



This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (*i.e.*, Capacity Export Limits (CEL)); determining the Planning Reserve Margin; Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource

Auction process; settlement provisions; and Planning Resource performance requirements for each Season.

### **Establishment of Planning Reserve Margins**

The Transmission Provider will determine a Planning Reserve Margin (PRM) in terms of Unforced Capacity for each Season using analytical study methods described in Section 68A.2, provided that if a State Regulatory Authority establishes a PRM for its regulated entities that is higher or lower than the PRM determined by the Transmission Provider, then the State Regulatory Authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

### **Planning Reserve Margin Analysis**

The Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and the Transmission Provider will publish the results by November 1 preceding the applicable Planning Year. The PRM analysis shall be consistent with Good Utility Practice and the reliability requirements of the REs and the applicable states in the Transmission Provider 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 Energy Efficiency Resources, load forecast uncertainty, and the Transmission System's import and export capability with external systems. The Transmission Provider annually will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific planning reserve requirements.

### **Loss of Load Expectation Analysis**

The Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The following process will be utilized to determine the minimum PRM requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity. If the LOLE for the Planning Year 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. If the LOLE for the Planning Year 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. If the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the  
Transmission Provider Region.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. 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 LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those Balancing Authorities with only Coordinating Owner resources that are qualified to obtain local credit and/or Border External Resources.



### **Establishment of SRRZs, SRECs and SRICs**

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs for each Season as soon as practical but no later than the first business day of March for the following Planning Year. To calculate the SRECs and SRICs, the Transmission Provider will determine the transfer limit between SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

Next, the Transmission Provider will then complete a feasibility analysis in accordance with the Resource Adequacy Business Practices Manual to review operational events from each Coincident Peak Demand hour during the previous Planning Year, and forecasted expected conditions for each Season in the upcoming Planning Year, to determine if a further reduction to the transfer limit is warranted for reliability. If such a reduction is necessary, the Transmission Provider will reduce the regional directional transfer limit, as appropriate. The Transmission Provider will then subtract the sum of Firm Transmission Service Reservations on the MISO OASIS that utilize the contract path between SRRZs and are exporting from or wheeling through the Transmission Provider's Balancing Authority for the applicable Season in the Planning Year. This difference determines the SREC and SRIC to be utilized for the applicable Season in the Planning Year.

Prior to publishing the SRRZs, SRECs, and SRICs on its public website, Transmission Provider will present the feasibility analysis and resulting SREC and SRIC calculation to stakeholders.

### **Establishment of CIL and CEL Limits**

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for each Season in the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources for each Season. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each Season for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each Season for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

### **Establishment of Local Reliability Requirement**

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed for each Season, without consideration of the benefit of the LRZ's CIL. First, the LOLE analysis for the Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year 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. If the LOLE for the Planning Year 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. If the LOLE for a Season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that Season reaches 0.01 day per year for the LRZ.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR for each Season.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak

Demand for each Season as provided by LSEs or EDCs, or as developed by the Transmission

Provider, pursuant to Section 69A.1.

### **Establishment of Local Clearing Requirement**

The Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

### **Establishing Planning Reserve Margin Requirements**

- a. The Transmission Provider will establish Planning Reserve Margin Requirements (PRMR) for each Season for an LSE's Load within any given LRZ. The Initial PRMR will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by  $(1 + \text{Transmission Provider Region PRM})$ .
- b. The Transmission Provider will use the Transmission Provider Region PRM for the Initial PRMR calculation unless an alternate PRM is established by a State Regulatory Authority. In such event, the Transmission Provider will use the alternate PRM that a State Regulatory Authority has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any State Regulatory Authority provided PRM to a comparable Unforced Capacity basis.

### **Calculation of Transmission Losses**

- a. The Transmission Provider shall calculate the LBA transmission loss percentages for each Season 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 values for each Local Balancing Authorities (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 Coincident Peak Demand from the calendar year two years prior to the upcoming Planning Year.
  6. For the purposes of the Transmission Provider Region, the LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour for each Season. For purposes of a Local Resource Zone, the LBA transmission loss percentages are calculated as the

total LBA transmission losses divided by the total LBA peak data at the LRZ peak hour for each Season.

- b. The Local Balancing Authority (LBA) transmission loss percentage shall apply to the LSE's applicable LBA Coincident Peak Demand and Local Resource Zone Peak Demand forecast to determine the LSE transmission losses. Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Behind-the-Meter-Generation Resources and Distributed Energy Aggregated Resources that are not interconnected to the Transmission System, Demand Resources, and Energy Efficiency Resources shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by  $(1.0 + \text{the appropriate LBA transmission loss percentage})$ .



### **Marginal Reliability Impact (MRI) Curves**

- A. The following process will be used to determine the MRI Curves for the Transmission Provider Region for each Season of the upcoming Planning Year. The minimum PRM requirement for each Season established in the LOLE analysis, as described in Section 68A.2, will be the starting point. Then, for each Season, a perfect negative unit(s) with a capacity of at least 50MW and no more than 250MW, or perfect proxy unit(s) with a capacity of at least 50MW and no more than 250MW will be added to the model and the LOLE analysis will be performed. The capacity of both the perfect negative unit(s) and perfect proxy unit(s) will be of equal value. The change in EUE as a result of adding or removing capacity will be calculated. An additional unit(s) with the same capacity value will be added or removed in addition to the first increment or decrement and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the minimum PRM requirement.
- B. The First Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the First Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the First Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the

Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the Second Planning Area will be fixed, and capacity in the First Planning Area will then be added or removed to calculate changes to EUE in the First Planning Area.

- C. The Second Planning Area MRI curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the Second Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the Second Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the First Planning Area will be fixed, and capacity in the Second Planning Area will then be added or removed to calculate changes to EUE in the Second Planning Area.

## **RAR Process**

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year to be used by the Transmission Provider. The Transmission Provider will then calculate each LSE's Initial PRMR for each Season. LSEs will meet their RAR obligation by: (i) submitting a Fixed Resource Adequacy Plan; (ii) submitting ZRCs for an RBDC Opt Out; (iii) Self-Scheduling ZRCs; (iv) purchasing ZRCs through the Planning Resource Auction process; and/or (v) paying the Capacity Deficiency Charge to meet a portion of their PRMR. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR. LSEs not submitting an RBDC Opt Out may use one or more of all other available options, or any combination of available options, to satisfy their Initial or Final PRMR. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ for each Season and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in either a submitted Fixed Resource Adequacy Plan or an RBDC Opt Out) must meet the applicable performance requirements as described in sections 69A.3.9 and

69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

### **Load Serving Entity Responsibilities**

- a. LSEs shall provide Coincident Peak Demand (and also, if available, Local Resource Zone Peak Demand forecasts) forecasts as specified in Section 69A.1.1b and will also be responsible for meeting their Final PRMR for each LRZ where they serve Load by submitting Fixed Resource Adequacy Plans, by Self-Scheduling ZRCs, by purchasing ZRCs through the PRA process, by submitting ZRCs for an RBDC Opt Out and/or by paying the Capacity Deficiency Charge.
- b. The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts for each Season that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE.
- c. All LSEs shall report to the Transmission Provider, through the MECT, whether such LSE will meet their PRMR for each LRZ for each Season in which the LSE serves Load by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; (iv) submitting an RBDC Opt Out; and/or, (v) paying the Capacity Deficiency Charge.

### **Forecasted Demand Identification**

a. The Demand forecasts required in Section 69A.1 shall include: (1) the Coincident Peak Demand within each LBA Area in the Transmission Provider Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within each LBA Area, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within each LBA Area, for each Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available Local Resource Zone Peak Demand within each LBA Area in the Local Resource Zone for the upcoming Planning Year. All of these forecasts shall be submitted by November 1<sup>st</sup> prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.

b. The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs and Demand behind a DEAR. Such forecasts shall include Demand that would have occurred but for the existence of Energy Efficiency Resources that have been in operation less than four (4) years. All submissions for such forecast values shall include distribution losses, but not transmission losses. The Transmission Provider will be responsible for the calculation of the applicable transmission losses for the forecasts provided

and for annually publishing such values for each LBA on its website by October 1, as specified in Section 68A.8 and the BPM for Resource Adequacy.

c. In order to assist with the development of the Coincident Peak Demand and Local Resource Zone Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, or as available, for the Transmission Provider Region and for each Local Resource Zone. On or before March 1<sup>st</sup> of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, or if Local Resource Zone Peak Demand forecasts are not available, then the Transmission Provider will provide the required forecast values.

d. All Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

e. Consistent with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution ("PLC") in each Season, including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15<sup>th</sup>. At least five (5) Business Days before January 15, LSEs must notify the EDC and the Transmission Provider if they disagree with the EDC calculated PLC value.

f. If an LSE knows it will gain a wholesale customer by the beginning of any Season in the next Planning Year, then that LSE may provide the Transmission Provider with the Coincident Peak Demand and the Local Resource Zone Peak Demand forecast for such acquired load by November 1. In all other cases, the existing Market Participant serving such wholesale customer shall provide the Transmission Provider by November 1<sup>st</sup> with the Market Participant's forecast of the wholesale customer's Coincident Peak Demand and Local Resource Zone Peak Demand.



**Accounting for Total Demand Forecasts Given Wholesale and Retail Load Switching**

- a. On or before January 15<sup>th</sup>, an EDC must notify the Transmission Provider through the MECT of the Initial PRMR for the LSE's proportion of the EDC's forecast Demand that it expects to serve on the 1<sup>st</sup> day of each Season in the next Planning Year. The LSE that is the provider of last resort ("POLR") for the EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand (*i.e.*, the remaining Demand is the EDC's forecast Coincident Peak Demand minus the sum of the LSE's allocated portion of forecast Coincident Peak Demand, identified as described above, in the EDC's service territory). The Transmission Provider will notify the POLRs of any remaining Initial PRMR within five (5) Business Days after January 15<sup>th</sup>.
- b. On or before January 15<sup>th</sup>, to account for wholesale customers that may switch LSEs during the next Planning Year, the PRMR will be met as follows: (1) if an LSE has responsibility to serve a wholesale load on the 1<sup>st</sup> day of any Season in of the next Planning Year, then such LSE shall have the obligation to procure the required PRMR for such load for such Season; (2) if no LSE has responsibility for serving a wholesale load on of the 1st day of any Season in of the next Planning Year, then the LSE with an obligation to serve such load on November 1 before the Planning Year, shall have the obligation to procure capacity for the required PRMR for each Season in the upcoming Planning Year for such load, provided that such LSE anticipates that the contract for wholesale load will be extended; or (3) if the LSE advises the Transmission Provider that the LSE will not serve the contract for wholesale load, then the customer for such wholesale load shall inform the Transmission Provider by January

30<sup>th</sup> of the name of the Market Participant that will be responsible for the PRMR obligation for  
such wholesale load.

