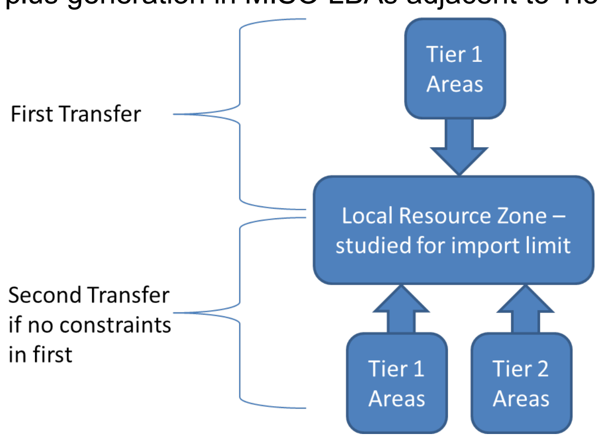



**Figure 5.1: Tiered import illustration**

Import limit studies are analyzed first using Tier 1 generation only. If no constraint is identified, the source is expanded to include Tier 2 and the transfer is retested. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the source is expanded to include Tier 2 and the transfer is retested. If constraints are identified using Tier 1 generation, Tier 2 generation is not needed to determine the zone's import limit.

The results of the analysis produce the seasonal Zonal Import Ability. This value will be used to determine the seasonal CIL after accounting for exports to non-MISO load.

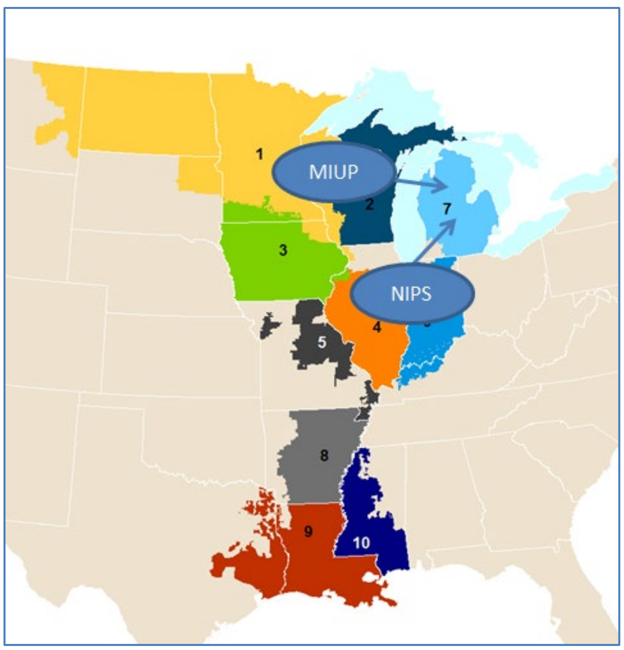



**Figure 5.2: Example - MISO LBAs Used for First Test of LRZ 7 import limits**

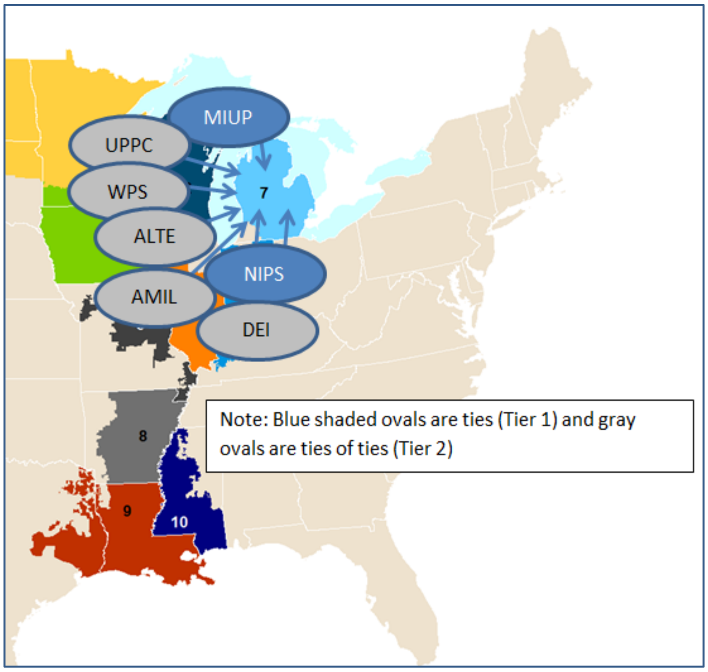



**Figure 5.3: Example - MISO LBAs Used for Second Test of LRZ 7 import limits**

**Seasonal Zonal Export Ability (ZEA) and Seasonal Capacity Export Limit (CEL) Determination**

The LRZ being studied for a seasonal export limit, is the source subsystem for the transfer. Available generation within the LBA(s) contained in that particular LRZ is increased proportionately while all generation dispatched, except for nuclear, in all other MISO LBAs is decreased proportionately. This method produces the seasonal ZEA which is used to determine the seasonal CEL after accounting for exports to non-MISO load.


**Figure 5.4: Example - MISO LBAs Used for LRZ 7 export limits**

**Redispatch**

LOLE study redispatch is based on prior MTEP study methods. The base assumptions are as follows:

- No more than 10 conventional plants or wind plants will be used
- Redispatch limited to 2,000 MW total (1,000 MW up and 1,000 MW down)
- Nuclear units are excluded
- Wind and other intermittent resources can only be ramped down

For import redispatch scenarios, all generation resources in the zone being studied and adjacent systems (Tier 1 or Tiers 1 & 2) used for the transfer will be eligible to be ramped up. All MISO generation resources will be eligible to be ramped down. If the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

For export redispatch scenarios, only MISO generation resources within the zone being studied are eligible to be ramped up. All MISO generation resources are eligible to be ramped down. As with import redispatch, if the limiting constraint is a Reciprocal Coordinated Flowgate (RCF), MISO will work with the Seam entity to determine if an adjustment to external dispatch is appropriate and impactful.

**Adjustment for Exports to Non-MISO Load**

FERC issued an order on December 31, 2015 which required studies to be neutral to units within MISO areas that are exporting to non-MISO load. MISO identifies and removes the impact of these exporting units on zonal area interchange. These adjustments result in an increase to CIL and decrease to CEL for zones with exports to non-MISO load.

**Generation Limited Transfer**

When conducting transfer analysis, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO has developed a process referred to as Generation Limited Transfer, or GLT, to identify transmission constraints in these situations.

After running the FCITC analysis to determine import and export limits for each LRZ, MISO will determine whether a zone is experiencing a GLT. If the LRZ is experiencing a GLT, MISO will adjust the base model dependent on whether the analysis is an import or export study and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LBAs under study) MISO will decrease load and generation dispatch in the study zone. The objective of the adjustment is to create additional capacity to export from the zone. After the adjustments are complete, MISO will perform transfer analysis on the adjusted model to be in line with section 5.2.2.1. If a GLT is observed again, further adjustments will be made to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after (a) decreasing all generation within the LRZ under study, (b) or dispatching all generation within Tiers 1 & 2, MISO will adjust load and generation in the source subsystem, Tiers 1 & 2. This will increase the capacity available to import into the study zone. After the adjustments are complete, the transfer analysis will be completed on the adjusted model to be in line with section 5.2.2.1. If a GLT is observed again, further adjustments to the model would be made to the load and generation in Tiers 1 & 2.

FCITC could result in the transmission system supporting large thermal transfers for some zones which might result in some additional considerations. First, large GLT adjustments for export limits could result in reactive-power issues in the zone. Additionally, any load scaling beyond 50% of the zone's load in the base model could result in unrealistic modeling for a summer peak scenario and could lead to unreliable limits and constraints. Therefore, load scaling for both import and export studies will be limited to 50% of the zone's load.

If the GLT does not produce a limit for a zone(s), whether due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph or in the case of a Zone where no valid limit is found in a particular season, then the seasonal CIL or seasonal CEL will use the following equation where Capacity is the amount available to export or import from Tier 1 & 2 LBA's in the Base Case and where Base Case Flows is the Area Interchange for the study LRZ in the base Powerflow model.

ZIA/ZEA = Capacity + Base Case Flows

MISO shall report that LRZ as having no seasonal CIL/CEL limit and ensure that the transfer amount in the PRA will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

**Voltage Limited Transfer for import studies**

Zonal imports may be limited by voltage constraints due to a decrease in the generation dispatch in the zone being studied. Voltage constraints might occur at lower transfer levels than thermal limits that are determined by linear FCITC. As such, LOLE studies may include evaluation of Power-Voltage curves for major disturbances for LRZs with known voltage-based transfer limitations. Known transfer limitations will be identified through existing MISO or member Transmission Owner studies. Additionally, a study could be considered if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from non-zonal resources. MISO will coordinate with stakeholders as these scenarios are encountered.

**Processing and Reporting Results**

The transfer analysis results for each LRZ consist of a list of constraints and their corresponding FCITC and FCTTC values up to the requested transfer level. The constraint with the smallest FCTTC will be used to determine each seasons' ZIA, ZEA, CIL and CEL. The limits are the total transfer capability of the corresponding limiting constraint. Refer to Section nfo regarding how the seasonal ZIA impacts the seasonal Local Clearing Requirement (LCR) calculation. Stakeholder review of the constraints will occur through the LOLE working group.

If a zone's seasonal Local Clearing Requirement (LCR) is greater than the zone's seasonal Planning Reserve Margin Requirement (PRMR) and an existing MTEP project is not expected to increase the seasonal ZIA, MISO will follow the process outlined in section 4.5.1 of the Transmission Planning BPM to identify a project to increase the zone's seasonal CIL.

**Timeline and Posting of Results**

Stakeholder review of power flow models and input files will be completed before analysis begins. The models and associated input files will be made available to the same location where MTEP models are kept (https://misoenergy.sharefile.com/).

The outcome of this process will identify a ZIA, ZEA, CEL and CIL for each of the LRZs for each season within the next Planning Year. MISO will publish the values for each LRZ by November 1st preceding the applicable Planning Year, or at least thirty (30) calendar days prior to a TPRA. Out-year analysis will begin as the Planning Year efforts are winding down towards the end of the year preceding the Planning Year. Results will be published early the following year.

#### 5.2.2.2 Establishment of Local Reliability Requirement

Each LRZ's seasonal Local Reliability Requirement (LRR) is the amount of SAC MWs required, locatedwithin the specific LRZ to yield a 0.1-day-per-year LOLE at the load level for the LRZ at the time of the LRZ peak, without assistance from resources outside the respective LRZ (other than Border External Resources and Coordinating Owner External Resources modeled in the zone as described in section 4.2.5.2). The LOLE study process is further described in the annual LOLE Study report posted on MISO's website.

Each seasons' LRR will be established using the following iterative process:

- Use the LOLE model to determine the resources required in the LRZ to maintain 1 day in 10 years LOLE, representing the LRZ as isolated from the rest of MISO with no transmission ties to the outside world.
- Each LRZ contains the same load and internal resources from the PRM Analysis.
- For each LRZ the model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year for the LRZ for that season.

This is comparable to adding coincident peak seasonal demand. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the LRZ until the LOLE reaches 0.1 day per year for the LRZ.

The minimum amount of capacity above the zonal seasonal coincident peak demand required to meet the reliability criterion of a 0.1 day per year LOLE value will be utilized to establish the Local Reliability Requirement (LRR) for each Local Resource Zone for each season within the Planning Year. The LRR study utilizes the Year 2 zonal seasonal coincident peak demand supplied by LSEs in the prior Planning Year PRA cycle. The per-unit LRR values are annually calculated by MISO and reviewed with stakeholders through the Loss of Load Expectation Working Group. The zonal per-unit seasonal LRR values are multiplied by the total zonal seasonal Coincident Peak Demand forecast (which is the sum of all CPD forecasts submitted by LSEs in each LRZ) for the prompt Planning Year PRA(s), inclusive of transmission losses, to calculate each Local Resources Zone's Local Reliability Requirement that will be enforced in each annual and Transitional Planning Resource Auction.

#### 5.2.2.3 Establishment of Local Clearing Requirement

The final steps in calculating an LRZ's seasonal LCR is to account for the external transmission ties and controllable exports to non-MISO systems, by reducing the seasonal LRR by the seasonal ZIA determined in accordance with Section 5.2.2.1 and by controllable exports. Controllable exports are firm capacity commitments from MISO units to non-MISO load and may be committed and dispatched by MISO during emergencies.

The formula for determining the seasonal LCR is as follows:

$$\text{Seasonal } LCR_{z1} = \text{Seasonal } LRR_{z1} - \text{Seasonal } ZIA_{z1} - \text{controllable exports}$$

MISO will publish preliminary seasonal LCR determinations by November 1st prior to the upcoming Planning Year. These values will be updated no later than mid-March with final, updated controllable export values and seasonal ZIAs.

## 5.3 Fixed Resource Adequacy Plan ("FRAP")

The FRAP will identify resources that an LSE has ownership or contractual rights that will be relied upon to meet the LSE's Planning Reserve Margin Requirement while also conforming to the Local Clearing Requirement ("LCR") in each LRZ where the LSE has a PRMR in each season within the Planning Year. An LSE must submit its FRAP for applicable season(s) via the MECT by the 7th business day of March prior to each Planning Year. MISO will review the FRAP and endeavor to notify the LSE of any issues by March 15th. LSEs will have until the PRA(s) offer window opens to resolve any issues identified by MISO.

An LSE can designate its seasonal ZRCs in the FRAP up to the LSE's seasonal PRMR. The seasonal ZRCs used in a FRAP will be deducted from the available seasonal ZRC balance of Planning Resources in the MECT. Any portion of an LSE's seasonal PRMR not covered by the FRAP or met through paying the Capacity Deficiency Charge will be cleared in the Seasonal PRA.

An LSE submitting a FRAP may be subject to a Zonal Deliverability Charge (ZDC). The ZDC is the difference between the seasonal ACP in the LRZ where the LSE has PRMR obligation and the ACP in the LRZ or ERZ where the ZRC associated with the FRAP is physically located multiplied by the volume of the FRAP. An LSE can obtain a ZDC Hedge as a hedge against zonal price differences in each season within the Planning Year.

Seasonal ZRCs and seasonal PRMR included in a FRAP will be modeled in the PRA for the applicable season.

**LSE's Local Clearing Requirement for LSE's Using a FRAP**

LSEs that choose to use a FRAP must designate a sufficient volume of Planning Resources located in the same LRZ as the LSE's PRMR to meet the LRZ's LCR requirement in each season individually. The amount of resources that must be sourced from within the LRZ to satisfy the LSE's seasonal LCR share is equal to the load ratio share of the LSE's seasonal PRMR multiplied by the total seasonal LCR for its LRZ. The following formula is used to determine each LSEs FRAP LCR requirements for each season:

$$LSE\ LCR = \left[\frac{LSE\ PRMR}{Zonal\ PRMR}\right] * Zonal\ LCR$$

$$Minimum\ LSE\ FRAP\ ZONE\ = \left[\frac{LSE\ LCR\ X\ LSE\ FRAP\ NON\ ZONE}{(LSE\ PRMR - LSE\ LCR)}\right]$$

$$for\ the\ given\ LSE\ FRAP\ NON\ ZONE$$

$$Maximum\ LSE\ FRAP\ NON\ ZONE\ = \left[\frac{LSE\ FRAP\ ZONE * \ (LSE\ PRMR -\ LSE\ LCR)}{LSE\ LCR}\right]$$

$$for\ the\ given\ LSE\ FRAP\ ZONE$$

Where:

| | |
|---|---|
| LSE LCR: | Amount of ZRCs that must be from the same LRZ as the LSE's PRMR if they met the entire PRMR using a FRAP. |
| LSE FRAP ZONE: | ZRCs that are in the same LRZ as the PRMR that is being met through a FRAP by the LSE |
| LSE FRAP NON ZONE: | ZRCs from an ERZ or that are not in the same LRZ as the PRMR that is being met through a FRAP by the LSE |
| LSE PRMR: | Total PRMR the LSE has in the LRZ |
| Zonal LCR: | The minimum amount of ZRCs that are located within an LRZ that is required to meet the LOLE while fully using the Capacity Import Limit for such LRZ. |

EXAMPLE:

LSE PRMR = 100 MW in LRZ 1
LSE LCR = 80 MW in LRZ 1

To apply ZRCs from other LRZs or an ERZ in the FRAP, the following condition must be satisfied:

$$\left[\frac{(LSE\ FRAP\ ZONE + \ LSE\ FRAP\ NON\ ZONE)}{LSE\ PRMR}\right] \leq \left[\frac{LSE\ FRAP\ ZONE}{LSE\ LCR}\right]$$

Substituting the value for *LSE LCR* from above, the above formula can be rearranged and rewritten as:

$$\left[\frac{Zonal\ LCR}{Zonal\ PRMR}\right] \leq \left[\frac{LSE\ FRAP\ ZONE}{(LSE\ FRAP\ Total)}\right]$$

Where *LSE FRAP Total* is simply the sum of the FRAP from within and outside of the zone. To state more simply, an LSE must maintain a balance of FRAP in zone to total FRAP greater than or equal to the ratio of the zone's LCR and PRMR.

Case 1: LSE FRAP ZONE = 40MW in LRZ 1
LSE FRAP NON ZONE = 10 MW from LRZ 2

$$\left[\frac{(40+10)}{100}\right] \leq \left[\frac{40}{80}\right] \Rightarrow \left[\frac{1}{2}\right] \leq \left[\frac{1}{2}\right] \Rightarrow Pass\text{: } 10\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ allowed$$

$$for\ the\ given\ LSE\ FRAP\ NON\ ZONE\ of\ 10\ MW,$$

$$Minimum\ LSE\ FRAP\ ZONE\ = \left[\frac{80 * 10}{(100-80)}\right] = 40\ MW$$

NOTE: 40 MW represents the minimum amount of FRAP that must be fulfilled by the ZRCs in LRZ 1 in this case.

Case 2: LSE FRAP ZONE = 60 MW
LSE FRAP NON ZONE = 20 MW

$$\left[\frac{(60+20)}{100}\right] \leq \left[\frac{60}{80}\right] \Rightarrow \left[\frac{4}{5}\right] \leq \left[\frac{3}{2}\right] \Rightarrow Fail: 20\ MW\ of\ ZRCs\ from\ other\ LRZ\ is\ not\ allowed$$

$$for\ given\ LSE\ FRAP\ ZONE\ of\ 40\ MW,$$

$$Maximum\ LSE\ FRAP\ NON\ ZONE\ = \left[\frac{60 * (100-80)}{80}\right] = 15\ MW$$

NOTE: 15 MW represents the maximum amount of ZRCs from other zones which can be used to FRAP LSE's PRMR in LRZ 1 in this case.

## 5.4 Hedges and Zonal Deliverability Benefit

### 5.4.1 Zonal Deliverability Benefit

Price separation between Local Resource Zones (LRZs), External Resource Zones (ERZs), or groupings of LRZs, including Sub-Regional Resource Zone (SRRZs) occurs due to constraints binding in the Planning Resource Auction(s) (PRA). Zonal Resource Credits (ZRC) will receive the Auction Clearing Price (ACP) based upon the LRZ or ERZ where the Planning Resource underlying the ZRC is physically located for each season within the Planning Year.

As a result of price separation, the Transmission Provider may collect more debits from LSEs than it credits the owners of the seasonal ZRCs. Excess amounts will be distributed as follows:

1. Historical Unit Considerations (HUCs) and Zonal Deliverability Charge (ZDC) Hedges owed payment.

2. Any remaining excess revenue shall be distributed on a *pro rata* basis to Deliverability Benefit Zones (DBZs). A DBZ is a group of one or more LRZs with equal ACPs driven by the same auction constraint.

#### 5.4.1.1 Zonal Deliverability Benefit Pro Rata Allocation Methodology

The *pro rata* distribution is applied to each applicable season and is based upon the LSE's eligible PRMR which excludes PRMR associated with HUCs and ZDC Hedges.

MPs with Fixed Resource Adequacy Plans are eligible to receive ZDB.

The *pro rata* methodology to allocate ZDB uses a weighted average approach to calculate the benefit, in dollars, to importing DBZs of all exports within MISO – a weighted average exporting ACP. This weighted average pool of dollars is then allocated to importing DBZs within MISO on a *pro rata* methodology based upon the difference between the importing DBZ ACP and the weighted average exporting ACP and the MW amount of imports into a DBZ. The ACP for each LRZ within an importing DBZ is adjusted by dividing the benefit dollars allocated to the DBZ by the total PRMR of all LRZs within a specific DBZ. The specific steps to allocate ZDB are described below.

1. Subtract PRMR and ZRCs associated with HUC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC).
2. Create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint.
3. For each DBZ, subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon this weighted average approach.
4. Calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$\text{Weighted Average Export ACP} = \frac{\sum(\text{Net Export}_\text{j} \times \text{ACP}_\text{j})}{\sum \text{Net Export}_\text{j}}$$

Where j = Each net exporting DBZ

5. Calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$\text{ZDB Credit}_{\text{k}} = \text{Net Import}_{\text{k}} \times (\text{ACP}_{\text{k}} - \text{Weighted Average Export ACP})$$

Where k = Each net importing DBZs

6. Distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. Subtract this amount from the initial ACP calculated for each LRZ from the PRA.

FRAP Contribution to ZDB

Furthermore, ZDB includes credits collected from FRAPs that contain ZRCs located in LRZs that have a greater ACP than the respective PRMR's LRZ. This ZDB will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ where the ZRC associated with the FRAP is physically located.

Allocation of Zonal Deliverability Charge ("ZDC")

A FRAP will be subject to a ZDC if the ACP of the LRZ where the ZRC is physically located is less than the ACP of the LRZ where the PRMR associated with the FRAP is physically located. ZDC collected by the Transmission Provider that is not associated with a ZDC Hedge will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ where the PRMR associated with the FRAP is physically located.

A detailed example of ZDB *pro rata* allocation methodology is in Appendix P.

### 5.4.2 Historical Unit Considerations (HUCs)

A HUC is a financial hedge against ACP differentials between LRZs or between an LRZ and an ERZ. HUCs for existing capacity agreements hold LSEs harmless from price separation to the extent that excess auction funds are sufficient. HUCs for existing LSEs will be eligible until the end of the original term of the arrangement, not including any evergreen extensions, or for two years – whichever is longer.

The following criteria must be satisfied for HUC approval:

- LSE must have ownership or contractual rights to the resource
- Must have resource and load located in two different LRZs or a resource located in an ERZ
- Must have either NRIS or firm transmission service from the resource LRZ to the load LRZ
- Contracts and its associated NRIS or firm transmission service must be valid through the entire Planning Year

- Contracts must be a) Grandfathered Agreements, b) arrangements executed and in place on or before July 20, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones
- For both new and existing LSEs, HUCs will expire at the end of the contract term, unit ownership change or unit retirement date, whichever is sooner. Contracts expiring during the upcoming Planning Year are not eligible for a HUC covering the planning year. Contracts that have been renewed by evergreen contract provisions are only valid for two Planning Years from the date of the HUC registration
- A HUC must be registered in the MECT by November 1st prior to each Planning Year[3]. HUC Registrations will need to have all information populated except for the Planning Resource, Asset Owner, Resource Zone and TSR and/or NITS identification number(s). Once the SAC MW for Planning Resources is published, MISO will allow Market Participants to update the Planning Resource, Asset Owner, Resource Zone, and TSR and/or NITS ID number information only. Updates will need to be completed by February 1st prior to the Planning Year
- A separate HUC registration is required for each Planning Resource and load within each LRZ or a resource located in an ERZ
    - One Planning Resource in a registration can only select one LRZ or ERZ
- The MW in HUC registrations should not exceed the LSE's seasonal PRMR, contract amount, ZRCs, or transmission service
- If Market Participants enterinto a seasonal ZRC transaction to fulfill contracts that meet the criteria for a hedge, MISO must be able to determine the source of the ZRCs in order to apply the HUC financial hedge to the auction results
    - ZRCs transacted to fulfill existing contracts will need to have specific unit identifiers from aggregate deliverable generators
- Based on the ZRCs transacted, MISO will work with the MP that qualified the HUC to determine in which LRZ or ERZ the Planning Resource is located

If a Load is in an LRZ with a higher ACP than the LRZ or ERZ where the Resource is located, the MP serving the Load will pay an amount equal to the difference of the ACPs between the LRZ and the LRZ or ERZ where the Resource is located, multiplied by the amount of the unhedged load if a HUC Hedge does not exist. This distribution will be limited by the excess auction revenue collected in a given PRA.

[3] Deadline for PY 2019-2020 **only** will be December 1st, 2018

A combination of capacity agreements that require the delivery of capacity throughout the Planning Year will qualify for treatment as HUCs, provided that the agreements otherwise satisfy the criteria.

Facilities under construction on or before July 20, 2011 that subsequently become Planning Resources will be eligible for the HUC Hedge provided that the HUC criteria is satisfied.

Firm resources that meet HUC Hedge criteria may be included as part of a FRAP or offered into the annual auction. Any MWs of ZRCs in a FRAP that are qualified under a HUC will not be subject to a Zonal Deliverability Charge assessment.

### 5.4.3 Zonal Deliverability Charge Hedge

LSE can obtain a ZDC Hedge as described herein as a financial protection from zonal price differences. Market Participants will be eligible for a hedge against congestion in the auction if the LSE invests in new or upgraded transmission to serve the LSE's load if located in a different LRZ. Network upgrades made for interconnection service (NRIS/ERIS) do not qualify for a ZDC Hedge. Also, any cost shared upgrades would not be eligible for a ZDC Hedge. The participant that funds the upgrades and submits the transmission service request is the participant who is eligible for the ZDC Hedge. However, Network upgrades associated with a Transmission Service Reservation (TSR) from the new resource to load located in a different LRZ would qualify. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm transmission service request. Market Participants must register the ZDC Hedge and provide supporting documentation in the MECT by November 1st prior to the Planning Year to demonstrate eligibility. ZDC Hedges will be granted only to LSEs that have Planning Resources that cleared in a PRA.

## 5.5 Planning Resource Auction (PRA)

### 5.5.1 Timing of Auctions

Seasonal Planning Resource Auctions will be conducted in the beginning of April, which is approximately two months before the beginning of the first season of the associated Planning Year. All four seasonal (Summer, Fall, Winter and Spring) PRA's will be conducted in April prior to the PY.

### 5.5.2 Amount of Capacity Cleared in Each Auction

The seasonal PRA(s) and Transitional PRA shall clear seasonal ZRC offers in order to satisfy 100% of the seasonal PRMR for each LSE, less the amount of seasonal PRMR associated with the Capacity Deficiency Charge and inclusive of any resources used in a seasonal FRAP, in each LRZ. For a Season, if the total volume of seasonal ZRC offers is less than total seasonal PRMR, MISO will clear the total volume of offered ZRCs for that season respecting established CIL, CEL, SRIC and SREC.

### 5.5.3 Conduct of the PRA

The Seasonal Planning Resource Auctions shall be sealed bid auctions, which will determine the seasonal Auction Clearing Price (ACP) for each LRZ modeled in that auction. The auction shall determine the outcome of all seasonal ZRC offers accepted during the qualification process and submitted during the auction offer window.

**Step 1: Compilation of Offers**

Offers for each of the seasonal auctions must be submitted in the MECT's Submit Offer screen for each specific seasonal auction during the auction offer window period. The offer window for the auction will be opened during the last four business days in the month of March prior to the start of the new Planning Year. Owners of jointly owned facilities can individually offer their share of any such resources into the seasonal PRAs, either as self-schedule price takers or with specific offers, or use their share of such resources as part of a seasonal FRAP.

MISO shall compile all of the offers for each season, as follows: The MP acting on behalf of any Planning Resource accepted in the qualification process for participation in the auction may submit an offer consisting of price and quantity pairs, indicating the minimum acceptable price and the associated quantity of seasonal ZRCs that the MP would commit to provide from the Resource in the associated modeled LRZ and/or ERZ during the season within the Planning Year. An offer shall be defined by the submission of up to five price and quantity pairs, each having a strictly greater price than the previous price in the submittal. Each price shall be expressed in dollars per megawatt-day, and each quantity shall be expressed in 0.1 MWs. The MW/Price pairs must be monotonically increasing for each price. Each segment of each offer is separately evaluated.

**Step 2: Determination of the Outcome**

MISO shall use the seasonal ZRC offers to determine the aggregate supply curves for each MISO modeled LRZ and/or ERZ. MISO will use the seasonal offers in conjunction with the seasonal import and export constraints, seasonal local clearing requirements, and other inputs to determine the least cost set of offers that respects the various constraints expressed as described in the Tariff. The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e. an LRZ needs 50 MW, but Market Participant has a 100 MW Resource; only 50 MW will clear). At any non-zero clearing price, a pro-rated clearing from tied bids will be applied in conjunction with need, location of resources subjected to tied bids, and import and export limits of respective LRZs. At a zero-clearing price, all zero-price and price-taking offers will be accepted.

**Inadequate Supply**

While the auction process will endeavor to select seasonal ZRC offers sufficient to meet the seasonal requirements of each LRZ, it is possible that sufficient resources are not available in the region. In such cases, the auction will clear all seasonal ZRC offers in the LRZ for that season at the Cost of New Entry (CONE) price approved by FERC and the LRZ or Transmission Provider region would be short of Planning Resources for that season within the Planning Year. In the situation where a region is short ZRC's to meet the regional PRMR the entire region will clear at the lowest CONE value of the LRZ's in that region.

### 5.5.4 Market Monitoring

All participation by Market Participants is subject to the market power mitigation rules regarding physical and economic withholding of capacity as described in Module D of MISO's Open Access Transmission Tariff and Market Monitoring BPM-009. All Planning Resources except for External Resources, Demand Resources, and Energy Efficiency Resources are subject to physical and economic withholding monitoring. Below are additional details regarding the application of these market monitoring provisions. In addition to these details, please refer to Module D and BPM-009 Market Monitoring and Mitigation for additional details.

#### 5.5.4.1 Physical Withholding

Sec. 64.1.1.d of Module D describes the Physical Withholding Provisions in the PRA. The IMM has established a Physical Withholding Threshold Limit of 50 MW per LRZ that is applied as a sum to a Market Participant (MP) and its Affiliates. Thus, there is a total of 50 MW of deliverable SAC (ZRCs) whose rights are owned by an MP and its Affiliates in each LRZ that are not required to submit an offer into the PRA or be part of a FRAP. If the sum of deliverable SAC MW withheld exceeds the Physical Withholding Threshold limit, the MP and its Affiliates would fail for conduct (Conduct Test) for physical withholding and be subject to the Impact Test described in Module D.

#### 5.5.4.2 Economic Withholding

Sec. 64.1.2.d of Module D describes the Economic Withholding Provisions in the PRA. By default, each Planning Resource subject to economic withholding has an initial Reference Level for their PRA offer of $0/MW-Day. A Conduct Threshold equal to 10% of the LRZ CONE is allowed for a

PRA offer without failing conduct (Conduct Test) for economic withholding and be subject to the Impact Test described in Module D.

An MP may submit a request for a facility specific Reference Level to the IMM. The request must be accompanied by evidence and documentation of Going Forward Costs (operating and capital) to operate the Planning Resource for the next Planning Year. Going Forward Costs must be sufficient detail to specify costs specific to suspension or retirement. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

Market Participants have the option to use Default Technology Specific Avoidable Costs (DTSAC) calculated by MISO as specified in Module D for operating cost recovery in lieu of submitting their own documentation for operating costs. The DTSAC values in Module D are broken down by different generator classifications for suspension and retirement requests. Refer to BPM-009 Market Monitoring and Mitigation for additional details.

