Manual No. 010

Business Practices Manual

Network and Commercial Models

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Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-010-r19	Annual review completed: minor formatting changes, correction to BPM-030 title, and clarification regarding Resource CPNode and External PSG CPNode relationship to EPNodes.	J. Phillips	MAY-1-2024
BPM-010-r18	Annual review completed. Removed references to Modeling Webtool. Removed phased-out Stored Energy references. Added details for SCADA Update Process.	J. Phillips	JUN-15-2023
BPM-010-r17	Added Electric Storage Resource (ESR) to Section 4, with additional ESR parameter table in Attachment E. Updated to include references to new Model Manager data submittal process.	K. Trotter	JUN-06-2022
BPM-010-r16	Updated Attachment E to include Short-Term Reserve (STR) Parameters. Inserted section 4.2.7 for SATOA CPNodes.	K. Trotter	DEC-07-2021
BPM-010-r15	Annual review completed. Updated sections include 3.1.1.6 (solar DIRs) and 5.2 (ad hoc asset transfers).	K. Trotter	JAN-01-2021
BPM-010-r14	Clarified minimum limits for market resource participation. Clarified language of Section 5.2 involving ad hoc asset ownership procedure and Section 4.2.2.1 on slice of system load zones. Relocated ICCP Update Process section from 3.3 to 3.2. Updated QF section 3.1.1.7.	K. Trotter	JAN-01-2020
BPM-010-r13	Annual Review completed. Updated Demand Response definitions to match Tariff. Clarified DIR language in Section 3.1.1.6. Updated references in Section 3.3, and various links through doc. Added section for SER-Type II Resource.	E. Swanson K. Trotter	JAN-01-2019
BPM-010-r12	Annual review completed.	E. Swanson K. Trotter	JAN-01-2018
BPM-010-r11	Clarifying language per Tariff revisions surrounding Regulation, Spin and Supplemental Qualified reserves. Language for TMW2 and modifications to Exhibit 3-1 and 3.2. Correct Note in example D1 of Appendix D. Annual Review completed.	E. Swanson	OCT-27-2016
BPM-010-r10	Sect 2 - Remove definition for Physical Scheduling System; 3.1.1.1 – remove some misleading language; 3.3 - Update tie line requirements; 5.1 - replace old hyperlink to Network and Commercial Model Update Schedule	E. Swanson	APR-01-2016

BPM-010-r9	Clarifying text added to Regulation and Spin parameters. Minor formatting changes.	E. Swanson	JAN-01-2016
BPM-010-r8	Exhibit 5-1 modified for clarity. Minor modifications to text of section 5.2. Annual Review completed.	E. Swanson	SEP-01-2015
BPM-010-r7	Clarification for ARR zone CPNode Rename section 4.2.7 Aggregated Pricing Nodes	Z. Xie	JAN-01-2015
BPM-010-r6	Annual Review completed. MISO LOGO change, Qualifying Facilities, Generation Assets – Attachment Y process, ICCP Update Process, DRR-Type I parameter updates, Designated Network Resources flag removal, Attachment B updates, Attachment C updates	R Sooryavaram	OCT-01-2014
BPM-010-r5	BPM revision number change, MISO Rebranding Changes. Annual Review completed.	Sherry DeMaire, R Sooryavaram	OCT-09-2013
BPM-010-r4	Market tie line ICCP Data Requirements, ARC registration process, Addition of EDC parameter to load zone, Changes to section Network and Commercial model Review. Annual Review completed.	R Sooryavaram	OCT-09-2012
BPM-010-r3c	Incorporating BPM review comments	R Sooryavaram	NOV-28-2011
BPM-010-r3b	Updates to FTR and ARR Auction	R Sooryavaram	JUL-06-2011
BPM-010-r3a	Dispatchable Intermittent Resources, Updates for Small Generator modeling and various others	P, Addepalle	FEB-24-2011
BPM-010-r2b	MISO Rebranding Changes JUL-01-2011	E. Nicholson	MAR-18-2010
BPM-010-r2a	Various Updates. Below Threshold Generation and Stored Energy Resources. Incorporating BPM review comments.	P, Addepalle	MAR-18-2010
BPM-010-r1	Revised to the Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest ISO Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.	P. Addepalle	JAN-06-2009
BPM-010	Added clarifying note relating to JOUs under Section 4.2.1.2, added network and commercial model process flow diagram under Section 5 and added new Section 5.2 describing commercial model change times. Converted to new template	P. Addepalle	JUL-09-2008