### **Daily Assignment of Coincident Peak Demand Obligations**

- a. For those areas of service where an LSE's Coincident Peak Demand forecast is included in the Coincident Peak Demand forecast submission of an EDC, the EDC will determine and report each LSE's portion of such Demand to the Transmission Provider, using the default method set forth in Section 69A.1.2.1.
- b. In a state that permits retail load switching, the Transmission Provider shall allocate resource capacity costs on a daily basis to LSEs by multiplying the Final PRMR associated with identified customers served by the LSE times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the load is located, consistent with Section 69A.1.2.1.
- c. In states where wholesale load may switch, the Transmission Provider shall allocate costs on a daily basis to LSEs. The LSE that acquires wholesale load will be charged for such load based upon the Final PRMR for the wholesale load's forecast Coincident Peak Demand times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the wholesale load is located.
- d. An LSE may challenge the EDC Demand forecast under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

### Default Method

- a. The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.
- b. EDC will assign a peak load contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand during each Season (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP")). Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (*e.g.* LMRs). In the aggregate, the PLCs determined by the EDC must equal the Initial PRMR that is calculated from the forecast Coincident Peak Demand provided by the EDC for each Season. This equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during each Season prior to the Planning Year by the same adjustment factor, as shown in the equation below:

$$\sum_i \text{PLC}_i = \text{Initial PRMR}_{\text{EDC}}$$

$$\text{Factor} = \text{Initial PRMR}_{\text{EDC}} \div \sum_i \text{PSRCCP}_i$$

In other words, for each EDC, the sum of the individual retail customer (*i.e.*, *i*) PLC values must equal the EDC's Initial PRMR. In addition, a single value ("Factor") is defined as the ratio of the Initial PRMR for any EDC divided by the sum of all of the PSRCCP values for each of the EDC's retail customers. The EDC must use the same Factor in the following equation:

$$\text{PLC}_i = \text{Factor} \times \text{PSRCCP}_i \quad \forall i$$

Thus, for each EDC it must also be true that the PLC for any individual retail customer shall be equal to the product of that customer's PSRCCP times the same Factor identified in the second equation above. For the purposes of these equations, the following mathematical symbols are used: (1)  $\Sigma$  equals sum; (2)  $i$  equals individual retail customer, as in  $PLC_i$  or  $PSRCCP_i$ ; and (3)  $\forall i$  equals for all  $i$ , as in: for each member of the set of retail customers.

c. The PSRCCP shall be adjusted (upward) to reflect any demand that was reduced during the Coincident Peak for each Season hour through the effect of a Load Modifying Resource, or through the effect of an Energy Efficiency Resource during the first four (4) full Planning Years of the EE Resource's existence. The Transmission Provider will provide to the EDC the amount of measured (or estimated if final settlement data is forthcoming) load reduction that occurred as a result of an ARC or LSE deploying a DRR, LMR or EDR following a Setpoint Instruction, Scheduling Instruction or EDR Dispatch Instruction during the Transmission Provider's Coincident Peak Demand.

MISO  
FERC Electric Tariff  
MODULES

69A.1.2.2  
[RESERVED]  
31.0.0

### **Load Switching**

Beginning the first Calendar Day of each Season in the Planning Year, the EDC will be responsible for tracking the individual customer Final PRMR values transferred from the originally supplying LSE to the newly supplying LSE now responsible for resource adequacy commitments.

### **Forecasted Demand for FRP/FRS Agreements**

Full Responsibility Purchases/Sales (FRP/FRS) agreements are treated effectively like a transfer of Demand and all RAR obligations from one LSE to another Market Participant. A purchaser under an FRP/FRS agreement shall submit the forecasted Coincident Peak Demand and Local Resource Zone Peak Demand associated with such agreement to the Transmission Provider through the MECT for the applicable Planning Year. A seller under an FRP/FRS agreement is contractually obligated to comply with all of the RAR obligations for the transferred Demand during the Planning Year encompassing the planned Coincident Peak Demand. The purchaser under an FRP/FRS agreement no longer has the RAR obligations for the transferred Demand; provided however, that if the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of the Transmission Provider, then the purchaser under the FRP/FRS agreement will remain responsible for any RAR obligations associated with the Demand transferred under the FRP/FRS agreement. A seller under an FRP/FRS agreement will be responsible for the transferred Demand to meet this additional obligation like it was their own Demand. If a seller and a purchaser under an FRP/FRS agreement cannot agree on whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in Section 12 of the Tariff.



### **Multiple Region Planning Resources**

If an LSE serves Demand both in the Transmission Provider Region and outside the Transmission Provider Region, then the LSE must separately satisfy its Final PRMR in all areas of the Transmission Provider Region. Compliance with RAR shall not affect an LSE's obligation to maintain distinct and separate amounts of resources to cover its applicable planning reserve obligation for the amount of Demand outside the Transmission Provider Region.

### **Capacity Tracking Tool**

To facilitate RAR, the Transmission Provider shall administer the MECT, a title tracking and registration tool that shall include the ability to enable Market Participants and LSEs to meet their RAR responsibilities.

### **Planning Resource Requirements**

Nothing herein shall infringe upon the requirement that LSEs comply with applicable state safety standards, planning reserve margins, or be subject to the enforcement thereof. If the Transmission Provider becomes aware that any Planning Resource fails to meet the requirements of this section, then the Transmission Provider shall promptly notify the Market Participant and specify the reasons for any such failure. Wherever possible, the Transmission Provider and the Market Participant will work in good faith to remedy deficiencies, if any, in meeting the Planning Resource requirements, through informal communications rather than Commission filings.

### **Capacity Resources**

As described below, a Generation Resource, External Resource, Demand Response Resource - Type I, Demand Response Resource - Type II, Intermittent Generation, Dispatchable Intermittent Resource, Electric Storage Resource, Hybrid Resource or Distributed Energy Aggregated Resource, is eligible to become a Capacity Resource. The Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy. Electric Storage Resources can be Capacity Resources if they meet all the requirements as specified in the BPM for Resource Adequacy, including the requirement to be able to continuously discharge for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day, in accordance with the BPM for Resource Adequacy, provided that an Electric Storage Resource may de-rate its capacity in order to comply with this requirement.

**Generation Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources**

1. Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights for the Resource by:
  - (a) registering such resource with the Transmission Provider as documented in the BPM for Market Registration;
  - (b) demonstrating GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy;
  - (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System (GADS) information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy;
  - (d) by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.a.4; and
  - (e) demonstrating deliverability as described in Section 69A.3.1(g). All new Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources and Distributed Energy Aggregated Resources, or an existing Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource and s Distributed Energy Aggregated Resource that has an increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later

than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource (including a Generation Resource and Electric Storage Resource that has the status of Suspend pursuant to Section 38.2.7) and a Distributed Energy Aggregated Resource that has not completed GVTC testing by the deadlines provided in 69A.3.1.a.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA or in a FRAP (including through bilateral ZRC transactions), subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and a Distributed Energy Aggregated Resource and that is less than 10 MW if the Market Participant has never provided such data for such Resource. A Market Participant that begins reporting generator availability data based on GVTC for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and that is less than 10 MW must continue to report such data. A Generation Resource or Electric Storage Resource that has provisional Interconnection Service does not qualify as a Capacity Resource.

4. A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning

Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

**Demand Response Resources:**

1. Demand Response Resources - Type I and DRR - Type II are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in the DRR by registering such resources as Capacity Resources with the Transmission Provider as documented in the BPM for Market Registration. A DRR - Type-I or a DRR - Type-II that interrupts or controls demand shall demonstrate capability and availability to reduce demand in response to instructions from the Transmission Provider for each applicable Season and shall submit such data to the Transmission Provider, as established in the BPM for Resource Adequacy. A Market Participant that wants to qualify a DRR - Type II that is a behind the meter generation facility as a Capacity Resource shall: (i) demonstrate GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy; (ii) submit GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.b.4; and (iii) submit generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider. A Market Participant that wants to qualify a new DRR or an existing DRR that has an increased installed capacity that is a behind the meter generator as a Capacity Resource shall submit GVTC data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.



2. Installed Capacity (ICAP) Deferral

If a Market Participant for a DRR has not completed GVTC testing by the deadlines provided in 69A.3.1.b.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a DRR behind the meter generation facility of less than 10 MW if the Market Participant has never provided such data for such behind the meter generation facility. A Market Participant that begins reporting generator availability data for a behind the meter generation facility that is less than 10 MW based on GVTC must continue to report such data. A Demand Response Resource that has provisional Interconnection Service does not qualify as a Capacity Resource. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify a Demand Response Resource for the applicable Season in the upcoming Planning Year.

4. A Market Participant for a DRR required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the DRR by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the

deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the DRR from utilizing the ICAP Deferral process as described in Section 69A.7.9.

**External Resources:**

1. External Resources, including those specified in Diversity Contracts and PPAs (which are subject to additional qualification requirements in section 69A.3.1.c.4), are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in External Resources by: (a) registering such resources with the Transmission Provider as documented in the BPM for Resource Adequacy; (b) demonstrating GVTC capability for each Season that the resource will be registered in as established in the BPM for Resource Adequacy by providing operational data, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.c.5; (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy; (d) identifying one or more specific External Resource(s) that can be verified by the Transmission Provider as Capacity Resource(s) and which does not include any portion(s) of an External Resource that has already qualified as a Capacity Resource; (e) demonstrating that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability as described in Section 69A.3.1.g; and (f) certifying that any External

Resources being identified are not otherwise being used as capacity resources in any other RTO/ISO, in another resource adequacy construct, or in an external balancing authority's resource plan for its firm end-use load and capacity sales requirements within the external balancing authority area.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for an External Resource has not completed GVTC testing by the deadlines provided in 69A.3.1.c.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data for an External Resource of less than 10 MW based upon GVTC is not required if the Market Participant has never provided such data for such External Resource. A Market Participant that begins reporting generator availability data for an External Resource that is less than 10 MW based on GVTC must continue to report such data. All new External Resources or an existing External Resource that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification as established in the BPM for Resource Adequacy. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify an External Resource for the applicable Season in the upcoming Planning Year.