### 5.5.5 Target Reliability Value

The resultant target reliability value for each Season for each LRZ will be the greater of the system-wide seasonal Planning Reserve Margin Requirement based on MISO's seasonal PRM or the seasonal LCR value. The sum of these seasonal LRZ target reliability values will be the system's target seasonal reliability value, that is, the amount of SAC MW that must be obtained, if available, from the auction.

### 5.5.6 Resource Offers

Any seasonal ZRCs that were not used in a FRAP can be offered into the seasonal PRA during the auction window period. The following business rules are applied to the seasonal ZRC offers for the seasonal PRA:

- Offer cannot be changed or withdrawn after the auction window is closed.
- Smallest Offer MW = 0.1 MW.
- Offer Segment defined as a price-quantity pair.
- Up to 5 Offer Segments per Planning Resource.
- Lowest Offer price is $0.00/MW-Day.
- Highest Offer Price for each season and zones (LRZ and ERZ) is the annual LRZ/ERZ CONE divided by the total number of days in the season.
- The Transmission Provider will clear offers based on the needs of the LRZ and not the size of a Resource (i.e., LRZ needs 50 MW, but Market Participant has a 100 MW

Resource; only 50 MW will clear). At a zero-clearing price, all zero-price and price-taking offers will be accepted.

**Self-Scheduling**

LSEs that "self-schedule" ZRCs by submitting offers into the PRA(s) with a price of $0.00 will always clear the auction.

**Sub-Regional Constraints**

The Sub Regional Import Constraint (SRIC) and the Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) are the transmission constraint parameters which must be respected, in addition to CILs and CELs for each LRZ, when conducting the PRA or in the Resource Replacement process. A SRRZ consists of more than one LRZ.

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, seasonal SRECs and seasonal SRICs as soon as practical but no later than the first business day of March for the following Planning Year.

### 5.5.7 Seasonal Simultaneous Feasibility Test (SFT)

Background

The test identifies transmission constraints resulting from power transfers between LRZs and imports to the MISO system from ERZs. To the extent transmission constraints cannot otherwise be mitigated via redispatch of seasonal Planning Resources while holding LRZ imports and exports constant, new seasonal CIL and CEL values (as applicable) are established. Resulting transfers in the auction will be simultaneously reliable and feasible. The seasonal SFT is completed after the seasonal auction clears and is driven by section 69A.7.1 of Tariff Module E-1.

Base Model

Base modeling represents the transmission topology and associated transmission ratings, demand, and anticipated net interchange for the associated season: summer, fall, winter spring. This is accomplished by the following modeling assumptions:

- Base model
    - Latest available MISO model with expected generation and transmission topology for the effective date of each season within the Planning Year
- Transmission Topology

  - Includes Appendix A and other Model On Demand projects in-service by the effective date of the specific season within the Planning Year
- Load
  - Coincident Peak Forecast for each season and seasonal transmission losses plus seasonal Planning Reserve Margin
  - LMRs are modeled as reduction of seasonal PRMR where LMRs are physically located
- Dispatch
  - Seasonal FRAP
  - Seasonal ZRC offers cleared through the auction

- External representation
  - Latest Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group series model matching Planning Year timeframe for each season where applicable within the Planning Year

The latest seasonal models from the annual MISO series model build provides the best representation of the system and is a better representation than the one year old LOLE model used to establish the seasonal CIL and CEL limits. The latest model contains the up-to-date topology and has gone through more recent stakeholder review.

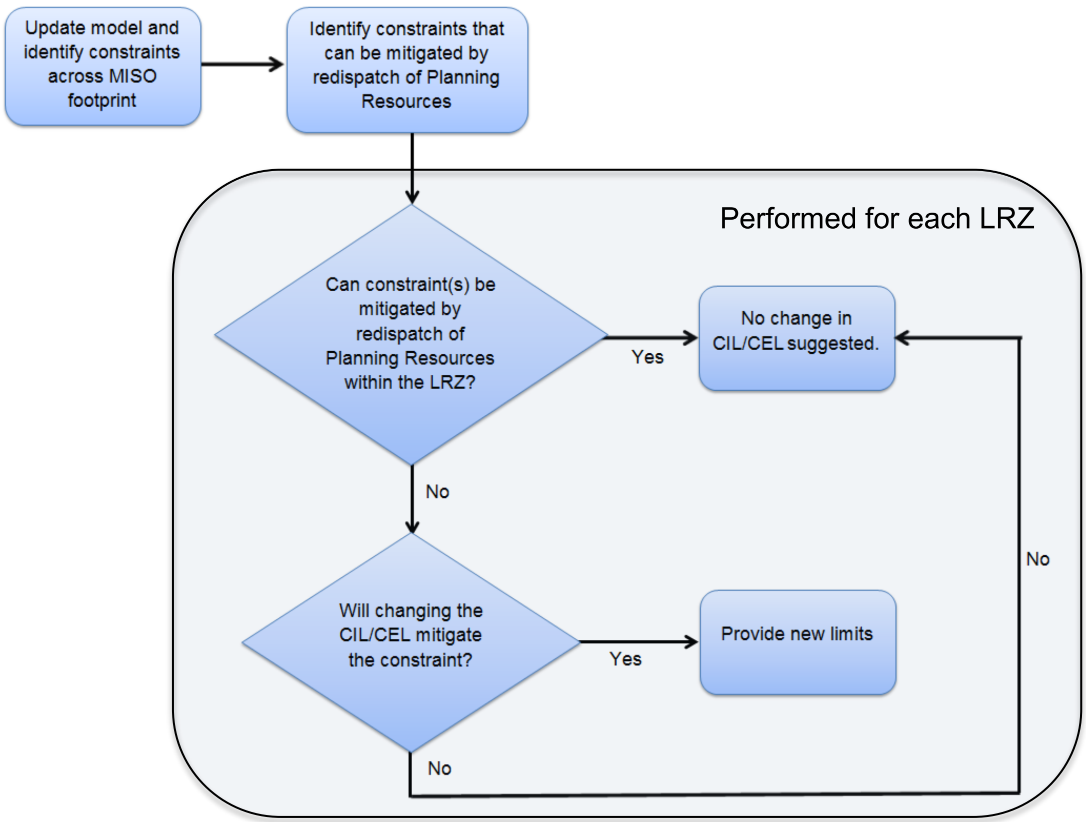
Interchange Detail
External units that clear the auction are accounted for by Balancing Authority Area and then the interchange between MISO and the Balancing Authority Areas with cleared units is adjusted to represent the cleared amount. Units within MISO with an external capacity commitment will be dispatched to external load. Interchange will be adjusted to reflect the transaction.

Topology Validation
Model checks are performed prior to the SFTs and PRAs. First, the ratings of facilities found to be limiting in the LOLE study are checked for rating changes. If the facility ratings are updated, the impact on seasonal CEL, CIL and/or ZIA must be determined and included as inputs to the PRAs. Transmission projects included in the LOLE models were expected to be in-service prior to the effective date of the specific season within the Planning Year and in-service dates occasionally change, so the model is updated to include only those projects still expected to be in-service by the individual seasons effective date.

Powerflow Analysis

The only controllable elements of the auction are the seasonal CIL and CEL. The seasonal SFT determines if any changes to CEL and CIL are required. The initial limits are determined in the annual LOLE study where seasonal CIL and CEL limits are established. These limits are an input to the initial auction clearing process. The SFT process is outlined in Figure 1 below.

**Figure 1: SFT Process Flow**




Seasonal CIL and CEL may be modified when the dispatch of Planning Resources within that season outside the LRZ is the only action to mitigate constraints. To determine if changes are required, it must first be determined if the LRZ is an exporter or importer as a result of the auction clearing in that season. If the LRZ is an exporter within the seasonal CEL bounds, no change to limits should cause the LRZ to export more. Similarly, no change to limits should cause an importing LRZ to import more. The changes to limits that are impactful for exporters and importers are outlined as:

- Potential change if Planning Resources outside an LRZ is the only mitigation identified
- Decrease export or import limit if Planning Resources outside LRZ can be ramped up or down respectively to mitigate the constraint
- Decrease limit by MW amount needed to mitigate constraint

The Tariff allows for up to three iterations of the auction clearing process. The first iteration uses the seasonal CEL and CIL from the LOLE study while the second and third iteration use any updated CIL and CEL values as determined by the seasonal SFT. The second and third iterations are performed only if needed. The clearing iterations are outlined as:

1st Pass

- Inputs to the auction clearing process are seasonal CILs and CELs from LOLE study, seasonal LCR, seasonal SRECs, and seasonal SRICs as applicable
- If all LRZs pass the SFT in that season, auction results are final and the 2$^{nd}$ and 3$^{rd}$ iteration of auction clearing is not required.

2nd Pass

- Inputs to the auction clearing process are updated seasonal CILs and CELs from the 1$^{st}$ Pass and
- If all LRZs pass the SFT, results are final.

3rd Pass

- Inputs to the seasonal auction clearing process are updated seasonal CILs and CELs from the 2nd PassIf all zones pass the SFT, results are final. If at least one LRZ does not pass the SFT, the iteration with the fewest MWs of network violations will be deemed as the final auction result.

### 5.5.8 Auction Results Posting

MISO will post the summary of the Planning Resource Auction(s) results on its website twenty (20) Business Days after the auction(s) offer window is closed. The summary includes the following information for MISO system wide and each LRZ for each season within the Planning Year: PRMR, Total Offer + FRAP, Offer Cleared + FRAP, LCR, Import Limit (CIL), Export Limit (CEL), Import/Export amount, ACP, deficient amount, and Total Offer Cleared volume for the system.

One month following the completion of any PRA, MISO will post the ZRC Offers in price/quantity pairs on its website without revealing the names of the Market Participants submitting such offers and the names of the Planning Resources offered.

**Resource Adequacy Settlement**

Transmission Provider will settle each auction using the following steps:

1. Determine the ACP for ZRCs and PRMR within each LRZ for every Season.
2. Provide HUC credits equal to the zonal ACP differential to Load subject to HUCs in every Season in the Planning Year.

3. Provide ZDC Hedge credits equal to the zonal Auction Clearing Price differential to ZDC Hedge Load amounts in every Season in the Planning Year.
4. Provide ZDB credits to all remaining PRMR in the LRZ. The ZDB is a credit against the ACP paid by LSEs with PRMR in each LRZ in every Season in the Planning Year.

Settlement calculations for the seasonal PRAs will be conducted on a daily basis and the results will be shown under the Real Time Settlements statement. Please refer to the Market Settlements BPM for further details. Below are charge types under the PRA(s) Settlement:

- PRA Charge
- Distribution of PRA Charge
- Zonal Deliverability Charge (ZDC) (*Only applies to the FRAP)
- Distribution of ZDC
- Capacity Deficiency Charge (Covered outside of the daily settlements)

Cleared seasonal ZRCs from Diversity Contracts that are not self-scheduled or in the LSE's seasonal FRAP will receive reduced payment based on the total number of days the external resource identified in the Diversity Contract are dedicated to MISO load when an LSE clears more seasonal ZRC in the PRA than its seasonal PRMR. The LSEs that converted SAC MW to seasonal ZRCs will receive the seasonal auction clearing price for the entire season r for those seasonal ZRCs that cleared in the seasonal PRA.

## 5.6 Retail and Wholesale Load

Retail and Wholesale Load switching between LSEs can be tracked through the MECT after the start of the in each season within the new Planning Year. As a result of load switching, the seasonal PRMR of the LSEs involved in the load switching will change. Switching of seasonal Retail load will not change an Electric Distribution Company's (EDC) total area seasonal PRMR. Similarly, wholesale seasonal load transaction will not change the total MISO seasonal PRMR.

**Retail Load Switching**

By January 15th 11:59 p.m. EST prior to start of the new Planning Year, retail supplier LSEs will confirm their share (e.g. PLC) of the EDC's area seasonal PRMR. The Retail LSE's seasonal PRMR will change during each season within the Planning Year when the load from one LSE is switched to another LSE within the EDC area.

Market Participants with demand in areas subject to retail choice are required to provide the name of the EDC and the CPNode names associated with the LSEs within the EDC area at the time of registration. The CPNode to EDC mapping information is important for determining LSEs' retail load switching method.

### 5.6.1 Wholesale (Non-Retail) Load Switching

For the case of Wholesale Load switching, the amount of the seasonal PRMR transferred via the wholesale load transaction process will transfer the PRMR of the current LSE to the new LSE starting with the effective date specified in the wholesale transaction for the applicable season. The transaction must be confirmed in the MECT by both parties before the start of the effective date.

### 5.6.2 Peak Load Contribution (PLC)

The EDC calculates each retail LSE's load ratio share of the retail LSEs peak demand of the EDC's peak demand at the MISO seasonal Coincident Peak Load prior to the Planning Year. The aggregate PLCs will be set equal to the seasonal PRMR of the EDC. Specific methods used by the EDC to calculate each Retail LSE's PLC must be provided to both MISO and LSEs no later than December 15$^{th}$ prior to the upcoming Planning Year. LSEs will have until January 15$^{th}$ to verify the seasonal EDC provided data in the MECT.

### 5.6.3 Retail Load Switching

EDCs are responsible updating the seasonal PRMR associated with each retail choice LSE in the MECT. The Retail Load screen in the MECT is provided for EDCs in Retail Choice states to track the Retail LSE's day-to-day migration of loads at the Asset Owner (AO) level.

Using the daily retail load switching information in the MECT, MISO Settlements calculates each retail choice LSE's new seasonal PRMR. The LSEs' PRMR are subject to resettlement calculations based on the resubmission of load switching information.

The daily retail load switching information includes:

- Name of the EDC
- Name of the LBA
- Operating Date of Retail load switching
- Season (Summer, Fall, Winter or Spring)
- Name of AO(s)
- AO's new Retail MW (with granularity of tenth of a MW)

### 5.6.4 Wholesale Load Switching

A Wholesale Load obligation can be switched from one LSE to another using the Wholesale Load Switching screen in the MECT during each season of the Planning Year. When Wholesale Load switching occurs, the daily capacity charges of the Wholesale Load will be transferred from the current LSE to the new LSE. The seasonal PRMR for affected LSEs will be decreased or increased, as appropriate, by the amount of the wholesale load plus the seasonal PRM. Procedures for billing, settlement, and credit requirements will be as specified in the appropriate BPMs. LSEs with wholesale contracts that change during the Season within the Planning Year may enter a Wholesale Load switching contract representing seasonal PRMR in the MECT.

### 5.6.5 Settlements of Wholesale and Retail Switching

All confirmed load switching information submitted by the Settlements deadline (per the Market Settlements BPM) will be transferred to Market Settlements for settlement calculation purposes.

An LSE’s seasonal PRMR will change based on the information submitted in the MECT for both Wholesale and Retail Load Switching.

MISO will calculate the new charges and credits by applying the seasonal Auction Clearing Price (“ACP”) for the applicable LRZ to the new daily seasonal PRMR for each AO.

At the end of each weekly billing cycle, MISO will sum up the daily charges for each LSE for the weekly invoicing. The Market Settlements BPM provides more information regarding this process. An LSE’s seasonal PRMR will change if Retail Load switching information in the MECT or daily load data for Settlements is resubmitted per the Settlement’s rerun process (i.e., S55, S105). Please see Market Settlements BPM for the Market Settlements Timeline.

## 5.7 Capacity Deficiency Charge

LSEs are allowed to opt out all or a portion of their seasonal PRMR from participating in the auction by paying the Capacity Deficiency Charge. This is achieved by making a voluntary entry into the “Capacity Deficient Amount (MW)” field of the MECT equal to the MW amount of seasonal PRMR opting out of the seasonal auction before the auction window opens. The Capacity Deficiency Charge for an LSE is the MW amount in the “Capacity Deficient Amount (MW)” field multiplied by 2.748 times the seasonal Cost of New Entry (“CONE”) for the LRZ where the LSE’s seasonal PRMR is located.

Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed on a *pro rata* basis based upon the cleared MW of seasonal PRMR to other LSEs in the Transmission Provider's footprint who did not opt to pay the Capacity Deficiency Charge. If the LRZ where the LSE opted to pay the Capacity Deficiency Charge failed to meet its seasonal LCR, then seasonal Capacity Deficiency Charge revenues will be allocated solely to LSEs within that LRZ that did not opt out of the seasonal auction by paying the seasonal Capacity Deficiency Charge. MISO will assess the seasonal Capacity Deficiency Charge on the first business day after the results of the seasonal PRA have been published.

# 6 Performance Requirements

## 6.1 Must Offer Requirement

The must offer requirement applies to any Market Participant who converts the SAC of a Capacity Resource to seasonal ZRCs, and those ZRCs are used in a seasonal FRAP or clear in a seasonal auction within the Planning Year. The must offer volume is the ICAP times the % of the total seasonal ZRCs a resource clears (for example, a unit eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP), with the exception of Intermittent Resources. The must offer for Intermittent Resources is based on the cleared seasonal ZRCs, or ZRCs used in a FRAP, divided by the seasonal Resource credit (e.g. wind capacity credit for wind) as described in Section 4.2.3.5. Additionally, no must offer requirement will exceed the resource's firm level of transmission service.

### 6.1.1 Generation Resource but not Dispatchable Intermittent Resource or Intermittent Generation

MP that owns a Capacity Resource with ZRCs that clear in the PRA or identified in a Fixed Resource Adequacy Plan (FRAP) must offer the ICAP equivalent of the cleared or FRAP ZRCs into the Day-Ahead Energy market and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Capacity Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff. Outages and derates must be reported in the MISO Outage Scheduler (CROW).

Compliance with "must-offer" requirements will be evaluated by MISO on a non-discriminatory basis. MISO will analyze compliance with "must offer" requirements in both the Day-Ahead and RAC by considering information provided by the MISO Outage Scheduler (CROW) and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation and Dispatchable Intermittent Resources.

### 6.1.2 Dispatchable Intermittent Resource and Intermittent Generation

An MP that owns a Capacity Resource that has ZRCs identified as part of a Fixed Resource Adequacy Plan or ZRCs which clear in a PRA must submit the ICAP equivalent MW value of the cleared ZRCs into the Day-Ahead Energy Market, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

The must offer requirement applies to the Installed Capacity of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the SAC rating. Installed Capacity typically refers to the amount of cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by (1 – $XEFOR_d$) of the Capacity Resource. For wind resources, Installed Capacity is cleared ZRCs and/or ZRCs used in a Fixed Resource Adequacy Plan divided by the wind capacity credit. For non-wind Intermittent Generation and Dispatchable Intermittent Resources, the XEFORd will be set equal to the SAC divided by the ICAP, where the ICAP shall be the maximum value registered in the Commercial Model. For non-wind Intermittent Resources not modeled in the Commercial Model, the ICAP will be the nameplate capacity value as provided by the MP.

DA Reliability Forecast submissions for Intermittent Generation and Dispatchable Intermittent Resources received by the close of both the DA and Forward Reliability Assessment Commitment (FRAC) market offer periods will be used to monitor compliance with the must-offer requirement when the unit's availability is affected by non-mechanical and/or non-maintenance reasons. The must-offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that submit a DA Reliability Forecast by DA Market close and FRAC close will check that the offers submitted are greater than or equal to the volumes submitted via the DA Reliability Forecast. The same Intermittent Forecast data file used in Day Ahead Must-Offer compliance shall be utilized in FRAC if no further update is provided. If a DA Reliability Forecast is submitted on time and in the correct format, it replaces the cleared Installed Capacity as the must-offer requirement. Intermittent Resource Generation cannot submit a DA Reliability Forecast if being registered as a Use Limited Resource.

When submitting data to the Intermittent Resource Forecast Update tool, a header row should be included at the beginning of the file in this format; Resource, Day, Hour Ending (HE), and MW. The must offer monitoring process for Intermittent Generation and Dispatchable Intermittent Resources that do not to provide the DA Reliability Forecast by the DA Market close and the FRAC close, will be based on offers submitted and outages or derates submitted in MISO's Outage Scheduler (CROW). The must-offer process will be based on the daily and hourly offers submitted by the Asset Owner. Additionally, maintenance and mechanical outages to Intermittent Forecasts will be based on the forecasts only; and the thresholds established in Section 6.1 will not be used for Intermittent Generation and Dispatchable Intermittent Resources that provide the DA Reliability Forecast.

### 6.1.3 Use Limited Resource

An MP that commits a Capacity Resource that has ZRCs which clear in a Season or are used in a Fixed Resource Adequacy Plan must submit the ICAP value of ZRCs which either clear the Planning Resource Auction or is used in a Fixed Resource Adequacy Plan in the Day-Ahead Energy Market, each pre Day-Ahead, and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Generation Resource is unable to provide Energy, Contingency Reserve, or Short-Term Reserve due to a forced or planned outage or other physical operating restrictions consistent with MISO's Tariff.

A Use Limited Resource are required to submit into the Day Ahead Market to satisfy the must-offer requirement of at least four (4) continuous hours daily across MISO's forecasted daily peak (including weekends). The must offer period of four (4) hours includes the two (2) hourly intervals prior to the forecasted peak hour, the peak hourly interval, and one (1) hourly interval after the forecasted peak load. This approach enables MISO to have an opportunity to schedule the Resource for the period in which the Use Limited Resource will not be recharging or replacing depleted resources. MISO's peak period will be based on the forecast published one day prior to the operating day in the Market Report section of the MISO website:
https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports
>Select “Summary” under Navigator to find the latest reports.
All outages and derates for Use Limited Resources need to be reflected in MISO's Outage Scheduler (CROW) or SDX. Thresholds for Use Limited Resources will only be applied during the four continuous hours across MISO's peak. MISO will not call upon a Use Limited Resource during its recharge hours, except in the case of an Emergency.

### 6.1.4 External Resources

The maximum must offer requirement applies to the registered Capacity of the External Resource.

An MP that owns a Capacity Resource that has ZRCs which are identified in a Fixed Resource Adequacy Plan or clear in a PRA must submit the ICAP value of registered Capacity and make an Offer into the Day-Ahead Energy market for every hour of every day, except to the extent that the Generation Resource is unavailable due to a full or partial forced scheduled outage. Installed

Capacity refers to the amount of ZRCs divided by (1-XEFORd) of the Capacity Resource. The must offer requirement will be capped at the resource's ICAP value.

Offers in the Day-Ahead Energy Market can only be Normal Energy type with the transaction type of either fixed or dynamic. Dispatchable and market type of Day-Ahead cleared schedules are accounted for in the first post Energy and Operating Reserve Market. In addition, the Normal Energy type with the transaction type of either Fixed or Dispatchable offers with market type of Real-Time Energy and Operating Reserve Market only will also be considered in Day-Ahead Reliability Assessment Commitment (FRAC).

Therefore, the must-offer requirement for External Resources in FRAC is met by being available for declared capacity emergencies via MISO Market Capacity Emergency SO-P-EOP-00-002.

The MP that has either identified ZRCs from a FRAP or cleared ZRCs in a Planning Resource Auction from an External Resource shall ensure the resource operator is reporting its outages and derates with their respective reliability coordinator. External Resources must be available to schedule Energy into MISO's Region during Emergencies if needed by MISO. MISO Market Capacity Emergency SO-P-EOP-00-002 includes a mechanism to schedule all External Resources into MISO's BAA. BPM 007 Physical Scheduling Systems Section 15 explains how External Resources should be identified as Capacity Resources. External Resources should select "YES" in the Miscellaneous (MISC) field of the E-tag and the Token field must contain "MISOCR" in all capital letters with no spaces. In the Value field, the MP should list the Capacity Resource name that matches the Module E External Resource registration name in the MECT.

External Resources that are Use Limited Resources must follow the Day-Ahead must-offer requirements for Use Limited Resources as documented in Section 4.2.4.2 of this BPM.

Compliance with "must offer" requirements will be evaluated by MISO on a nondiscriminatory basis. MISO will analyze the compliance with must-offers in both the Day-Ahead and RAC by considering information provided by MISO's CROW Outage Scheduler, and operational limitations, including, but not limited to, those related to fuel limited, energy output limited or Intermittent Generation.

### 6.1.5 DRR Type I and Type II

The same must offer requirement described in Sec. 6.1 applies to the Installed Capacity of DRR Type I and Type II, (and not the SAC rating) used to meet Resource Adequacy Requirements. Installed Capacity refers to the amount of ZRCs cleared in an PRA and/or used in a Fixed Resource Adequacy Plan divided by (1 – $XEFOR_d$) of the Capacity Resource.

### 6.1.6 SER Type II

SER Type II resources that clear the PRA or are used as part of a FRAP will be required to offer the ICAP equivalent into the Day-Ahead Energy and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for the four hours across the expected peak hour for each operating day. The must offer period of four hours includes the two hourly intervals prior to the forecasted peak hour, the peak hourly interval, and the hourly interval after the forecasted peak load. MISO's peak period will be based on the forecast published one day prior to the operating day in the Market Report provided at the link below.

https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc

All outages and derates for SER Type II resources should be reflected in MISO's Outage Scheduler (CROW).

## 6.2 Must Offer Monitoring

MISO will monitor whether the offers submitted by the Asset Owner of each Capacity Resource in the Day-Ahead Energy and Operating Reserve Market, and first post Day-Ahead RAC process meets the seasonal must-offer requirements for the amount of Installed Capacity (ICAP) of the resource.

The offers should be greater than or equal to the seasonal must offer requirement minus approved outages or derates minus the applicable threshold as detailed in this section but not to exceed the firm level of established transmission service. This excludes Capacity Resources that submit Intermittent Forecasts that have been accepted by MISO including DIR registered Hybrid Resources.

*[Firm Service] > [Offer] ≥ [Offer requirement] – [Outage or Derate] – [tolerance threshold]*

If the offer amount is greater than or equal to the must offer requirement minus the approved outage or derate in CROW minus the appropriate threshold, then the MP will have passed the must-offer monitoring check. Otherwise, the MP will not pass the must offer monitoring check. MISO will notify MPs through a report published on the market portal of their must offer status.

Outages & Derates

If the Offers for Day Ahead and first post Day-Ahead RAC are less than the must-offer requirement, then MISO will compare the difference to approved outages or derates in MISO's Outage Scheduler (CROW) for such resources. Approved outages, approved derates, and offers will be captured based on the information provided at both the DA Market close and first post Day-Ahead RAC close. DA Market close and first post Day-Ahead RAC close times are addressed in the Energy and Operating Reserve Markets BPM.

Tolerance Threshold

MISO will apply a tolerance threshold to all resources based on the must offer requirement listed in the MECT for the applicable season. The thresholds were developed to recognize that data entry errors could occur when providing derate volumes through MISO's Outage Scheduler (CROW). Importantly, this does not relieve the MP of the obligation to meet the overall seasonal must-offer requirement. The tolerance threshold volume will be applied at the CPNode level except for those resources noted otherwise in this BPM. The thresholds are as follows:

- The lesser of 10 MW or 10% for Capacity Resources greater than or equal to 50 MW
- The greater of 1 MW or 10% for Capacity Resources less than 50 MW

Market Participant Review

If a Market Participant believes there is a discrepancy in their must-offer report, the Market Participant can notify MISO via email to MISO Resource Adequacy (help@misoenergy.org) of the discrepancy and submit supporting documentation. Outage information should include all revisions from the outage submission to the completion of the outage.

MISO will review the information submitted and notify the Market Participant within seven (7) Business Days via email of the outcome of the review.

IMM Access

The IMM also has access to the reports published on the market portal and may contact Market Participants directly on any compliance issues.

## 6.3 Annual Calculation of CONE

MISO will work with the Independent Market Monitor (IMM) to recalculate the CONE value for each LRZ annually by September 1 of each year for the following Planning Year. The CONE value for each individual LRZ will be the same in every season (Summer, Fall, Winter and Spring).

In calculating CONE values, the IMM and MISO will consider the following factors:

- Physical factors: type of resource, location, costs for fuel
- Financial factors: debt/equity ratio, cost of capital, ROE, taxes, interest, insurance
- Other factors: permitting, environmental, Operating and Maintenance costs, etc.

MISO and the IMM will not consider anticipated net revenues from the sale of capacity, Energy, or Ancillary Services as factors in the annual recalculation of the CONE.

Once the IMM and MISO have calculated the CONE for each LRZ, MISO will make a filing with the Commission under Section 205 of the Federal Power Act seeking approval from the Commission for the re-calculated CONE. CONE values approved by FERC are posted on the MISO website.

## 6.4 Replacement Resources

### 6.4.1 Maximum Outage & Derate Threshold (Greater than 31 day rule)

If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs or new resources per Section 6.4.5 to transfer the performance requirements applicable to the planning Resource or pay the Capacity Replacement Non-Compliance Charge (Tariff Module E-1 Section 69A.3.1.h).

### 6.4.2 Attachment Y Retirement or Suspend Status

A Planning Resource used to meet seasonal RAR must be replaced by the registering Market Participant prior to the effective date of a status change to 'retired' or 'suspend' via an Attachment Y filing.

### 6.4.3 Transfer of Resource Adequacy Requirement and Performance Requirements through ZRC Replacement

ZRC replacement is available for use by Planning Resources that cleared a Season in the Planning Year and that go on suspension, retirement, catastrophic outage, or that experience a Generator Planned Outage or derate greater than 31 days in that Season. In the event of such ZRC Replacement any performance requirements associated with the Resource that is being replaced (e.g., must offer obligation) will be transferred to the substituting Resource(s) for the duration of the ZRC Replacement period.

A Resource being used for ZRC replacement must not be on a full or partial Generator Planned Outage during the term of the ZRC replacement and must otherwise meet the applicable performance requirements set forth in section 69.A.3.1.h of Module E-1 of the Tariff.

### 6.4.4 ZRC Replacement Transactions

Replacement transactions in each Season can be entered at any time during the planning year and, unless otherwise modified, are valid through the end of the applicable Season within the planning year.

Replacement ZRCs may be sourced from any LRZ or ERZ subject to LCR, CIL, CEL, SREC, and SRIC from the associated seasonal PRA. Planning Resource replacement transactions should be entered into the MECT tool at least seven (7) Calendar Days prior to effective date of replacement.

Replacement ZRCs can be from the Market Participant's own Planning Resources or ZRCs procured through a bilateral transaction from another Market Participant in the same seasonal auction. If an LMR is involved in a replacement transaction, the Market Participant entering the transaction should notify MISO Resource Adequacy (help@misoenergy.org) to ensure that the replacement is reflected in the DSRI properly. ZRC replacements from LRZs other than the original resource will be processed in accordance with the following parameters:

- ZRC replacement shall be processed on a first come, first served basis.

- The amount of cleared seasonal ZRCs in each LRZ at the time of a ZRC replacement shall be based upon the current amounts of cleared seasonal ZRCs, including any previous replacement transactions.

Replacement ZRCs should be input in the MECT with an intended effective date. The termination date of a Replacement ZRC transaction will be set as end of the Season by default. Market Participants can update the termination date to a different date before end of the Season, provided that replacement capacity must be designated for RAR until at least 95% of its ZRCs have been replaced.

ZRC replacement shall have no impact on settlements from the PRA, TPRA and FRAPs. The “Replacement Calculator” option is available in the MECT which can be used for verifying if the Planning resource being used for the replacement will meet all of the required LRZ parameters including LCR, CIL and CEL, as well as ERZ CEL.

### 6.4.5 On Ramping New Resources Mid-Planning Year for ZRC Replacement

If a new resource is expected to be available at the start of a season within the Planning Year, the preferred course for the Market Participant would be to enter the ICAP Deferral process.