1. Contents

1. Introduction

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

1.1. Purpose of the MISO Business Practices Manuals

The BPMs developed by MISO provide background information, guidelines, business rules, and processes established by MISO for the operation and administration of the MISO markets, provisions of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website. All definitions in this document are as provided in the MISO Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

1.2. Purpose of this Business Practices Manual

This *BPM for Network and Commercial Model* describes the models used for the Energy Management System (EMS) power system and market operations applications and the associated real-time data submitted via Inter Control Center Protocol (ICCP) needed to support those applications. The Network Model referenced in this BPM reflects only the Network Model associated with the Integrated Control Center Systems (ICCS) and Midwest Market system applications and does not refer to other power system models developed and maintained by MISO to support functions such as long-range planning.

MISO prepares and maintains this *BPM for Network and Commercial Model* as it relates to the reliable operation of MISO's region of authority. This BPM conforms and complies with MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), the North American Electric Reliability Corporation (NERC) Reliability Standards (as applicable), and the NERC Regional Entity specific Reliability Standards (as applicable) and is designed to facilitate administration of efficient Energy and Operating Reserve Markets.

This BPM benefits readers who want answers to the following questions:

- What are the Network and Commercial Models and how are they used?
- What are the contents of the Network Model?
- What are the contents of the Commercial Model?
- What contribution do the Market Participants (MPs) need to make to the maintenance of the models?

1.3. 1.3 References

Other reference information related to this BPM includes:

Posted on the MISO website:

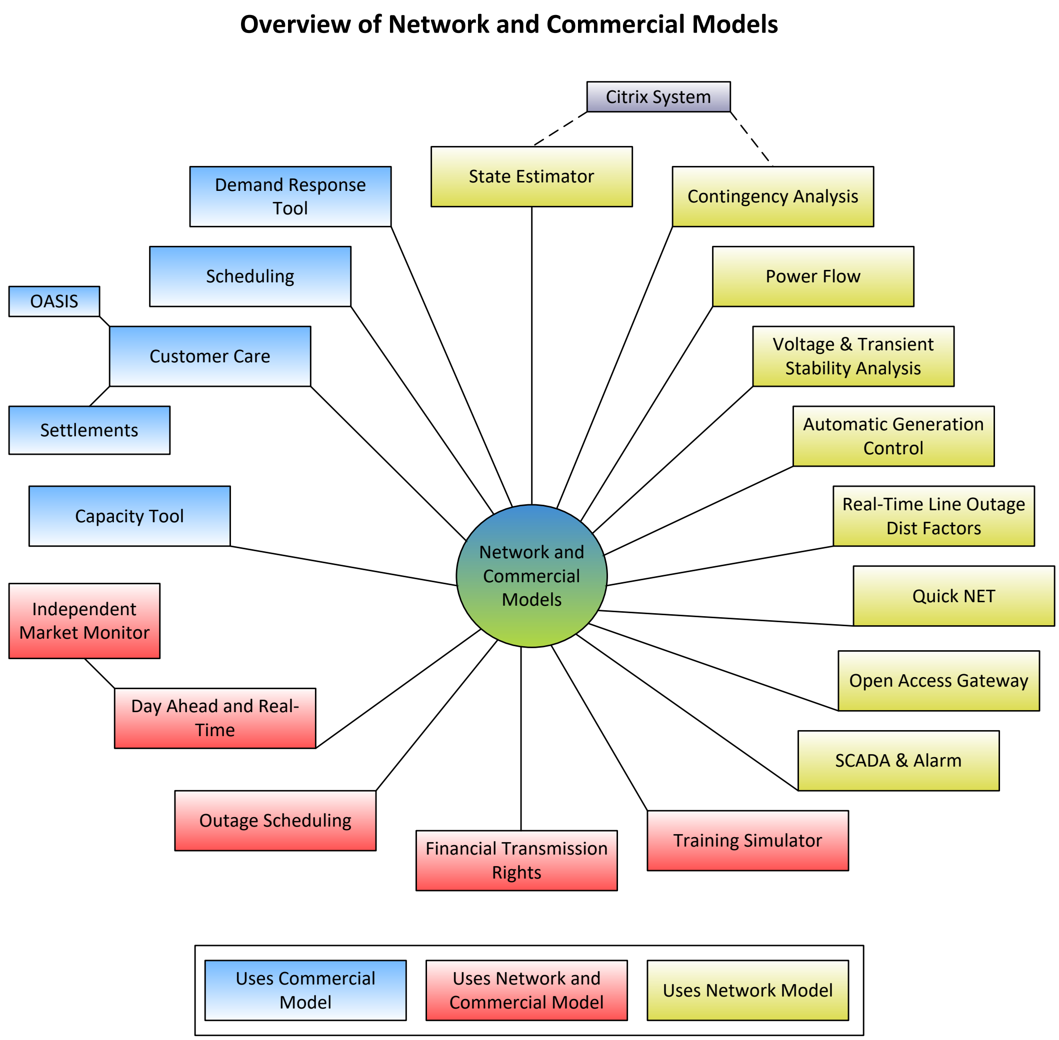
- Other BPMs
    - BPM 001 – Market Registration
    - BPM 002 – Energy and Operating Reserve Markets
    - BPM 005 – Market Settlements
    - BPM 011 – Resource Adequacy
    - BPM 026 – Demand Response
    - BPM 030 – Dynamic Transfers: Pseudo-ties and Dynamic Interchange Schedules
    - BPM 031 – ICCP Data Requirements
- MISO Tariff
- MISO Learning Center
    - MISO Model Manager Quick Start Online User Guide