4. In the case of a power purchase agreement (PPA), including, but not limited to a Diversity Contract, then the agreement shall meet the additional qualification requirements set forth below:
  - i. A PPA that does not identify the full Installed Capacity of the External Resource from which power will be supplied must specify the portions of each such External Resource that is available under the PPA (i.e. slice-of-system resources) and that are verifiable by the Transmission Provider. Each External Resource specified in such PPA must meet the criteria for a Capacity Resource for all of the portion of the contract amount assigned to the External Resource(s). The capacity from the External Resource will be reduced proportionately to remove amounts that fail to meet such criteria.
  - ii. A copy of every PPA must be provided by the Market Participant using External Resources from such PPA as a Capacity Resource to the Transmission Provider to enable it to verify the External Resource(s) that are backing the PPA and to confirm compliance with RAR. Any redacted versions of a PPA submitted by a Market Participant must contain sufficient information to allow the Transmission Provider to verify compliance with RAR. The Transmission Provider will maintain the confidentiality of these agreements in accordance with the confidentiality provisions in Section 38.9 of the Tariff.
  - iii. For PPAs executed after April 3, 2014, one of the following must apply regarding the external balancing authority in which the External Resource is located:

(a) 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 PPA Schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced outage.

(b) In the case of slice-of-system sales, if the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the external balancing authority will only interrupt the PPA Schedule on a pro rata basis with the shedding of firm end-use load in the external balancing authority area. Pro rata interruption of the PPA Schedule from the External Resource will be determined as the ratio of the PPA Schedule to the sum of the external balancing authority firm end-use load plus the PPA Schedule. (c) If the external balancing authority (1) is located within the Transmission Provider's reliability coordinator area; (2) participates in a contingency reserve sharing group with the Transmission Provider; and (3) has a Seams Operating Agreement with the Transmission Provider containing the following features, then in the event that the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the Transmission Provider and the external balancing authority will share interruption of PPA Schedules from an External Resource and load shedding in the external balancing authority area on a pro rata basis in proportion to the end-use load in the area under the Energy Emergency. Pro rata sharing shall be

determined as the respective ratio of each of the balancing authority's end-use load in the Energy Emergency Area divided by the sum of the end-use load of each balancing authority in the Energy Emergency Area. The Seams Operating Agreement must (1) ensure that the external balancing authority has established a planning reserve margin and qualifications for planning resources using processes and criteria comparable to the Transmission Provider; (2) specify the actions that will be taken by both entities during an Energy Emergency prior to implementing firm end-use load shedding, and (3) specify that the external balancing authority will submit end-use load estimates to the Transmission Provider in a comparable manner as submitted by Load entities in Module E-1, provide generator GVTC and GADS data for all resources used to serve firm requirements of the external balancing authority, and provide transparency in the form of submittal of fixed resource plans comparable to processes used by Market Participants for Fixed Resource Adequacy Plans in the Transmission Provider's Module E-1.

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

- v. A Market Participant may only qualify a PPA as a Capacity Resource if such agreement establishes a firm obligation on the part of the seller of the Capacity to deliver the Capacity to the Market Participant.
- vi. If the terms and conditions in a PPA do not explicitly conform with every requirement of Section 69A.3.1.c. 4 (i) through (iv) above, the Transmission Provider will use alternative documentation and verification procedures to determine if the PPA qualifies as a Capacity Resource. A party seeking Capacity Resource status for a non-conforming PPA must provide the Transmission Provider with written information regarding whether: (a) the PPA was executed prior to October 20, 2008; (b) an RE 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 Transmission Provider 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. 4 (i) through (iv) and (vi). The Transmission Provider will analyze all available alternative documentation and verification information.

Based upon such analysis, the Transmission Provider will inform the party seeking Capacity Resource status for the PPA within 30 days whether the PPA qualifies as a Capacity Resource.

- vii. No PPA may be qualified as a Capacity Resource if such agreement includes provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure.
5. A Market Participant for an External Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the External Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the External Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

6. Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b.

### **Use Limited Resources**

The Market Participant shall identify eligible Generation Resources, Electric Storage Resources, Distributed Energy Aggregated Resources or External Resources to the Transmission Provider that are Use Limited Resources. The Market Participant that seeks to qualify a Generation Resource, Distributed Energy Aggregated Resource or External Resource as a Use Limited Resource under RAR shall meet all the requirements as specified in the BPM for Resource Adequacy. A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy.

## **Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy**

### **Aggregated Resources**

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy

Aggregated Resources are resources that are eligible to qualify as a Capacity Resource by a Market Participant provided that the Market Participant: (a) possesses ownership or equivalent contractual rights for the resource; (b) supplies historical performance data or required documentation for the resource as established in the BPM for Resource Adequacy; and (c) registers the resource with the Transmission Provider in accordance with the BPM for Market Registration (if the resource is located within the MISO Balancing Authority Area metered boundary), or the BPM for Resource Adequacy (if the resource is located outside the MISO Balancing Authority Area metered boundary).

### **Curtailments**

At its sole discretion, the Transmission Provider may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency. Procedures for such actions shall be specified in the operating procedures. With respect to external balancing authorities that have a Seams Operating Agreement with the Transmission Provider pursuant to Section 69 A.3.1.c.4, during a declared Energy Emergency in the MISO Balancing Authority Area, the Transmission Provider shall only interrupt or reduce Export Schedules associated with a sale of capacity on a reciprocal pro rata basis to that required of the external balancing authority in Section 69A.3.1.c.4.(iii).

**A. Determination of Deliverability of Generation Resources, Electric Storage**

**Resources, and External Resources:**

The Transmission Provider shall be responsible for determining whether Generation Resources, Electric Storage Resources, and External Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Generation Resources, Electric Storage Resources, and External Resources will be any combination of the following:

- i. The amount of Network Resource Interconnection Service under Attachment X;
- ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;
- iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;
- iv. The amount of aggregate deliverability that a Generation Resource or External Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or
- v. The amount of non-aggregate deliverability that a Generation Resource or External Resource was granted 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 corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of

the Network Customer for that term of the confirmed designation, as such term may be extended.

**B. Determination of Deliverability of Intermittent Generation, Dispatchable**

**Intermittent Resources, and Electric Storage Resources:**

The Transmission Provider shall be responsible for determining whether Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources will be any combination of the following:

- i. The amount of Network Resource Interconnection Service under Attachment X;
- ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;
- iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;
- iv. The amount of aggregate deliverability that the Intermittent Generation or Dispatchable Intermittent Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or,
- v. The amount of non-aggregate deliverability that a Intermittent Generation or Dispatchable Intermittent Resource was granted 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 corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

**C. Determination of Deliverability of Distributed Energy Aggregated Resources**

The Transmission Provider shall be responsible for determining whether Distributed Energy Aggregated Resources eligible to be Capacity Resources are deliverable to Load. The Distributed Energy Resource Aggregator will coordinate with the Electric Distribution Company in order for the Electric Distribution Company to perform a technical review of the Distributed Energy Aggregated Resource's transmission system impacts. Any MW found to be injecting onto the transmission system as a result of the technical review must demonstrate deliverability by obtaining External Network Resource Interconnection Service or firm Transmission Service in order to qualify for the Planning Resource Auction or a FRAP.



## **Retirement, Suspension, Installed Capacity (ICAP) Deferral and Replacement of Planning Resources**

### **a. Retirement, Suspension, ICAP Deferral and Replacement**

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. A Planning Resource for which a Market Participant submits an ICAP Deferral Notice will be subject to ICAP Deferral Requirements and Charges pursuant to Section 69A.7.9. As used in this section, “cleared ZRCs” include ZRCs that cleared in the PRA, were used in a FRAP, were used in an RBDC Opt Out, or were used to replace ZRCs in accordance with this section. As used in this section, “uncleared ZRCs” include ZRCs that did not clear in the PRA, were not used in a FRAP, were not used in an RBDC Opt Out or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. If a Market Participant’s Planning Resource fails to satisfy the ICAP deferral requirements set forth in Section 69A.7.9 and the Market Participant does not replace

cleared ZRCs with uncleared ZRCs, an ICAP Deferral Non-Compliance Charge will be assessed pursuant to Section 69A.7.9. 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 to transfer the performance requirements applicable to the Planning Resource. If a Market Participant does not replace such ZRCs associated with a Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. A Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.3.1 and 69A.5 for the balance of the Season of the Planning Year, subject to the same replacement requirements set forth above. 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. 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 Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season(s) of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, ICAP deferral, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA; (2) does not violate any CEL used in the PRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

- i. ZRC replacement shall be processed on a first come, first served basis.
- ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, FRAPs, and RBDC Opt Out, including any assessed Capacity Replacement Non-Compliance Charges.

**b. Capacity Replacement Non-Compliance Charge and Distribution**

- i. Capacity Replacement Non-Compliance Charges will be calculated as follows:  
  
the number of days for which the Market Participant had a replacement requirement but failed to replace per section 69A.3.1.h.a above multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP for the applicable Season and the daily CONE value ( $1/365$  times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource cleared those ZRCs. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in the respective SRRZ. For External Resources represented in ERZs that are connected to multiple SRRZs or that are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.
- ii. Distribution of Capacity Replacement Non-Compliance Charges: Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a *pro rata* basis, based upon their respective LSEs' share of Final PRMR for the Transmission Provider Region.