However, if a new resource is unable to utilize the ICAP Deferral Process, the new resource may be eligible to receive uncleared Zonal Resource Credits (ZRCs) in the middle of the Planning Year and prior to the start of a season only under the following conditions:

i. The new resource must be used for replacement of a specific resource
ii. Must specify which Planning Resource the new resource will be replacing
iii. Market Participant must coordinate with the IMM to obtain confirmation the new resource did not physically withhold capacity from a particular seasonal auction
iv. The new resource must be in Commercial Model at time of request
v. The new resource must submit applicable testing (i.e. GVTC into MISO PowerGADS or Non-GADS Performance Template into MECT, DR tests, etc.).
vi. The new resource must become commercially operable as of date of replacement
vii. Requests must be submitted at least 3 weeks prior to start of replacement

### 6.4.6 MECT ZRC Replacement Calculator

The Replacement Calculator screen in the MECT is used to help MPs assess whether the ZRCs being used for the replacement will meet all of the required parameters including seasonal LCR, CIL, CEL, SREC, and SRIC.

The Replacement Calculator screen displays the seasonal PRMR, sum of cleared Offers and FRAPS, LCR, CIL, CEL, Total Import and Total Export for each LRZ, and Total Export for each ERZ from the seasonal PRA. Import Available and Export Available numbers are updated each time the Resource Replacement process is completed.

- Import Available number represents the maximum ZRCs allowed to import into the LRZ without violating the CIL in that season. Import Available for the LRZ is calculated as:
  Seasonal Import Available = CIL – Total Import from PRA + (Sum of all Export* - Sum of all Imports*)
- LRZ Export Available number represents the maximum seasonal ZRCs allowed to export out of the LRZ without violating the CEL. Export Available for the LRZ is calculated as:
  LRZ Export Available = CEL – Total Export from PRA + (Sum of all Import - Sum of all Exports*)
  ERZ Export Available represents the maximum ZRCs allowed to export out of the ERZ without violating the CEL. It is calculated as:ERZ Export Available = ERZ CEL – ZRCs cleared, including FRAPs, in ERZ

**Example:**

LRZ 1 has an LCR of 15,070 MW; and Import Available of 4,628.7 MW
LRZ 2 has an Export Available of 1,023.7 MW
LRZ 3 has an Export Available of 1,759.4 MW
ERZ 1 has an Export Available of 1,000 MW

**Total MW needing replacement** in LRZ 1: = 200 MW (Original Resource = AAA1)

**Replacement ZRCs from LRZ 1:** Of that 200 MW, 100 MW will be replaced by other Planning Resources located in LRZ 1 (Substitution Resource = AAA2)

**ZRCs in LRZ 1 (after same LRZ replacement)**: LRZ 1's total ZRCs from LRZ 1 after replacement = Offers Cleared + FRAP - Total MW needing replacement + Replacement ZRCs from the same LRZ = 18,522.3 – 200 + 100 = 18,422.3

**LCR Test**: Since 18,422.3 > LRZ 1's LCR of 15,070, the LCR Test result is "Pass"

**Amount Exported**: Remaining Replacement ZRCs of 100 MW are imported from LRZ 2 and LRZ 3:

- o LRZ 2's Exported ZRCs = 40 MW (Substitution Resource = BBB3)
- o LRZ 3's Exported ZRCs = 60 MW (Substitution Resource = CCC4)

**Import Test**: LRZ 1's total Imported ZRCs = 100 MW (40 MW + 60 MW). Since 100 MW < Import Available of 4,628.7, the Import Test result is "Pass"

**Export Test**: Since LRZ 2's Export of 40 MW < Export Available of 1,023.7 MW and LRZ 3's Export of 60 MW < Export Available of 1,759.4 MW, the Export Test results for LRZ 2 and 3 are "Pass".

This scenario will require the following 3 separate Resource Substitution Registrations to replace AAA1 for the full amount of 200 MW in LRZ 1:

- o First 100 MW of AAA1: replaced by AAA2 for 100 MW from LRZ 1
- o Second 40 MW of AAA1: replaced by BBB3 for 40 MW from LRZ 2
- o Remaining 60 MW of AAA1: replaced by CCC4 60 MW from LRZ 3
- o No change for ERZ 1

### 6.4.7 Capacity Replacement Non-Compliance Charge and Distribution

Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. The charges will be applied to the originally cleared Resource.

Capacity Non-Compliance Charge = [# days failure to comply with replacement ] * [ # ZRCs failed to be replaced ] * [Seasonal Zonal ACP + Daily Zonal CONE ]

The number of Days counted will be on an hourly basis (31 days x 24 hours = 744 hours) since outages may only cover a portion of some Days. The number of hours that failed to comply or replace will be determined by ranking generator performance across the Season and applying charges to hours with the least violations in the Season beyond 744 hours. The charges assessed will round down to the number of whole Days in excess of 31 Days. For example, 815 hours minus 744 hours and then divided by 24 hours = 2.96 Days. In this case, the penalty charged for will be for two days.

Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their PRMR during the applicable Season of the Planning Year on a pro rata basis, based upon their respective LSEs' share of total PRMR for the Transmission Provider Region.

## 6.5 LMR performance

### 6.5.1 BTMG Performance

When a BTMG that either is used in a seasonal FRAP or cleared in a seasonal PRA fails to perform during an Emergency when included in a Market Participant's response to a Scheduling Instruction, the penalties are calculated for each hour in which a BTMG fails to respond in an amount greater than or equal to the target level of generation increase as the sum of: (1) the product of (a) the amount of increased generation not achieved and (b) the LMP at the CPNode associated with the BTMG; and (2) applicable Revenue Sufficiency Guarantee (RSG) Charges. The amount of increased generation not achieved for BTMG is equal to the greater of: (1) the difference between (a) the target level of generation increase and (b) actual increased generation; and (2) zero. The applicable RSG Charges are equal to the product of: (1) the difference between (a) the target level of increased generation and (b) actual increased generation; and (2) the applicable RSG charges.

The revenues from charges resulting from BTMGs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a BTMG does not increase generation in response to a Scheduling Instruction or where the resource is claimed to be unavailable as indicated in the DSRI as a result of maintenance requirements or for reasons of Force Majeure, MISO shall initiate an investigation into the cause of the BTMG not being available as needed during Emergency and may, if deemed appropriate, disqualify that resource from receiving ACP payments for that Planning Year. The

BTMG may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the BTMG's registered availability period; or the resource has reached its registered maximum number of deployments for that season). However, should a BTMG resource indicate availability in the DSRI at any time in any season of the Planning Year, it is considered available in the event of an Emergency during that season and may receive Scheduling Instructions.

In the event the same BTMG does not sufficiently respond or is unavailable, except for reasons of Force Majeure or other acceptable reasons defined in the Tariff or in this BPM on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours), the MP that registered the BTMG will be subject to the penalties described herein (if that BTMG fails to increase generation to the level instructed). Such BTMG shall be assessed the same penalty as indicated above for its first performance failure, and the BTMG will no longer be eligible to receive ACP payments for the current Planning Year and for the next Planning Year.

If, in review of the BTMG's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

### 6.5.2 DR Performance

If a DR that either is used in a seasonal FRAP or cleared in the seasonal PRA fails to perform during an Emergency when included in a Market Participant's response to Scheduling Instructions, penalties will be calculated for each hour in which a DR fails to respond in an amount greater than or equal to the target level of Load reduction as the sum of: (1) the product of (a) the amount of load reduction not achieved, including Load above the registered firm service level for those DR registered as such and (b) the LMP at the CPNode associated with the DR; and (2) applicable RSG Charges. The amount of Load reduction not achieved for DRs is equal to the greater of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) zero. The RSG Charges are equal to the product of: (1) the difference between (a) the target level of Load reduction and (b) actual Load reduction; and (2) the applicable RSG charges.

The revenues from charges resulting from DRs that fail to respond in an amount greater than or equal to the MP responses to Scheduling Instructions shall be allocated, *pro rata*, to MPs representing LSEs in the LBA area(s) that experienced the Emergency, on a load ratio share basis.

For any situation where a DR does not respond in an amount greater than or equal to the target level of Load reduction or registered firm service level or the resource is unavailable, including those circumstances where the resource is unavailable for maintenance reasons or Force Majeure, MISO shall initiate an investigation into the cause of the DR not being available when called upon, and may, if deemed appropriate, disqualify that resource from ACP payments for that Planning Year. The DR may be called but not required to respond if the Emergency call is outside the resource's registration limitations (i.e. less than the registered time to respond, the event lasts longer than the registered duration, is made outside the DR's registered availability period; or the resource has reached its registered maximum number of deployments for that season). However, should a Demand Resource indicate availability in the DSRI at any time in a season within the Planning Year, it is considered available in the event of an Emergency during that season and may receive scheduling instructions.

In the event the same DR is not sufficiently responsive, including being unavailable, on a second occasion during a Season within the Planning Year (with a separation period of at least 24 hours) when included in a Market Participant's response to Scheduling Instructions; except when unavailable due to maintenance reasons, Force Majeure or other acceptable reasons as outlined in the Tariff or this BPM, the MP that registered the DR that was used to meet Resource Adequacy Requirements will be subject to the penalties described herein The MP using the DR shall be assessed the same penalty as indicated above for a first performance failure, and the DR will no longer be eligible to receive ACP payments for the remainder of the current Planning Year and for the next Planning Year (s).

If, in review of the DR's measurement and verification data following an Emergency, MISO determines that the MP has committed fraud to receive excess payments or avoid penalties, MISO will have the right to ban the MP or its customers from participation in the wholesale electricity markets, as well as, pursue other legal options at the sole discretion of MISO.

# 7 Integration of New LSEs

This section serves as a guide for those new Load Serving Entities (LSEs) integrating into MISO's region between the time MISO has completed the PRA(s) and the next Planning Year starts.

Once the integration date is set, MISO will work with both existing and new LSEs to ensure that the newly integrating LSEs have sufficient Planning Resources to meet their anticipated Coincident Peak Load Forecast plus an appropriate planning reserve margin.

To ensure the PRMR for new LSEs is met, MISO may conduct a Transitional PRA following the same registration requirements and auction protocols as the PRA.

MISO may provide the following when integrating New LSEs for applicable season(s):

1. Define, as needed, new Local Resource Zone and their associated zonal parameters including:
    - Calculate CONE for the LRZ
    - Determine ZIA, ZEL, CIL and CEL
    - LOLE Analysis (Section 3.5.2)
    - Establishment of Local Reliability Requirement (Section 5.2.2.2)
2. Calculate Planning Reserve Margin and Transmission Losses for the new LBAs
    - Determination of Planning Reserve Margin (Section 3.5.1)
    - Review of CPD Forecasts (Section 3.2.5)
3. Conduct Transitional Planning Resource Auction
    - Amount of Capacity Cleared in Each Auction (Section 5.5.2)
    - Conduct of the PRA (Section 5.5.3)
    - Auction Results Posting (Section 5.5.8)

MISO may coordinate the proper timing of the data collection effort with the New LSEs for the successful completion of the Transitional PRA. The Transitional PRA will ensure that sufficient Planning Resources are procured to meet the PRMR of the newly integrating MISO region for the applicable seasons in the remaining Planning Year.

The RA Timeline for the seasonal PRAs is shown in Appendix K. MISO will determine the RA timeline for the Transitional PRA and will publish it on the Resource Adequacy webpage under the Planning Section of the MISO public website. The RA timeline for the Transitional PRA will be reviewed by stakeholders prior to publishing on the MISO public website.

# 8 Testing Procedures and Requirements

## 8.1 Generator Real Power Verification Testing Procedures

MISO has developed generator test standards as documented in Appendix J that apply for Planning Years 2011-2012 and beyond.

# 9 Appendices

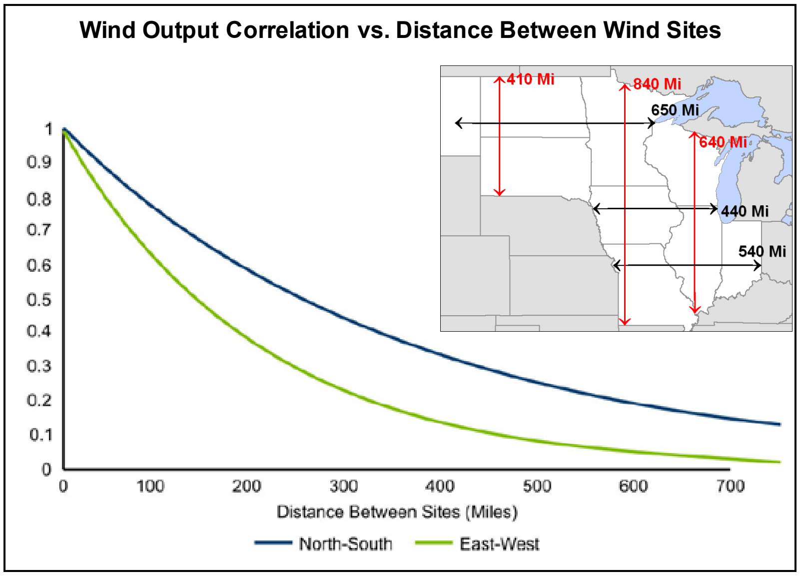
## Appendix A – Wind Capacity Credit

The basic goal is to estimate the reliable output of wind as a percentage of the installed capacity, for each season, for the MISO System and by Commercial Pricing Node (CPNode). This involves the following data. Driving Data for Wind Capacity Credit:

- The hourly load and the hourly wind output for 8,760 hours. This concurrent load and wind data, along with the normal complement of generator data in an LOLE simulation, is essential for determining the system-wide Effective Load Carrying Capacity (ELCC) of the wind resources.
- MISO tracks the hourly wind output for the top 8 seasonal MISO coincident daily peak hours, by MISO total and individual wind CPNodes. The system-wide and CPNode data is used to allocate the system wide ELCC among individual CPNodes.
- MISO tracks the hourly amounts by which individual wind CPNodes are dispatched downward as part of the Dispatchable Intermittent Resources (DIR) activity. Similarly, MISO estimates the MW that CPNodes may have been curtailed.

Since 2009, MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the system. The MISO process as developed and vetted through the MISO stakeholder community consists of a two-step method. The first-step utilizes a probabilistic approach to calculate the MISO seasonal system-wide ELCC value for all wind resources in the MISO footprint. The second step employs a deterministic approach using unit-specific metrics to allocate the single seasonal system-wide ELCC value across all wind CPNodes in the MISO system, resulting in an individual wind capacity credit for each wind node in operation for the study period.

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This leads to a higher average output from wind for a more geographically diverse set of wind plants, relative to a closely clustered group of wind plants. Due to the increasing diversity and the inter-annual variability of wind generation over time, the process needs to be repeated annually to incorporate the most recent historical performance of wind resources into the analysis. For each upcoming Planning Year, the wind capacity credit values in MISO are updated to account for both the stochastic nature of wind generation and the increasing integration of new resources into the system. The sections of this write-up and current results illustrated here are broken down to provide an example detailing the two-step method adopted by MISO for determining wind capacity credit from the 2012-13 Planning Year.




**Step-1: MISO System-Wide Wind ELCC Study**

<u>Probabilistic Analytical Approach</u>

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the “Less than 1 Day in 10 Years” criteria for LOLE. This measure is often expressed as 0.1 days/year, as one year is the period for which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC [1].

To measure ELCC of a particular resource, the reliability effects need to be isolated for the resource in question, from those of all the other sources. This is accomplished by calculating the LOLE of two different cases: one “with” and one “without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Fig. 1 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) LOLE criteria. In MISO’s seasonal construct, each season establishes a baseline of 0.025 days/year so that the summation of the seasonal LOLE equals the industry standard of 0.1 days/year.

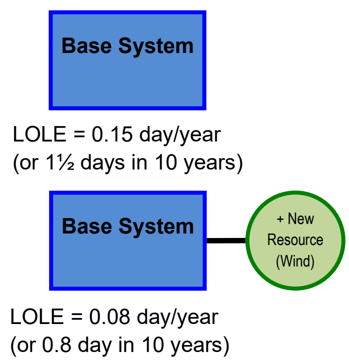



Figure 1: Example System “With” and “Without” New Resource

With each case being at the same reliability level, as shown in Fig. 2, the only difference between the two cases is that the load was adjusted. This difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 minus -200) for the new resource in this example. This number may be divided by the Registered Maximum Capacity (RMax) of the new resource and then expressed in percentage form. The new resource in the ELCC example Fig. 2 has an ELCC of 30 percent of the resource’s nameplate capacity.

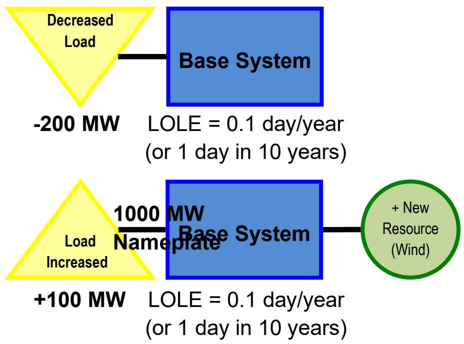



Figure 2: ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Fig. 2 was utilized as the analytical approach for the determination of the seasonal system-wide ELCC of the wind resource in the much more complex MISO system. For each historic year studied there were two types of cases analyzed, ones with and ones without the wind resources included in the model. Each case was adjusted to the same common baseline LOLE and the ELCC was measured off those load adjustments. Using ELCC is the preferred method of calculation for determining the capacity value of wind [2].

LOLE Model Inputs & Assumptions

To apply the ELCC calculation methodology MISO uses an LOLE model capable of sequential Monte Carlo simulation to calculate LOLE values with and without the wind resource modeled. This model consisted of three major inputs:

- Generator Forced Outage Rates (EFORd)
- Actual Historic Hourly Load Values
- Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These EFORd are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional types units in the MISO system.

To incorporate historical performance, the actual historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the historic ELCC values for the wind generation in the MISO on a system-wide basis.

**Step-2: Wind Capacity Credit by CPNode Calculation**

Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system a deterministic approach involving an historic-period metric is used to allocate the single system-wide ELCC value of wind to all the registered wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is important to assign the capacity credit of wind at the individual CPNode locations, because in the MISO market the location relates to deliverability due to possible congestion on the transmission system. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance are valuable inputs in determining the tradeoffs between constructing wind facilities in high capacity factor locations, that in the case of the MISO are located in more remote locations far from load centers, and requiring more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

The fleet-wide wind ELCC value (%) multiplied by the installed registered wind capacity (MW) results in the total fleet-wide wind capacity (MW). The fleet-wide wind capacity (MW) is then allocated to the CPNodes in the MISO system.

Allocation considers the historic output, both in terms of with and without curtailments, for each wind CPNode over the top 8 daily peak hours for each season included in the analysis. A capacity factor for each CPNode during all historical daily peak hours is represented in the Wind CPNode Equations contained in this appendix by “$PKmetric_{CPnode}$” for a particular CPNode, which is also referred to as the peak performance capacity factor.

This peak capacity factor for each season is calculated using two methods:

- one method includes (adds back in) megawatts of a wind resource that were curtailed
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two methods above, for each individual resource, forms the basis for allocating the fleet-wide wind capacity to the CPNodes.

The Wind Capacity Rating (MW) for new wind CPNodes that do not have historic output data, will receive the fleet-wide wind capacity credit percentage as their default capacity credit (%) for their first year in operation

Tracking the top 8 daily peak hours in a season is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2011, all of the 0.1 days/year LOLE occurred in the month of July, but only 4 of the top 8 daily peaks occurred in the month of July. Therefore, no more than 4 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 4 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $PKmetric_{CPnode}$ over multiple years.

Wind CPNode Equations

The relationship of the wind capacity rating (MW) to a CPNode's installed capacity value (RMax) and Capacity Credit (%) is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPNode n}} = \text{RMax}_{\text{CPNode n}} \times (\text{Capacity Credit \%})_{\text{CPNode n}}$$

(1)

Where $RMax_{CPnode\ n}$ = Registered Maximum installed capacity of the wind facility at the CPNode n. Registered Maximum (RMax) is the MISO market term for the installed capacity of a resource, in terms of megawatts (MW).

The right most term in equation (1) above, the $(\text{Capacity Credit \%})_{CPNode\ n}$, can be replaced by the expression (2):

$$(\text{Capacity Credit \%})_{\text{CPNode n}} = \text{K} \times (\text{PKmetric}_{\text{CPNode n}} \%) \quad (2)$$

Where "K" for was found by obtaining the PKmetric at each CPNode over the time period, and solving expression (3):

$$K = \frac{\text{ELCC}}{\sum_{1}^{n}(\text{RMax}_{\text{CPNode n}} \times \text{PKmetric}_{\text{CPNode n}})} \qquad (3)$$

This results in the sum of the Wind Capacity Rating (MW) calculated for the CPNodes approximately equal to the fleet-wide wind ELCC.

**References**

[1] Garver, L.L.; "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on, vol. PAS-85, no. 8, pp. 910-919, Aug. 1966

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; "Capacity Value of Wind Power," Power Systems, IEEE Transactions on, vol. 26, no. 2, pp. 564-572, May 2011

## Appendix B – GADS Events Outside Management Control (OMC Codes)

There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. Such outages include (but are not limited to) ice storms, hurricanes, tornadoes, poor fuels, interruption of fuel supplies, etc.

A list of GADS causes and their cause codes for OMC events are listed on the following page. MISO has generated a list of OMC codes accepted by MISO for GADS purposes. For more detailed information regarding OMC outages and codes please refer to Appendix K of the NERC GADS Data Reporting Instructions.

The lists of GADS Cause Codes applicable to reporting outages to MISO are as follows:

**GADS Cause Codes Outside Plant Management Control (OMC)**

| | |
|---|---|
| 3600 | Switchyard transformers and associated cooling systems – external |
| 3611 | Switchyard circuit breakers – external |
| 3612 | Switchyard system protection devices – external |
| 3619 | Other Switchyard equipment – external |
| 3710 | Transmission line (connected to powerhouse switchyard to 1$^{st}$ Substation) |
| 3720 | Transmission equipment at the 1$^{st}$ Substation (see code 9300 if applicable) |
| 3730 | Transmission equipment beyond the 1$^{st}$ Substation (see code 9300 if applicable) |
| 9000 | Flood |
| 9001 | Drought |
| 9010 | Fire, not related to a specific component |
| 9015 | Pandemic |
| 9020 | Lightning |
| 9025 | Geomagnetic disturbance |
| 9030 | Earthquake |
| 9031 | Tornado |
| 9035 | Hurricane |
| 9036 | Storms (ice, snow, etc.) |
| 9040 | Other catastrophe |
| 9130 | Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc.) where the operator is not in control of contracts, supply lines, or delivery of fuels |

| | |
|---|---|
| 9132 | Wet Fuel – Biomass |
| 9135 | Lack of water |
| 9139 | Ground water or other water supply problems |
| 9150 | Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems |
| 9200 | High ash content |
| 9210 | Low grindability |
| 9220 | High sulfur content |
| 9230 | High vanadium content |
| 9240 | High sodium content |
| 9250 | Low Btu coal due to low BTU vane of coal not expected (Outside Management Control) |
| 9260 | Low Btu oil |
| 9270 | Wet coal |
| 9280 | Frozen coal |
| 9290 | Other fuel quality problems |
| 9300 | Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730) |
| 9320 | Other miscellaneous external problems |
| 9500 | Regulatory (nuclear) proceedings and hearings - regulatory agency initiative |
| 9502 | Regulatory (nuclear) proceedings and hearings - intervener initiated |
| 9504 | Regulatory (environmental) proceedings and hearings - regulatory agency initiated |
| 9506 | Regulatory (environmental) proceedings and hearings - intervener initiated |
| 9510 | Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.) |
| 9520 | Oil spill in Gulf of Mexico |
| 9590 | Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event) |

# Appendix C – Registration of Energy Efficiency Resources

**Energy Efficiency Resource**

| Registration Requirements | Explanation |
|---|---|
| Auction | The Auction you are registering your Energy Efficiency Resource for displays in this field. |
| Name | Enter Name of the Energy Efficiency Resource. |
| Description | Enter type of resources and additional names and sizes if registering more than one unit. |
| Asset Owner | Select the name of the entity that owns or has rights to this asset. |
| Local Resource Zone (LRZ) | The LRZ where this Energy Efficiency Resource is located displays once the Asset Owner and LBA is selected and the registration is saved. |
| Local Balancing Area (LBA) | Select the LBA where this Energy Efficiency Resource is located. |
| Load Zone CP Node | Enter the CP Node where the Energy Efficiency Resource is located. |
| Program Information | Indicate if this is a new program or previously registered program |
| Program Inception Year | Select year program began |
| Program Name | Name of program that is being registered |
| Capability | Indicates the capability of the program for each Planning Year. |
| Added Capability | Enter MW capability of program for given Planning Year. |
| Total Capability | Total cumulative MW capability of program. |
| Eligible Capability | Sum of MW capability of 4 most recent Planning Years. |
| Forecast Capability | Total Capability minus Eligible Capability. |
| Energy Efficiency Capability at MISO Peak | MW value of program at MISO Peak. |
| Documentation | Attach supporting documentation. |
| Certify that registrant possesses ownership or equivalent contractual rights | Indicate whether registrant has all necessary rights to register this resource |
| Comments | Submit any comments for this registration. |

## Appendix D – Registration of DRs

| Demand Resource (DR) | |
|---|---|
| **Registration Requirements** | **Explanation** |
| Auction | The Season(s) in the PY you are registering your DR for displays in this field. |
| Name | Enter Name of the DR. |
| Description | Enter type of resources and additional names and sizes if registering more than one unit. |
| Asset Owner | Select the name of the entity that owns or has rights to this asset. |
| Local Resource Zone (LRZ) | The LRZ where this DR is located displays once the Asset Owner and LBA is selected and the registration is saved. |
| Local Balancing Area (LBA) | Select the LBA where this DR asset is located. |
| Load Zone CP Node | Enter the CP Node where the DR asset is located. |
| Aggregate Retail Customer (ARC) | Check box if resource registered as an ARC |
| Retail Choice | Check box if Resource is for Retail Choice and if yes, type in name of Retail Choice Customer |
| Accreditation | Choose accreditation method and attach supporting documentation |
| Monthly Availability | Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated the amount of MW you can reduce in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.<br><br>Seasonal values shall be provided beyond the 2 year monthly window. Provide seasonal (Summer and Winter) MW levels associated the amount of MW you can reduce in a given month consistent with the actual |

| Demand Resource (DR) | |
|---|---|
| **Registration Requirements** | **Explanation** |
| | physical availability of the resource, limited by any relevant regulatory or contractual restrictions. |
| Operator Contact Name | Enter who to contact for deployment of DR. The contact should be available 24 x 7 for commitment by MISO or LBA. |
| Operator Contact Phone Number | Enter phone number for 24 x 7 operator. |
| Operator Contact Email | Enter email address for 24 x 7 operator. |
| M&V protocol to be applied to this DR | Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO Emergency. If other selected, please describe in box. |
| Exclude Season | Check this box to exclude the registration from participation in the specified season |
| Capability at MISO Peak | Enter MW capability being registered at MISO's Seasonal Peak |
| DRR Registered | Check box if resource is registered as a DRR and if yes, select the name of the DRR CP Node |
| Emergency Demand Response (EDR)? | Check box if DR registered as an EDR and if yes, select the name of the EDR resource |
| Load Control Method | Select if load is direct control or interruptible load |
| Max Interruptions | Select the max interruptions for the resource |
| Max duration (hours) | Select the max duration for the resource |
| | |
| | |
| Notification details | Enter the notification time required for this DR. Notification time(s) must cover all hours and cannot be more than 12 hours and should be available 24 hours/Everyday (From 0000 to 2300 acceptable for 24 hours). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300) |
| | |

| Demand Resource (DR) | |
|---|---|
| **Registration Requirements** | **Explanation** |
| | |
| | |
| | |
| Accept terms and conditions of the MISO Tariff | Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource |
| Certify that registrant holds all permits in place to operate resource | Indicate whether registrant has all necessary permits to operate this resource |
| Certify that registrant holds all rights in place to operate resource | Indicate whether registrant has all necessary rights to operate this resource |
| Comments | Submit any comments for this registration |

## Appendix E – BTMG registration

| Behind the Meter Generation (BTMG) | |
|---|---|
| **Registration Requirements** | **Explanation** |
| Auction | The Season(s) within the the PY you are registering your BTMG for displays in this field. |
| Name | Enter Name of the BTMG. |
| Description | Enter type of resources and additional names and sizes if registering more than one unit. |
| Asset Owner | Enter the name of the entity that owns or has rights to this asset. |
| Local Resource Zone (LRZ) | The LRZ where this BTMG is located displays once the Asset Owner and LBA is selected and the registration is saved. |
| Local Balancing Area (LBA) | Select the LBA where this BTMG asset is located. |
| Load Zone CP Node | Enter the CP Node where the BTMG asset is located. |
| Documentation | Add supporting documentation as necessary. |
| Monthly Availability | Monthly values shall be provided for the first two years from the Effective Start Date. Provide monthly MW levels associated with the amount of MW you can inject in a given month consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions.<br>Summer and Winter values shall be provided beyond the 2-year monthly window for levels associated with the amount of MW you can inject in the given Summer and Winter season consistent with the actual physical availability of the resource, limited by any relevant regulatory or contractual restrictions. |
| Operator Contact Name | Enter who to contact for deployment of DRBTMG. The contact should be available 24 x 7 for commitment by MISO or LBA. |

| Behind the Meter Generation (BTMG) | |
|---|---|
| **Registration Requirements** | **Explanation** |
| Operator Contact Phone Number | Enter phone number for 24 x 7 operator. |
| Operator Contact Email | Enter email address for 24 x 7 operator. |
| M&V protocol to be applied to this BTMG | Select the protocol that should be applied. This is used for determination of whether the LMR performed if called on during a MISO declared Emergency. If other selected, please describe in box provided. |
| Exclude Season | Check this box to exclude the registration from participation in the specified season |
| Generators | Select the name of the GADS Generator(s) |
| Wind Capacity Factor % | If a wind unit is selected, the Wind Capacity Factor will be displayed. |
| Transmission Loss % | Indicates the Transmission Loss % to be applied to the UCAP calculation based on the LBA selected. |
| DR Capability at MISO Peak | Indicates the calculated MW value for the BTMG resource based on the GVTC |
| XEFORd | Displays the XEFORd to be applied in the UCAP calculation for the BTMG resource. If multiple Generators are selected, this field will display the weighted average XEFORd. |
| Emergency Demand Response (EDR)? | Check box if DR registered as an EDR and if yes, select the name of the EDR resource |
| Max Interruptions | Select the maximum interruptions for the resource |
| Max Duration (hours) | Select the maximum runtime hours for the resource |
| | |
| Startup notification time details (in hours) | Enter the notification time required to deploy this BTMG. Needs to be no more than 12 hours and cover all hours. Needs to be available 24 hours/Everyday (From 0000 to 2300 acceptable). Multiple notification times should start and stop with different hours (from 0000 to 0700, 0800 to 1600, 1700-2000, 2100 to 2300) |
| | |
| Accept terms and conditions of the MISO Tariff | Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this resource |

| Behind the Meter Generation (BTMG) | |
|---|---|
| **Registration Requirements** | **Explanation** |
| Certify that registrant holds all permits in place to operate resource | Indicate whether registrant has all necessary permits to operate this resource |
| Certify that registrant holds all rights in place to operate resource | Indicate whether registrant has all necessary rights to operate this resource |
| | |
| | |
| | |
| Comments | Submit any comments for this registration |

## Appendix F – External Resources

| External Resources | |
|---|---|
| **Registration Requirements** | **Explanation** |
| External Resource Name | Enter Name of the External Resource. |
| Description | Enter type of resources and additional names and sizes if registering more than one unit. |
| BER/COR | Indicate if this Resource is a Border External Resource or Coordinating Owner Resource by checking this box. |
| Auction | The Season(s) in the PY you are registering your resource for displays in this field. |
| Registering Asset Owner | Select the name of the entity that owns or has rights to this asset. |
| Load Zone CP Node | Select Load Zone CP Node where this Resource is serving load. |
| Local Balancing Area (LBA) | Select the LBA where the External Resource sinks within MISO. |
| Local Resource Zone (LRZ) | Indicates the Local Resource Zone where the load served by this resource is located. |
| Direct Ownership or PPA | Indicate if the External Resource is Directly Owned or PPA. |
| Direct Ownership | Enter MW value the Market Participant can register. |
| PPA | Select whether PPA MWs are defined in MISO ICAP or SAC. |
| Generator | Select name of GADS Generator and input entitled capacity in MW or %. |
| External Balance Authority where Resource(s) are located | Enter Balancing Authority where Resource(s) are physically located. |
| Interface CPNode | Select Interface CPNode. |
| NERC Regional Entity | Select NERC Regional Entity. |
| Use Limited Qualification | Indicate if this Resource meets the Use Limited Qualification. |
| Diversity Contract | Indicate whether this Resource is part of a Diversity Contract exchange. |

| External Resources | |
|---|---|
| **Registration Requirements** | **Explanation** |
| IDC Name | Indicate the IDC name used for entering outages via the SDX. List separate IDC name for each unit being registered. This is used for the must offer requirement. |
| Documentation | If Resource is not owned directly, attach supporting PPA or other pertinent documentation here. |
| Firm transmission to MISO border | Input effective date and OASIS reservation number and select Transmission Provider. |
| Firm transmission within MISO | Input effective date and OASIS Reservation number. |
| Accept terms and conditions of the MISO Tariff | Indicate whether registrant accepts the terms and conditions of the MISO Tariff applicable to this Resource. |
| Have you notified the host BA? | Indicate if you have contacted your host BA of this registration. |
| Will this External Resource be used exclusively as a Capacity Resource for MISO? | Indicate that you certify that this External Resource is being used as a Capacity Resource exclusively for MISO. |
| Is this External Resource available the entire auction? | Indicate if this External Resource is available for the entire season within the upcoming Planning Year. |
| Have all other requirements been met? | Indicate if all other requirements have been met. |
| Resource Operator Contact Name (24 x7) | Enter who to contact for deployment of External Resource. The contact should be available 24 x 7 for commitment by MISO or LBA. |
| Resource Operator Contact Phone Number (24 x7) | Enter phone number for 24 x 7 operator. |
| Resource Operator Contact E-mail (24 x 7) | Enter e-mail address for 24 x 7 operator. |
| Season(s) registration is being submitted for | Summer ☐ Fall ☐ Winter ☐ Spring☐ |
| Comments | Submit any comments for this registration. |

## Appendix G – Placeholder

# Appendix H – Non-Schedule 53 Seasonal Accredited Capacity (SAC) Calculations for Planning Resources

The following sets of equations establish how the SACvalues (NRIS SAC, including E-NRIS SAC, and ERIS SAC) are determined for Planning Resources to account for resource performance and availability. Schedule 53 resource accreditation is outlined in Appendix Y.