- Posted on the MISO Extranet website under EMS Model Information: MISO Model Manager (MMM) Data Requirements Document

2. Network and Commercial Modeling Overview

The Network and Commercial Models are datasets used by the Energy Management System (EMS) and Day Ahead and Real Time Market (DART) System and their related interfaces and applications. Most of the applications used to perform real-time and short-term business functions of MISO are fully dependent on the network and/or commercial aspects of the model. Refer to Exhibit 2-1 for a graphical representation of the use of the Network and Commercial Models.

Exhibit 2-1: Business Applications Using the Network and Commercial Models



The Network Model is accessed by those functions used for circuit analysis of the electric power system. These functions include both Real-Time and study applications. The Real-Time applications include:

- ***State Estimator (SE)***: The SE is a steady state power system analysis function that calculates the complex voltages at all network Buses using the power flow equations and redundant Real-Time measurements. The voltages are then used to calculate real and reactive power flows even though measurements are not available at all locations.
- ***Real-Time Line Outage Distribution Factor Calculator (RTLODFC)***: The RTLODFC determines the contingency flow distribution factor for monitored elements of flowgates based on real-time topology.
- ***Real-Time Contingency Analysis (RTCA)***: The RTCA is used to determine the secure feasibility of the existing power system if components are removed from operation. Both real and reactive power flow and bus voltage violations are determined. The RTCA uses the results of the SE as the base case for its calculations.

The study applications include:

- ***Power Flow (PF)***: The PF is used for the steady state study of specified power system conditions. The PF uses values of generation and load along with the power flow equations to determine real and reactive power flows, bus voltages, and limit violations.
- ***Study Contingency Analysis (STCA)***: The STCA performs the same analysis as the RTCA, but uses a base case that is established for specified power system conditions. The base case is usually developed from power flow results.
- ***Voltage Stability Analysis Tool (VSAT)***: VSAT performs dynamic studies to determine voltage security problems and provides information about voltage stability margin, voltage decline and reactive power reserves.

The Network Model is also used for the Dispatcher Training Simulator (DTS).

The Commercial Model is accessed by those functions used to process financial reconciliation tasks. These include:

- ***Open Access Same-Time Information System (OASIS)***: OASIS is used to manage transmission service reservations.
- ***Settlements System***: The Settlements system is used to calculate the Market Participant (MP) charges and credits for the Day-Ahead Energy and Operating

Reserve Market, the Real-Time Energy and Operating Reserve Market, and the FTR auctions.