### **Energy Efficiency Resources (EE Resource)**

An Energy Efficiency Resource is a Planning Resource, in which the Market Participant possesses ownership or equivalent contractual rights, from an end-use customer project (including the installation of more efficient devices or equipment or implementation of more efficient processes or systems) that was implemented after July 20, 2011, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous reduction in electric energy consumption during On Peak daylight hours, as further described in the BPM for Resource Adequacy. EE Resources are eligible to qualify as Planning Resources by registering such EE Resources as Planning Resources with the Transmission Provider, as documented in the BPM for Resource Adequacy. An EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year. ZRCs from EE Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. EE Resources shall not require notice, dispatch, or operator intervention, such that the EE Resource will reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service, in accordance with the BPM for Resource Adequacy. The additional requirements for EE Resource measurement and verification are found in Attachment UU.

### **Load Modifying Resources**

Load Modifying Resources can be offered as ZRCs in the PRA or can be used in FRAPs pursuant to Section 69A.9 or used in an RBDC Opt Out pursuant to Section 69A.9.1. As described below, a Demand Resource or a BTMG is eligible to qualify as a Load Modifying Resource if it meets the following requirements. All LMRs that are cleared in the PRA or were submitted in a FRAP for a Season or submitted in an RBDC Opt Out must be available for use in the event of an Emergency as declared by the Transmission Provider, pursuant to the Emergency operating procedures of the Transmission Provider, unless replaced with other ZRCs pursuant to Section 69A.3.1.h. ZRCs from Demand Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. ZRCs from BTMGs will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify an LMR for the applicable Season in the upcoming Planning Year. The amount of ZRCs from Demand Resources and BTMG has to be consistent with the expected reduction in demand at the time of the Transmission Provider's expected Coincident Peak Demand.

### **Deployment Procedures for LMR**

Procedures for deployment of LMR are found in the BPM for Resource Adequacy and emergency operating procedures. Such procedures shall be consistent with the information provided by the Market Participant regarding availability and notice time. At a minimum the Market Participant will provide the deployment parameters of the LMR (as described in Sections 69A.3.5 and 69A.3.6), during declared Emergencies prior to the use of Operating Reserves to achieve energy balance. The Market Participant shall, at all times, notify the Transmission Provider or Local Balancing Authority when the status or availability of an LMR changes, except for de minimis changes that do not need to be reported, according to procedures specified in the BPM for Resource Adequacy and emergency operating procedures. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to deploy or notify such LMR of a planned deployment. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to notify such LMR of a planned deployment through the issuance of Scheduling Instructions. Market Participants may be issued Scheduling Instructions during a declared Emergency or in anticipation of an Emergency at the discretion of Transmission Provider. Market Participants shall acknowledge Scheduling Instructions issued in accordance with BPM for Resource Adequacy for its LMRs. In the event of an anticipated Emergency where the Transmission Provider does not declare the actual Emergency at least two hours prior to the anticipated Emergency event, Market Participants are not obligated to meet the Scheduling Instructions issued in anticipation of such Emergency and

will not be penalized for non-performance. This does not apply to Scheduling Instructions issued after the declaration of an Emergency.

A Market Participant that acknowledges Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an Emergency is declared. However, a Market Participant that fails to acknowledge the Scheduling Instructions as required by the BPM for Resource Adequacy will not receive credit for such deployment or interruption for its LMR(s).

An LMR that is also registered as an EDR resource that responds to Transmission Provider's notification will be eligible to receive compensation for costs incurred, subject to Transmission Provider and IMM review. However, an LMR that does not perform consistent with the Market Participant's response to its Scheduling Instructions in the event of an Emergency is subject to the penalty provisions of Section 69A.3.9 and will not receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season.



### **Demand Resources (DR)**

Demand Resources may be deployed to reduce Demand either: (i) by a targeted Demand reduction amount; or (ii) to a specified firm service level. A LMR MP shall test, validate, and measure its Demand Resources and submit the results to the Transmission Provider, which shall verify all Demand Resources claimed by a LMR MP, consistent with the procedures specified in the BPM for Resource Adequacy. The accrediting, testing, validation, measurement and verification procedures developed by the Transmission Provider shall take into account any applicable State Regulatory Authority, RE or other non-jurisdictional entities' requirements regarding duration, frequency and notification processes for the candidate Demand Resource. A Demand Resource that is sensitive to temperature changes must identify the extent of such temperature sensitivity to the Transmission Provider with sufficient detail to enable the Transmission Provider to verify whether the Demand Resource would be subject to penalties in Section 69A.3.9 for failure to achieve the targeted Demand reduction amount or move the LSE to a specified firm service level. Temperature sensitive analysis must include, but is not limited to, identifying the measure used for temperature changes and the temperature elasticity of the LSE's Load to weather, as further described in the BPM for Resource Adequacy. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year.

### **Demand Resource Eligibility**

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can request accreditation for a Demand Resource as an LMR by registering such resource with the Transmission Provider as documented in the BPM for Resource Adequacy and by meeting the following requirements:

- a. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together that can reduce an LSE's Coincident Peak Demand for the applicable Season may qualify in meeting this standard).
- b. The Demand Resource must be available to be scheduled for a Demand reduction at the targeted Demand reduction amount or by moving to a specified firm service level with notice based on their physical availability but with no more than 12 Hours advance notice required from the Transmission Provider. Limitations due to applicable regulatory restrictions that are more restrictive than the physical limitations of the Demand Resource will supersede the physical availability of the Demand Resource; however, in no event shall the Demand Resource's maximum notice requirement be greater than 12 hours. Further, limitations due to contractual obligations that are more restrictive than the physical limitations of the Demand Resource in place as of December 21, 2018 will supersede the physical availability of the Demand Resource for the 2019/2020 and 2020/2021 Planning Years; however, in no event shall the Demand Resource's maximum notice requirement be greater than 12 hours. A Demand Resource 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, Demand Resources 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 Demand Resource must have a notification time requirement less than or equal to six (6) hours to receive credit as a Planning Resource in the applicable Seasons.

- c. Once Scheduling Instructions are given by the Transmission Provider that require a Demand reduction, the Demand Resource must be capable of ramping down to meet the targeted Demand reduction amount or to achieve the firm service level by the Hour designated by the Transmission Provider's Scheduling Instructions.
- d. Once the targeted amount of Demand reduction or firm service level is achieved, the Demand Resource must be able to maintain the targeted amount of Demand reduction or firm service level for at least four (4) continuous Hours.
- e. For the 2022/2023 Planning Year, the Demand Resource must be capable of being interrupted for at least the first five (5) times requested based on their physical availability (when called upon by the Transmission Provider for an Emergency) during any Planning Year for which the Demand Resource receives credit as a Planning Resource. This availability must include at least the entire Summer Season. In addition to notification time requirements, the amount of credit that a Demand Resource receives as a Planning Resource will be based on the number

of interruptions allowed on the Demand Resource during the Planning Year.

Demand Resources with a notification time requirement less than or equal to 6 hours will receive credit as a Planning Resource based on a multiplier of: (i) 80% if 5 to 9 interruptions per Planning Year are allowed on the Demand Resource; or, (ii) 100% if 10 or more interruptions per Planning Year are allowed on the Demand Resource.

Beginning in the 2023/2024 Planning Year, the Demand Resource must have a notification time equal to or less than six (6) hours and be capable of being interrupted for: (i) at least the first five (5) times requested in the Summer Season; (ii) at least the first five (5) times requested in the Winter Season; (iii) at least the first three (3) times requested in the Spring Season; and (iv) at least the first three (3) times requested in the Fall Season, based on their physical availability when called upon by the Transmission Provider for an Emergency during any applicable Season in the Planning Year for which the Demand Resource receives credit as a Planning Resource. These obligations only apply to Seasons in which a Demand Resource clears the Planning Resource Auction.

Limitations due to applicable regulatory restrictions that are more restrictive than the physical limitations of the Demand Resource will supersede the physical availability of the Demand Resource.

- f. Unless the Demand Resource is unavailable as a result of maintenance requirements or for reasons of Force Majeure, when a Demand reduction is requested by the Transmission Provider for an Emergency, the resultant reduction

must be a reduction that would not have otherwise occurred within the next twenty four (24) hour period. There shall be no penalties assessed to a Market Participant representing the entity that has offered ZRCs from the LMR if the Demand Resource is unavailable for interruption as a result of maintenance requirements in accordance with Good Utility Practice, or for reasons of Force Majeure, or in the event that the specified Demand reduction had already been accomplished for other reasons (*e.g.*, economic considerations, operating one's own Demand Resource at or above the credited level of Demand Resource, or local reliability concerns in accordance with instructions from the Local Balancing Authority).

- g. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify as an LMR.
- h. A Market Participant shall be prohibited from registering a Demand Resource for which credit is already being taken by a Market Participant.
- i. Demand Resources that are offered into the Day-Ahead and/or Real-Time Energy and Operating Reserve Markets as price sensitive Bids are obligated to be interrupted during an Emergency pursuant to the Transmission Provider emergency operating procedures regardless of the projected or actual Real-Time Energy Market LMP.
- j. A Market Participant must demonstrate demand reduction capability for each Planning Year on an annual basis as established in the BPM for Resource

Adequacy. Beginning with the 2020/2021 Planning Year each Demand Resource must validate its performance by meeting the Transmission Provider's Scheduling Instructions when called upon during the prior Planning Year or conducting a real power test. A Demand Resource for which a real power test is conducted will receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season of the Planning Year in which such a test occurs.

A Demand Resource may provide operational data, or develop an alternative mechanism, subject to the approval of the Transmission Provider, by which the demand reduction capability can be demonstrated without requiring an actual demand reduction if a real power test is precluded or waived due to one of the two conditions as specified below:

- 1) Such a real power test is precluded by any applicable regulatory restriction and such a limitation is documented during DR registration; or
- 2) A Market Participant may waive the obligation to conduct a real power test by notifying the Transmission Provider during DR registration and accepting a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode described in and distributed pursuant to Section 69A.3.9. 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.