## H.1 Planning Resource SAC calculation for a Generation Resource, a Demand Response Resource backed by a generator, or a Behind-the-Meter Generator, with a Point of Interconnection on MISO's Transmission System

The Seasonal Accredited Capacity calculation is based on its type and volume of seasonal interconnection service, seasonal GVTC, and seasonal forced outage rate ($XEFOR_d$).

### H.1.1 Planning Year SAC Calculation for each Season

The following steps are used to calculate NRIS SAC and ERIS SAC for each Planning Resource.

<u>Determine ICAP:</u>

The first step is to determine the Installed Capacity (ICAP) the Planning Resource can reliably provide, which is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test. The equation is shown below.

$$ICAP = \begin{cases} Total\ Interconnection\ Service,\ If\ GVTC > Total\ Interconnection\ Service \\ GVTC,\ If\ GVTC \leq Total\ Interconnection\ Service \end{cases}$$

<u>Determine Total SAC:</u>

The next step is to convert the resultant ICAP value into a SAC value, Total SAC, by applying its seasonal forced outage rate (XEFORd).

A forced outage rate class average for each season is used if the Planning Resource has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

$$Total\ SAC = ICAP \times (1 - XEFOR_d)$$

If the Planning Resource has provisional Interconnection Service, then the Planning Resource will receive zero (0) Interconnection Service and therefore the calculated Total SAC will be zero (0).

Allocate Total SAC into NRIS SAC and ERIS SAC based on Deliverability:

The Resource's Total SAC is allocated into NRIS SAC and ERIS SAC based upon its type of deliverability.

$$Total\ SAC = NRIS\ SAC + ERIS\ SAC$$

To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to calculate the NRIS SAC.

$$NRIS\ SAC = \begin{cases} ICAP * (1 - XEFORd), & If\ ICAP = NRIS \\ \left(Minimum\ of\ (NRIS, GVTC)\right) * (1 - XEFORd), & If\ ICAP > NRIS \end{cases}$$

The remaining balance of Total SAC is allocated to ERIS SAC (i.e. ERIS SAC = Total SAC – NRIS SAC.

$$ERIS\ SAC = \begin{cases} 0, & If\ ICAP = NRIS \\ Total\ SAC - NRIS, & If\ ICAP > NRIS \end{cases}$$

Eligibility of NRIS SAC and ERIS SAC conversion into Seasonal Zonal Resource Credits

The NRIS SAC represents capacity in MWs that is eligible to be converted into seasonal Zonal Resource Credits.

In determining the amount of ERIS SAC eligible for conversion into seasonal ZRCs, seasonal firm Transmission Service must be paired with ERIS where seasonal ZRCs are calculated by taking the lesser of ERIS or the firm Transmission Service multiplied by one minus XEFORd.

Total SAC which can be converted into seasonal ZRCs are the summation of the resources's NRIS SAC plus the lesser of the resource's ERIS of firm Transmission Service.

$$Total\ SAC\ Eligible\ for\ ZRC\ Convsersion\ = \{NRIS\ SAC\ +\ Lesser\ of\ [ERIS\ or\ firm\ TSR\ *\ (1 - XEFORd)]$$

| Ex | Size | NRIS | SAC | Total IS | GVTC | ICAP | Forced Outage Rage | Total SAC | NRIS SAC | ERIS SAC | TSR | ZRC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | 100 | **100** | 0 | 100 | 100 | **100** | 0.25 | **75.0** | 75.0 | 0.0 | 0.0 | **75.0** |
| **2** | 100 | **50** | 50 | 100 | 100 | **100** | 0.25 | **75.0** | 37.5 | 37.5 | 50.0 | **75.0** |
| **3** | 100 | **50** | 50 | 100 | 75 | **75** | 0.25 | **56.3** | 37.5 | 18.8 | 25.0 | **56.3** |
| **4** | 100 | **0** | 100 | 100 | 100 | **100** | 0.25 | **75.0** | 0.0 | 75.0 | 100.0 | **75.0** |

Examples for Illustrative purposes

In example 3 above, a 100 MW Resource with 50 MW NRIS and 50 MW ERIS submitted a seasonal generator test (GVTC) at 75 MW and has a 0.25 XEFORd rate based on the resource's GADS submittals.

The ICAP will be determined to be 75 MW because the seasonal GVTC is less than the Interconnection Service of 100MW.

Total SAC is calculated to be 56.3 MW (75 MW of ICAP * (1 - 0.25 of XEFORd) = 56.3 MW.

Since the 50 MW NRIS is less than the resource's ICAP, the NRIS SAC is determined to be:

50 MW x (1 – 0.25) = 37.5 MW (fully deliverable and thus eligible to be converted to seasonal ZRCs), the remaining Total SAC minus the NRIS SAC is allocated into the resource's ERIS SAC. Thus, ERIS SAC level is 56.3 MW – 37.5 MW = 18.8 MW.

Assume hypothetically that the MP obtains 25 MWs of firm Transmission Service to apply to the ERIS SAC allocation. Since the 25 MW of firm Transmission Service is less than 50 MW ERIS, the ERIS SAC eligible to be converted into seasonal ZRCs is 18.8 MW {25 MW x (1 – 0.25) = 18.8 MW ERIS SAC}.

The resource would be credited with 56.3 MW of Total SAC which is comprised of 37.5 MW NRIS SAC + 18.8 MW ERIS SAC with firm Transmission Service for the corresponding seasonal PRA.

The resource was able to convert its entire Total SAC into seasonal ZRCs because the resource obtained full deliverability up to its ICAP, where 50 MW of NRIS plus 25 MW of firm Transmission Service is equal to its ICAP of 75 MW.

### H.2 SAC calculation for an External Resource that qualified as a Capacity Resource

The External Resource Capacity Resource SACcalculation is based on its seasonal GVTC and seasonal forced outage rate ($XEFOR_d$). The ERIS SAC is calculated by applying its seasonal $XEFOR_d$ to its seasonal GVTC.

$$ERIS\ SAC = GVTC \times (1 - XEFOR_d)$$

A seasonal forced outage rate class average is used if the Capacity Resource has a GVTC < 10 MW and has not submitted generator availability data, or does not have sufficient generator availability data to calculate a Planning Resource specific forced outage rate. A Planning Resource has sufficient generator availability data when it has a minimum of 12 months of generator availability data between September 1st and August 31st for the previous 3 years. The applicable class average for a Planning Resource is based on its unit size and type.

The ERIS SAC represents the capacity in MWs that are eligible to be converted into seasonal Zonal Resource Credits with valid transmission service.

### H.3 SAC calculation for a Planning Resource that is classified as Intermittent Generation and Dispatchable Intermittent Resources

For resources that don’t report outage data to GADS, MISO calculates the Total SAC based on the past historical Season-specific output assessing either the median for Run-of-River Hydro or average for all other intermittent non-wind, non-ESR resource types. The calculation requires a minimum of 30 consecutive seasonal  days of output or else class average seasonal XEFORd will be applied to the nameplate of the resource. A capacity factor adjusted by the resource’s deliverable amount is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

For wind resources, MISO produces an annual wind capacity credit study for every season in the upcoming Planning Year using the Effective Load Carrying Capability (ELCC) methodology, as described in Appendix A, to determine a fleet-wide SAC value to be allocated across all in-front-of-the-meter wind resources in that season. Deterministic allocation of the total fleet-wide wind SAC across the studied wind resources is dependent on the reliability value of the entire wind fleet (as determined through probabilistic modeling) at the aggregate level and the historical performance history of the wind resources at the unit level during specific historical MISO system peak demand hours.

A capacity factor adjusted by the resource's deliverable amount is applied to the resource's Total SAC to determine the amount of Total SAC eligible to be converted into seasonal ZRCs.

BTMG wind resource owners are required to submit the historical performance history of their BTMG wind resources during these specified hours for the purpose of accrediting these resources with a SAC value based on their performance during periods of MISO system seasonal peak demand for the three years prior. This results in resource-specific SAC values for each BTMG wind resource in operation.

*BTMG Wind SAC = [capacity factor over the 8 seasonal peaks over the past 3 years] * [k] * [RMax]*

*Where k = [seasonal MISO Fleet ELCC] / Sum of [Fleet RMax * PKmetric] (see BPM-011 Appendix A)*

New wind resources that do not yet have historical performance history for an entire season would receive the class average wind capacity credit for that season (as determined by the annual wind capacity credit study) applied to the wind resource's nameplate capacity to derive an appropriate Total SAC value. Please reference Appendix A for more details regarding the accreditation procedure for wind resources.

The Seasonal Accredited Capacity (SAC) calculation also considers the type and volume of season-specific interconnection service for a Planning Resource that has a Point of Interconnection to MISO's Transmission System.

The amount of SAC eligible to be converted into seasonal Zonal Resource Credits will be based on upon the application of a deliverability adjusted capacity factor.

### H.3.1 Intermittent Generation and Dispatchable Intermittent Resources with a Point of Interconnection on MISO's Transmission System

The following sections establish how SACvalues (NRIS SAC and ERIS SAC) are determined for Intermittent Generation and Dispatchable Intermittent Resources that has a Point of Interconnection on MISO's Transmission System to account for resource performance, and deliverability.

#### H.3.1.1 Intermittent Generation and Dispatchable Intermittent Resources Fueled by Wind

MISO sets the seasonal GVTC to either the Pmax submitted through the Market Registration process if the Intermittent Generation and Dispatchable Intermittent Resources are registered in the Commercial Model or the registered maximum in its BTMG registration in the MECT Tool.

##### H.3.1.1.1 Planning Year SAC Calculation for Wind Resources

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total seasonal Interconnection Installed Capacity (ICAP). It is equal to the lesser of its seasonal GVTC, or its total volume of seasonal Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

The next step is to determine the resource's Total SAC. MISO determines a wind resource specific seasonal wind capacity credit, by CPNode, for each Planning Resource that is fueled by wind by allocating the fleet-wide seasonal ELCC capacity. The wind capacity credit is determined by applying the larger of two allocation methodologies, as noted in Appendix A:

- one method which includes (adds back in) megawatts of a wind resource that were curtailed
- a second method excludes (does not add back in) those same curtailed megawatts

The larger of the two results becomes the individual resource's Total SAC.

$$Total\ Interconnection\ SAC = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$

**Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor**

The next step is to determine how much of the Total SAC is eligible to be converted into seasonal ZRCs.

The Total SAC for a wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs, either convertible SAC or undeliverable ERIS SAC.

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical seasonal peak observances of an intermittent resource and is calculated by 'capping' historical intermittent output during seasonal peak load observances to the resource's demonstrated deliverable amount divided by the resource's ICAP. Whereas, a peak performance capacity factor also uses the same historical seasonal peak observances divided by the resource's ICAP but does not cap those observances.

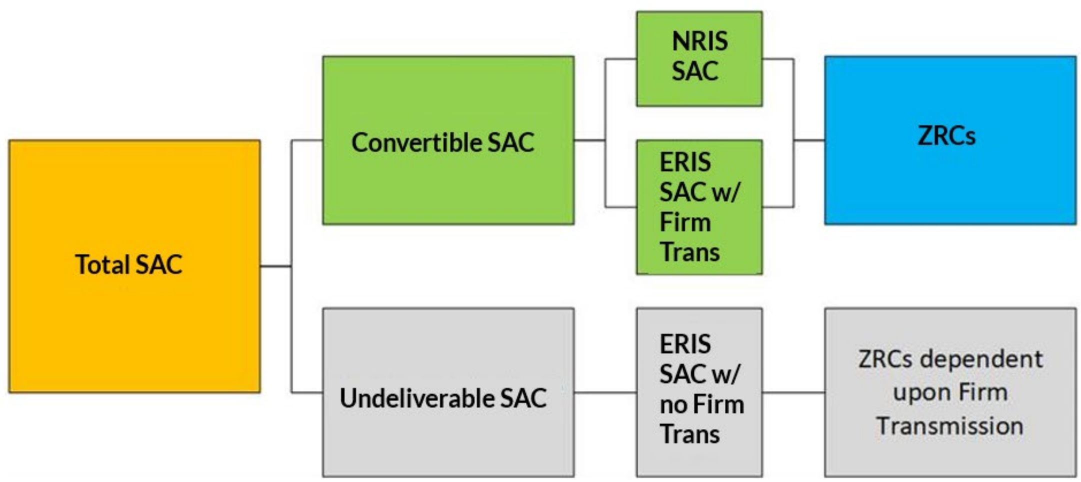
**Formula for determining Convertible SAC**

$$Convertible\ SAC = Total\ Interconnection\ SAC * \frac{Deliverability\ Adjusted\ Capacity\ Factor}{Peak\ Capacity\ Factor}$$

The remaining Total SAC that is left after calculating Convertible SAC is considered the undeliverable ERIS SAC.

$$ERIS\ SAC = \begin{Bmatrix} 0, Total\ Interconnection\ SAC = Convertible\ SAC \\ Total\ Interconnection\ SAC - Convertible\ SAC, Total\ Interconnection\ SAC > Convertible\ SAC \end{Bmatrix}$$

Optionally, the classified undeliverable ERIS SAC can become eligible to be converted into seasonal ZRCs by procuring firm Transmission Service.

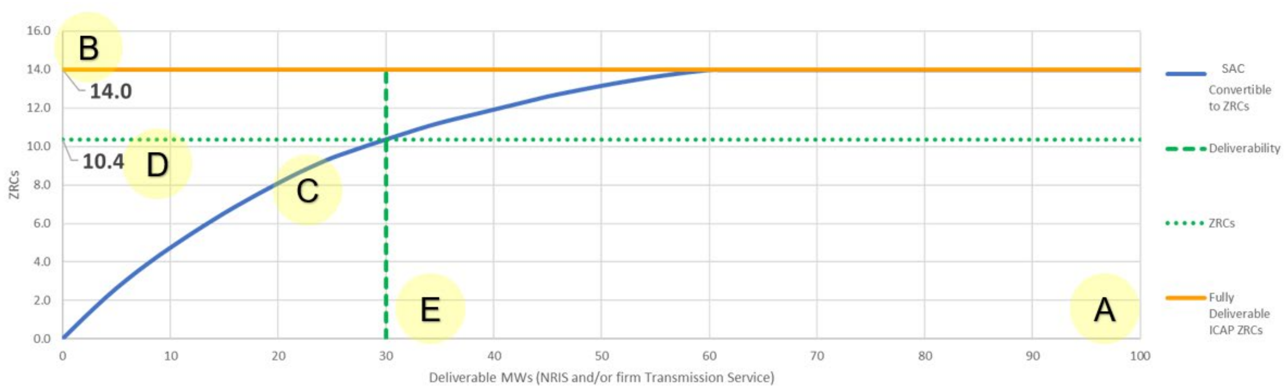


**Converting ERIS SAC to Convertible SAC using the Resource's Deliverability Adjusted Historical Performance**

ERIS SAC is not generally convertible to seasonal ZRCs at a one-to-one MW ratio. Each resource will have unique conversion data generated based on its past seasonal performance and deliverability which indicates the level of firm Transmission Service necessary to be obtained to gain a given level of seasonal ZRCs.

An example and further explanation is shown in the figure below:

ZRC Deliverability Curve Chart




Where:

A: Equals the maximum output of resource (RMax). In this example, this resource is 100 MW.

B: Total SAC, or max SAC that can potentially be converted into seasonal ZRCs. This also represents the share of the fleetwide seasonal ELCC capacity. This value is based on the size and performance of the resource.

C: This is the Convertible SAC function which is the resource's Total SAC multiplied by the ratio of its Deliverability Adjusted Capacity Factor divided by its Peak Capacity Factor. Convertible SAC varies depending on the amount of Deliverability of the resource.

D: This is the resulting Convertible SAC value for a corresponding Deliverable amount in MW.

E: This is the example Deliverable value. The point at which E intersects C provides the amount of Seasonal ZRCs the Market Participant would obtain based on the size, performance, and deliverable amounts of the resource.

### H.3.1.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The seasonal GVTC for Intermittent Generation and Dispatchable Intermittent Resources with a fuel source other than wind is calculated in section 4.2.3.

The first step is to determine the total installed capacity that the Planning Resource can reliably provide, which is the Total Interconnection Installed Capacity (ICAP). It is equal to the lesser of its GVTC, or its total volume of Interconnection Service (Network Resource and Energy Resource Interconnection Service) granted either through MISO's Generation Interconnection Procedures or through a market transition deliverability test.

$$Total\ Interconnection\ ICAP = \begin{cases} Total\ Capacity\ Tested, & GVTC > Total\ Capacity\ Tested \\ GVTC, & GVTC \leq Total\ Capacity\ Tested \end{cases}$$

The next step is to allocate the Total Interconnection SAC based upon its type of Interconnection Service. To the extent the Planning Resource has Network Resource Interconnection Service (NRIS) or was determined to be aggregate deliverable through the market transition deliverability test then that quantity will be allocated first to the NRIS SAC. The remaining Total Interconnection SAC will then be allocated to ERIS. If the Planning Resource has provisional interconnection service, then the Planning Resource will receive zero (0) interconnection service and therefore the calculated SAC will be zero (0).

$$NRIS\ SAC = \begin{cases} Total\ Interconnection\ SAC, & Total\ Interconnection\ SAC \leq NRIS \\ NRIS, & Total\ Interconnection\ SAC > NRIS \end{cases}$$

$$ERIS\ SAC = \begin{cases} 0, & Total\ Interconnection\ SAC \leq NRIS \\ Total\ Interconnection\ SAC - NRIS, & Total\ Interconnection\ SAC > NRIS \end{cases}$$

**Determining Convertible SAC based on a Deliverability Adjusted Capacity Factor**

The Total SAC for an intermittent non-wind resource is distributed into two categories for the purpose of determining the amount of Capacity eligible for conversion into seasonal ZRCs. This would be considered Convertible SAC, either NRIS SAC or ERIS SAC coupled with firm Transmission, or undeliverable ERIS SAC (no associated firm Transmission).

To calculate convertible SAC, which is eligible to be converted into seasonal ZRCs, a Deliverability Adjusted Capacity Factor is first applied. The Deliverability Adjusted Capacity Factor uses historical summer peak observances of an intermittent non-wind resource and is calculated by 'capping' historical intermittent output during peak load observances to the resource's demonstrated deliverable amount divided by the resource's ICAP. (See Appendix V for examples)

### H.3.2 Intermittent Generation and Dispatchable Intermittent Resources that does not have Point of Interconnection on MISO's Transmission System

The following sections apply to Intermittent Generation and Dispatchable Intermittent Resources that do not have a Point of Interconnection on MISO's Transmission System. The ERIS SAC represents the capacity in MWs that are eligible to be converted into seasonal ZRCs.

#### H.3.2.1 Intermittent Generation and Dispatchable Intermittent Resources Fueled by Wind

MISO sets the seasonal GVTC to either the Pmax submitted through the Market Registration process if the Intermittent Generation and Dispatchable Intermittent Resources are registered in the Commercial Model or the registered maximum in its BTMG registration in the Module E-1 Capacity Tracking Tool.

##### H.3.2.1.1 Planning Year SAC Calculation

MISO calculates a wind resource specific seasonal wind capacity credit for each Planning Resource that is fueled by wind. The wind capacity credit is determined by performing an Effective Load Carry Capability study on a seasonal basis and using wind resource specific past metered data, reference section 4.2.3.3 of the BPM for Resource Adequacy.

$$ERIS\ SAC = GVTC \times (Wind\ Capacity\ Credit_{CPNode})$$

#### H.3.2.2 Non-wind Intermittent Generation and Dispatchable Intermittent Resources

The seasonal GVTC for Intermittent Generation and Dispatchable Intermittent Resources with a fuel source other than wind is calculated in section 4.2.3.

$$\text{ERIS} = GVTC$$

## Appendix I – XEFOR$_d$ Calculation

XEFORd is equivalent forced outage rate demand excluding events outside of management control (OMC). XEFORd will be calculated on a seasonal basis. description and list of the MISO OMC events can be found in Appendix B. The MISO equation is~~.~~:

$$\frac{(FOHd + EFDHd)}{(FOHd + SH + Synch\ Hours)} * 100\%$$

where:

SH = service hours

Synch Hours = synchronous hours

RSH = reserve shutdown hours

FOH$_d$ = forced outage hours demand = $f_f$ x FOH

$f_f$ = full forced outage demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})}$

r = average forced outage duration = (FOH)/(# of FO occurrences)

D = average demand time = (SH + Synch Hours)/(# of unit actual starts)

T = average reserve shutdown time = (RSH)/(# of unit attempted starts)

FOH = forced outage hours

EFDH$_d$ = ($f_p$ x EFDH)

AH = available hours

$f_p$ = partial forced outage demand factor = (SH + Synch Hours)/AH

EFDH = equivalent forced derated hours

Special cases are evaluated in the following order:

If reserve hours < 1, then $f_f$ =1,

then if (SH + Synch hours) = 0, then $f_f$ = 1,

then if (1/r + 1/T + 1/D) = 0, then $f_f$ = 0,

then if # of FO occurrences = 0 or FOH = 0, then 1/r = 0,

then if RSH = 0 or # of unit attempted starts = 0, then 1/T = 0,

then if # of unit actual starts = 0 or (SH + Synch Hours) = 0, then 1/D = 0,

then if (SH + RSH + Synch Hours) = 0, then $f_p$ = 0,

then if ((FOHd + SH + Synch Hours) = 0, then EFOR$_d$ = 0

SH, RSH and Synch Hours are reported through the MISO Market Portal in the PowerGADS application by the users in their Performance data. The rest of the statistics are calculated by PowerGADS based on the user submitted Event data. Forced outage rates for each unit can be found in the Generator Outage Rate Program (GORP) report. The statistics used in calculating forced outage rates can be found in the Statistics Report and the Performance Report.

The MISO calculation is based on the EFORd equation defined in the NERC Generating Availability Data System Data Reporting Instructions Appendix and the IEEE Standard No. 762-2006 Standard *Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity*. The MISO XEFORd calculation differs as follows:

- The NERC and IEE EFDH formula is (Derated Hours * Size of Reduction)/Net Max Capacity while the MISO formula uses net dependable capacity rather than net max capacity and is (Derated Hours * Size of the Reduction)/Net Dependable Capacity. The size of the reduction is the Net Dependable Capacity minus the Net Available Capacity.
- MISO also includes synchronous hours in the XEFORd, average demand time (D), and the partial demand factor ($f_p$) calculations while NERC and IEE do not.

**<u>Example XEFORD Calculations</u>**

| Raw Data | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Unit | SH | Synch Hours | RSH | AH | Actual Starts | Attempted Starts | EFDH | FOH | FO Events |
| 1 | 4,856 | 0 | 2,063 | 6,919 | 34 | 34 | 146.99 | 773 | 12 |
| 2 | 4,556 | 0 | 1,963 | 6,519 | 31 | 31 | 110.51 | 407 | 5 |
| 3 | 3,942 | 132 | 3,694 | 7,768 | 36 | 36 | 19.92 | 504 | 11 |
| 4 | 6,460 | 0 | 516 | 6,976 | 17 | 18 | 131.03 | 340 | 14 |
| 5 | 6,904 | 0 | 62 | 6,966 | 16 | 16 | 35.81 | 138 | 12 |

| Calculated Values | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Unit | 1/r | 1/T | 1/D | $f_f$ | FOHd | $f_p$ | EFDHd | XEFORd |
| 1 | 0.0155 | 0.0165 | 0.0070 | 0.8205 | 634.25 | 0.7018 | 103.16 | 13.43% |
| 2 | 0.0123 | 0.0158 | 0.0068 | 0.8049 | 327.61 | 0.6989 | 77.23 | 8.29% |
| 3 | 0.0218 | 0.0097 | 0.0088 | 0.7813 | 393.78 | 0.5245 | 10.45 | 9.05% |
| 4 | 0.0412 | 0.0349 | 0.0026 | 0.9666 | 328.63 | 0.9260 | 121.34 | 6.63% |
| 5 | 0.0870 | 0.2581 | 0.0023 | 0.9933 | 137.08 | 0.9911 | 35.49 | 2.45% |

**Unit 3 Example XEFORd Calculation Detail**

r = average forced outage duration = $\frac{FOH}{FO\ events} = \frac{505}{11} =$ 45.82 hours, then 1/r = 0.0218

T = Average reserve shutdown time = $\frac{RSH}{attempted\ starts} = \frac{3694}{36}$ = 102.61 hours, then 1/T = 0.0097

D = average demand time = $\frac{(SH+synch\ hours)}{actual\ starts} = \frac{3942+132}{36} =$ 113.17 hours, then 1/D = 0.0088

$f_f$ = full forced outage demand factor = $\frac{(\frac{1}{r}+\frac{1}{T})}{(\frac{1}{r}+\frac{1}{T}+\frac{1}{D})} = \frac{(0.0218+0.0097)}{(0.0218+0.0097+0.0088)} =$ 0.7813

FOHd = forced outage hours demand = $f_f$ x FOH = 0.7813 x 504 = 393.78 hours

$f_p$ = partial forced outage demand factor = $\frac{(SH+synchhours)}{AH} = \frac{(3942+132)}{7768}$ = 0.5245

EFDH = fp x EFDH = 0.5245 x 19.92 = 10.45 hours

XEFORd = $\frac{(FOHd+EFDHd)}{(FOHd+SH+synch\ hours)} * 100 = \frac{(393.78+10.45)}{(393.78+3942+132)} * 100 =$ 9.05%

Units with 12 or more consecutive months of actual data: The XEFORd of a unit in service twelve or more full calendar months prior to the calculation month will be based on the number of consecutive months that that unit has data for up to 36 months.

Units with less than 12 consecutive months of actual data: The XEFORd of a unit in service less than twelve full calendar months shall be determined by the class average rate for units of the same type and within the same range of capability. A unit will use the class average value until 12 consecutive months of data is obtained and a new Planning Year begins. The class average will be the 5-year forced outage rate from the latest Loss of Load Expectation (LOLE) Study.

**Units with Low Service Hours**

Units with an average of less than 20 service hours per season and attempted starts greater than zero will have their service hours adjusted if the unit has at least 12 consecutive seasonal months of GADS data. The adjusted service hours will be based on 60 service hours (20 service hours x 3 seasons) or a fraction of 60 if there is less than 9 consecutive seasonal months of GADS data. This adjustment will be performed in the MECT. The calculation for the adjustment is as follows:

MO = consecutive seasonal months in operation
If SH = Service Hours < (MO/9*60) and attempted starts is greater than zero, then

SH' = seasonal adjusted low service hours = $\left[\left(\frac{actual\ starts}{atempted\ starts}\right) * \left(\frac{MO}{9} * 60 - SH\right)\right] + SH$

**External Resources**

Market Participants are responsible for making sure that GADS data is submitted for the External Resources that they are seeking qualification as ZRCs. The Market Participant can submit this data to MISO's GADS tool for the external resource or they can have the external resource submit the data. If an external resource is going to submit the GADS data, then they must receive access to the MISO Market Portal through their Local Security Administrator. If an External Resource does not have a Local Security Administrator, then it is the Market Participant's responsibility to receive and submit this data for the External Resource.

**Catastrophic Outages**

Catastrophic Outages are defined as forced outages that result in a unit being unavailable for a minimum of six (6) continuous months. A catastrophic outage may be a forced full or partial (forced derating) outage. A scheduled outage (planned, planned extension, maintenance, or maintenance extension) cannot be a catastrophic outage. For an outage to be considered catastrophic, the MP must notify the MISO Resource Adequacy team in writing within 75 days of determining the outage is a Catastrophic Outage, including a description of the Catastrophic Outage, start date of outage, expected return date, etc.

If the MP chooses not to replace a Planning Resource that suffers a Catastrophic Outage, then the XEFORd will be based on actual GADS data.

If the MP chooses to replace a Planning Resource that suffers a Catastrophic Outage, the XEFORd will be based on class average when the unit returns to service. The class average value will be used until 12 consecutive months of data is obtained and a new Planning Year begins.

Resource replacement must be completed within 75 days of catastrophic outage.
Resource replacement must be in accordance with section 6.3 of this BPM.
Once the unit returns from Catastrophic Outage, Planning Resource qualification requirements still apply. Partial replacements are allowed.

If the outage is a forced derate with total or partial replacement, or a full forced outage with partial replacement, the resources XEFORd upon returning to service will be the class average for the portion of the resource replaced and the actual XEFORd for the remainder of the unit. A blended XEFORd will be calculated by MW weighting the class average and actual XEFORd values.