- ***Customer Care System***: The Customer Care System provides customer services and the MISO response to market inquires.
- ***Module E Capacity Tracking (MECT)****:* The application used by the MISO and Market Participants to track and analyze compliance with Resource Adequacy Requirement obligations, including, but not limited to: Forecast LSE Requirements; the transfer and designation of Planning Resource Credits (PRCs); and other Resource Adequacy Requirement (RAR) attributes and information.

There is a group of functions that access both the Network and Commercial Models. These include:

- ***Financial Transmission Rights (FTR)***: The FTR system maintains records of FTR Holders, allocates new ARRs, and conducts auctions.
- ***Independent Market Monitor (IMM)***: MISO's IMM provides the independent observation of the Market Activities to detect market rule violations and the exercise of market power.
- ***Day-Ahead and Real-Time Energy and Operating Reserve Markets Operation System (DART)***: DART performs all of the Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) functions for the Day-Ahead and Real-Time Energy and Operating Reserve Markets.

2.1. Relationship between Network and Commercial Models

The Commercial Model is related to the Network Model through the basic element of the Commercial Model, the Elemental Pricing Node (EPNode). The EPNodes have a one-to-one relationship with the electrical Nodes connecting all of the loads and generators represented in the Network Model. In certain instances, EPNodes will also be created at locations within MISO that do not represent an injection or withdrawal from a generator or load but simply a Node at a transmission substation. Each EPNode is associated with a Local Balancing Authority (LBA). The LBA in which the EPNode is defined in the Commercial Model must match the LBA in which the EPNode is defined in the Network Model. A description of EPNodes and their relation to the Commercial Pricing Nodes (CPNodes) is provided in Section 4 of this BPM.

3. Network Model

The Network Model supports various real-time and study network analysis functions used to maintain power system reliability, securely commit and dispatch generation, and assess the availability of FTRs. The Network Model is populated with data provided by authorized Transmission Owners and MPs and provides a mathematical representation of the electric power system. The Network Model consists of two types of data – static and telemetered.

3.1. Network Static Data

The static data consists of mathematical representations of each power system component. The power system components are connected together to represent the actual power system circuits. The linking of the power system components describes the topology of the bulk power network.

MISO Transmission Owners must submit bulk power system data model additions, modifications, and deletions to MISO via the MISO Model Manager (MMM) tool by the Network Model due date, along with all required legal documents and/or certifications as set forth in the Tariff and/or Business Practices Manuals or the changes will not be processed. The MISO Model Manager Data Requirements document describes the required equipment information needed to ensure accurate equipment representation within the MISO models. Application introduction and use case training videos can be found on the MISO Learning Center, https://miso.csod.com/ui/lms-learning-details/app/course/85fbff8f-2c2f-48d5-86e9-36cc83c12d41.

3.1.1. Resource Modeling

MISO's general policy is that all Resources that are registered to participate in the Energy and Operating Reserve Markets must be represented in the Network Model. Additionally, applicable Resources that are not registered to participate in the Energy and Operating Reserve Markets but that are connected to the MISO Transmission System must be represented in the Network Model. This section discusses some of the exceptions to the general policy and guidelines related to cutoff thresholds, combining Resources and behind-the-meter representations.

Market Participants that need to move a Resource from one Local Balancing Authority (LBA) to another will submit a request to pseudo-tie the Resource from the current LBA to the new LBA. Moving Resources changes the Resource-Load balance of both LBAs and, therefore, requires the Market Participant to provide MISO with approvals from both LBAs.

Resources such as Generators that are physically located outside the MISO Balancing Authority area can be pseudo-tied into MISO. A Market Participant requesting such a change shall provide MISO with a copy of the approval from the Local Balancing Authority within the MISO Region that will host this pseudo-tied Resource. The pseudo-tied capacity offered into the MISO market shall remain in the market until the next regularly scheduled Network/Commercial model update. When only a portion of a Resource is pseudo-tied into the MISO Balancing Authority, the change in total output of the physical unit shall include the change in MW value sent to the MISO for this portion of the unit. The Market Participant should be prepared to provide evidence that the output of the Resource is being moved in response to the market dispatch. For more information on pseudo-tied generation and related processes, refer to the *BPM for Dynamic Transfers: Pseudo-ties and Dynamic Interchange Schedules (BPM 030)*.