All existing accredited Demand Resources that neither conduct a real power test nor meet Scheduling Instructions issued by the Transmission Provider during the prior Planning Year must participate in training provided by the Transmission Provider on the deployment of LMRs during the prior Planning Year. Any existing accredited Demand Resource must submit (1) the real power test results, (2) reference performance of Scheduling Instructions for demand reduction when called upon during the calendar year prior to the upcoming Planning Year, (3) alternate testing mechanism, relevant data, and a reference of training participation to the Transmission Provider, or (4) a Demand Resource Deferral Notice pursuant to 69A.3.5(1) and a reference of training participation to the Transmission Provider no later than February 1 prior to such Planning Year for existing accredited DR. For new Demand Resources, (1) a real power test must be conducted and results submitted to the Transmission Provider, (2) alternate testing mechanism must be submitted, or (3) a Demand Resource Deferral Notice must be submitted prior to qualifying as a Demand Resource, but no later than March 1 prior to the PRA in accordance with the BPM for Resource Adequacy. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market

Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource.

- k. Market Participants providing physical, regulatory, or contractual limitations of the notice times and availability of Demand Resources must provide appropriate documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.
- l. A Market Participant may defer the obligation to conduct a real power test, as set forth in section 69A.3.5(j), by providing a Demand Resource Deferral Notice to the Transmission Provider in writing and signed by an officer of the company no later than February 1<sup>st</sup> prior to the Planning Year. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource. The Demand Resource Deferral Notice shall contain: (1) the expected Demand Resource test value (in megawatts) from such Demand Resource and if the Demand Resource is new, the LBA or external BA where it is represented; and (2) appropriate information validating that real power test results will be submitted to the Transmission Provider by the last Business Day of May prior to the Planning Year. A Market Participant that provides a Demand Resource Deferral Notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the amount of Demand Resource test value



provided in the Demand Resource Deferral Notice multiplied by \$2,400/MW, where \$2,400 is the product of  $3 \times 4 \times \$200$  to account for the three (3) times energy penalty assumed under the deferral, the four (4) hours of LMR requirements, and a \$200 LMP as a proxy for pricing under emergency conditions. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants that have elected to submit a Demand Resource Deferral Notice must satisfy credit requirements by March 31, 2021. If the Market Participant submits the real power test results on or before the last Business Day of May prior to the Planning Year that are equal to or greater than the expected Demand Resource 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. In the event ZRCs associated with a Planning Resource for which Demand Resource testing has been successfully deferred are unconverted in accordance with section 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred Demand Resource value, in which case the Transmission Provider will adjust the Market Participant's Demand Resource value and credit requirement within twenty (20) Business Days. A Market Participant that provides a Demand Resource Deferral Notice and that either (1) has not submitted any real power test result for such Demand Resource by the last Business Day of May prior to the Planning Year, or (2) has submitted a real power test result by the last Business Day of May prior to the Planning Year that

demonstrates fewer megawatts are available than the expected Demand Resource test value submitted in the Demand Resource 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 described in and distributed pursuant to Section 69A.3.9. 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 Demand Resource Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

### **Behind the Meter Generation Eligibility**

1. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a BTMG for the applicable Season in the upcoming Planning Year. A Market Participant that possesses ownership or equivalent contractual rights in a BTMG can request accreditation for such BTMG by meeting the following requirements:
  - a. registering such resource(s) with the Transmission Provider as documented in the BPM for Resource Adequacy.
  - b. demonstrating GVTC capability for applicable Season in each Planning Year on an annual basis as established in the BPM for Resource Adequacy, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing accredited BTMG unless the Transmission Provider has granted an extension pursuant to Section 69A.3.6.1.k. All new BTMGs or an existing accredited BTMG that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA as established in the BPM for Resource Adequacy.
  - c. submitting generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a BTMG less than 10 MW if the Market Participant has never provided such data for such BTMG. A Market Participant that begins reporting generator availability data

based upon GVTC for a BTMG that is less than 10 MW must continue to report such data.

- d. confirming such BTMG can be available to provide energy with notice based on their physical capability but with no more than 12 Hours advance notice from the Transmission Provider. Limitations due to applicable regulatory restrictions that are more restrictive than the physical limitations of the BTMG will supersede the physical availability of the BTMG; however, in no event shall the BTMG's maximum notice time requirement be greater than 12 hours. 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.
- e. demonstrating that the BTMG is able to sustain energy production at the accredited MW level for at least four (4) continuous Hours;
- f. demonstrating that the BTMG is capable of being deployed at the accredited MW level for: (i) at least the first five (5) times requested in the Summer Season; and (ii) at least the first five (5) times requested in the Winter Season; (iii) at least the first three (3) times requested in the Spring Season; and (iv) at least the first three

(3) times requested in the Fall Season, based on their physical capability when called upon by the Transmission Provider during an Emergency during any applicable Season in a Planning Year for which the BTMG receives credit as a Planning Resource. Limitations due to applicable regulatory restrictions that are more restrictive than the physical limitations of the BTMG will supersede the physical availability of the BTMG.

- g. There shall be no penalties assessed to a Market Participant representing the entity that has offered ZRCs from the LMR if the BTMG Resource is unavailable for interruption as a result of maintenance requirements in accordance with Good Utility Practice, or for reasons of Force Majeure, or in the event the specified BTMG reduction had already been accomplished for other reasons (e.g., economic considerations, operating the BTMG Resource at or above the credited level of BTMG Resource, or local reliability concerns in accordance with instructions from the Local Balancing Authority).
- h. A BTMG Resource for which operation is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify as an LMR.
- i. A Market Participant shall be prohibited from registering a BTMG Resource for which credit is already being taken by a Market Participant.
- j. Market Participants providing physical, regulatory, or contractual limitations of the notice time and availability of BTMG must provide appropriate

documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.

- k. A Market Participant for a BTMG required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a BTMG has not completed GVTC testing by the deadlines provided in 69A.3.6.1.b, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions) or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

MISO  
FERC Electric Tariff  
MODULES

69A.3.7  
RESERVED  
31.0.0

### **Measuring and Verifying LMR**

- a. Demand Resources: The Transmission Provider will review meter data provided by the Market Participant to verify that a Demand Resource reduced to the targeted Demand reduction amount or to a specified firm service level when called upon. Following a declared Emergency in which a Demand Resource is deployed, the Market Participant who registered the Demand Resource will collect meter data and perform calculations, consistent with the Measurement and Verification protocol specified in Attachment TT and identified at the time of registration with the Transmission Provider. The Market Participant shall document the metered data and calculations and submit the certified results to the Transmission Provider as documented in the BPM for Resource Adequacy.
- b. Behind the Meter Generation: The Transmission Provider will review meter data provided by the Market Participant to verify that the BTMG produced energy to the target level requested by the Local Balancing Authority or Transmission Provider. Following a declared Emergency in which a BTMG is deployed, the Market Participant who registered the BTMG will collect meter data and perform calculations, consistent with the Measurement and Verification protocol specified in Attachment TT and identified at the time of registration. The Market Participant shall document the metered data and calculations and submit the certified results to the Transmission Provider as documented in the BPM for Resource Adequacy.



### **Penalty Provisions for LMRs**

Unless an LMR is unavailable as a result of maintenance requirements, for reasons of Force Majeure, or because the number of required deployments based on the registered number has been reached, the Market Participant representing the entity that had ZRCs from LMRs that cleared in the PRA, were used in a FRAP, or were used in an RBDC Opt Out will be subject to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to perform in accordance with its Market Participant's response to such Market Participant's Scheduling Instructions. The penalties defined below will only apply to the portion of the Market Participant's response to such Market Participant's Scheduling Instruction that is not followed during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (*e.g.*, for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the Local Balancing Authority) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

- a. The Transmission Provider shall assess the responsible Market Participant the costs that were otherwise incurred to replace the deficient Planning Resource at the time the Market Participant's LMR is called upon by the Transmission Provider and does not respond in full or in part consistent with the Market Participant's response to MISO's Scheduling Instructions. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any applicable Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such penalty revenues only 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. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand. If deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year when the LMR was unavailable. If such

LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current Planning Year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

- b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69A.3.9.a above, and the Demand Resource or BTMG will no longer qualify as an LMR and will not receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year. If such LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current planning year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

### **Planning Resource Capacity Values**

In order for the Transmission Provider to account for resource performance and availability, Capacity Resources will be given a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type; LMRs will be given capacity values which recognize historical performance and availability; and EE Resources will be given capacity values based on the measurement and verification data provided for such resources, as provided in the BPM for Resource Adequacy.

### **Seasonal Accredited Capacity of Capacity Resources**

The Transmission Provider will determine the Seasonal Accredited Capacity for each Capacity Resource.

- a. The Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource, Use Limited Resource or Distributed Energy Aggregated Resource, is based on an evaluation of the type and volume of interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource or Electric Storage Resource for each Season as set forth in Schedule 53.
- b. The Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation Use Limited Resource or Distributed Energy Aggregated Resource, is based on the GVTC value and  $XEFOR_d$  values of such External Resource for each Season. External Resources that are not required to report generator availability data will have a forced outage rate based on the class average forced outage rate of the resource type.
- c. The Transmission Provider will determine the Seasonal Accredited Capacity for a DRR that qualifies as a Capacity Resource and that interrupts or controls Load, based upon historical performance and availability, for each Season, as set forth in Schedule 53.

- d. The Transmission Provider will determine the Seasonal Accredited Capacity for each DRR that qualifies as a Capacity Resource and that is a behind the meter generation facility based on an evaluation of the GVTC value and Real-Time offered availability for such behind the meter generation facility for each Season as set forth in Schedule 53. If such behind the meter generation facility is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity.
- e. The Seasonal Accredited Capacity for a Capacity Resource that is a Dispatchable Intermittent Resource or Intermittent Generation will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM for Resource Adequacy.
- f. The Seasonal Accredited Capacity value for a Capacity Resource that is a Hybrid Resource will be established by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of its respective Electric Facilities for the production and/or storage for later injection of electricity, up to the level of firm interconnection service, prior to a minimum amount of operating data becoming available. Once sufficient operation data is available, as defined in the BPM, the Seasonal Accredited Capacity value for a Hybrid Resource will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in

accordance with the BPM.