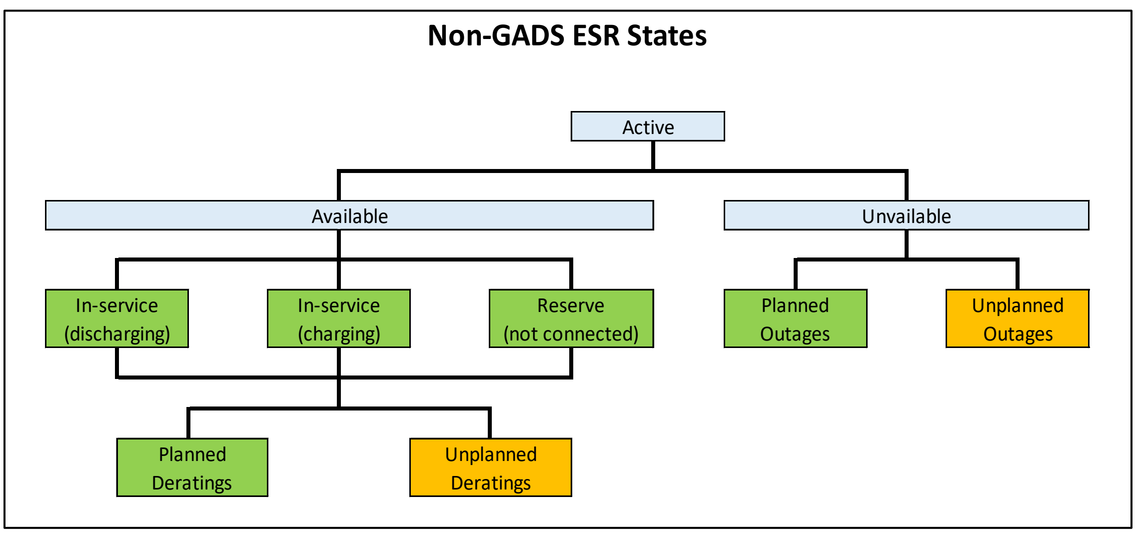
**Fleet Weighted Average Forced Outage Rates**

External Resources may participate using a fleet of resources. A weighted average forced outage rate is calculated using the individual unit forced outage rates and GVTC values. The resulting rate is applied to the total fleet GVTC to determine the fleet UCAP. See Appendix Q for more information regarding the Fleet XEFORd Calculation.

**XEFORd for Non-GADS Electric Storage Resources (ESR)**

The XEFORd for a non-GADS ESR is its Forced Unavailability and will be determined as follows.

A non-GADS ESR is forced unavailable when it is in an unplanned outage or an unplanned derating (see oranges boxes). All other states are unforced availability and include in-service (discharging or charging), reserve (not connected), planned outages, or planned deratings (see green boxes).



An available resource that is not derated is 100% available. If a resources availability changes during an hour, the Forced Availability should be pro-rated. For example, if a 10 MW resource experiences a 23 minute Unplanned Outage during the hour its equivalent Forced Unavailability would be (23 min/60 min) * 10 MW = 3.8 MW or 38%. Similarly, for an Unplanned Derating of 2.4 MW for 47 minutes of the hour the equivalent Forced Unavailability would be (47 min/60 min) * 2.4 MW = 1.9 MW or 19%.

| Examples for a 10 MW resource | Unforced Availability (MW) | Forced Unavailability (MW) | Unforced Availability (%) | Forced Unavailability (%) |
|---|---|---|---|---|
| The resource is 100% available and in-service discharging | 10.0 | 0.0 | 100.0% | 0.0% |
| The resource is 100% available and charging | 10.0 | 0.0 | 100.0% | 0.0% |
| The resource is 100% available and in reserve not discharging | 10.0 | 0.0 | 100.0% | 0.0% |
| A portion of the resource is unavailable due to a planned derating and the remainder is available | 10.0 | 0.0 | 100.0% | 0.0% |
| 4 MW of the resource is unavailable due to an unplanned derating and 6 MW is available | 6.0 | 4.0 | 60.0% | 40.0% |
| 4.5 MW of the resource is unavailable due to a planned derating and 5.5 MW is unavailable due to an unplanned | 4.5 | 5.5 | 45.0% | 55.0% |
| The resource is unavailable due to a planned outage | 10.0 | 0.0 | 100.0% | 0.0% |
| The resource is unavailable due to a unplanned outage | 0.0 | 10.0 | 0.0% | 100.0% |
| 23 minutes unplanned outage | 6.2 | 3.8 | 62.0% | 38.0% |
| 2.4 MW unplanned derate for 47 minutes | 8.1 | 1.9 | 81.0% | 19.0% |

Additional information:

- Pumped Storage Resources submit their availability and GVTC data through the MISO PowerGADS application.
- All other ESR types must submit their availability and GVTC (Hourly Equivalent Discharge Amount) data using the Non-GADS Performance template.
  - The template provides the 8 MISO coincident peak hours per season for the last three years.
  - The average of these 24 seasonal unforced availability values is divided by the Hourly Equivalent Discharge Amount (MW) to calculate a seasonal unavailability factor.
  - Market Participants with less than 8 availability values in a season will be given the default unavailability factor.
- Availability Reporting is optional for resources less than 10 MW. Resources that choose not to report, will be given the default unavailability factor. Once a resource chooses to report for the first time, they will be required to report every year thereafter.

# Appendix J – GVTC Testing Requirements

### J.1 Overview

All Generation Resources, External Resources, Behind the Meter Generation (BTMG) and Demand Response Resources backed by BTMG that intend to qualify as a Planning Resource are required to perform a real power test or provide past operational data. This test, or past operational data, shall be used to determine a planning resource's GVTC value. GVTC data is submitted through the MISO Market Portal into MISO PowerGADS.

Each seasonal corrected net test capability is the gross output (MW) that a planning resource can sustain averaged over the test period, if there are no equipment, operating, or regulatory restrictions, less station service and process load served, corrected to MISO coincident seasonal peak conditions.

| | | | (A) | (B) | (C) | (D)=(A)-(B)-(C) | (E) | (F) | (G) | (H)=(D)+(E)+(F)+(G) |
|---|---|---|---|---|---|---|---|---|---|---|
| NERC Unit Type | | Example Unit | Gross (MW) | Station Service (MW) | Process Load Served (MW) | Net Test Capacity (MW) | Air Temperature Correction (MW) | Relative Humidity Correction (MW) | Cooling Water Temperature Correction (MW) | Net Corrected (MW) |
| Combined Cycle | CC | CT1 | 95.0 | 1.0 | 0.0 | 94.0 | -15.0 | -0.1 | N/A | 78.9 |
| Combined Cycle | CC | ST1 | 300.0 | 15.0 | 0.0 | 285.0 | N/A | N/A | -1.0 | 284.0 |
| Combined Cycle | CC | Unit 4 | 250.0 | 5.0 | 100.0 | 145.0 | -3.5 | -0.1 | -0.5 | 140.9 |
| Combustion Turbine | CT | CT3 | 50.0 | 0.1 | 0.0 | 49.9 | 3.0 | 0.1 | N/A | 53.0 |
| Diesel | DS | Diesel 5 | 2.5 | 0.0 | 0.0 | 2.5 | N/A | N/A | N/A | 2.5 |
| Fluidized Bed Combustion | FB | Unit 4 | 200.0 | 10.0 | 0.0 | 190.0 | N/A | N/A | -2.0 | 188.0 |
| Hydro | HD | Hydro 12 | 10.0 | 0.0 | 0.0 | 10.0 | N/A | N/A | N/A | 10.0 |
| Nuclear | NU | Unit 1 | 1,000.0 | 50.0 | 0.0 | 950.0 | N/A | N/A | -1.5 | 948.5 |
| Pumped Storage | PS | Unit 5 | 300.0 | 1.0 | 0.0 | 299.0 | N/A | N/A | N/A | 299.0 |
| Fossil Steam | ST | Unit 2 | 600.0 | 30.0 | 0.0 | 570.0 | N/A | N/A | -3.0 | 567.0 |

GVTC Table J.1 – Examples of net corrected net test capability for different unit types. **Examples may not be representative of your situation. If you have unit specific questions, please contact Resource Adequacy.

If a Planning Resource fails to perform a real power test and report the test data to MISO's PowerGADS by the reporting deadline, it will result in the Planning Resource not qualifying as a Planning Resource and will receive zero (0) SAC MWs for the upcoming Planning Year.

### J.1.1 Test Period and Reporting Deadline

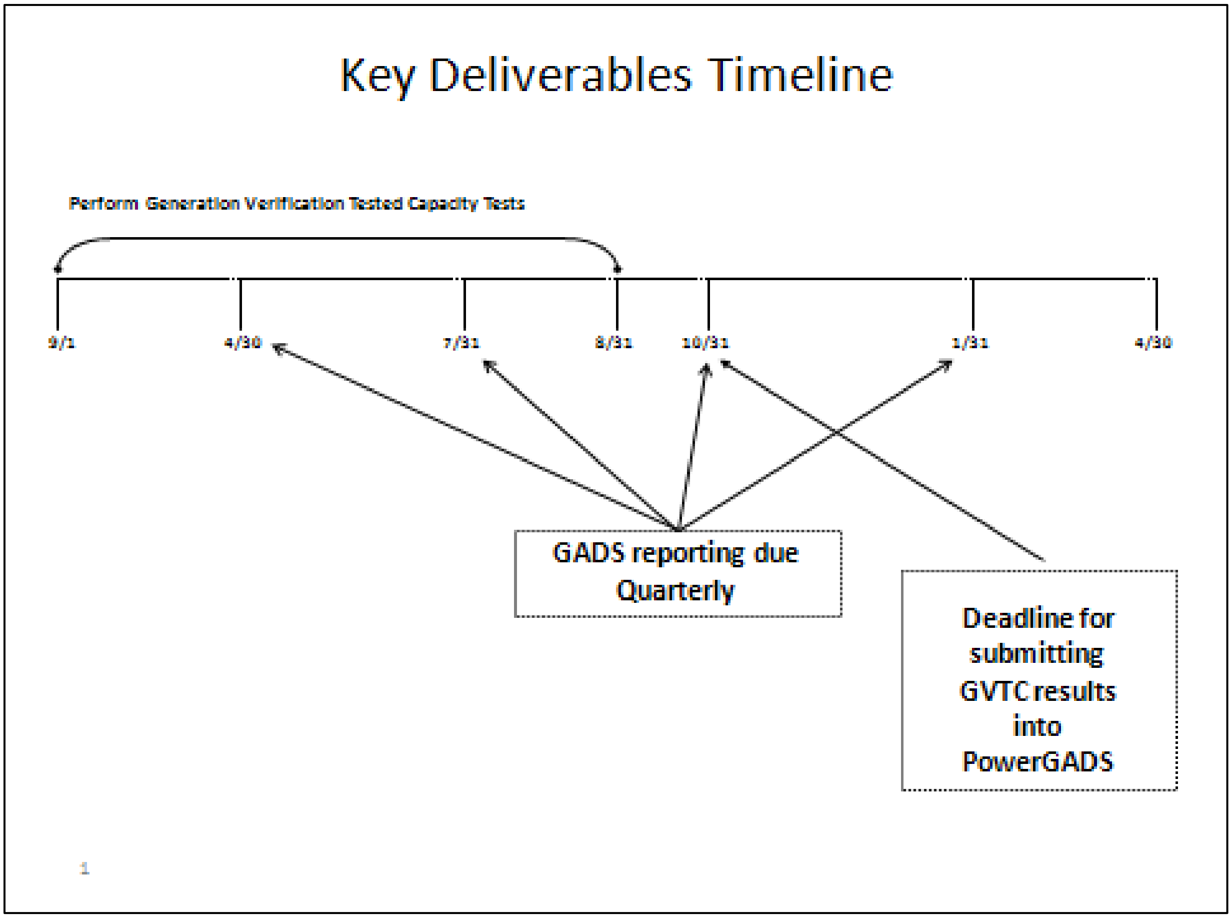
The real power test shall be performed between September 1st and August 31st prior to the upcoming planning year. The test data shall be submitted no later than October 31st.

**Example:** For the 2023-2024 planning year (June 1, 2023 through May 31, 2024), the test must be conducted between September 1, 2021 and August 31, 2022, and submitted no later than October 31, 2022.

### J.2 When to Perform and Submit a Generation Verification Test Capacity

- Generation Resources, External Resources, Demand Response Resources backed by behind the meter generation, or Behind the Meter Generation that qualified as Planning Resources for the current Planning Year shall submit their GVTC no later than October 31st to qualify as a Planning Resource for the upcoming Planning Year. A real power test shall be performed, or past operational data may be used, during the period between September 1st and August 31st prior to the upcoming Planning Year. In addition to performing and submitting GVTC data to qualify as a planning resource for the annual capacity auction, a planning resource must conduct a test and submit data when:
- 
    - a modification that changes, increases, or decreases, the rated capacity of a unit is completed,
    - returning from a suspension,
    - returning to MISO after an absence including but not limited to, catastrophic events,
    - not qualifying as a Planning Resource under Module E-1
    - being qualified as a Planning Resource for the first time
    - or for a Planning Resources in an approved “Suspension” status.

If a Planning Resource is unable to complete a real power test, the responsible MP must include the timing and cost requirements to complete a test when requesting a facility specific reference level.




## J.3 Corrections to Establish GVTC

The GVTC shall be corrected to the average conditions of the date and times of MISO's four seasonal coincident Peaks, measured at or near the generator's location, for the last 5 years. MISO publishes the date and time of the past 5 seasonal coincident Peaks. When local weather records are not available at the plant site, the values shall be determined from the best data available (i.e., local weather service, local airports, river authority, etc.).

The corrections required to establish the GVTC of a unit include, as appropriate for each electric generating technology, dry air temperature, relative humidity, cooling water temperature, fuels, steam heating loads, reservoir level, nuclear fuel management programs and scheduled reservoir discharge.

### J.3.1 Process Load Reporting in MISO PowerGADS to Establish GVTC

The Generator Owner shall forecast the maximum process load (PL) expected to be present at the time of the upcoming MISO seasonal peaks. MISO publishes the date and time of past coincident seasonal peaks as a reference for predicting the PL that is forecasted to be present at the time of the upcoming MISO peaks.

For the purpose of calculating GVTC, the PL being forecasted and reported by the Generator Owner is allocated to the underlying generating unit of the Planning Resource and deducted from a unit's gross MW unless provisions are in place to curtail the load in the event of a MISO Capacity Emergency, or for electric load, is included in an LSE forecast. If such provisions for curtailment are in place or, for electric load, it is included in an LSE forecast, the PL is non-firm for the purpose of calculating GVTC.

Process Load can be electric load or thermal load in the case of a Combined Heat and Power (CHP) facility. Thermal PL is converted to units of MW by determining the reduction of power output caused by serving that load. Thermal loads can be PL because steam that would have otherwise been used to drive turbines to produce electricity may have been diverted to support process load, thus reducing the electrical capacity of the overall plant relative to the MISO system.

Thermal load that causes an increase in power output, as served from a back-pressure turbine for example, is not a PL for these purposes. However, the GVTC test should be performed or corrected for conditions that are a conservative expectation of the amount of thermal load that would be present coincident with MISO peak load conditions.

PL can be firm or non-firm. The following criteria should be applied to determine whether the PL is firm or non-firm:

- PL is firm if it continues to exist when one or more of the underlying generating units of the Planning Resource are derated or out of service. Such firm PL would be served by one or more of the underlying generating units of the Planning Resources at the same location or from the MISO system.
- PL is non-firm if it does not continue when the underlying generating unit of the Planning Resource is out of service.
- To the extent that PL that continues to exist when the underlying generating unit of the Planning Resource is out of service is served by resources that are not Planning Resources, such as auxiliary boilers, that portion of the PL is non-firm.

The amount of firm PL will be adjusted by multiplying by (1+PRM) and dividing by (1-XEFORd). The sum of the firm and non-firm PL will be reported in PowerGADS.

PL = (adjusted firm PL) + (non-firm PL)

Adjusted firm PL = firm PL * (1 + PRM) / (1 - XEFORd)

PL calculations are performed outside of PowerGADS and the MECT. PL is only deducted from an underlying generating unit of the Planning Resource's gross MWs one time. PL is part of the GVTC calculation that is entered into PowerGADS. MISO performs a PowerGADS integration that retrieves the GVTC value from the PowerGADS data base and populates the MECT. A Planning Resource may be comprised of one or more underlying PowerGADS units.

The UCAP PRM is from the most recent LOLE Study Report. The XEFORd is the appropriate value for the 36-months ending on August 31 proceeding the planning year, which can be found in PowerGADS.

### J.4 Generation Verification Test Capacity During a Derate

A Market Participant that performs a GVTC when a unit has a documented derate in MISO PowerGADS can request MISO to adjust its GVTC if the documented derate in MISO PowerGADS lasted a minimum of 90 consecutive days prior to the test date and generator availability data has been reported to MISO prior to any adjustments to the GVTC. The Market Participant shall contact MISO's Resource Adequacy Department for a review of its request.

#### J.4.1 Interconnection Service Limitations

All Planning Resources GVTC are subject to Interconnection Service limitations to the bus to which the facility is currently or about to be connected to as verified by the Transmission Service Planning Department of MISO.

### J.5 GVTC Real Power Test Requirements by NERC Unit Type

#### J.5.1 Fossil Steam (FS), Fluidized Bed Combustion (FB), and Nuclear (NU)

The test shall be at least two (2) continuous hours and data shall be averaged over the test period. The impact of the observed steam turbine exhaust pressure will be corrected to the past five years average rated daily maximum circulating water temperature measured at the unit location, at the date and time of MISO's coincident peaks.

### J.5.2 Combined Cycle (CC)

The determination of the GVTC of a combined-cycle unit will depend on the structure of the unit and its components. The steam turbine and combustion turbine(s) shall adhere to the guidelines in this manual. In the case of thermally dependent components the determination of the GVTC shall require the operation of both combustion and steam turbine components simultaneously. The output of the components can be netted to determine the combined-cycle unit GVTC.

The test shall be at least two (2) continuous hours and data shall be averaged over the test period.

For each season, the impact of the observed steam turbine exhaust pressure will be corrected to the past five years average daily maximum circulating water temperature measured at the unit location on the day of MISO's Coincident Peak.

The impact of the observed ambient air temperature and relative humidity on combustion turbine performance will be corrected to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's Coincident Peaks. Where inlet cooling is used to reduce inlet air temperature, the temperature at the discharge of the inlet coolers shall be the basis for ambient temperature adjustment.

### J.5.3 Combustion Turbine (CT)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The impact of observed dry air temperature and relative humidity on combustion turbine performance will be corrected, for each season, to the past five years average rated conditions experienced at the unit location measured at the date and time of MISO's seasonal coincident peaks. Where inlet cooling is used to reduce turbine inlet air temperature, the temperature at the discharge of the Inlet coolers shall be the basis for air temperature correction.

### J.5.4 Hydro (HD) and Pumped Storage (PS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

The GVTC established for hydroelectric plants shall recognize the head available considering environmental, operational, and regulatory restrictions and ambient conditions such as forecasted reservoir levels or water flow conditions. The test capability shall be corrected to historic median head conditions as specified below.

The seasonal historic median head shall be determined as the median of all head measurements from the most recent five (5) years up to the most recent fifteen (15) years. If 15 years of historic data is not available for this period when the 15-year time period is chosen, or is no longer relevant due to environmental, operational, regulatory or other restrictions, all available relevant data shall be used and accumulated until the 15-year requirement is met. The hours ending 1500, 1600, and 1700 EST apply to all days of the Summer (June, July, August), Fall (September, October, November), and Spring (March, April, May). The hours ending 0900, 1000, 1900, and 2000 EST apply to all days of the Winter (December, January, February).

Once the number of years and methodology is chosen and submitted as GVTC requirements, the same number of years must be submitted in future GVTC data collection.

Each hydro unit shall be verified individually.

The entire hydro plant shall be verified if the sum of individual unit capabilities is greater than the total plant capability.

#### J.5.5 Diesel (DS)

The test shall be at least one (1) continuous hour and data shall be averaged over the test period.

No corrections apply to this unit type.

#### J.5.6 Electric Storage Resources (ESR)

This section is for all ESR except Pumped Storage. For pumped storage see J.5.4.

The test shall be at least one (1) continuous hour and data shall be averaged over the test period. The test shall be conducted at the discharge rate that would be expected if the ESR were dispatched for four (4) continuous hours.

#### J.5.6 General Requirements

If a generating unit has not been in operation for five years, then as many years as the unit has been in operation shall be used. The GVTC for new generating units will be corrected based on estimated average daily maximum circulating water temperature measured at the date and time of MISO's Peaks.

The unit shall be operated with the regularly available type and quality of fuel.

The Station Service shall be representative of the conditions expected to occur during MISO's coincident peaks.

For facilities consisting of multiple units, shared station power and process load served shall be allocated to the individual units to compute unit net capability.

### J.6 Reporting

The following information shall be reported to MISO's PowerGADS as described in MISO's *Net Capability Verification Test User Manual*. Certain data will be reported or calculated for each of the 4 seasons – summer, fall, winter and spring.

| | |
|---|---|
| CARD | Must be "90" |
| Utility | Required |
| Unit | Required |
| Year | Required |
| | |
| Test Index | Must be a "1" |
| REVISIONCODE | Must be "0" for initial upload, "R" to Revise, or "D" to Delete |
| Corrected Net - Seasonal | Calculated by PowerGADS |
| | |
| | |
| | |
| Test Start Date | Required |
| Test End Date | Required |
| Gross MW | Required |
| Station Service | Required |
| Process Load Served | Required |
| Net Test Capability | Required, Gross MW – Station Service – Process Load Served |
| Reactive Generation MVAR | Optional |
| Total Power MVA | Calculated by PowerGADS if Reactive Generation MVAR entered |
| Power Factor | Calculated by PowerGADS if Reactive Generation MVAR entered |
| Dry Air Temperature Observed - Seasonal | Required for certain unit types |

| | |
|---|---|
| Dry Air Temperature Rated - Seasonal | Required for certain unit types |
| Air Temperature Correction | Required, may be zero (0) |
| Relative Humidity Observed - Seasonal | Required for certain unit types |
| Relative Humidity Rated - Seasonal | Required for certain unit types |
| Relative Humidity Correction | Required, may be zero (0) |
| Cooling Water Temperature Observed - Seasonal | Required for certain unit types |
| Cooling Water Temperature Rated - Seasonal | Required for certain unit types |
| Cooling Water Temperature Correction | Required, may be zero (0) |
| STANDARD | Must be "MISO" |

## Appendix K – Resource Adequacy Timeline

Please check for the latest online version posted on the Resource Adequacy webpage of MISO's corporate website.

| Date | Process and Notes | Responsible Entity | Tariff Reference |
|---|---|---|---|
| Sep 01, 2022 | Cost of New Entry (CONE) arranged to be calculated in coordination with IMM by Sept 1. Later file with FERC. | MISO | 69A.8(a)(3) |
| Sep 01, 2022 | MISO publish historical monthly and seasonal Coincident Peak Load hours and LRZ seasonal coincident factors. | MISO | 69A.1.1.(c) |
| Oct 03, 2022 | MISO opens the new Planning Year in the MECT for all 4 seasons.<br>(1st Business Day - October) | MISO | |
| Oct 03, 2022 | Transmission losses by Local Balancing Authority are posted by MISO.<br>(1st Business Day - October) | MISO | 69A.1.1(b) |
| Oct 31, 2022 | Generation Verification Test Capacity (GVTC) due.<br>Resource Owners submit operational data or real power test for Sep. 1 - Aug. 31 period. | Resource Owner | 69A.3.1.a, b, & c, 69A.3.6 |
| Oct 31, 2022 | Updated historical performance submittal due for hours ending 15, 16, and 17 EST in summer, fall and spring cases, hours ending 8, 9, 19, 20 EST for the winter season for Intermittent Generation & Intermittent BTMG that are not powered by wind. | Resource Owner | 69A.3.1.a(1)(d) |
| Oct 31, 2022 | Generator Availability Data due in GADS for those resources that are required to report for Q3.<br>Resource Owners must also ensure at least 36 months of data is provided, if applicable. | Resource Owner | 69A.3.1.a(1)(c) |
| Nov 01, 2022 | Seasonal Coincident and Non-Coincident Peak Demand forecasts by LSE/EDC, monthly peak demand, seasonal peak demand and energy-for-load forecast values by LSE due.<br>No action needed by Retail Choice LSEs. | LSE, EDC | 69A.1.1(a) |
| Nov 01, 2022 | Loss of Load Expectation study results published by MISO<br>(Publish seasonal: PRM, Determine seasonal CIL and CEL, Establish seasonal LRRs)<br>Published by Nov. 1 | MISO | 68A.2<br>68A.4<br>68A.5 |
| Nov 07, 2022 | MP must request an extension from within 5 Business Days after Oct 31 deadline. | Resource Owner | 69A.3.1.a, b, & c, 69A.3.6 |
| Nov 15, 2022 | Review list of units with Conditional Interconnection Service for results of annual study. Units may have NRIS/ERIS balance re-allocated.<br>Published by Nov. 15 | MISO | |
| Dec 15, 2022 | Seasonal Capacity accreditation values are published by MISO.<br>Resources that do not meet the Oct. 31 milestones will not have capacity accreditation calculated at this date. | MISO | |

| Date | Process and Notes | Responsible Entity | Tariff Reference |
|---|---|---|---|
| Dec 15, 2022 | Peak Load Contribution (PLC) submissions by EDC due (EDC will send the details of the PLCs to both the respective LSEs and MISO for review). The EDC-provided PLC data will be the default value for the LSEs' Retail Choice Coincident Peak. | Retail Choice EDCs | 69A.1.1( e) |
| Dec 31, 2022 | For individual States establishing their own seasonal PRM, written letter by authorized State regulatory authority representative notifying MISO. | State Regulatory Authority | 68A.1 |
| Jan 15, 2023 | LSEs confirm the seasonal Retail Choice PLC in the MECT.<br>LSEs should have all PLC questions resolved at this milestone. If an LSE desires a change in their PLC value, the appropriate EDC should be contacted directly for discussion | LSEs, Retail Choice EDC | 69A.1.1.1 |
| Jan 15, 2023 | Evidence for seasonal HUC/Zonal Deliverability Charge hedges due | LSE | 69A.7.7(b) |
| Jan 31, 2023 | Default technology specific avoidable costs posted by the IMM.<br>Resource owners may use the default costs in lieu of submitting facility specific operating costs for a facility specific Reference Level request.<br>(59 days prior to deadline for offers) | IMM | 64.1.4(f)(ii) |
| Feb 01, 2023 | Existing Load Modifying Resource / Energy Efficiency / External Resource registrations due for prompt Planning Year | LMR/EE/ER Owner | |
| Feb 01, 2023 | Loss of Load Expectation study begins for next Planning Year | MISO | |
| Feb 01, 2023 | Resource Owners confirm Seasonal Accredited Capacity posted in the MECT.<br>Excludes SAC values for LMR and External Resource registrations. | Resource Owner | |
| Feb 01, 2023 | Evidence of Demand Resource testing due.<br>Last day to submit evidence.<br>DR testing or performance should take place during the calendar year prior to the upcoming Planning Year. | DR Owner | 69A.3.5 |
| Feb 01, 2023 | Written letter from officer of company stating intention to leverage DR testing deferral provisions due. | DR Owner | 69A.3.5(l) |
| Feb 14, 2023 | If utilizing FSRL, last day to request from IMM Going-Forward Cost determination.<br>Submit data for facility ZRC reference levels to IMM.<br>(45 days prior to close of PRA offer deadline) | Generation Owner | 64.1.4.f.iii.b |
| Feb 15, 2023 | New Load Modifying Resource / Energy Efficiency Resource / External Resource registrations must be submitted for approval to be considered for inclusion in seasonal FRAP. | LSE | 69A.9(a) |
| Feb 15, 2023 | LSEs submit request to revise seasonal Coincident Peak Demand forecast originally submitted on November 1st.<br>MISO will review and approve/deny request | LSE | |

| Date | Process and Notes | Responsible Entity | Tariff Reference |
|---|---|---|---|
| Feb 15, 2023 | Written letter from officer of company stating intention to leverage ICAP Deferral provisions | Resource Owner | 69A.7.9(a) |
| Feb 28, 2023 | Capacity accreditation updated for resources granted ICAP Deferral | MISO | |
| Mar 01, 2023 | Seasonal Generator Verification Test Capacity / Generator Availability Data for new resources or resources with increased capacity due for prompt Planning Year | Generation Owner | 69A.3.1.a(d) |
| Mar 01, 2023 | New Load Modifying Resource / Energy Efficiency Resource / External Resource registrations must be submitted for approval in the MECT for the prompt Planning Year | LMR/EE/ER Owner | 69A.9(a) |
| Mar 01, 2023 | Deadline to satisfy credit requirements for DRs opting out of or deferring testing. Credit posting only required if DR doesn't have regulatory restriction or contractual obligation that precludes testing. | DR Owner | 69A.3.5 (j)(2)&(l) |
| Mar 01, 2023 | Publish seasonal Sub Regional Import Constraint (SRIC) and the seasonal Sub Regional Export Constraint (SREC) for each Sub Regional Resource Zone (SRRZ) no later than first business day in March. | MISO | 68A.3.1 |
| Mar 01, 2023 | MISO to complete its seasonal Coincident Peak Demand forecast review process | MISO | 69A.1.1( c) |
| Mar 01, 2023 | Satisfy credit requirement for seasonal capacity accreditation issued from resources granted ICAP Deferral | Resource Owner | 69A.7.9(b) |
| Mar 01, 2023 | Resource Owners Confirm SAC posted in the MECT - Catch Up resources only | Resource Owner | |
| Mar 01, 2023 | Resource Owners submit Att Y for units scheduled for retirement/suspension between 3/30 and 5/31 to receive exemption from physical withholding | Resource Owner | 38.2.7.a.(i) |
| Mar 09, 2023 | Seasonal Fixed Resource Adequacy Plan due by LSE<br>(7th Business Day of March) | LSE | 69A.9(a) |
| Mar 14, 2023 | Last day to notify IMM of deliverable resources requesting to be excluded from offering into seasonal PRAs or included in a FRAP. | Generation Owner | |
| Mar 15, 2023 | Fixed Resource Adequacy Plan review completed by MISO (The LSE will have until the PY offer window opens to remedy any deficiencies in their FRAP) | MISO(LSE) | 69A.9(a) |
| Mar 21, 2023 | Final date to update seasonal CIL and CEL values for each LRZ prior to the Planning Resource Auction.<br>Changes due to firm capacity commitments from MISO resources to neighboring regions prior to the PRA | MISO | 68A.4 |
| Mar 21, 2023 | CEL determined for each ERZ.<br>Equal to the ZRC quantity of the External Resources registered to participate in the PRA.<br>(8th Business Day before the last Bus. Day) | MISO | 68A.4 |

| Date | Process and Notes | Responsible Entity | Tariff Reference |
|---|---|---|---|
| Mar 21, 2022 | Final Preliminary seasonal PRA data is released by MISO. Reflects updated information from LSEs, Resource Owners and PJM auction results. Coincides with seasonal CIL/CEL calculations. | MISO | |
| Mar 24, 2023 | Provide Facility Specific Resource Level(s) to MPs 5 days prior to the close of the PRA offer window | IMM | 64.1.4.g |
| Mar 28, 2023 | Planning Resource Auction offer window for all seasons is opened<br>Auction Offer window is opened at 8:00 am EPT 3 Business Days prior to the last Business Day in March<br>(28th-31st of March) | MISO | 69A.7.1(a) |
| Mar 31, 2023 | Planning Resource Auction offer window for all seasons is closed<br>Auction Offer window is closed at 6:00 pm EPT<br>(Last Business Day of March) | MISO | 69A.7.1(a) |
| Apr 03, 2023 | Iterations of seasonal auction runs with adjusted seasonal CILs and CELs may be required to ensure that a network loading is not violated. Additionally, MISO will work with the IMM to evaluate potential withholding. The reference levels are used to determine financial withholding. The mitigation of financial withholding can be expected to reduce the auction clearing price<br>(1st 20 Business Days of April) | MISO/IMM* | 69A.7 |
| Apr 28, 2023 | Seasonal Planning Resource Auctions results posted<br>(20th Business Day of April) | MISO | 69A.7 |
| May 1, 2023 | For MP's selecting this option, assess the seasonal Capacity Deficiency Charge | MISO | 69A.10(a) |
| May 8, 2023 | MISO sends out the Capacity Deficiency Charge 5 business days (or as soon as practical) after assessment. | MISO | |
| May 17, 2023 | Capacity Deficiency Charge payment due<br>Payment made within 7 business days of receipt. | MISO | |
| May 19, 2023 | Capacity Deficiency Charge payments made to MPs.<br>Actual payment date may vary depending on above payment receipt date. | MISO | |
| May 29, 2023 | Publish details of the seasonal ZRC offers submitted in the PRA - Market Participant IDs are not revealed.<br>(One month after PRA) | MISO | 69A.7.4 |
| May 29, 2023 | MISO publishes cleared LMRs to applicable operations tool.<br>Must Offer performance requirements in the applicable operations tool. | MISO | |
| May 31, 2023 | Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Summer season.<br>(Last Business Day) | LSE | 69A.7.9(a) (2) |

| Date | Process and Notes | Responsible Entity | Tariff Reference |
|---|---|---|---|
| May 31, 2023 | Information due to satisfy DR Deferral Notice must be submitted to MISO in order to release credit requirements and avoid potential 3 x LMP performance penalties. | DR Owner | 69A.3.5 |
| Jun 01, 2023 | Summer season in New Planning Year starts | All | 69A.7 |
| Jun 01, 2023 | Daily settlements for the Summer season starts | All | |
| August 31, 2023 | Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Fall season. (Last Business Day) | LSE | 69A.7.9(a) (2) |
| Sep 01, 2023 | Fall season in New Planning Year starts | All | 69A.7 |
| Sep 01, 2023 | Daily settlements for the Fall season starts | All | |
| November 30, 2023 | Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Winter season. (Last Business Day) | LSE | 69A.7.9(a) (2) |
| Dec 01, 2023 | Winter season in New Planning Year starts | All | 69A.7 |
| Dec 01, 2023 | Daily settlements for the Winter starts | All | |
| February 29, 2024 | Information due to satisfy ICAP Deferral must be submitted to MISO to avoid ICAP Deferral Non-Compliance Charge for Spring season. (Last Business Day) | LSE | 69A.7.9(a) (2) |
| Mar 01, 2024 | Spring season in New Planning Year starts | All | 69A.7 |
| Mar 01, 2024 | Daily settlements for the Spring season starts | All | |

# Appendix L – Transmission Losses Calculation

The Transmission Provider will calculate the seasonal LBA Transmission loss percentages using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.