Resources that have been decommissioned or retired and have a completed and approved Attachment Y (Notification of Potential Resource/SCU/Pseudo-tied Out Generator Change of Status) per Section 38.2.7 of the MISO Tariff will be removed from the Network Model in the next scheduled network model update, per the date specified in the Attachment Y and model data notification requirements.

3.1.1.1. Below Threshold Generation

All generators with a maximum output greater than or equal to 5 MW that are directly connected to MISO's Transmission System shall be modeled explicitly in the Network Model. Generators modeled in the Network Model must have Real-Time telemetry (MW, MVAR, Status). If the generator is connected at a lower voltage than is included in the Network Model, the generator must be reflected up to an appropriate transmission system bus in the Network Model.

Generators greater than or equal to 1 MW but less than 5 MW (that are not registered as Demand Response Resources) need not be explicitly modeled in the Network Model but may register in the Commercial Model to get the Locational Marginal Price as described in Section 4.2.1.1.

3.1.1.2. Modeling of Multiple Small Generating Resources at a Single Bus

In some instances, plants having multiple small units or distributed generation on distribution level facilities may be modeled as a single unit. For example, a wind farm made up of fifty 1.5 MW units with one meter indicating the total energy injection to the Transmission System would qualify for modeling treatment as a Generation Resource of 75 MW. Considerations for granting this exception to the general policy include:

- Size of units

- Type of units
- Number of units
- Telemetry/metering availability
- Offer/Instruction implications, that is, if individual units or the entire plant will be considered.

3.1.1.3. Behind-the-Meter Generation

There are many units owned and operated by municipal and cooperative systems that operate in a behind-the-meter mode. This is also true for some industrial retail customers. Load served by behind-the-meter generation may be excluded from the LBA Market Load if such behind-the-meter generation is not being modeled as a DRR-Type II. Although the load and generation can be netted from a commercial perspective, not all of these situations allow the removal of the generators from the Network Model. If these generators are not required in the Network Model, there will be a simple representation of a net load that will be associated with a Load Zone and the generator will be removed. If the true generation provides a large enough reactive power component to have an impact on the convergence capability or solution quality of Alternating Current (AC) analysis applications such as SE and Contingency Analysis, or if the facilities behind-the-meter are actually networked with the MISO Transmission System and not connected radially, MISO may require that the generation and load be included in the Network Model. See Section 4 of this BPM for more information on commercial aspects of behind-the-meter situations.

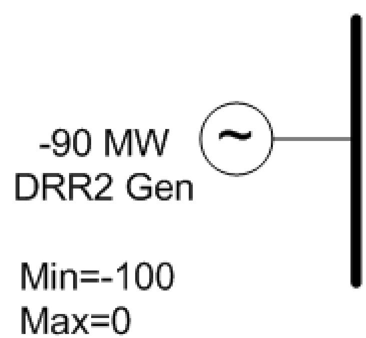
3.1.1.4. Modeling of Demand Response Resources – Type I

A DRR-Type I is defined as a Resource owned by a single Load Serving Entity or an ARC within the MISO Balancing Authority Area that is capable of supplying a specific quantity of Energy, Contingency Reserve or Capacity, at the choice of the Market Participant, to the Energy and Operating Reserve Market through Behind the Meter Generation and/or controllable load. DRR – Type I's may represent end-use customer programs such as industrial interruptible load programs, controlled appliance programs and load reduction programs registered by Aggregators of Retail Customers. Each DRR-Type I will be modeled as a CPNode consisting of defined EPNodes that comprise injections of customer demand response within a single LBA. The DRR-Type I can be modeled as aggregations of whole or portions of Elemental Pricing Nodes. A DRR-Type I's Targeted Demand Reduction Level must be at least 1 MW to be registered in the Commercial Model.