- g. The Seasonal Accredited Capacity of a Capacity Resource that is an Electric Storage Resource will be established by the Transmission Provider based on an evaluation of the type and volume of interconnection service, a GVTC value based upon a power and energy test, and an XEFOR<sub>d</sub>. Electric Storage Resources that are not required to report generator availability data will have an XEFOR<sub>d</sub> rate based on their class average forced outage rate.
- h. The Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and XEFOR<sub>d</sub> values of such Use Limited Resource in accordance with the BPM for Resource Adequacy.
- i. The Seasonal Accredited Capacity for a Capacity Resource that is a Distributed Energy Aggregated Resource will be determined by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of the underlying Distributed Energy Resources within the aggregation. The Seasonal Accredited Capacity values of the underlying DERs will be determined based on their corresponding resource types as set forth in subsections above and in accordance with the BPM for Resource Adequacy.

### **Seasonal Accredited Capacity of Demand Resources**

The Transmission Provider will determine the appropriate Seasonal Accredited Capacity value for Demand Resources that qualify as a Planning Resource as established in the BPM for Resource Adequacy.



### **Seasonal Accredited Capacity of Behind the Meter Generation**

The Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG that qualifies as an LMR as set forth in the Resource Adequacy Business Practices Manual. If such BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity. If the Market Participant is not required to report generator availability data, the BTMG will have a forced outage rate based on the class average forced outage rate of the resource type.

### **EE Resources**

The Seasonal Accredited Capacity for a qualified EE Resource will be determined by the Transmission Provider based upon submitted measurement and verification documents, as provided in the BPM for Resource Adequacy.

### **Attributes of ZRCs**

A Market Participant that owns or possesses equivalent contractual rights to a qualified Planning Resource can convert the convertible Seasonal Accredited Capacity of the Resource (Seasonal Accredited Capacity MW) as determined in section 69.A.3.1.g into ZRCs through the MECT in order to offer such ZRCs into a PRA. Market Participants also can unconvert and/or transfer ZRCs through the MECT to another Market Participant, as described in the BPM for Resource Adequacy.

#### **A. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Planning Resource that is not Intermittent Generation or Dispatchable Intermittent Resource.**

For a Capacity Resource that is not Intermittent Generation or Dispatchable Intermittent Resource the amount of Capacity that is eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Capacity Resource. The convertible Seasonal Accredited Capacity shall be determined by:

- i. Determining the Installed Capacity;
- ii. Determining the Seasonal Accredited Capacity of the Capacity Resource;
- iii. Allocating the Capacity Resource's Seasonal Accredited Capacity value where:
  - a. If the Capacity Resource has only Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated to the Capacity Resource's Energy Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Energy Resource Interconnection Service by SAC divided by ICAP;

- b. If the Capacity Resource has both Network Resource Interconnection Service and Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated first to the Capacity Resource's Network Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Network Resource Interconnection Service by SAC divided by ICAP, as provided below:

$$NRIS\ SAC = MIN\ (NRIS,\ ICAP) \times (SAC/ICAP)$$

- c. Any remaining total Seasonal Accredited Capacity value will then be allocated to Energy Resource Interconnection Service Seasonal Accredited Capacity as provided below:

$$ERIS\ SAC = MAX\ (0,\ (ICAP-NRIS)) \times (SAC/ICAP)$$

- d. The resulting Network Resource Interconnection Service Seasonal Accredited Capacity value shall be eligible to be converted into Zonal Resource Credits; and
- e. The resulting Energy Resource Interconnection Service Seasonal Accredited Capacity value that is coupled with firm Transmission Service shall be eligible to be converted into Zonal Resource Credits up to the Energy Resource Interconnection Service Unforced Capacity value of the Capacity Resource, by multiplying the firm Transmission Service amount by SAC divided by ICAP.

**B. Eligibility for Zonal Resource Credits for a Capacity Resource that is an Intermittent Generation or Dispatchable Intermittent Resource**

For Intermittent Generation and Dispatchable Intermittent Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Intermittent Generation or Dispatchable Intermittent Resource, which is equal to the total Seasonal Accredited Capacity value multiplied by the quotient of the deliverability adjusted Capacity factor divided by the peak performance Capacity factor of the Capacity Resource where:

- a. the deliverability-adjusted capacity factor is the average of the actual Energy output capped at the demonstrated deliverability of the Intermittent Generation or Dispatchable Intermittent Resource determined in Section 69A.3.1.g during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource; and,
- b. the existing peak performance Capacity factor is the average of the actual Energy output during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource.

**C. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Distributed Energy Aggregated Resource**

For Distributed Energy Aggregated Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal

Accredited Capacity value of the Distributed Energy Resources within the aggregation according to their resource type as determined in section 69A.3.1.g.

### **Capacity Resource Must Offer and Performance Requirements**

- a. Market Participants that convert Seasonal Accredited Capacity from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h) or used in an RBDC Opt Out, including Capacity Resources that are the subject of Diversity Contracts, must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to ZRCs and clear in a Season in the PRA or used in a FRAP or used in an RBDC Opt Out for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process. This must offer obligation does not apply to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage, in accordance with the BPM for Resource Adequacy and the BPM for Outage Operations. Additionally, this must offer obligation is modified to the extent the Capacity Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described above, for the duration of such limitation.

Any such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any Days greater than thirty-one (31) Days and must replace ZRCs in

accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than thirty-one (31) Days in total during any Season, will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h.

Self-Schedules or Offers for Energy must be made consistent with requirements specified in Sections 39 and 40 of this Tariff as well as in the BPM for Resource Adequacy and the Business Practices Manual for Energy and Operating Reserves Markets. Partial or full forced or scheduled outages or derates of Capacity Resources (other than DRRs) must be reported in the Transmission Provider's Outage Scheduler, as described in further detail in the Business Practices Manual for Outage Operations. Must offer requirements specified in the BPM for Resource Adequacy will reflect resource operational limitations, including those related to Use Limited Resources, fuel limited, energy output limited or Intermittent Generation and including all state regulations and laws, including but not limited to, state safety standards, planning reserve margins, or the enforcement thereof. The Transmission Provider will monitor compliance with must offer requirements in accordance with the BPM for Resource Adequacy.

- b. If a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season or used in an RBDC Opt Out is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not



respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations. These costs will be the product of the amount of qualified ZRCs not achieved and the real-time LMP at the Capacity Resource's CPNode, plus any applicable related Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such revenues to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency. Such revenues shall be distributed on a Load Ratio Share basis.

- c. Market Participants must input all Energy Efficiency Resource and Load Modifying Resource information into the MECT at least seven (7) Business Days prior to the Planning Resource Auction.

MISO  
FERC Electric Tariff  
MODULES

69A.6  
Reports  
31.0.0

### **State RAR Standards**

The Transmission Provider will assist states in meeting any state resource adequacy standards by providing relevant MECT information as available and as may be requested by states, subject to the data confidentiality provisions in Section 38.9 of this Tariff. Nothing in the RAR shall prohibit any state from requesting data relating to state safety standards, planning reserve margins, or the enforcement thereof.

### **Information regarding RAR Obligations**

The Transmission Provider will maintain databases and will report to states and the affected LSEs, upon request, aggregated, non-confidential information regarding jurisdictional LSEs' RAR obligations during relevant time periods. Confidential Data regarding RAR status will be provided to states only in accordance with the data confidentiality provisions in Section 38.9 of this Tariff.

### **Facilitation of a Bilateral Capacity Bulletin Board**

The Transmission Provider shall maintain an electronic bulletin board platform that may be used by Market Participants to facilitate voluntary bilateral ZRC transactions and to monitor the conversion of Seasonal Accredited Capacity to ZRCs.

**Facilitation of LSE's RAR Information**

The Transmission Provider shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state (in the case of an LSE subject to regulation or using delivery services rates, terms or conditions established by such State Regulatory Authority) or to the Commission, subject to the provisions of Section 38.9 of this Tariff.

## **Reliability Based Demand Curve Procedures**

### **A. Translation of MRI Curves to RBDCs**

The following process will be utilized to determine the RBDC for the Transmission Provider Region for each Season of the upcoming Planning Year. The MRI Curves for the Transmission Provider Region as described in Section 68A.9 will be multiplied by a scaling factor measured in \$/MWh. The scaling factor for an RBDC is calculated to support ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. LOLE risk across the Seasons is modeled as described in Section 68A.2.1. The scaling factors shall be determined as set forth in the Business Practices Manual for Resource Adequacy.

The process used to determine the RBDCs for each of the First Planning Area and the Second Planning Area for each Season in the Planning Year is similar to the process used for developing the RBDC curve for the Transmission Provider Region.

### **B. Monte Carlo Analysis**

Every three Planning Years, the Transmission Provider will evaluate the ability of RBDCs, through probabilistic analysis, to reliably serve the Transmission Provider Region's Demand while supporting ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. The probabilistic analysis shall use a Monte Carlo study that assumes there are no internal transmission limitations within the Transmission Provider Region.

The Monte Carlo analysis will model both in-market supply and demand based on historic supply and demand variability, respectively, observed through a minimum of the three

most recent PRAs. The Monte Carlo model will produce seasonal clearing prices and quantities with each draw. Overall model results will be assessed by comparing the average of seasonal prices from the study against the estimate of Net CONE described in section 69A.8. The scaling factor is adjusted in each successive Monte Carlo simulation so that long run equilibrium conditions are ultimately achieved, indicated by the average of seasonal prices from the study equal to the estimate of Net CONE. Net CONE values used for the Monte Carlo analysis will be the simple arithmetic average of all LRZ Net CONE values.

A separate Monte Carlo analysis will be performed to evaluate the RBDCs for the First Planning Area and the Second Planning Area. Separate scaling factors will be used in the Monte Carlo analysis for each of the First Planning Area and the Second Planning Area that supports achievement of Net CONE values for the corresponding Planning Area, indicated by the average of seasonal capacity prices under long run equilibrium conditions. Net CONE values used in the Monte Carlo analysis for the RBDCs for the First Planning Area and the Second Planning Area will be the simple arithmetic average of LRZ Net CONE values for the specific LRZs in the corresponding Planning Area.



### **Planning Resource Auction**

Within twenty (20) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA.