3. The individual transmission losses (MW) for each element are summed to a total transmission value for each Local Balancing Authority (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Transmission Provider's system peak during each of the four previous seasons.
6. The LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at each seasonal MISO peak hour.

The seasonal LBA transmission loss percentage calculated by the Transmission Provider will apply to the LSE's applicable seasonal LBA Coincident Peak Demand forecast to determine the LSE transmission losses for the calculation of the seasonal PRMR. The LBA transmission loss percentage calculated by the Transmission Provider coincident with each LRZ's seasonal Peak Demand forecast will determine the LSE transmission losses for the calculation of LRR.

PRMR met with Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. PRMR met with Behind-the-Meter-Generation Resources that are not interconnected to the Transmission System shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

# Appendix M – Auction Formulation

## Planning Resource Auction Software Formulations

### Disclaimer

This document is prepared for informational purposes only to support the application of the MISO Tariff provisions relating to Resource Adequacy Requirements. MISO may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by MISO to update this document and inform its users of changes as soon as practicable. Nevertheless, it is the user's responsibility to ensure you are using the most recent version posted on the MISO website. In the event of a conflict between this document and the Tariff, the Tariff will control, and nothing in this document shall be interpreted to contradict, amend or supersede the Tariff.

### Purpose of this document

MISO's Resource Adequacy construct provides LSEs in MISO footprint an ability to procure planning resources through an Planning Resource Auction (PRA) for each season within the Planning Year. An AIMMS based Auction Clearing Tool has been developed to clear the auction and calculate Auction Clearing Prices (ACP). This document provides a detailed mathematical representation of the constrained optimization objective function that is used for clearing the seasonal PRA and explains how zonal Auction Clearing Prices would be calculated for each season within the PY.

AIMMS ("Advanced Interactive Multidimensional Modeling System") is an integrated modeling system that supports modeling and solving large-scale optimization problems.

## Notations

Set $Z$ = {All LRZs in the market}
Set $Zn$ = {All Northern region LEZs (LRZ 1 to 7 are considered in Northern MISO Zones)}
Set $Zs$ = {All Southern region LRZs (LRZ 8 to 10 are considered in Southern MISO Zones)}
Set $E$ = {All external BAs participating in the PRA}
Set $G$ = {All resources in LRZs}
Set $G_k$ = {All resources in LRZ *k*}
Set $G_n$ = {All resources in Northern region LRZs}
Set $G_s$ = {All resources in Southern region LRZs}
Set $H$ = {All resources in External zones (including dual connected external zones)}
Set $H_e$ = {All resources in External zone *e*}
Set $H_d$ = {All resources in dual connected External zones}
Set $H_n$ = {All resources in External zones connected solely to Northern LRZs}
Set $H_s$ = {All resources in External zones connected solely to Southern LRZs}
*PRM* = Planning Reserve Margin
$PRMR_k$ = Planning Reserve Margin Requirement for LRZ *k*
*CPDF*= Coincident Peak Forecasted Demand
$CIL_k$ = Capacity Import Limit for LRZ *k*
$CEL_k$ = Capacity Export Limit for LRZ *k*
$CEL_e$ = Capacity Export Limit for External zone *e*
$LCR_k$ = Local Clearing Requirement for LRZ *k*
$ZReq_k$ = Total capacity requirement for loads in LRZ *k*

$$ZReq_k = max\,\{PRMR_k, LCR_k\}$$

$$PRMR_k = CPDF_k \times (1 + PRM)$$

$OfferPrice_i$ = The offer price for LRZ resource *i*
$OfferPrice_j$ = The offer price for External Zone resource *j*
$RDTNS$ = Regional Directional Transfer limit from Northern region to Southern region
$RDTSN$ = Regional Directional Transfer limit from Southern region to Northern region

Note*:* In this document, a resource can offer only one price. Multiple price segments are treated as multiple resources.

$OfferMW_i$ = Offered MW value for LRZ resource *i*.
$OfferMW_j$ = Offered MW value for External zone resource *j*.
$SF_l^{NS}$ = North to South shift factor for dual connected External resource *l*
$SF_l^{SN}$ = South to North shift factor for dual connected External resource *l*

$SF_e^{NS}$ = North to South shift factor for dual connected External zone *e*
$SF_e^{SN}$ = South to North shift factor for dual connected External zone *e*

Note: All resources in dual connected External zone will have same shift factors. For instance, North to South shift factor for dual connected External zone *e* = North to South shift factor of all External resources in External zone *e.*

$MWCleared_i$ = Cleared MW value for LRZ resource *i*.
$MWCleared_j$ = Cleared MW value for External zone resource *j*.
$P1_k, P2_k$ = Penalty prices for shortage
$SSlack_k, ZSlack_k$ = Slack variables representing capacity shortage, nonnegative
$ZACP_k$ = Auction Clearing Price for Zone $k$
$CONE_k$ = Cost of new entry for LRZ *k*
$CONE_n$ = maximum Cost of new entry in Northern region LRZs
$CONE_s$ = maximum Cost of new entry in Southern region LRZs
$CONEmax$ = maximum Cost of new entry in all LRZs (Northern region LRZs as well as Southern region LRZs)

**Objective Function**

The auction is cleared by solving the following optimization problem. The objective function is expressed with the following mathematical terms:

Minimize $f =$

$$\sum_{i \in G} OfferPrice_i \times MWCleared_i + \sum_{j \in H} OfferPrice_j \times MWCleared_j + \sum_{k \in Z} (P1_k \times SSlack_k + P2_k \times ZSlack_k)$$

The slack variables are used to make sure the LP is feasible. The penalty prices are set to be a little higher than CONE values.

**Constraints:**

C1a) $MWCleared_i \leq OfferMW_i, \forall i \in G$
C1b) $MWCleared_j \leq OfferMW_j, \forall j \in H$
C2a) $MWCleared_i \geq 0, \forall i \in G$
C2b) $MWCleared_j \geq 0, \forall j \in H$
C3) $\sum_{i \in G} MWCleared_i + \sum_{j \in H} MWCleared_j + \sum_{k \in Z} SSlack_k = \sum_{k \in Z} ZReq_k - \varepsilon_0$

This is the system demand constraint; its shadow price is referred as $SPsys$.
$\varepsilon_0$ is nonnegative and would be less than 0.001.
If $\varepsilon_0$ equals zero, the shadow price $SPsys$ may not be unique at certain situations. A small positive $\varepsilon_0$ would ensure $SPsys$ is unique.

C4) $\sum_{i \in G_k} MWCleared_i + SSlack_k \geq ZReq_k - CIL_k - \varepsilon_k$

Each zone has a minimal clearing constraint with corresponding shadow price $SPmin_k$.
$\varepsilon_k$ is nonnegative and would be less than 0.001.

C5) $\sum_{i \in G_k} MWCleared_i + SSlack_k \leq ZReq_k + CEL_k + \varepsilon_k$

Each zone has a maximal clearing constraint with corresponding shadow price $SPmax_k$
Again, the purpose of $\varepsilon_k$ is to guarantee a unique shadow price $SPmax_k$.

C6) $\sum_{i \in G_k} MWCleared_i + ZSlack_k \geq LCR_k - \varepsilon_k$

The corresponding shadow price is referred as $SPlcr_k$.

C7) $\sum_{j \in H_e} MWCleared_j \leq CEL_e + \varepsilon_e$

Each External zone has a maximal clearing constraint with corresponding shadow price $SPcel_e$.
$\varepsilon_e$ is nonnegative and would be less than 0.001.

C8) $SSlack_k \leq \max(0, \; ZReq_k - \sum_{i \in G_k} MWCleared_i)$

**Regional Directional Transfer Limit**

Flows between the MISO South and Northern MISO Zones is limited by the Regional Directional Transfer Limit per the settlement agreement by MISO, SPP, and the Joint Parties. Prior to the 2016-2017 Planning Year, flows between the two MISO Sub-Regional Resource Zones were limited to 1,000 MW. Beginning with the 2016-2017 Planning Year, MISO modified its process to calculate the limit based upon several factors as described previously in this BPM. In order to minimize changes to the auction logic section, all references to 1,000 MW in this Appendix shall represent the directionally SREC and SRIC effective for each Planning Year. The sub-regional power balance constraint is introduced by the transmission capacity limitation of 1000MW between the South Region (Zones 8, 9, and 10 in MISO) and the rest of the MISO system (Zones 1 through 7). This results in a condition that zones 8, 9, and 10 must be treated both as a group and an individual. At the same time, the rest of the zones (1 through 7) can also be thought of as a group and an individual. The combination of zones has been termed as SuperZone for reference purposes. Following constraints are used to model Regional Directional Transfer limit.

C9) $\sum_{i \in G_n} ClearedMW_i + \sum_{j \in H_n} ClearedMW_j + \sum_{l \in H_d} SF_l^{NS} \times ClearedMW_l + \sum_{l \in Z_n} SystemSlack \leq \sum_{l \in Z_n} ZReq_l + RDTNS$

The corresponding shadow price is referred as $SPnel$.

C10) $\sum_{i \in G_n} ClearedMW_i + \sum_{j \in H_n} ClearedMW_j + \sum_{l \in H_d} SF_l^{NS} \times ClearedMW_l + \sum_{l \in Z_n} SystemSlack \geq \sum_{l \in Z_n} ZReq_l - RDTSN$

The corresponding shadow price is referred as $SPnil$.

C11) $\sum_{i \in G_s} ClearedMW_i + \sum_{j \in H_s} ClearedMW_j + \sum_{l \in H_d} SF_l^{SN} \times ClearedMW_l + \sum_{l \in Z_s} SystemSlack \leq \sum_{l \in Z_s} ZReq_l + RDTSN$

The corresponding shadow price is referred as $SPsel$.

C12) $\sum_{i \in G_s} ClearedMW_i + \sum_{j \in H_s} ClearedMW_j + \sum_{l \in H_d} SF_l^{SN} \times ClearedMW_l + \sum_{l \in Z_s} SystemSlack \geq \sum_{l \in Z_s} ZReq_l - RDTNS$

The corresponding shadow price is referred as $SPsil$.

Note: (C11) and (C12) constraints are redundant but are used for consistency. (C9) and (C12) constraints definitions are for illustration purposes, the implementation in the tool is generic.

**Pricing**

The clearing price for each LRZ *k* ($ZACP_k$) would be equal to the minimum of 1) the CONE value and 2) the sum of the shadow prices of $SPsys, SPmin_k, SPmax_k, SPlcr_{k,}$ and applicable Regional Directional Transfer limit constraints (for the LP problem).

For all LRZ *k* connected to Northern region,

$$ZACP_k \; = \; min\,(CONE_k, SPsys + SPmin_k + SPmax_k + SPlcr_k + SPnel + SPnil)$$

For all LRZ *k* connected to Southern region,

$$ZACP_k \; = \; min\,(CONE_k, SPsys + SPmin_k + SPmax_k + SPlcr_k + SPsel + SPsil)$$

The clearing price for each non-dual connected External zone *e* ($ZACP_e$) would be equal to the minimum of 1) the maximum CONE value in the region and 2) the sum of the shadow prices of $SPsys, SPcel_{e,}$ and applicable Regional Directional Transfer limit constraints (for the LP problem).

For all non-dual connected External zone *e* connected to Northern region,

$$ZACP_e \ = \ min\ (CONE_n, SPsys + SPcel_e + SPnel + SPnil)$$

For all non-dual connected External zone *e* connected to Southern region,

$$ZACP_e \ = \ min\ (CONE_s, SPsys + SPcel_e + SPsel + SPsil)$$

The clearing price for each dual connected External zone *e* ($ZACP_e$) would be equal to the minimum of 1) the system wide maximum CONE value (Northern and Southern region together) and 2) the sum of the shadow prices of $SPsys, SPcel_{e,}$ and Regional Directional Transfer limit constraints with shift factors (for the LP problem).

$$ZACP_e = \ min\ (CONEmax, SPsys + SPcel_e + SF_e^{NS} \times SPnel + SF_e^{NS} \times SPnil + SF_e^{SN} \times SPsel + SF_e^{SN} \times SPsil)$$

### Additional Post Processing and Notes on Scarcity Pricing

- After clearing the first time, if in the same zone there are multiple offers with prices equal to the $ZACP_z$, the second run will ensure those offers are cleared proportional to their offered MW
- After that, all $0 offers are cleared

Note:

- When there is system shortage, even if all zones meet their local requirements (max(ZReq-CIL,LCR)), the engine must allocate the system shortage to each zone so that it can solve with different CONE price. The engine allocates the shortage to zones with the lowest CONE first. Each zone is allocated with no more than ZReq-Zclear, i.e. build new resources up to ZReq. For all the zones allocated with shortage, it will solve at its CONE price. All other zones will take the highest CONE of the zone with shortage allocated if nothing else binding.
- It is equivalent to have a system wide demand curve formed as from the lowest CONE to the highest CONE. However, the width of each price segment depends on the solution, i.e. ZReq-ZClear.

**Capacity Market Settlement Examples**

For simplicity, Regional Directional Transfer limits are not considered in following examples.

High Level Clearing Constraints

- Input
  - PRM, Load Forecast, LRR, $CIL_z$, $CEL_z$
  - $LCR_z = LCR_z - ZIA_z$ – controllable exports
  - $PRMR_z = (1 + PRM) * \text{Load Forecast}_z$
  - $LRR_z \geq PRMR_z \longrightarrow LCR_z = \geq PRMR_z - CIL_z$
  - $ZReq_z = \max\{LCR_z, PRMR_z\}$
  - $CONE_z$: may be different for each zone
- Objective
  - $\sum_{i=1}^{m} OfferPrice\ i \times MWClearedi + \sum_{z=1}^{z}(CONEz\ \times SSLACKz + CONEz\ \times ZSLACKk)$
- Market wide and zonal constraints and shadow prices

| | | |
|---|---|---|
| $\sum_z \{ZClear_z + SSlack_z\} \geq \sum_z ZReq_z - \varepsilon_o$ | $(\alpha_{mkt} \geq 0)$ | (1) |
| $ZClear_z + SSlack_z \leq ZReq_z - CEL_z$ | $(\alpha_{max,z} \leq 0)$ | (2) |
| $ZClear_z + SSlack_z \geq ZReq_z - CIL_z - \varepsilon_k$ | $(\alpha_{min2,z} \geq 0)$ | (3) |
| $ZClear_z + ZSlack_z \geq LCR_z - \varepsilon_k$ | $(\alpha_{min1,z} \geq 0)$ | (4) |

- For export zones, check and resolve to make sure $SSlack_z \leq ZReq_z - ZClear_z$
- Clearing Price
  - Market-wide: MACP = $\alpha_{mkt}$
  - Zonal: ZACP = $\alpha_{mkt} + \alpha_{max,z} + \alpha_{min,z} + \alpha_{min,z} =$ MACP + + $\alpha_{max,z} + \alpha_{min,z} + \alpha_{min,z}$
  - When both (30 and (4) are violated, $ZACP_z$ may be higher than $CONE_z$. If so, then cap $ZACP_z$ at $CONE_z$.
- Initial Settlement
  - Gen revenue: $\sum_z (ZACPz * ZClearz))$
  - Load Payment: $\sum_z (ZACPz * ZReqz))$

### FRAP and HUC

- Before the auction, the engineers should have checked the FRAP and HUC data to ensure they are consistent with CIL and CEL;
- All FRAP Gen will be treated as $0 offer and participate the auction clearing;
- All HUC Gen will have an offer and will participate the auction with the offered price;
- After the auction clearing, it will go through all GMAHUCs:
  - If $ACP_{HUCGMAHUC,Gen} \leq ACP_{GMAHUC,load}$, the GMAHUC will be honored and will be excluded from the auction settlement based on ZACP
  - If $ACP_{GMAHUC,Gen} > ACP_{GMAHUC,load}$, the GMAHUC will be not be honored. It will be settled based on ZACP.
- This may cause $\{GMAHUC_{zgen\_to\_exld}-FRAP_{exgne\_to\_zld}\} > CEL_z$ or $\{GMAHUC_{exgen\_to\_zld}-FRAP_{zgen\_to\_exld}\} > PRMP_z - LCR_z$. When this happens, we may pay more to resources than charge from load. The auction clearing engine will check each zone and identify potential issues. If any problem is identified, we will report it and go back to step 1) for proper adjustment of FRAP, CIL and/or CEL to re-run the auction clearing.
- If there is any human error, we may have FRAP in conflict with CIL and/CEL. The engine will not be able to clear all FRAP in this scenario. The engine should report the issue so that FRAP, CIL and/or CEL can be properly adjusted.
- Input validation
  - $FRAP_{exgen\_to\_zld}$ from outside to load in the import binding zone should be no more than $ZReq_z$-$LCR_z$: $FRAP_{exgen\_to\_zld} \leq ZReq_z - LCR_z$
  - There is no limitation on $FRAP_{zgen\_to\_exld}$ from generators in zone z to load outside.
    - When there is limitation on $CEL_z$, $FRAP_{zgen\_to\_exld}$ may not always be cleared from the auction process. However, it will all be treated as cleared at $0 afterwards. In this case, the export binding zone price must be $0.
  - GMAHUC $FRAP_{exgen\_to\_zld}$ from outside to load in the import binding zone will always be no more than $PRMR_z$-$LCR_z$: $GMAHUC_{exgen\_to\_zld} \leq ZReq_z - LCR_z$
  - $CEL_z$ will be set so that $GMAHUC_{zgen\_to\_exld}$ from generators can be cleared: $GMAHUC_{zgen\_to\_exld} \leq CEL_z$
- Warning messages from clearing engine for inputs with:
  - $FRAP_{exgen\_to\_zld} > ZReq_z - LCR_z$

- $FRAP_{zgen\_to\_exld} > CEL_z$
- $HUC_{exgen\_to\_zld} > ZReq_z\text{-}LCR_z$
- $GMAHUC_{zgen\_to\_exld} > CEL_z$

- After clearing, GMAHUC and FRAP met the following conditions will be excluded from the auction settlement
  - **The same amount of FRAP Gen or load is excluded if $ACP_{FRAP,Gen} > ACP_{FRAP,load}$**
  - **GMAHUC is honored and excluded if $ACP_{GMAHUC,Gen} < ACP_{GMAHUC,load}$.**
- For GMAHUC and FRAP that are settled outside market (TrGMAHUC, TrFRAP), MISO may have negative revenue if the following conditions are met. Hence the clearing engine will issue ERROR messages when:
  - $TrGMAHUC_{zgen\_to\_exld} - TrFRAP_{exgen\_to\_zld} > CEL_z$
  - $TrGMAHUC_{exgen\_to\_zld} - TrFRAP_{zgen\_to\_exld} > ZReq_z\text{-}LCR_z$
  - $TrFRAP_{zgen\_to\_exld} - TrGMAHUC_{exgen\_to\_zld} > CEL_z$
  - $TrFRAP_{exgen\_to\_zld} - TrGMAHUC_{zgen\_to\_exld} > ZReq_z\text{-}LCR_z$

**Settlement Issue <u>Under no Scarcity</u>**

- Imbalance under zonal binding

$\sum_z \{ZACP_z*(ZClear_z\text{-}ZReq_z)$

$= \{MACP*\sum_z(ZClear_z\text{-}ZReq_z)\} + \sum_z \{(\alpha_{min1,z} + \alpha_{min2,z})*(ZClear_z\text{-}ZReq_z)\} + \sum_z \{\alpha_{max,z}*(ZClear_z\text{-}ZReq_z)\}$

- <u>$\{MACP*\sum_z(ZClear_z\text{-}PRMR_z)\}=0$</u> because

1) If $MACP= \alpha_{mkt}>0$, then (1) is binding. Hence $\sum_z(ZClear_z\text{-}ZReq_z)\}=0$ if $MACP= \alpha_{mkt}>0$.

2) If (1) is not binding, i.e. $\sum_z ZClear_z > \sum_z ZReq_z$, then $MACP=\alpha_{mkt}=0$.

Define $\alpha_{min,z} =\alpha_{min1,z} + \alpha_{min2,z}$

- $\{\alpha_{min,z}*(ZClear_z\text{-}ZReq_z)\} < 0$ when
- (3) and/or (4) is binding, i.e. $ZClear_z = LCR_z$ ➔Import binding $ZACP_z > MACP$
- $\alpha_{min,z}>0$, $\{\alpha_{min,z}*(ZClear_z\text{-}ZReq_z)\}=\alpha_{min,z}*(LCR_z\text{-}ZReq_z) \leq 0$
- $\{\alpha_{max}*(ZClear_z\text{-}ZReq_z)\} < 0$ when
- (2) is binding, i.e. $ZClear_z = ZReq_z+ CEL_z$ ➔Export binding $ZACP_z < MACP$
- $\alpha_{max,z}<0$, $\{\alpha_{max,z}*(ZClear_z\text{-}ZReq_z)\}=\alpha_{max,z}*CEL_z \leq 0$

**Allocation of Imbalance Fund for Import Binding Zones**

- For import binding zone
  - Zone with $ZACP_z\text{-}MACP= \alpha_{min,z} >0$

– Imbalance amount

$\{\alpha_{min,z}*(ZClear_z-ZReq_z)\}=\alpha_{min,z}*\{LCR_z-ZReq_z\}$

$=\alpha_{min,z}*(LCR_z-ZReq_z)\leq 0$

– This amount should be refunded to load in the zone because the extra load is served by cheaper generation outside

➔Refunding dollar (calculated as part of zone z benefit):

$$\alpha_{min,z}*\{(ZReq_z - TrHUC_{load\ in\ z} - TrFRAP_{load\ in\ z}) - (ZClear_z - TrHUC_{gen\ in\ z} - TrFRAP_{gen\ in\ z})\}$$

This also covers $Zslack_z>0$ and $Sslack_z=0$

➔Amount of load in the zone eligible for refunding:

$ZReq_z-(TrHUC_{load\ in\ z})-(TrFRAP_{load\ in\ z})$ (where $TrFRAP_{load\ in\ z}$ should most likely be 0)

(Note, may also be allocated to FRAP and HUC per tariff)

- For export binding zone
  - Zone with $ZACP_z-MACP=\alpha_{max,z}<0$
  - Imbalance amount

$\{\alpha_{max,z}*(ZClear_z-ZReq_z)\}=\alpha_{max,z}*CEL_z<0$

– This amount should be refunded to load outside the zone because excess load outside is served by cheaper generation from export binding zones

➔For imbalance from export binding zone z1, refunding dollar:

$$-\alpha_{max,z1}*\{(ZClear_{z1} - TrHUC_{gen\ in\ z1} - TrFRAP_{gen\ in\ z1}) -(ZReq_{z1} - TrHUC_{load\ in\ z1} - TrFRAP_{load\ in\ z1})\}$$

➔ It is distributed to load in non export binding zones based on the following logic (calculated as part of zone z benefit ):

1) For non-binding zones: $LZ_z=\min\{CEL_z-(ZClear_z-ZReq_z), CIL_z, ZReq_z-LCR_z\}$
2) For each import binding zone, calculate: $LZ_z=ZReq_z-LCR_z$
3) Distribute the imbalance amount proportionally based on $LZ_z$

➔Amount of load in the zone eligible for refunding:

$ZReq_z-(TrHUC_{load\ in\ z})-(TrFRAP_{load\ in\ z})$

(Note, may also be allocated to FRAP per tariff)

### Refund under Scarcity ($Sslack_z>0$)

- With zonal CONE and cap ZACP at its CONE, the allocation is more complicated

- If MACP<min(CONEz), all scarcity is considered zonal.
  - $ZACP_z$*$Sslack_z$ is refund to the zone. (if $Zslack_z$ and $Sslack_z$ are both non-zero, price capping will remove the impact from $Zslack_z$)
  - If MACP≥min(CONEz),
  - Zonal scarce (min($Zslack_z$, $Sslack_z$)>0)

  $ZACP_z$*min($Zslack_z$, $Sslack_z$) refund to the zone

  - Market-wide constraint can be violated for zonal or market-wide scarcities.
    - Allocate "$\sum_z${$ZACP_z$*[Sslackz -min(Zslackz, Sslackz)]} the same ways as the benefit from export zones, i.e. For non-binding zones based on LZz=min{CELz-(ZClearz-ZReqz), CILz, ZReqz –LCRz} and for import binding zone based on $LZ_z$=$ZReq_z$ -$LCR_z$.

Amount of load in the zone eligible for refunding:

$ZReq_z$- ($TrGMA_{\text{load in z}}$)-($TrFRAP_{\text{load in z}}$)

(Note, may also be allocated to FRAP per tariff)

## Appendix N – Seasonal Demand and Energy Forecast Characteristics

| Forecast Criteria | Coincident Peak Demand and Zonal Coincident Peak Demand Forecasts | Non-coincident Peak Demand Forecast | Energy for Load Forecast |
|---|---|---|---|
| Includes Demand Served by Energy Efficiency Planning Resources | Yes | Yes | Yes |
| Includes Demand Served by energy efficiency programs | No | No | No |
| Includes Demand Served by Demand Resources | Yes | Yes | Yes |
| Includes Demand Served by BTMG Planning Resources | Yes | Yes | Yes |
| Includes Demand Served by resources that are not qualified as Planning Resources | Yes | No | No |
| Includes Demand Pseudo-Tied Out of MISO BA and Included Subject to other RAR | No | Yes | Yes |
| Includes Transmission Losses | No | No | Yes |
| Coincident with reporting Load Serving Entities' system | No | Yes | No |
| Demand reported at Physical LBA Location | Yes | Yes | Yes |
| Include Demand from Power Plant Station or Auxiliary Needs | No | No | No |

## Appendix O – Parties Responsible for Reporting Seasonal Demand and Energy Forecasts

| Data | EDC | Retail Choice LSE | Non-Retail Choice LSE |
|---|---|---|---|
| MISO Coincident Peak (Total CPF) | No | No | Yes |
| MISO Coincident Peak (Total NCPF) | No | No | Yes |
| Zonal Coincident Peak (Total CPF) | No | No | Yes |
| RC Coincident Peak (Total CPFEDC Area) | Yes | No | No |
| RC Coincident Peak (Total NCPF) Load Contribution | Yes | No | No |
| RC Zonal Coincident Peak (Total CPFEDC Area) | Yes | No | No |
| Non-Coincident Peak | Yes | No | Yes |
| RC Non-Coincident Peak | No | Yes | No |
| Energy for Load | Yes | No | Yes |
| Retail Choice (MISO Peak) | Yes | No | No |
| Retail Choice (Zonal Peak) | Yes | No | No |

## Appendix P – Zonal Deliverability Benefit *Pro Rata* Allocation

This Appendix is an illustrative example of the ZDB *pro rata* allocation methodology in presence of Historical Unit Considerations and FRAP. The results from the Planning Resource Auction for the 2020/2021 Planning Year are used in this example to educate Market Participants. The resulting Auction Clearing Prices illustrated here are different than those settled for the 2020/2021 Planning Year. Starting in Planning Year 2023-2024, the ZDB calculation will be performed separately for each season in which the ZDB calculation is required.