3.1.1.5. Demand Response Resources – Type II

A DRR-Type II is defined as a Resource hosted by a single Load Serving Entity or an ARC within the MISO Balancing Authority Area that is capable of supplying a range of Energy, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability, at the choice of the Market Participant, to the Energy and Operating Reserve Markets through Behind-The-Meter generation and/or controllable load, and is capable of complying with MISO's setpoint instructions with the appropriate metering equipment installed. The effective load can be physically curtailed in total or incrementally. Because a DRR-Type II may consist of both behind-the-meter generation and controllable load, special modeling is required to account for the DRR-Type II properly as a Resource. For Network modeling purposes, the load and generator combination is represented by a single equivalent generator. A DRR-Type II's Maximum Output must be at least 1 MW to be included in the Network and Commercial Models.

The following illustration shows a DRR-Type II providing 10 MW of demand response:



3.1.1.6. Intermittent Resources and Dispatchable Intermittent Resources

The criterion for Intermittent Resource (IR) and Dispatchable Intermittent Resource (DIR) Registration is described here.

A Generation Resource can be considered Intermittent if it is incapable of being dispatched or following Setpoint Instructions, the Generation Resource has not previously been registered as a Dispatchable Intermittent Resource (DIR), and it meets one of the following scenarios:

- Generation Resource is not fueled by wind or solar (or)
- Generation Resource is fueled by solar energy and began commercial operation prior to March 15, 2020 (or)
- Generation Resource began commercial operation prior to April 1, 2005 (or)

a) Generation Resource has Network Resource Interconnection Service (NRIS) for 100% of its capacity
b) Generation Resource has Network Integration Transmission Service (NITS) for 100% of its capacity
c) Generation Resource has Long-Term Firm Point-to-Point Transmission Service for 100% of its capacity
d) Generation Resource has any combination of a) through c) that sums to 100% of its capacity, without double counting

Additionally, any Generation Resource fueled by solar energy not in commercial operation but with a Generator Interconnection Agreement (GIA) executed prior to March 15, 2020 may currently qualify as an Intermittent Resource, but must register as a Dispatchable Intermittent Resource by March 15, 2022.

An existing Intermittent Resource can register as a DIR only during full Network & Commercial model updates. Once a Resource registers as a DIR, it is no longer eligible to register as Intermittent, regardless of its status with respect to these exemptions. Existing Intermittent Resources are required to re-register as a DIR if the Resource is upgraded such that the entire Resource becomes capable of following MISO's setpoint instructions. In the event that an existing Intermittent Resource is partially upgraded such that only a portion of the Resource becomes capable of following MISO's setpoint instructions, the Market Participant must register the Dispatchable portion of the Resource separately as a new DIR.

3.1.1.7. Qualifying Facilities (QF)

The Public Utility Regulatory Policies Act of 1978 (PURPA) established a new class of generating facilities, known as qualifying facilities, that may receive special rate and regulatory treatment. This treatment causes them to differ from traditional utility-owned generators or power plants, which therefore drives a difference in the resource's network and commercial modeling. In general, there are three ways in which Qualified Facilities may be modeled in MISO's Network and Commercial Models. These are referred to as Hybrid, Behind-the-Meter Legacy, and Front-of-the-Meter QF.

In *Hybrid* QF modeling, the network model will include a "Net" generator to represent the net injection of the QF into the transmission system, and all of the physical BES elements (generators, loads, etc.) will be included in the network model as behind-the-meter. A pricing node is created in the commercial model at the "Net" generator for market participation.

In *Behind-the-Meter Legacy* QF modeling, the network model will include all of the physical BES elements as behind-the-meter, and the facility is represented within a load zone in the commercial model.

In *Front-of-the-Meter* QF modeling, the network model will include all of the physical BES elements, and all generators and loads at the facility are assigned corresponding elemental pricing nodes in the commercial model.