## **PRA Procedures**

**a. Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Seasonal Accredited Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not submitted a FRAP, or RBDC Opt Out, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs, or RBDC Opt Outs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in the PRA. The PRA offer window shall begin at 8:00 am EPT three (3) Business Days before the last Business Day in March and shall end at 6:00 pm EPT on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or

reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs. Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Seasonal Accredited Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner that (i) borders the Transmission Provider Region; (ii) whose external ties are predominantly to the Transmission System; and (iii) has Seams Operating Agreements that allow for coordinated operations, will be granted ZRCs in the LRZ where their firm transmission service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation, Electric Storage Resources, and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g. To the extent a Capacity Resource is located on the border of two or more LRZs (e.g., has transmission lines from two or more LRZs terminating at the substation containing the Capacity Resource's interconnection facilities), the Capacity Resource will be assigned to an LRZ as follows:

- (i) if the Capacity Resource is located within the MISO BA, MISO will assign that Capacity Resource to the LRZ that contains the Local Balancing Authority in which the Capacity Resource is physically located; or
- (ii) if the Capacity Resource is a Border External Resource, MISO will assign that Capacity Resource to the LRZ with which it has the greatest electrical connection. This connection will be determined by the impacts of the Resource on the system, including (i) the electrical loading of transmission facilities within and tying to the Zone and (ii) the transmission constraints which define the CIL and CEL for the Zone.

Once assigned, Capacity Resources which border two or more LRZs will not be reassigned unless significant changes occur in the Transmission Provider Region, including but not limited to, significant changes in LRZ boundaries, membership, the Transmission System, and/or Resources.

**b. Participating Demand:** All LSEs will be required to meet their Final PRMR through the PRA process, unless they have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-

Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a variable reliability target through RBDCs for all of the LSEs located within the Transmission Provider Region.

**c. Conducting the PRA:** The Transmission Provider will conduct the PRA for each Season using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to the Final PRMR determined by application of the RBDC for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP and an RBDC Opt Out, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply and demand balance both for the Transmission Provider Region and for each of the First Planning Area and the Second Planning Area by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs, minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to maximize social surplus, using the as-offered overall

costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to LCR, network constraints, and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of two (2) successive iterations per Season to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over each Season for the next Planning

Year for the Transmission Provider Region. Coincident Peak Demand is used to establish an LSE's Initial PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for each Season in the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to maximize the social surplus of procuring PRMR to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the peak Hour of each Season in the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

**Network Constraints.** The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of

transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

**Transmission Losses.** The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation for each Season.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ with which the ERZ interconnects. For ERZs which connect with more than one



SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day (\$/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the Final PRMR for the Transmission Provider Region minus the amount of Initial PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Seasonal Accredited Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the Final PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

**(x) ACP for multiple Seasons with ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirements:**

When an LRZ has more than one Season in any combination of ZRC Shortage Conditions and/or ZRC Near-Shortage Conditions the final Auction Clearing Price (ACP) for the LRZ will be set as the minimum of: (a) the original ACP as determined in Section 69A.7.1.c.(v) reflecting the effective financial binding of an LCR constraint; or (b) the summation of: (i) the amount composed of the system marginal cost of capacity, the regional marginal cost of capacity, and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable; and (ii) the LCR price adder. The LCR price adder will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the summation of the number of days in Seasons in each Season of the Planning Year in which the LRZ was in ZRC Shortage Conditions in the Planning Resource Auction and the number of days in each Seasons of the Planning Year in which the LRZ was in ZRC Near-Shortage Conditions in the Planning Resource Auction.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the twentieth Business Day following the last Business Day in March. The Transmission Provider may extend the publishing deadline based on unanticipated events that: (i) interfered with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) were

otherwise likely to have a widespread negative impact on the results of the PRA.

The Transmission Provider shall notify Market Participants and post such notice of any extension of publishing the results of the PRA on its website. The notice shall state the extension's circumstances, rationale, and duration.

### **Consequences of PRA**

All PRA transactions will be financially binding. Market Participants with cleared ZRC Offers must comply with all of the ZRC requirements for all ZRCs that clear in the PRA.

### **Uncleared ZRCs**

Once the PRA has concluded, a Market Participant may convert back to Seasonal Accredited Capacity any ZRCs that do not clear in the PRA.

### **PRA Reporting**

The Transmission Provider will not reveal the ZRC Offers submitted by any Market Participant in a PRA until one (1) month following the completion of the PRA, except as required pursuant to the provisions of Section 38.9 of the Tariff. When the ZRC Offers are posted, price/quantity pairs will be made public, however the names of the Market Participants submitting such offers and the names of the Planning Resources offered shall not be publicly revealed.

### **Market Monitoring**

All actions of Market Participants participating or failing to participate in the PRA shall be subject to the provisions of Module D, except to the extent that a Market Participant has opted out of the PRA as described in Section 69A.9. The Transmission Provider will report any known attempt to exercise market power by LSEs or by Market Participants in the PRA procedures to the Independent Market Monitor.

## **PRA Settlement**

- a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their Final PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9 or submitted an RBDC Opt Out pursuant to Section 69A.9.1. For LSEs not selecting RBDC Opt Out, the Final PRMR will be established based on the financial binding of RBDCs representing the Transmission Provider Region and applicable planning area (i.e., the First Planning Area or the Second Planning Area).

Final PRMRs will be determined as follows:

- i. LSEs using the RBDC Opt Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by  $(1 + \text{Transmission Provider Region PRM} + \text{RBDC Opt Out Adder})$ .
- ii. LSEs not using the RBDC Opt Out will have Final PRMRs calculated using the formula below:



*Final PRMR for a LSE not using the RBDC Opt Out*

$$= \left( \text{PRA Cleared Capacity} \right. \\ \left. - \sum \text{Final PRMR for LSEs using the RBDC Opt Out} \right) \\ \times \frac{\text{Initial PRMR of the LSE not using the RBDC Opt Out}}{\sum \text{Initial PRMR of all LSEs not using the RBDC Opt Out}}$$

- iii. LSEs under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider will have Final PRMRs for each Season calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + the planning reserve margin established by the State Regulatory Authority).

The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts.

The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region in each Season divided by the total number of days in the Season.

- b. An LSE that submits a FRAP or an RBDC Opt Out with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:
  - (i) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand

that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP or for LSEs submitting ZRCs for an RBDC Opt Out.

- c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.
- d. For instances where a LRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirement in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPs. In this case, such cleared ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit, to the extent that settlement amounts credited in paragraph 69A.7.6.a above for a Planning Year are insufficient to cover Allowable ZRC Offer Costs, needed to be incurred by the Planning Resource to be available for cleared Seasons.

ZRC Offer Revenue Sufficiency Credit will be calculated as the greater of: (i) zero; or, (ii) the difference between Allowable ZRC Offer Costs, and the total settlement amounts credited per paragraph 69A.7.6.a for the associated cleared

ZRC Offers for all Seasons in a Planning Year.

Where Allowable ZRC Offer Costs shall equal the minimum of: (i) the sum of all cleared ZRC Offer segment volumes multiplied by the ZRC Offer segment price, multiplied by the number of Days in the Season, calculated for all Seasons for which the ZRCs clear in the Planning Resource Auction; or, (ii) the annual CONE for the LRZ where the ZRCs are represented; or, (iii) the applicable facility-specific Reference Level costs for the Planning Resource, if a Market Participant received a facility-specific Reference Level per Section 64.1.4.

ZRC Offer Revenue Sufficiency Credits will be allocated pro-rata across the Seasons where the ZRC Offer cleared for settlement and distribution.

- e. ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ clearing under ZRC Shortage Conditions or ZRC Near-Shortage Conditions on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in the appropriate LRZ.

### **Distribution of Excess Auction Revenue**

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

- (i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then
- (ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a pro rata basis to all HUCs and ZDC Hedges.

### **Historic Unit Considerations (HUCs)**

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, limited to a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones in which:

- i. The LSE has Initial PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;
- ii. The Planning Resource designated in the arrangement and Initial PRMR obligation span multiple LRZs and/or ERZs;
- iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated Initial PRMR obligation; and
- iv. LSEs must note qualification for HUCs and submit information supporting HUC eligibility to the Transmission Provider by January 15<sup>th</sup> prior to the upcoming Planning Year.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of Initial PRMR that are

associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the current term of the executed contract, excluding any evergreen contract extension, or for two Planning Years, whichever is longer. In the event that the owned resource status is changed to retired, the transmission service is not maintained, or the arrangement is terminated or otherwise expires, the arrangement shall no longer be eligible to receive excess PRA revenue.

### **ZDC Hedges**

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent(100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. 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. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

### **Zonal Deliverability Benefit**

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones.

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will 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 the 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 a weighted average approach. Fourth, the Transmission Provider will 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:

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

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

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



Where  $k$  = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZ $k$  by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZ $k$ . This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP and RBDC Opt Out related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. The Transmission Provider will also receive FRAP and RBDC Opt Out related revenues derived from ZRCs that would have received payments greater than the charges to the associated FRAP or RBDC Opt Out PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. After calculating the ZDB rate(s), if there exists any remaining excess revenue (i.e. surplus), the surplus will be allocated back to the Deliverability Benefiting Zone(s) on a PRMR *pro-rata* basis.

Whenever an LRZ has an ACP that exceeds the System ACP because the LCR for that LRZ exceeds the sum of PRMR for LSEs within that LRZ, payments made to ZRCs in that LRZ will exceed the sum of receipts from LSEs within that LRZ plus any receipts from other LRZs related to such ZRCs. The revenue shortfall within such LRZ will be recovered from all LSEs within that LRZ on a PRMR pro-rata basis. PRMR covered by FRAPs and RBDC Opt Outs will be included in the pro-rata calculation, and the related amounts charged to the LSEs that use FRAPs and RBDC Opt Outs through this Local Clearing Requirement Charge.

**Self-Scheduling Option:**

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP for the Final PRMR by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

### **Installed Capacity (ICAP) Deferral Requirements and Charges**

- a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented for any Season for which it wants to be eligible to offer ZRCs, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of the Month prior to the start of any Season in which it wants to be eligible.
- b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e.,  $90/365$  times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market

Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

- i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of the Month prior to the start of any Season for which it has deferred, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on the first day of the any Season for which a Market Participant has an ICAP deferral and continue until ICAP is submitted and verified by the Transmission Provider, replacement ZRCs are registered per the BPM for Resource Adequacy, the ICAP value is forfeited, or the end of any deferred Season, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9

and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

- ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.
- iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge for the Transmission Provider Region during the applicable Season.