Step 1: Subtract PRMR and ZRCs associated with HUCs and ZDC Hedges. For this example, there are no MW associated with Historic Unit Considerations or ZDC Hedges, so the Adjusted PRMR and Adjusted ZRC for each Zone is unchanged from initial totals.

| RZ | ACP | PRMR | ZRC | HUC (MW) | ZDC Hedges (MW) | Adjusted PRMR | Adjusted ZRC |
|---|---|---|---|---|---|---|---|
| Z1 | $5.00 | 18,476.0 | 18,742.0 | 0 | 0 | 18,476.0 | 18,742.0 |
| Z2 | $5.00 | 13,728.2 | 13,590.0 | 0 | 0 | 13,728.2 | 13,590.0 |
| Z3 | $5.00 | 10,129.1 | 10,551.0 | 0 | 0 | 10,129.1 | 10,551.0 |
| Z4 | $5.00 | 9,794.6 | 8,462.1 | 0 | 0 | 9,794.6 | 8,462.1 |
| Z5 | $5.00 | 8,456.3 | 7,952.8 | 0 | 0 | 8,456.3 | 7,952.8 |
| Z6 | $5.00 | 18,720.6 | 17,054.6 | 0 | 0 | 18,720.6 | 17,054.6 |
| Z7 | $257.53 | 21,945.3 | 21,727.5 | 0 | 0 | 21,945.3 | 21,727.5 |
| Z8 | $4.75 | 7,986.9 | 10,183.1 | 0 | 0 | 7,986.9 | 10,183.1 |
| Z9 | $6.88 | 21,711.7 | 20,893.7 | 0 | 0 | 21,711.7 | 20,893.7 |
| Z10 | $4.75 | 5,030.6 | 5,244.2 | 0 | 0 | 5,030.6 | 5,244.2 |
| E20 | $4.90 | 0.0 | 347.2 | 0 | 0 | 0.0 | 347.2 |
| E22 | $5.00 | 0.0 | 633.8 | 0 | 0 | 0.0 | 633.8 |
| E23 | $5.00 | 0.0 | 30.1 | 0 | 0 | 0.0 | 30.1 |
| E24 | $5.00 | 0.0 | 148.4 | 0 | 0 | 0.0 | 148.4 |
| E26 | $4.92 | 0.0 | 24.0 | 0 | 0 | 0.0 | 24.0 |
| E27 | $4.89 | 0.0 | 168.3 | 0 | 0 | 0.0 | 168.3 |
| E28 | $4.90 | 0.0 | 226.5 | 0 | 0 | 0.0 | 226.5 |

Step 2: Create a Deliverability Benefit Zone (DBZ) for each group of LRZs that have equal ACPs resulting from the same auction constraint. In this example, Zone 7 is a DBZ because the PRA bound on its LCR.

| **RZ** | ACP | Adjusted PRMR | Adjusted ZRC | **DBZ Grouping** |
|---|---|---|---|---|
| Z1 | $5.00 | 18,476.0 | 18,742.0 | Zone A |
| Z2 | $5.00 | 13,728.2 | 13,590.0 | Zone A |
| Z3 | $5.00 | 10,129.1 | 10,551.0 | Zone A |
| Z4 | $5.00 | 9,794.6 | 8,462.1 | Zone A |
| Z5 | $5.00 | 8,456.3 | 7,952.8 | Zone A |
| Z6 | $5.00 | 18,720.6 | 17,054.6 | Zone A |
| Z7 | $257.53 | 21,945.3 | 21,727.5 | Zone B |
| Z8 | $4.75 | 7,986.9 | 10,183.1 | Zone D |
| Z9 | $6.88 | 21,711.7 | 20,893.7 | Zone C |
| Z10 | $4.75 | 5,030.6 | 5,244.2 | Zone D |
| E20 | $4.90 | 0.0 | 347.2 | Zone E |
| E22 | $5.00 | 0.0 | 633.8 | Zone A |
| E23 | $5.00 | 0.0 | 30.1 | Zone A |
| E24 | $5.00 | 0.0 | 148.4 | Zone A |
| E26 | $4.92 | 0.0 | 24.0 | Zone F |
| E27 | $4.89 | 0.0 | 168.3 | Zone G |
| E28 | $4.90 | 0.0 | 226.5 | Zone E |

Step 3: Determine if each DBZ is a net importer or exporter by subtracting the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. In this example, Zones A, B, and D are net importing DBZ's and Zones C, E, F and G are net exporting DBZs.

| **DBZ** | Adjusted PRMR | Adjusted ZRC | **Difference** | **Result** |
|---|---|---|---|---|
| Zone A | 79,304.8 | 77,164.8 | -2140.0 | Net Importer |
| Zone B | 21,945.3 | 21,727.5 | -217.8 | Net Importer |
| Zone D | 21,711.7 | 20,893.7 | -818.0 | Net Importer |
| Zone C | 13,017.5 | 15,427.3 | 2,409.8 | Net Exporter |
| Zone E | 0.0 | 573.7 | 573.7 | Net Exporter |
| Zone F | 0.0 | 24.0 | 24.0 | Net Exporter |
| Zone G | 0.0 | 168.3 | 168.3 | Net Exporter |

The following table contains input and output data of the ZDB *pro rata* allocation methodology. Each additional step below will refer to this table.

| | Zone A | Zone B | Zone D | Zone C | Zone E | Zone F | Zone G | System |
|---|---|---|---|---|---|---|---|---|
| HUC Generation | 0.0 | 0.0 | 0.0 | 106.0 | 337.9 | 0.0 | 50.2 | 494.1 |
| HUC Load | 384.1 | 0.0 | 110.0 | 0.0 | 0.0 | 0.0 | 0.0 | 494.1 |
| FRAP Generation | 0.0 | 0.0 | 0.0 | 0.0 | 27.3 | 0.0 | 0.0 | 27.3 |
| FRAP Load | 0.0 | 0.0 | 0.0 | 27.3 | 0.0 | 0.0 | 0.0 | 27.3 |
| PRMR | 79,305 | 21,945 | 21,712 | 13,018 | 0 | 0 | 0 | 135,979 |
| Cleared (include FRAP) | 77,165 | 21,728 | 20,894 | 15,427 | 574 | 24 | 168 | 135,979 |
| ACP ($/MWD) | $5.00 | $257.53 | $6.88 | $4.75 | $4.90 | $4.92 | $4.89 | |
| ACP x PRMR | $396,524 | $5,651,573 | $149,376 | $61,833 | $0 | $0 | $0 | $6,259,307 |
| ACP x ZRC | $385,824 | $5,595,483 | $143,749 | $73,280 | $2,811 | $118 | $823 | $6,202,088 |
| Active HUC | $0.00 | $0.00 | $0.00 | $225.78 | $33.79 | $0.00 | $13.04 | $272.61 |
| Active FRAP | $0.00 | $0.00 | $0.00 | $0.00 | $4.10 | $0.00 | $0.00 | $4.10 |
| ZDB Determination | | | | | | Available ZDB >>> | | 56,951 |
| Net (Cleared - PRMR) | -2,140 | -218 | -818 | 2,410 | 574 | 24 | 168 | 0 |
| Classification | Net Imp. | Net Imp. | Net Imp. | Net Exp. | Net Exp. | Net Exp. | Net Exp. | |
| NET Import[1] | 1,756 | 218 | 708 | 0 | 0 | 0 | 0 | 2,682 |
| ACP * Net Export | $0 | $0 | $0 | $10,943 | $1,151 | $118 | $578 | $12,790 |
| Net Export | $0 | $0 | $0 | $2,304 | $236 | $24 | $118 | $2,682 |
| | | | | | | | | $4.77 |
| For Net Import: | | | | | | | | |
| ACP Δ ($/MWD) | $0.23 | $252.76 | $2.11 | $0.00 | $0.00 | $0.00 | $0.00 | |
| Import ACP * Net Import | $405 | $55,051 | $1,494 | $0 | $0 | $0 | $0 | $56,951 |
| ZDB Rate: ACP reduction/PRMR ($/MWD) | $0.01 | $2.51 | $0.07 | $0.00 | $0.00 | $0.00 | $0.00 | |
| Net ACP ($/MWD) | $4.9949 | $255.0214 | $6.8112 | $4.75 | $4.90 | $4.92 | $4.89 | |

[1] NET Import = PRMR - Cleared - HUC Load

Step 4: MISO charges from all LSEs based on their PRMR and Net ACP ($/MWD).
Charge = PRMR * Net ACP
Zone A: 79,304.8MW * $4.9949 = $396,119
Zone B: 21,945.3MW * $255.0214 = $5,596,522
Zone C: 21,711.7MW * $6.8112 = $147,882
Zone D: 13,017.5MW * $4.75 = $61,833
Step 5: MISO pays all ZRCs committed in the PRA, plus Active HUC $, less FRAP effect.
Credit = ZRC Cleared * ACP+ Active HUC $ - Active FRAP $

Zone A: 77,165MW * $5.00 = $385,824
Zone B: 21,728MW * $257.53 = $5,595,483
Zone C: 20,894MW * $6.88 = $143,749
Zone D: 15,427MW * 4.75 + $225.78 = $73,505
Zone E: 574MW * $4.90 + $33.79 - $4.10 = $2,841
Zone F: 24MW * $4.92 = $118
Zone G: 168MW * $4.89 + $13.04 = $836

## Appendix Q – Fleet XEFORd Calculation

This appendix walks through the process for calculating fleet XEFORd. This process is used for External Resources that participate in the PRA as one MECT resource which represents the aggregate of a fleet of units. For example, an external area might have 100 units in its fleet with a total capacity of 10,000 MW of which it plans to commit 1,000 MW on an installed capacity basis to MISO. MISO will then calculate a seasonal SAC based on a seasonal weighted average forced outage rate of all units in the fleet. Intermittent and class average units are excluded from the fleet XEFORd calculation. This appendix will walk through a weighted average example calculation for a set of fleet units.

| Utility | Unit | Unit Name | GVTC (MW) | XEFORd (%) | Weighted XEFORd (%) |
|---|---|---|---|---|---|
| 99A - Midwest ISO | 101 | Carmel 1 | 100.0 | 15.0% | 4.5% |
| 99A - Midwest ISO | 102 | Carmel 2 | 120.0 | 10.0% | 3.6% |
| 99A - Midwest ISO | 601 | Eagan 1 | 65.0 | 7.5% | 1.5% |
| 99A - Midwest ISO | 602 | Eagan 2 | 50.0 | 5.0% | 0.7% |
| 99A - Midwest ISO | 501 | Little Rock 1 | 20.0 | Intermittent | Excluded |
| 99A - Midwest ISO | 502 | Little Rock 2 | 25.0 | Intermittent | Excluded |
| 99A - Midwest ISO | 401 | Metarie 1 | 5.0 | Class average | Excluded |
| 99A - Midwest ISO | 402 | Metarie 2 | 3.0 | Class average | Excluded |
| | Fleet Total | | 388.0 | | |
| | Fleet Total included in Fleet XEFORd Calculation | | 335.0 | | 10.3% |

Formulas

- Unit Weighted Average XEFORd = (Unit GVTC (MW)) / (Total GVTC (MW) ) * (Unit XEFORd)

  (for Carmel 1 weighted XEFORd is 100.0/335.0*15.0% = 4.5%)

- Fleet Total GVTC (MW) = Sum of GVTC (MW) for all units

  (100.0 + 120.0 + 65.0 + 50.0 + 20.0 + 25.0 + 5.0 +3.0 = 388)

- Fleet GVTC w/ XEFORd = Sum of GVTC for all units with an XEFORd value

  (100.0 + 120.0 + 65.0 + 50.0 = 335)

- Fleet Weighted XEFORd = Sum of Weighted XEFORd for all units

  (84.5%+3.6%+1.5%+0.7%=10.3%)

## Appendix R – Annual CONE Calculation

MISO calculates gross Cost of New Entry (CONE) values for each LRZ for each Planning Year. This CONE value will be used for all seasons within the entire Planning Year. MISO calculates CONE for each LRZ based upon the costs associated with an advanced combustion turbine generator (CT). MISO uses the following approach:

1. MISO begins with an estimate of a CONE value not specific to an LRZ,
2. MISO uses “the law of one price” where applicable (e.g., turbines that are sold competitively),
3. MISO develops zonal differences to reflect different locational costs (e.g., labor, technical enhancements and others) using the most recent United States Energy Information Administration (EIA) document, and
4. MISO uses the Net Present Value (NPV) algorithm to calculate CONE values for each LRZ.

MISO allows factors such as the weighted average cost of capital, escalation rates (and other factors where global competition drives prices to have no locational differences) to be constant.

In order to determine the appropriate CONE value for each LRZ, MISO relies upon the most recent EIA report on “Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant (EIA Report)”. The EIA Report contains detailed specifications for a hypothetical advanced CT, including information regarding the differences in project costs for an advanced CT with a nominal capacity of 237 MW, based upon the state where the facility is constructed.

MISO uses an NPV analysis to determine an appropriate CONE value for hypothetical advanced CTs located in each LRZ. In accordance with Section 69A.8a of Module E-1, MISO considers many factors in its calculation of the CONE value, including the following: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). MISO does not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.

CONE values for each Planning Year are based, in part, upon data supplied by the EIA, which are adjusted using the implicit price deflator from the Bureau of Economic analysis in order to convert EIA cost data into present value dollars. In order to produce the annualized CONE value for each LRZ from these cost numbers, MISO assumes: (i) a 55/45 debt to equity ratio; (ii) a 20-year project life and loan term; (iii) a 5.78 percent debt interest rate; (iv) a 2.0 percent Operation and Maintenance escalation factor; (v) a 2.0 percent GDP deflator; (vi) a 26.7 percent combined effective federal and state tax rate; (vii) property tax and insurance costs of 1.5 percent of the capital costs; (viii) a calculated weighted average cost of capital of 8.36 percent; (ix) and a 13.4 percent after tax internal rate of return on equity. None of these factors vary by LRZ to any significant degree that is discernible in available data. MISO will continue to examine these factors in the future in order to determine if any LRZ specific modifications are indicated. These factors and assumptions are comparable to those used by other RTOs in the development of CONE estimates.

Steps for calculating CONE

1. Obtain latest 'Base Project Cost $/kW'
   Obtain the latest Energy Information Administration (EIA) report for *EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants* It provides the following data:

   - Plant Capital Cost in $/kW. MISO currently uses the number for advanced CT.
   - Location Based Costs Table: Location Percent Variation, Delta Cost Difference and Total Location Project Cost columns

2. Use Bureau of Economic Analysis (BEA) data to calculate implicit price deflator
   Use Table 1.1.9 - Implicit Price Deflators for Gross Domestic Product from NIPA data. Using the table, calculate the *Escalation Rate* from base year to planning year, based on historical and projected quarterly PCE deflator values. Use this Escalation Rate to calculate "Total Location Project Cost" in current year dollars.

3. Calculate LRZ and Base total capital costs, adjusted by multiplying with the Escalation Rate
   For LRZs - Use averages of adjusted project costs for locations (for which data is available) in each zone.

4. Calculate the after-tax weighted average cost of capital (WACC)
   $WACC = E * R_e + D * R_d + (1 – T_c)$

   Where $E$ = Equity Fraction of Project

$R_e$ = Cost of Equity. Assume as the after-tax IRR

$D$ = Debt Fraction of Project

$R_d$ = Cost of Debt (20-year BB corporate bond rate)

$T_c$ = Combined effective federal and state tax rate

5. Calculate estimated annualized costs for each LRZ and also for the Base

   - Calculate annualized capital costs using total capital costs, after-tax WACC and assuming the project lifespan. (Use PMT function)
   - Calculate the O&M costs based on O&M data, project lifespan, WACC and US GDP Deflator (Use PMT and NPV functions)
     - Assume suitable O&M escalation factor
     - Assume/Update US GDP Deflator
   - Assume insurance and property tax costs.

6. Adjust LRZ costs by scaling based on the number provided by the IMM.

## Appendix S – Example Scenarios of "Excess BTMG"

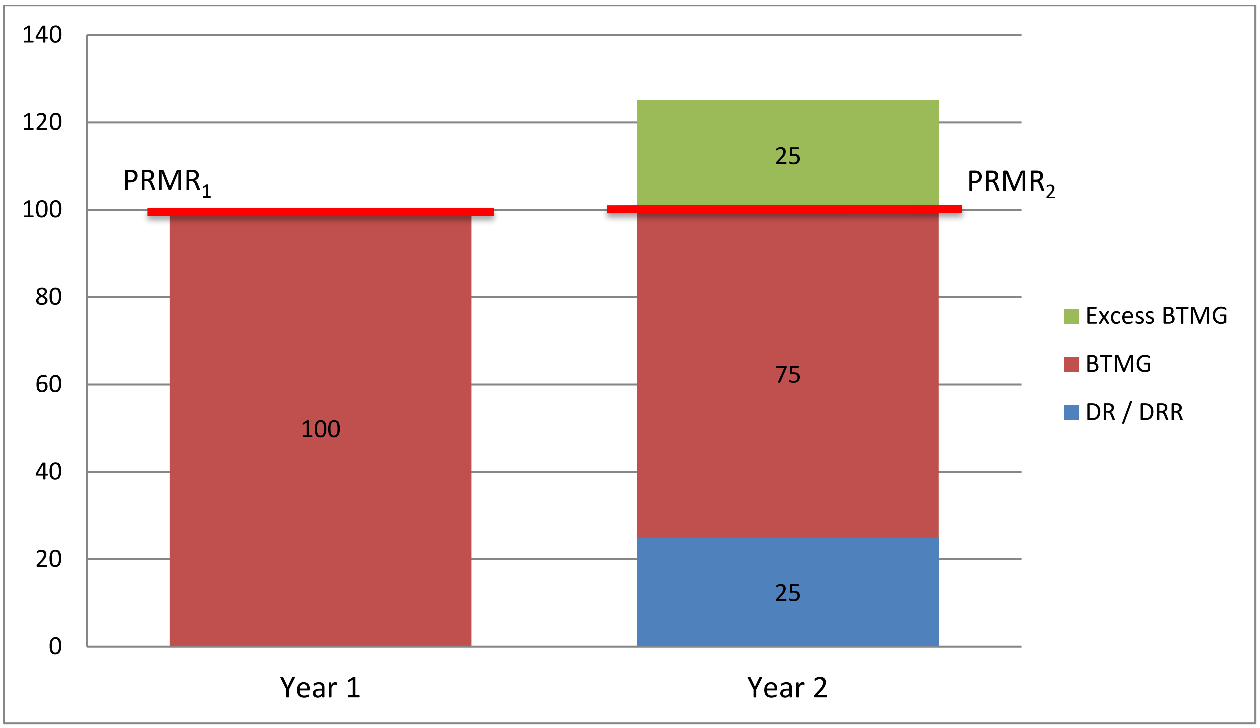
This Appendix shares a few illustrative examples of how BTMG may change to "Excess BTMG" from one year to the next. The examples below show how some specific factors may cause BTMG to be classified as "Excess BTMG" from one year to the next. Below are four examples of "Excess BTMG".

1. Increase in BTMG and No Change to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in BTMG SAC from one year to the next while PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in BTMG of 25 MW—however, seasonal PRMR remains unchanged. In Year 2, the chart shows that BTMG SAC is 125 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has 25 MW of "Excess BTMG" in Year 2.

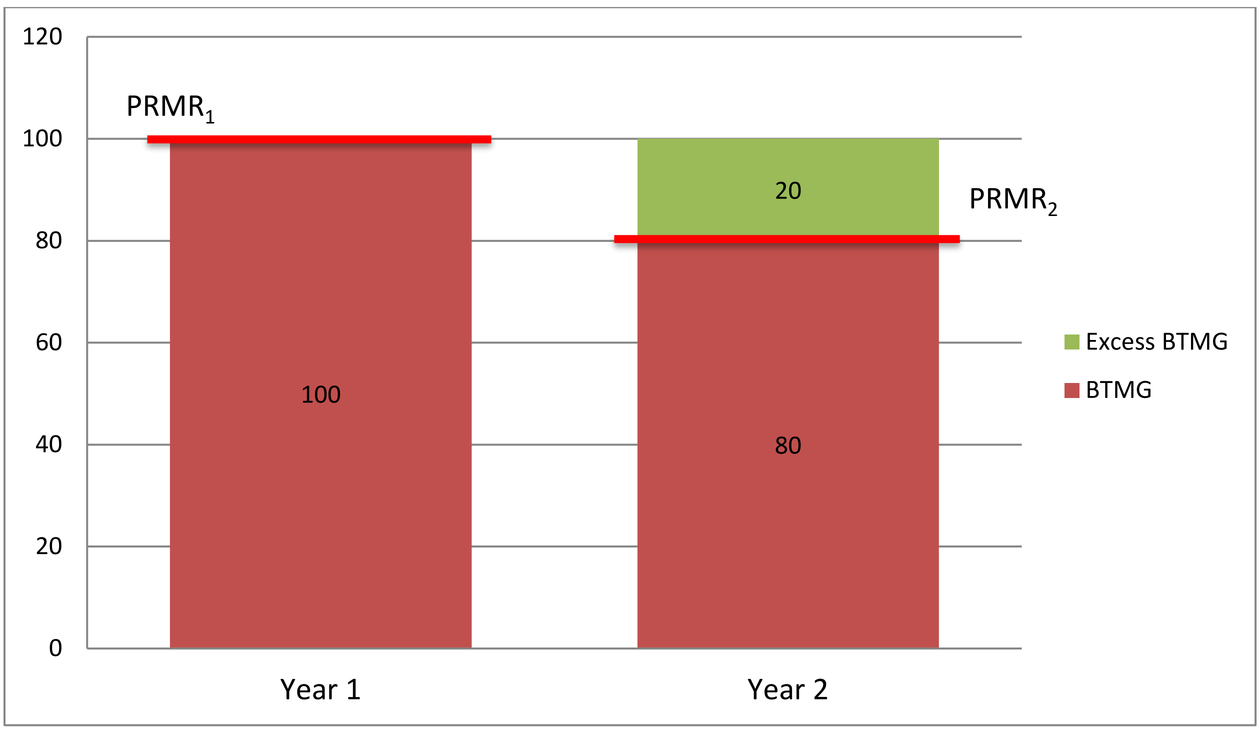
2. Increase in Demand Resources and/or Demand Response Resources and No Change to PRMR

The chart below illustrates the scenario in which a Market Participant experiences an increase in DR / DRR SAC from one year to the next while seasonal PRMR remains unchanged. In Year 1, the chart shows that the BTMG SAC is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no “Excess BTMG” in Year 1. Between Year 1 and Year 2, the Market Participant experiences an increase in DR / DRR SAC of 25 MW, however, seasonal PRMR remains unchanged. In Year 2, the chart shows that DR / DRR is 25 MW and BTMG is 100 MW and the seasonal PRMR is 100 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR; therefore, the Market Participant has 25 MW of “Excess BTMG” in Year 2.



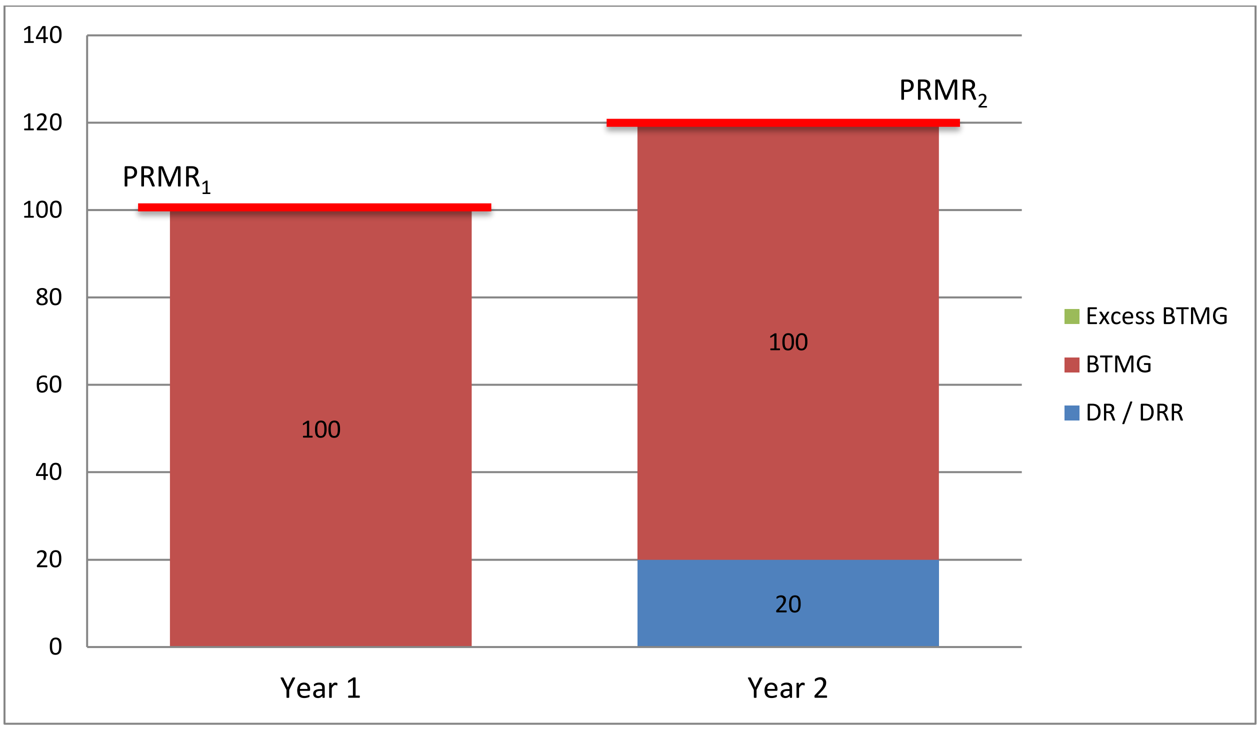
3. No Change to BTMG and Decrease to Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences a decrease in seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no "Excess BTMG" in Year 1. Between Year 1 and Year 2, the Market Participant experiences a decrease in seasonal PRMR of 20 MW, however, BTMG SAC remains unchanged. In Year 2, the chart shows that BTMG is 100 MW the seasonal PRMR is now 80 MW; therefore, the Market Participant has 20 MW of "Excess BTMG" in Year 2.



4. Equal Amount Increase in DR / DRR and Seasonal PRMR

The chart below illustrates the scenario in which a Market Participant experiences an equal increase in DR / DRR SAC and seasonal PRMR from one year to the next while BTMG SAC remains unchanged. In Year 1, the chart shows that the BTMG is 100 MW and the seasonal PRMR is 100 MW; therefore, the Market Participant has no “Excess BTMG” in Year 1. Between Year 1 and Year 2, the Market Participant experiences an equal increase in DR / DRR and seasonal PRMR of 20 MW each, however, BTMG remains unchanged. In Year 2, the chart shows that DR / DRR is 20 MW, BTMG is 100 MW and the seasonal PRMR is 120 MW. Since DR / DRR is netted against seasonal PRMR, the BTMG is stacked on top of the DR / DRR, however, due to the equal increase in DR / DRR and seasonal PRMR there is no “Excess BTMG” in Year 2.



# Appendix T – ICAP Deferral Notice

ICAP Deferral Notice
Midcontinent Independent System Operator
720 City Center Drive
Carmel, IN 46032-7574
Attn.: Resource Adequacy
(Delivered via email to help@misoenergy.org)

[Current Date]

[Insert Company Name] ICAP Deferral Notice – [Planning Resource Name/CPNode Name, if applicable]
Select Planning Resource being deferred:
☐Generation Resource – [Insert CPNode Name]
☐Dispatchable Intermittent Resource (DIR) – [Insert Name]
☐Demand Response Resource (DRR) – [Insert Name]
☐External Resource – [Insert Name]
☐Behind the Meter Generation (BTMG) – [Insert Name]

Dear Resource Adequacy,

[Insert Company Name] is providing this written notification in accordance with Section 69A.7.9 of the Midcontinent Independent System Operator (MISO) Tariff, Module E-1 Resource Adequacy regarding an Installed Capacity (ICAP) Deferral for the Planning Resource selected above. [Insert Company Name] intends to increase ICAP between March 1st and the last Business Day of the applicable season(s) for the [Insert Planning Year] Planning Year.

| | |
|---|---|
| [Contact Name, Phone Number and Email] | Planning Resource Type |
| MISO MP ID/NERC ID of Company | |
| Planning Resource Name | |
| Local or External Resource Zone (LRZ or ERZ) where located | |
| Planning Resource Fuel Type | |
| Estimated ICAP Value (MW)<br>*Note: this is the total ICAP value not the incremental increased value from a prior ICAP* | Summer |
| | Fall |
| | Winter |
| | Spring |
| Check applicable deferred season(s) | Summer [ ], Fall [ ], Winter [ ], Spring [ ] |
| Estimated completion date of ICAP | |
| Type of ICAP being deferred? | |
| **<u>Please fill out the following that is applicable to the Planning Resource being deferred:</u>** | |
| Generator Interconnection Agreement (GIA) Number and expected contract execution date<br>*Note: only necessary if deferral includes upgrades to Interconnection Service* | |

| | |
|---|---|
| Expected NRIS and ERIS values with Interconnection Service upgrades | |
| Commercial Operation Date | |
| TSR Number | |

Sincerely,
[Name], [Title – must be an officer], [Company Name], [Contact Information]

## Appendix U – ICAP Deferral Examples

- Deliverability
  Example 1: Unit is capable of testing at 150 MW, but currently only has 100 MW of NRIS with MISO. The unit is in the queue to have its NRIS increased to 150 MW by the last Business Day prior to the start of a season in the upcoming Planning Year. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW.

- Increased GVTC and Deliverability
  Example 1: Unit currently tested for 100 MW and has 100 MW of NRIS. The unit is in the queue to have NRIS increased to 150 MW and plans to retest after upgrades are in place. Although the difference is 50 MW, the MP would submit an ICAP Deferral Notice for the total ICAP amount of 150 MW.

- Commercial Operation
  Example 1: The unit currently is subject to an environmental regulation that prevents the unit from operating. The unit is in the process of installing additional equipment to comply with the new environmental regulation. Thus, the unit is deferring GVTC until after all necessary approvals are completed.
  Example 2: A resource that is a Dispatchable Intermittent Resource (DIR) would not submit GVTC, but instead receives capacity accreditation based on past historical data. If a DIR is new and is not expected to have Commercial Operation approved until after March 1$^{st}$, then it would be eligible to qualify for capacity credit by submitting an ICAP Deferral for Commercial Operation if Commercial Operation is expected before the last Business Day of prior to the deferred Season.
  Example 3: The unit is currently waiting for upgrades to existing Interconnection Service and the upgrades have been completed, however, the unit has yet to be declared Commercial with MISO. The resource owner needs to file an Exhibit E with MISO Resource Integration to finalize the Commercial Operation of the unit. Once this has been done, the Commercial Operation deferral will be considered complete. The resource owner should assist with coordination with MISO Resource Adequacy and MISO Resource Integration throughout the process.

- Suspension of Catastrophic Outage

Example 1: A unit is planning to return from suspension in August and will submit a new GVTC for the upcoming Fall season prior to the last Business Day of the summer season. Units returning from suspension are required to retest. The MP may defer the retested value.

- TSR Number
  Example 1: A unit is planning to participate in the upcoming Planning Year; however, the unit does not have a Transmission Service Request (TSR) or NITS Scheduling Rights (SR) on the MISO OASIS with a status of "Confirmed" by March 1st to convert the SAC to ZRC to offer into the Auction. The unit expects to have its TSR or SR Confirmed by MISO prior to the last Business Day of prior to the start of the deferred season. Once the TSR achieves "Confirmed" status on the MISO OASIS, the MP should reach out to help@misoenergy.org. If the TSR or SR status is "Confirmed" prior to June 1st, the deferral requirement has been met.

- Additional GVTC Examples
  Example 1: The unit defers 100 MW and the test submitted is for 80 MW. The unit is required to replace the UCAP value of 20 ICAP MW. For example, if the XEFORd for the unit is 25%, then the deferred ZRCs is 75 and the submitted test ZRCs is 60. The MP is required to replace the difference of 15 ZRCs through Resource Replacement, Interconnection Service, Cleared Volumes, Bi-lateral ZRC transactions, etc.

## Appendix V – Solar and Run-of-River Hydro Capacity Credit

This appendix walks through examples for calculating the Solar and Run-of-River Hydro Capacity Credits. For existing solar resources, the Total Seasonal Accredited Capacity (SAC) is determined by the historical average output of the resource during the summer, fall and spring seasons for the hours ending 15, 16, 17 EST and for hours ending 8, 9, 19, and 20 EST for the winter season. Existing run-of-river resources can submit up to 15 years of similar seasonal data, with Total SAC determined by the median of that data. Market Participants will use the Non-GADS Performance Template found on the MISO website to submit the appropriate historical data for the upcoming Planning Year. The Non-GADS Performance Template can be found on the MISO website under Planning > Resource Adequacy (Module E) > Planning Resource Auction. The template should be submitted to MISO by October 31 of each year via the Module E Capacity Tracking (MECT) tool.

For new solar resources, the maximum UCAP that can be credited is 50% for summer, fall, and spring and 5% for winter of the unit's registered capacity. To convert all SAC to seasonal ZRCs, the resource would need to show firm deliverability through NRIS or ERIS + firm TSR equaling the resource's ICAP value.