3.1.2. Load Modeling

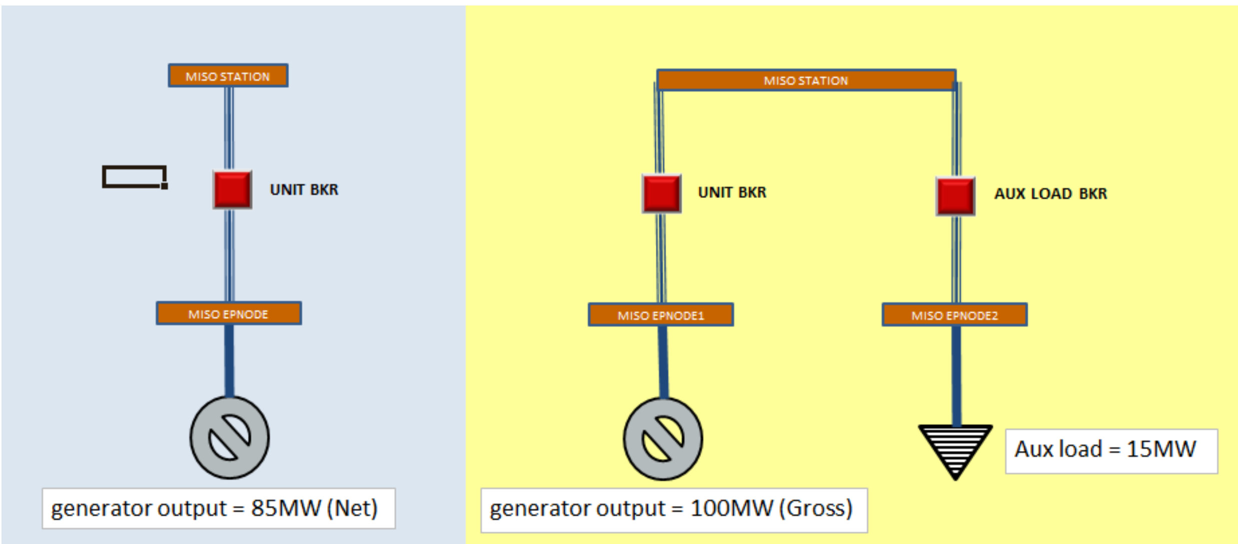
MISO's general policy is that loads be created at all buses where step-down transformers take Energy from the Transmission System and supply the distribution system. Some of these loads may be serving customers of multiple MPs at the distribution level. Each MP may have a separately modeled load representing its share, but this is not a requirement. In cases where it is not practical to split the loads, each MP will be assigned a static share of the load as identified by the Local Balancing Authority, which will be used for their respective Load Zone. For behind-the-meter situations and DRR-Type I and DRR-Type II modeling, see Sections 3.1.1.3, 3.1.1.4, and 3.1.1.5.

In some instances, Market Participants may wish to consolidate Loads into one Load Zone for the loads that are on the periphery of the Local Balancing Authority. This implementation is done in the Network Model by pseudo-tying loads from one Local Balancing Authority to another. This implementation redefines the Load boundary of both Local Balancing Authorities. A Market Participant requesting such a change shall provide MISO with approvals from both Local Balancing Authorities. For more information on pseudo-tied load and related processes, refer to the *BPM for Dynamic Transfers: Pseudo-ties and Dynamic Interchange Schedules (BPM 030)*.

3.1.2.1. Auxiliary Loads

Auxiliary load for a generation station should be modeled to support accurate state estimation, contingency analysis, and market operations. The capability for modeling auxiliary loads is based in part upon the nature of the available SCADA measurements and topology provided to the Modeling team, as well as any specific operational monitoring obligations of MISO. There are typically two modeling scenarios. Either the auxiliary load is modeled explicitly with gross generation, or the gross generation and auxiliary load on the same side of the GSU are modeled together as net generation. (See Exhibit 3-1) If the auxiliary load is served from a location that is remote to the generator interconnection point or there is overriding reliability concern (such as the ability to properly model system response as specified in Nuclear Plant Operating Agreements), then the auxiliary load must be explicitly modeled with gross generation.

Exhibit 3-1: Net versus Gross Generator modeling



3.1.3. Transmission Facilities

All transmission facilities including transmission lines, transformers, phase shifters and shunt reactive power devices must be modeled in the MISO Network Model. Transmission facilities are typically operated at 100 kV and above. Any requests for modeling facilities below 100 kV will be reviewed for justification and all available telemetered measurements must be made available to MISO through Inter Control Center Protocol (ICCP) data.