### **Calculation of CONE and Net CONE**

- a. The CONE value shall initially be the rate proposed by the Transmission Provider in a 2012 Federal Energy Regulatory Commission filing and approved by the Commission for the Planning Year commencing on June 1, 2013. The Transmission Provider and the IMM shall consider factors, including, but not limited to: (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). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated in concert with the IMM no later than September 1 beginning on September 1, 2012. The recalculated CONE values shall be filed with the Commission annually thereafter.
- b. The Transmission Provider shall calculate Net CONE values for each LRZ. Net CONE represents the difference between CONE values and Inframarginal Rents, for the Generation Resource type used in the CONE value calculation (the Reference Resource Type) . The following process will be used to estimate Net CONE:

To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each Generation Resource of the Reference Resource Type operating in the Transmission Provider Region consisting of all revenues for the Generation Resource from the Transmission Provider's Energy and Operating Reserve Markets, on a per MW or MWh basis, whichever is applicable, calculated hourly, and Production Costs calculated hourly. The greater of the market revenues minus Production Costs, or zero, shall be calculated hourly, and summed across all Hours for each Planning Year, for each resource of the Reference Resource Type. Inframarginal Rents outside of two standard deviations from the sample mean are removed. The Generation Resources are then grouped into LRZs based on their location. An average Inframarginal Rents is calculated for each LRZ and then scaled using a capacity factor for each LRZ. The capacity factor is the ratio of the commitment hours of the Generation Resource of the Reference Resource Type that is committed for the maximum number of hours in the Planning Year amongst all Generation Resources of the Reference Resource Type to the average commitment hours of all Generation Resources of the Reference Resource Type that were committed in the LRZ in the Planning Year. This results in Inframarginal Rents values for each LRZ for each Planning Year, which will be averaged over a three-year period to determine an initial Inframarginal Rents for each LRZ.

To determine the final Inframarginal Rents values to be used for the upcoming Planning Year, the Transmission Provider will apply a scaling factor to the initial Inframarginal Rents. The scaling factor will be based on statistical models between: a) LMPs to gas, and; b) LMPs to Inframarginal Rents. Readily available settled futures gas prices for the



upcoming Planning Year will be applied to the statistical models to calculate the scaling factor.

Each LRZ's final Inframarginal Rents are then grouped and averaged into values in the First Planning Area and Second Planning Area. The values from the First Planning Area and Second Planning Area are then subtracted from the LRZ-specific CONE values to get an estimate of Net CONE for each LRZ. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area.

The Transmission Provider shall arrange for Net CONE values to be calculated no later than September 1 prior to the subsequent Planning Year beginning on September 1, 2024.

The recalculated Net CONE values shall be filed with the Commission annually thereafter.

### **Use of FRAP in the Planning Resource Auction**

An LSE electing to use a Fixed Resource Adequacy Plan (FRAP) in the PRA for any Season can continue to use its existing resource planning processes to meet all or any portion of its Initial PRMR by providing the Transmission Provider with a FRAP, as described below:

- a. An LSE electing to use a FRAP for any Season must submit a FRAP for each LRZ to the Transmission Provider by the 7<sup>th</sup> Business Day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or any portion of the LSE's Initial PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning Year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year.  
  
Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two Business Days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for each Season and also identify the

ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet the FRAP designated portion of its Initial PRMR and also its load ratio share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the designated portion of the LSE's Initial PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that the portion of an LSE's Initial PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP for each Season.

- b. To the extent that the LSE's ZRCs satisfy the portion of the LSE's Initial PRMR for the applicable Season(s) submitted through a FRAP, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Initial PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- c. Any portion of an LSE's Initial PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA.

- d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- e. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's Initial PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.
- f. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

### **Use of RBDC Opt Out in the Planning Resource Auction**

An LSE electing to use the RBDC Opt Out can continue to use its existing resource planning processes to meet its Final PRMR by providing the Transmission Provider with an RBDC Opt Out, as described below:

- a. The RBDC Opt Out Lock-In Period will be three consecutive Planning Years for all Seasons. If an LSE fails to submit an RBDC Opt Out then the LSE will be required to participate in the PRA through any combination of the other Tariff-defined options, or pay the Capacity Deficiency Charge, for each Planning Year in which the LSE does not submit an RBDC Opt Out.
- b. An LSE under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider is not eligible to select the RBDC Opt Out.
- c. An LSE selecting the RBDC Opt Out will be required to meet its Final PRMR for the entirety of its load and losses, and its entire share of LCR for each LRZ, for each Season.
- d. An LSE must provide an initial notification of its intent to elect the RBDC Opt Out no later than January 15th prior to the upcoming Planning Year. An LSE electing the RBDC Opt Out must submit its final plan for each LRZ to the Transmission Provider by the 7<sup>th</sup> Business Day of March prior to each Planning Year during the RBDC Opt Out Lock-In Period in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet the LSE's Final PRMR, and share of LCR for each LRZ, for each Season. Market Participants

using the RBDC Opt Out must submit all registrations for new and existing resources to be used in the RBDC Opt Out through the MECT consistent with the timelines established in the Business Practices Manual for Resource Adequacy. The RBDC Opt Out must include the LSE's seasonal forecasted Coincident Peak Demand for each LRZ and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its Final PRMR, and also its share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's RBDC Opt Out on an annual basis to determine if it meets the LSE's Final PRMR and the LSE's share of LCR requirements for all Seasons. The Transmission Provider will notify the LSE prior to March 15<sup>th</sup> before the applicable Planning Year whether the submitted RBDC Opt Out meets the LSE's Final PRMR, and share of LCR for each LRZ, requirement for each Season during the applicable Planning Year. The LSE must remedy any deficiencies in its RBDC Opt Out for each Season before the PRA offer window opens.

- e. The Transmission Provider will notify the RERRA(s) following the submission of an initial intent to elect the RBDC Opt Out by an LSE. RERRA(s) may elect to notify the Transmission Provider within twenty (20) Business Days whether the LSE's load subject to the RERRA's respective jurisdiction is authorized to select the RBDC Opt Out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC Opt Out for the LSE's load subject to the RERRA's respective jurisdiction, the Transmission Provider will reject the

LSE's RBDC Opt Out for such load. If the Transmission Provider receives no notification from the RERRA(s) within the twenty (20) Business Day period, and an LSE has demonstrated that it has designated ZRCs in order to meet its Final PRMR, and share of LCR for each LRZ, for each Season, then the proposed RBDC Opt Out by the LSE will be deemed accepted by the Transmission Provider.

- f. To the extent that the LSE's ZRCs satisfy the LSE's Final PRMR for the applicable Season(s) submitted through an RBDC Opt Out, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the RBDC Opt Out into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Final PRMR within such LRZ. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in RBDC Opt Outs, as part of the Transmission Provider's reliability assessment when conducting the PRA.
- g. If an LSE owns or controls ZRCs that are not included in the LSE's RBDC Opt Out, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.
- h. To the extent that an LSE designates ZRCs in an RBDC Opt Out that are represented in the same LRZ as the LSE's Demand to meet the LSE's Final PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

- i. An LSE that designates ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).
- j. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR including: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process, and/or (iv) paying the Capacity Deficiency Charge to meet all or a portion of their Initial PRMR.
- k. LSEs that elect the RBDC Opt Out that do not meet their Final PRMR shall pay the RBDC Opt Out Deficiency Charge, which is 2.748 times applicable LRZ's CONE multiplied by the difference in ZRCs between the LSEs Final PRMR and the amount of ZRCs submitted as the LSEs RBDC Opt Out for each Season in which the LSE fails to meet its Final PRMR.
- l. RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR for the Transmission Provider Region minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge. If the LRZ where LSEs incurred RBDC Opt Out Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis,



based upon their respective LSE's share of Final PRMR minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge in such LRZ.

- m. The Transmission Provider will determine the RBDC Opt Out Adder that will be applicable for the upcoming Planning Year every year on or before December 15. The RBDC Adder applicable during the first Planning Year in which an LSE elects to use the RBDC Opt Out will apply for such LSE's entire RBDC Opt Out Lock-In Period.
- n. For Planning Year 2025/2026, the Transmission Provider will determine the RBDC Opt Out Adder based on an average of simulated RBDC PRA clearing for the prior three Planning Years (i.e., Planning Years 2022/2023, 2023/2024, and 2024/2025).
- o. The Transmission Provider will submit a filing to the Commission under Section 205 of the FPA no later than May 31, 2025, to establish the methodology for determining the RBDC Opt Out Adder for the 2026/2027 Planning Year and subsequent Planning Years. If a new methodology for determining the RBDC Opt Out Adder has not been accepted by the Commission prior to September 1, 2025, the methodology described in subsection n above will be applied for the 2026/2027 Planning Year, and will continue to apply until such time as the Commission accepts a new methodology to determine the RBDC Opt Out Adder.

### **Capacity Deficiency Charge**

- a. The Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has provided notification prior to the Planning Resource Auction that they will meet their Initial PRMR in part or in whole by removing Initial PRMR from the Transmission Provider's capacity construct for one or more Seasons by paying the Capacity Deficiency Charge. The Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its Initial PRMR by paying the Capacity Deficiency Charge for each Season of the Planning Year will be multiplied by 2.748 times the Initial PRMR volume indicated by the LSE. The Capacity Deficiency Charge will be assessed to Market Participants representing their respective LSE paying the Capacity Deficiency Charge on the first Business Day after the results of the Planning Resource Auction have been published.
- b. Distribution of Capacity Deficiency Charge Revenues: A Market Participant representing an LSE that provided notice it will be meeting all or part of its Initial PRMR by paying the Capacity Deficiency Charge will not be distributed any Capacity Deficiency Charge revenues for that LSE's Initial PRMR that was met by paying the Capacity Deficiency Charge. Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR for the Transmission Provider Region minus the Initial PRMR associated with the Capacity Deficiency Charge. If the LRZ where LSEs incurred Capacity Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then Capacity Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a *pro rata* basis,

based upon their respective LSE's share of Initial PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in such LRZ.