For existing solar resources, the performance of olar resources is taken into account to calculate the resource's Total SAC for a given season is based on their average output over the defined seasonal peak hours for the last 3 years.

- The amount of that Total SAC that is convertible into ZRCs is based on the amount of deliverability (NRIS or ERIS + firm TSR)
- NRIS SAC = Total SAC * (Deliverability Adjusted Capacity Factor / Average Capacity Factor)
- Where:
  - Deliverability Adjusted Capacity Factor is calculated by adjusting any the output across the seasonal peak hours so that it is capped to the deliverable amount (NRIS).

The examples below show how solar capacity credit is calculated for new resources in the summer season only—however, the examples may also be applied to run-of-river hydro resources as well. For the purposes of the examples, the following information will be used in each:

Solar Nameplate (GVTC) = 10 MW
Transmission Losses (vary by LBA) = 5%
Solar Class Average Summer XEFORd = 50%
Year 1 Average Historical Summer Output = 6.5 MW (Year 1 data only)
Year 2 Average Historical Summer Output = 7.0 MW (Average of Years 1 and 2 data)

**EXAMPLE 1: New Solar (or Run-of-River) Resources with less than 30 consecutive summer Days or no summer data**

In this example, the new solar resource does not have any summer data to submit. Thus, the solar resource will receive the solar class average XEFORd for the initial summer season in Planning Year. In Year 2, the resource will use the average (Run-of-River resources use a median value) historical summer output from Year 1 to determine the GVTC. In Year 3, the resource will use the average historical summer output from Years 1 and 2. In Year 4, the resource will use the average historical summer output from Years 1, 2, and 3. In Year 5, the average historical summer output from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical summer output. Below are examples of how both BTMG and CPNode resources would be accredited.

BTMG

Year 1 → $SAC_{BTMG}$ = GVTC * (1 – XEFORd) * (1 + Trans Loss)
→ $SAC_{BTMG}$ = 10 * (1 – 50%) * (1 + 5%)
→ $SAC_{BTMG}$ = 5.25

Year 2 → $SAC_{BTMG}$ = 6.5 * (1 – 0%) * (1 + 5%)
→ $SAC_{BTMG}$ = 6.8 (rounded to tenth)

Year 3 → $SAC_{BTMG}$ = 7.0 * (1 – 0%) * (1 + 5%)
→ $SAC_{BTMG}$ = 7.4 (rounded to tenth decimal place)

Capacity Resource (CPNode)

Year 1 → Total $SAC_{CPNode}$ = GVTC * (1 – XEFORd)
→ Total $SAC_{CPNode}$ = 10 * (1 – 50%)
→ Total $SAC_{CPNode}$ = 5.0

Year 2 → Total $SAC_{CPNode}$ = 6.5 * (1 – 0%)
→ Total $SAC_{CPNode}$ = 6.5

Year 3 → Total $SAC_{CPNode}$ = 7.0 * (1 – 0%)
→ Total $SAC_{CPNode}$ = 7.0

**Example 2: New Solar (or Run-of-River) Resource with at least 30 consecutive summer Days**

In this example, the new solar resource has at least 30 consecutive summer days of data. Thus, the solar resource will not receive the solar class average for the initial Planning Year. In Year 1, the average historical summer output from the Commercial Operation data will be used to determine the GVTC. In Year 2, the resource will use the average historical summer output from Year 1 and 2. In Year 3, the resource will use the average historical summer output from Years 1, 2, and 3. In Year 4, the average historical summer output from Year 1 will be replaced by Year 4 and the cycle will continue to repeat year-over-year using the 3 most recent years of average historical summer output.

BTMG

Year 1 → $SAC_{BTMG}$ = GVTC * (1 – XEFORd) * (1+ Trans Loss)
→ $SAC_{BTMG}$ = 6.5 * (1 – 0%) * (1 + 5%)
→ $SAC_{BTMG}$ = 6.8 (rounded to tenth decimal place)

Year 2 → $SAC_{BTMG}$ = 7.0 * (1 – 0%) * (1 + 5%)
→ $SAC_{BTMG}$ = 7.4 (rounded to the tenth decimal place)

Capacity Resource (CPNode)

Year 1 → Total $SAC_{CPNode}$ = GVTC * (1 – XEFORd)
→ Total $SAC_{CPNode}$ = 6.5 * (1 – 0%)
→ Total $SAC_{CPNode}$ = 6.5

Year 2 → Total $SAC_{CPNode}$ = 7.0 * (1 – 0%)
→ Total $SAC_{CPNode}$ = 7.0

Once the Total SAC value for a resource has been determined, it is compared with the interconnection service assigned to that resource. Resources that are fully deliverable (100% NRIS) are eligible to convert all of their total SAC to ZRCs with no further action needed.

For Capacity Resources that are not fully deliverable, having either partial or full ERIS, the following steps would be used:

1) MISO calculates a Deliverability Adjusted Capacity Factor for the resource and applies to the formula below to determine Convertible SAC.

2) For SAC not considered Convertible, the Market Participant may choose to obtain firm Transmission service in some level to convert some or all of the undeliverable SAC to Convertible. MISO supplies documentation to the MP on the MECT tool that can be used to determine the level of SAC that can be converted given some level of firm Transmission obtained.

3) Subsequently, the MP uses the Confirm SAC function to move the desired Convertible SAC amount to the Convert SAC MECT page. Once there, the associated firm Transmission information is entered after selecting the ERIS SAC value.

4) After MISO approval of the firm Transmission data that was entered by the MP, the SAC may then be converted to ZRCs for use in the PRA.

<u>Capacity Resource (CPNode)</u>

Year 1 → $SAC_{CPNode}$ = GVTC * (1 – XEFORd)
→ $SAC_{CPNode}$ = 6.5 * (1 – 0%)
→ $SAC_{CPNode}$ = 6.5

Year 2 → $SAC_{CPNode}$ = 7.0 * (1 – 0%)
→ $SAC_{CPNode}$ = 7.0

* For a Capacity Resource, SAC described here is the Total Interconnection SAC as described in Appendix H. SAC is allocated by type of Interconnection Service (NRIS and ERIS). SAC associated with ERIS may be converted into Zonal Resource Credits with a Transmission Service Request to offer into the PRA.

## Appendix W – Demand Resource Reliability Value Evaluation Process

This appendix describes the four-step process for periodically evaluating the reliability value of DR based on the number of available calls. This analysis is performed using the probabilistic Loss of Load Expectation (LOLE) model with the most recent resource mix and load forecasts. Recognizing that the reliability value of DR can change relative to the overall penetration of DR in the resource mix, the analysis is performed periodically to best capture changes in the evolving portfolio. The results of this analysis are used to review the values used for DR accreditation.

The steps of the analysis are:

Step 1: Determine the number of DR calls when the LOLE is at 0.1 days/year, such that additional calls do not further improve reliability.

Step 2: From the ceiling determined in step 1, decrease the number of available calls for all DR (but do not go below the registered amount for any particular DR) and re-solve the LOLE model to 0.1 days/year. Record the MW reduction in load (compared to the load in step 1) needed to solve the model in this step.

Step 3: Determine UCAP value by comparing the MW reduction in load in step 2 to the amount of DR determined in step 1. The difference in these adjustments is subtracted from the total DR ICAP to determine the UCAP at a given call limit.

Step 4: Use the ratio of UCAP from step 3 to ICAP in step 1 to determine the capacity credit as a percentage of ICAP.

Example results calculation:

In this example, 15 calls are determined to be the ceiling beyond which there is no improvement in LOLE. All subsequent cases are compared to the 15-call case to determine the reliability value of each decremented call sensitivity.

| | 15 Calls | 10 Calls | 7 Calls | 5 Calls | Key |
|---|---|---|---|---|---|
| DR ICAP | 7,836 | 7,836 | 7,836 | 7,836 | A |
| Perfect Case Adjustment | -9,425 | -9,425 | -9,425 | -9,425 | B |
| Sensitivity Adjustment | -9,425 | -9,225 | -8,440 | -7,650 | C |
| DR UCAP | 7,836 | 7,636 | 6,851 | 6,061 | D=B-C+A |
| Capacity Credit | 100.0% | 97.4% | 87.4% | 77.3% | E=D/A |

## Appendix X – Existing Hybrid Resource Accreditation Resources

This appendix describes the accreditation process for Hybrid Resources. As is laid out in section 4.2.14, Hybrid Resources will be accredited in one of two phases depending on how much operating data is available. The Phase I – Sum of Parts approach will apply the sum of default values for each separate Electric Facility comprising the Hybrid Resource. The Phase II – Availability-based approach will consist of tracking the availability of the Hybrid Resource. The determination will be on a seasonal basis. A resource can be Phase I for a season and then get Phase II for a subsequent season that it has operational data for. Once a hybrid resource begins getting Phase II performance based accreditation, the resource will continue to receive Phase II performance based accreditation.

**Phase I – Sum of Parts**

Every Hybrid Resource may be operating in very different ways from even others with a similar configuration depending on the goals of the unit owner and operator. Until that operating data exists, default values for each separate Electric Facility comprising the Hybrid Resource will be summed together, to a maximum of the total level of firm service (i.e. NRIS or ERIS with firm transmission service). Phase I accreditation will apply until the number of daily peak hours required for Phase II accreditation have been observed.

**Phase II – Availability-based**

Phase II accreditation will apply after a Hybrid Resource has sufficient operating history to demonstrate availability over the top seasonal 8 daily peak hours occurring of the prior planning year. A daily peak hour is the single hour of highest gross MISO coincident system peak in a given day. Both availability and performance are needed, just like other resource types. Therefore, if a Hybrid Resource operator indicates it will be available in a given timeframe covering one of the 8 peak-day hours, is called on to perform to that stated level and fails to perform to that level, then that Hybrid Resource's actual output data will be used for accreditation purposes.

Availability will the tracked in one of two ways:

- For DIR Hybrid Resources, the forecasts provided to MISO will be used to determine availability. All DIR units may rely on MISO provided wind or solar forecasts—however MISO will not be producing Hybrid Resource forecasts that account for charging or discharging of any integrated storage resource, or the dispatch of any other form of integrated resource. Providing that forecast is the obligation of the Hybrid Resource owner or operator.

- For Hybrid Resource that are not registered as DIR, offers will be made into the MISO energy market, market clearing prices will dictate what dispatches. If a unit fails to meet a dispatch signal, the accreditation of that unit would be reflected at the level of performance, not what it had originally offered and failed to provide.

## Appendix Y – SAC Calculations for Schedule 53 Resources

This appendix describes the process of calculating Seasonal Accredited Capacity (SAC) for Schedule 53 Resources.

1. Identification of Resource Adequacy Hours

Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a season and throughout the year. They include Emergency Declaration periods and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest. RA Hours are determined seasonally and at a subregional level (North/Central and South) based on emergency events, the tightestoperating margin hours (65 hours per season), and a maximum operating margin threshold established at 25 percent.

RA Hours will be used to determine each resources' availability for calculating its seasonal accreditation. The number of RA Hours in a season can exceed the target when a high number of hours during declared system or subregional emergencies occurs.

Provisions also ensure seasons have a minimum target number of RA Hours by supplementing any deficient hours with Annual Average Offered Capacity (AAOC) over all RA hours across the year. The RA Hours used for determining the AAOC (or AAOC Hours) are the hours with emergency events and the tightest 3 percent of operating margin hours below the 25% threshold for each year , up to 260 hours per year. The AAOC Hours are determined on a sub-regional (North/Central and South) basis. Not all AAOC Hours are RA hours.

1.1 **Definition and Identification of RA Hours**

RA Hours are defined over the three most recent historical  years from September - Agust, based on declared MaxGen alert, warning and event hours supplemented by the tightest 3 percent of hours per season where the realized operating margin for the region is at or below the threshold of 25 percent.

1.1.2 Hourly Operating Margin Calculation

The Operating Margin is determined using historical information to identify RA Hours and AAOC Hours within the three (3) most recent periods beginning September 1st and ending August 31st.

We first express the power balance between load and supply, where

$$Load = Thermal\ Resource\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange \qquad (1)$$

$$Supply = Thermal\ Resource\ EmergencyMax + Renewable\ Energy + Net\ Scheduled\ Interchange - Operating\ Reserve \qquad (2)$$

Substituting (1) into (2), we have

$$\begin{aligned} Margin(MW) = {} & [Thermal\ EmergencyMax + Renewable\ Energy \\ & + Net\ Scheduled\ Interchange\ (NSI)] \\ & - [Thermal\ Energy + Renewable\ Energy + Net\ Scheduled\ Interchange] \\ & - Operating\ Reserve \\ & = Thermal\ Resource\ EmergencyMax - Thermal\ Resource\ Energy \\ & - Operating\ Reserve \end{aligned}$$

The power balance between equation (1) and (2) suggests the renewable energy and net-scheduled interchange have been implicitly reflected in the margin calculation but has no impact on the overall margin calculation used for RA hour identification as in the steps below.

By re-arranging the $Margin(MW)$ and broken down to online and offline components, we re-express the Operating Margin Equation as below

$$Operating\ Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + offline\ margin\ (12\ hour\ leadtime)(MW)_j}{Real\ Time\ (RT)Load\ (MW)_j}$$

Where:

$$Online\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - EnergyMW_i - cleared\ operating\ reserve_i)$$

for all Resources that are online and under normal dispatch control; and

$$Offline\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} (EmergencyMax_i - cleared\ offline\ supplement\ reserve_i)$$

for Resources where all of the following is true: (i) Resource is Offline; (ii) its cold-start lead-time is less than or equal to 12 hours; and (iii) it is not on outage.

Load Modifying Resource (LMR), and Emergency Demand Response (EDR) are excluded in the Online margin (MW) and Offline margin (MW) calculations because they require emergency declarations in order to access.

1.1.2 Selection of RA Hours

Hours during which MaxGen declarations are in effect automatically become RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each season within each of the three (3) most recent September-August periods.

For non-MaxGen declaration hours in each of the 12 seasons of the past three-year period, additional RA Hours with the tightest margin will be identified until reaching the(65 hours) for each season; if a season already has more than 65 hours because of MaxGen declaration, this step will be skipped.

Finally, a maximum margin threshold is applied to exclude hours with an operating margin greater than 25 percent.

Going through the steps above, some seasons will have more than 65 hours because of MaxGen declarations, while some other seasons may have less than 65 hours if there are hours excluded based on the 25 percent maximum margin threshold criterion and a low number of hours with MaxGen declarations, reflecting underlying demand, supply and weather conditions. The deficiency from the 65 target hours leads to the need for AAOC Hour as described in the next section.

Additionally, each individual resource will have its own set of RA hours that are dependent on outage exemptions and whether it was designated for Resource Adequacy Requirements (RAR) in previous year's seasonal auctions. Like the system-wide RA hours, if a resource has deficient RA hours in a season, that resource's AAOC will be supplemented for the deficient hours.

Non-RAR resources are not subject to SAC calculation using seasonal RA and AAOC hours.

If the unit was designated as RAR within the 3 year lookback period the following logic will apply.

- When a unit is RAR and has 60 days or more during the 3 year lookback period of that particular seasons operational data, for that season SAC will be calculated with that historical operational data.
- If the unit has less than 60 days of data designated as a RAR for that season over the 3 year lookback period they will receive class average SAC accreditation.

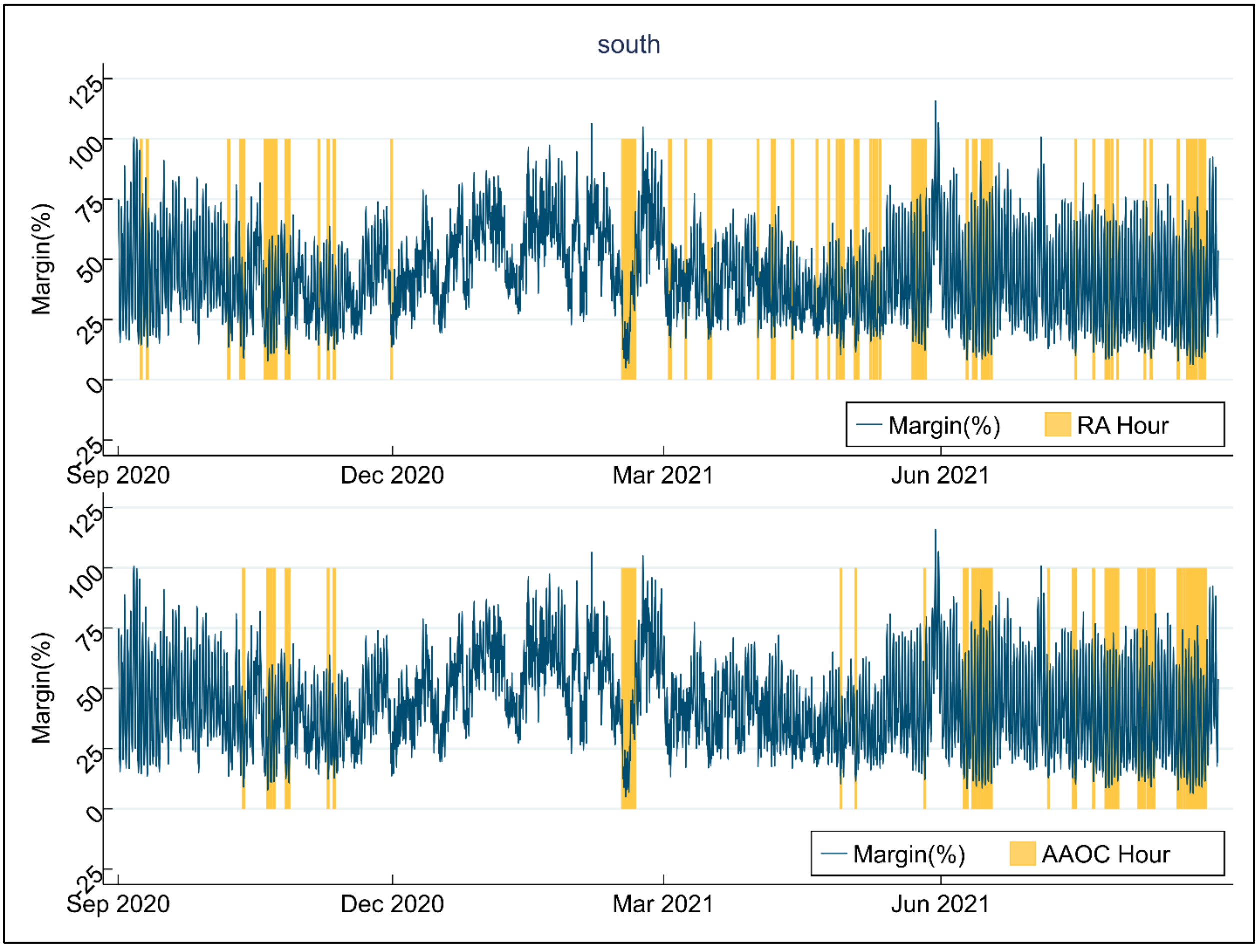
### 1.1.3 Selection of AAOC RA Hour

Hours where MaxGen declarations are in effect automatically become AAOC RA Hours, including all MaxGen Alert, Warning, or Event hours declared in each season within the three (3) most recent periods.

For the rest of non-MaxGen declaration hours in each year of the past three-year periods, additional AAOC RA Hours with the tightest margin will be identified until reaching the (260 hours) for each year. For a unit to receive exemption for a AAOC hour they must have Tier 2 exemption during that hour.

### 1.1.4 Illustration of Selected RA Hour

The figure below, using South region as example, illustrates the variation of hourly Margin (%) between September 1st, 2020 and August 31st, 2021 and labels the selected RA Hour / AAOC Hour. In this example, there are 65 RA Hours identified in each of the four seasons, hence the AAOC Hour will not be needed for backfilling any deficiency hour.




## 1.2 Seasonal Accredited Capacity Calculation

Resource Accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. The following sections illustrate the two-tiered weighting structure to calculate Intermediate Seasonal Accredited Capacity (ISAC) reflecting general availability while emphasizing availability during times of greatest need. Each Resource will have its ISACdetermined based on its Real-Time offered availability (Emergency Maximum Limit) during seasonal RA Hours (Tier 2) as described in Section 1.1 and Non-RA Hours (Tier 1).

### 1.2.1 Prepare Hourly Real-Time Offered Availability Dataset

The first step is to prepare the hourly Real-Time Offered Availability dataset for a Resource, including (1) hourly timestamp (EST); (2) offered Real-Time availability (EmerMax MW); (3) lead time(start up time + Start up notification time) (in hours); (4) binary indicator if a resource is in outagefrom either thecommit status or from records in Control Room Operations Window (CROW) Outage Scheduler; (5) binary identifier indicating if a Resource is online.; (6) ICAP (MW); and (7) binary indicator if a resource has received outage exemption.

Figure below provides a sample screenshot of the dataset, using a sample Resource located in Central/North region. If a Resource is in Derated status but not in outage, its offered availability already accounts for the impact of derates.

| season | timeest | RT Offer EmerMax (MW) | Cold Leadtime (hours) | Outage Identifier (1=Out-of-Service) | Online Identifier (1=online) | ICAP | Outage Exemption Identifier (1=Exemption) |
|---|---|---|---|---|---|---|---|
| summer | 2020-07-29 00:00:00 | 76 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 01:00:00 | 76 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 02:00:00 | 77 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 03:00:00 | 77 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 04:00:00 | 77 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 05:00:00 | 77 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 06:00:00 | 77 | 1 | 0 | | 71.6 | 0 |
| summer | 2020-07-29 07:00:00 | 77 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 08:00:00 | 76 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 09:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 10:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 11:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 12:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 13:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 14:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 15:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 16:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 17:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 18:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 19:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 20:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 21:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 22:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 |
| summer | 2020-07-29 23:00:00 | 76 | 1 | 0 | 1 | 71.6 | 0 |

### 1.2.2 Prepare Calculation for Annual Average Offered Capacity (AAOC)

If a Resource does not have 65 RA hours in a season, AAOC is needed for backfilling the availability during deficiency hours in later steps. To calculate AAOC, the RT Offer EmerMax data is paired with AAOC hours by timestamp. Availability (MW) during AAOC hour is then generated through these following steps:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during AAOC hour; this step caps RT Offer EmerMax at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during AAOC Hour;

(3) Set availability = zero if a Resource is not online and not in outage and has lead time (start up time + Start up notification time) greater than 24 hours during AAOC Hour.

(4) Set availability = NULL if a Resource has been granted outage exemption during AAOC Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during AAOC hour through the steps described above.

| season | timeest | RT Offer EmerMax (MW) | Cold Leadtime (hours) | Outage Identifier (1=Out-of-Service) | Online Identifier (1=online) | ICAP | Outage Exemption Identifier (1=Exemption) | Annual RA Hour Identifier (Classic) | Availability in AAOC Hour (MW) after Outage Exemption |
|---|---|---|---|---|---|---|---|---|---|
| summer | 2020-07-29 00:00:00 | 76 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 01:00:00 | 76 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 02:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 03:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 04:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 05:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 06:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | |
| summer | 2020-07-29 07:00:00 | 77 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 08:00:00 | 76 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 09:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 10:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 11:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 12:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 13:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 14:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 15:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 16:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 17:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 18:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 19:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | 71.6 |
| summer | 2020-07-29 20:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 21:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 22:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | |
| summer | 2020-07-29 23:00:00 | 76 | 1 | 0 | 1 | 71.6 | 0 | | |

### 1.2.3 Prepare Calculation for Intermediate Seasonal Accredited Capacity (ISAC)

To calculate SAC, the RT Offer EmerMax data is paired with RA Hour by timestamp. Availability (MW) during RA Hour is then generated through these following steps:

For availability during Tier 1 Non-RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 1 Non-RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 1 Non-RA Hour;

(3) Set availability = NULL if a Resource has been granted outage exemption during Tier 1 Non-RA Hour.

For availability during Tier 2 RA Hour:

(1) Set availability = Min (ICAP, Real-Time Offer EmerMax) during Tier 2 RA hour; this step caps RT Offer at ICAP;

(2) Set availability = zero if a Resource is in outage (based on outage identifier) during Tier 2 RA Hour;

(3) Set availability = zero if a Resource is not online and not in out-of-service outage and has lead time (start up time + Start up notification time) greater than 24 hours during Tier 2 RA Hour;

(4) Set availability = NULL if a Resource has been granted outage exemption during Tier 2 RA Hour.

Figure below shows the sample dataset fragment after generating the availability (MW) during seasonal Tier 1 and Tier 2 RA hour through the steps described above.

| season | timeest | RT Offer EmerMax (MW) | Cold Leadtime (hours) | Outage Identifier (1=Out-of-Service) | Online Identifier (1=online) | ICAP | Outage Exemption Identifier (1=Exemption) | Seasonal RA Hour Identifier (Classic) | Availability in Seasonal Tier 1 (non-RA) Hour (MW) after Outage Exemption | Availability in Seasonal Tier 2 RA Hour (MW) after Outage Exemption |
|---|---|---|---|---|---|---|---|---|---|---|
| summer | 2020-07-29 00:00:00 | 76 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 01:00:00 | 76 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 02:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 03:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 04:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 05:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 06:00:00 | 77 | 1 | 0 | | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 07:00:00 | 77 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 08:00:00 | 76 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 09:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 10:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 11:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 12:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 13:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 14:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 15:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 16:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 17:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 18:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | 1 | | 71.6 |
| summer | 2020-07-29 19:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 20:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 21:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 22:00:00 | 75 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |
| summer | 2020-07-29 23:00:00 | 76 | 1 | 0 | 1 | 71.6 | 0 | | 71.6 | |

1.2.4 Calculation of Annual Average Offered Capacity (AAOC)

For each of the past three years, the AAOC is calculated as the sum of availability over AAOC hours, divided by the total number of AAOC hours (excluding outage exemption hours) in each year, as shown in the table below for a sample resource.

| CY | # AAOC Hours | Sum of Availability (MW) over AAOC Hours | Annual Average Offered Capacity (MW) |
|---|---|---|---|
| Formula Key | A | B | B/A |
| CY17Sept18Aug | 260 | 15,990 | 62 |
| CY18Sept19Aug | 260 | 17,444 | 67 |
| CY19Sept20Aug | 243 | 17,171 | 71 |

1.2.5 Calculation of Intermediate Seasonal Accredited Capacity (ISAC)

For Non-RA Hours (Tier 1), Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal Tier 1 Non-RA hours, divided by the total number of seasonal Tier 1 Non-RA hours across the past three years.

| CY | Season | # of Tier 1 non-RA Hours after outage exemption | Sum of Availability (MW) over Tier 1 non-RA Hours after outage exemption | Tier 1 3-year average ISAC after outage exemption |
|---|---|---|---|---|
| Formula Key | | A | B | C=SUM(B1, B2, B3)/SUM(A1, A2, A3) |
| CY17Sept18Aug | fall | 2,119 | 3,509 | 44 |
| CY18Sept19Aug | fall | 2,119 | 128,215 | |
| CY19Sept20Aug | fall | 1,731 | 129,457 | |
| CY17Sept18Aug | winter | 2,095 | 131,376 | 61 |
| CY18Sept19Aug | winter | 2,095 | 89,229 | |
| CY19Sept20Aug | winter | 2,091 | 163,989 | |
| CY17Sept18Aug | spring | 2,143 | 147,505 | 72 |
| CY18Sept19Aug | spring | 2,142 | 151,993 | |
| CY19Sept20Aug | spring | 2,192 | 164,796 | |
| CY17Sept18Aug | summer | 2,143 | 154,731 | 71 |
| CY18Sept19Aug | summer | 2,143 | 149,724 | |
| CY19Sept20Aug | summer | 2,143 | 154,375 | |

For RA Hour (Tier 2), its Intermediate Seasonal Accredited Capacity is calculated as the sum of availability over seasonal RA hours and AAOC multiplied by the deficient RA hours, then averaged over total number of Tier 2 RA hours across the past three years.

| CY | Season | # of Tier 2 RA Hours **after outage exemption** | Sum of Availability (MW) over Tier 2 RA Hours **after outage exemption** | Deficient # of Tier 2 hours | Annual Average Offered Capacity (MW) **after outage exemption** | Sum of Availability (MW) over Deficient hours | Sum of total Availability (MW) | Sum of Tier 2 hours | Tier 2 3-year average ISAC **after outage exemption** |
|---|---|---|---|---|---|---|---|---|---|
| Formula Key | | A | B | C = Max((65 hours-A), 0) | D | E=C*D | F=B+E | G=A+C | H=SUM(F1, F2, F3)/SUM(G1, G2, G3) |
| CY17Sept18Aug | fall | 65 | 0 | 0 | 62 | 0 | 0 | 65 | |
| CY18Sept19Aug | fall | 65 | 4,788 | 0 | 67 | 0 | 4,788 | 65 | 47 |
| CY19Sept20Aug | fall | 31 | 1,949 | 34 | 71 | 2,402 | 4,352 | 65 | |
| CY17Sept18Aug | winter | 65 | 5,348 | 0 | 62 | 0 | 5,348 | 65 | |
| CY18Sept19Aug | winter | 65 | 3,274 | 0 | 67 | 0 | 3,274 | 65 | 68 |
| CY19Sept20Aug | winter | 4 | 321 | 61 | 71 | 4,310 | 4,631 | 65 | |
| CY17Sept18Aug | spring | 65 | 4,784 | 0 | 62 | 0 | 4,784 | 65 | |
| CY18Sept19Aug | spring | 55 | 3,256 | 10 | 67 | 671 | 3,927 | 65 | 68 |
| CY19Sept20Aug | spring | 16 | 1,178 | 49 | 71 | 3,462 | 4,640 | 65 | |
| CY17Sept18Aug | summer | 65 | 4,683 | 0 | 62 | 0 | 4,683 | 65 | |
| CY18Sept19Aug | summer | 65 | 4,678 | 0 | 67 | 0 | 4,678 | 65 | 72 |
| CY19Sept20Aug | summer | 65 | 4,674 | 0 | 71 | 0 | 4,674 | 65 | |

1.2.6 Tier Weighting of ISAC and final conversion to SAC

The final Intermediate Seasonal Accredited Capacity (ISAC) value is the weighted averaged over its values from two tiers as calculated from steps above. The corresponding tier weightings are:

| | Weighting by Planning Year | | |
|---|---|---|---|
| Tier | 2023- 2024 Planning Year | 2024-2025 Planning Year | 2025-2026 Planning Year and beyond |
| $ISAC_{Tier1\_weighting}$ | 40% | 30% | 20% |
| $ISAC_{Tier2\_weighting}$ | 60% | 70% | 80% |

$$ISAC = ISAC_{Tier\ 1\ MW} \times ISAC_{Tier\ 1\ weighting} + ISAC_{Tier\ 2\ MW} \times ISAC_{Tier\ 2\ weighting}$$

The table below illustrates the ISAC of a sample resource.

| WEIGHTED ISAC by SEASON **with outage exemption** | Season | ISAC |
|---|---|---|
| | fall | 46 |
| | winter | 67 |
| | spring | 69 |
| | summer | 72 |

Lastly, the ISAC is converted back to SAC in UCAP term using the formula and as illustrated in the sample table below.The Conversion Ratio is calculated for each seasys on a system-wide basis for all Schedule 53 resources.

$$SAC = ISAC \times Conversion\ Ratio_{UCAP/ISAC}$$

| Conversion Ratio UCAP / ISAC | Season | SAC |
|---|---|---|
| 1.1754 | fall | 54 |
| 1.131 | winter | 75 |
| 1.152 | spring | 80 |
| 1.068 | summer | 77 |