3.2. Network Model Telemetered Data

The Network Model is used to support Real-Time analyses; telemetered data supplied to MISO by the Transmission Owners and the MPs is mapped to the static model components. Some of the telemetered values used to support Real-Time analyses are:

- Switching Device Status (Open/Close)
- Line and Transformer Flows (MW and MVAR)
- Circuit Breaker Flows (MW and MVAR)
- Net or Gross Generation Output (MW and MVAR)
- Generation Plant Auxiliary Loads (MW and MVAR)
- Synchronous Condenser and Static VAR Compensator (MVAR)

- Load (MW and MVAR)
- Bus Voltage Magnitudes (kV)
- Transformer and phase shifter tap positions

The SE can use both paired and unpaired real and reactive power measurements. The more telemetry that is available to the SE, the more likely the SE will return a more accurate solution.

Refer to the MISO's Reliability Data Specification (RTO-SPEC-006) and *BPM 031 – ICCP Data Requirements* for the frequency and data format requirements for real-time ICCP data collection. Failure to provide the required data per MISO's deadlines may delay equipment energization or market participation.

Limits for transmission lines, loads, transformers, and shunts supplied by the Transmission Owners are assigned to each measurement. The MISO operators are alerted to limit violations that are detected as a result of the processing by the analysis programs. Typically, for Real-Time monitoring and study of the electric system the MISO operator will be concerned with three ratings for each piece of equipment. These ratings are the:

- Normal ratings
- Emergency ratings
- Interconnection Reliability Operating Limit ratings (load-shed)

3.2.1. ICCP Update Process

Market participants, Transmission Owners and Local Balancing Authorities must notify MISO of any/all ICCP changes (ICCP object ID or mapping). These changes include:

- Addition of new ICCP points
- Deletion of ICCP points that MISO already has access to
- Modifications of ICCP points that MISO already has access to

MISO ICCP data providers must submit bulk data model additions, modifications, and deletions to MISO via the MMM application. Application introduction and use case training videos can be found on the MISO Learning Center, https://miso.csod.com/ui/lms-learning-details/app/course/85fbff8f-2c2f-48d5-86e9-36cc83c12d41. The ICCP Request Inbox will be reserved for requests that cannot be fulfilled through the MMM.

3.2.2. SCADA Update Process

SCADA holders are needed to link ICCP data to Network based equipment for use in the Operational EMS system.

3.2.2.1. ICCP data is available

In general, If the telemetry data (ICCPID) is available or will be available before the next quarterly model update, MISO requests SCADA holders be added on the following types of equipment that are defined in the MMM regardless of voltage level:

- SynchronousMachine
- PowerTransformerEnd
- ACLineSegment
- SeriesCompensator
- ConformLoad
- NonConformLoad
- LinearShuntCompensator
- Breaker
- Disconnector
- LoadBreakSwitch
- BusbarSection

3.2.2.2. ICCP data is not available

In addition, if telemetry data is not available, MISO requests SCADA holders also be added for the following equipment:

- All new Market Units (SynchronousMachine)
- All new Tie Lines between MISO LBAs and external areas (ACLineSegment)
- All new Pseudo-Tie load (ConformLoad) (Where the GeographicalRegion and LoadGroup differ)
- All new 100 kV and above equipment listed below

    - SynchronousMachine
    - PowerTransformerEnd
    - ACLineSegment
    - SeriesCompensator
    - ConformLoad
    - NonConformLoad
    - LinearShuntCompensator

- Breaker
- Disconnector
- LoadBreakSwitch

The training document about how to Create New SCADA Points in the MMM can be found at the link below (MISO Extranet access required):

https://www.misoenergy.org/api/extranetdocuments/getEdcDocument/20396

3.3. Market Tie Line Modeling and Telemetry Requirements

Requirement 12 of NERC Reliability Standard BAL-005-0.2b for Automatic Generation Control states that each Balancing Authority shall include all tie line flows with Adjacent Balancing Authority (BA) Areas in the ACE calculation. Therefore, MISO is responsible for real time monitoring of the tie line flows as the BA operator and the Reliability Coordinator. A tie line is defined as any connection between a MISO LBA and a MISO Tier 1 BA, including physical ties and pseudo-ties. All the LBAs and Tier 1 BAs should send accurate tie line flows to MISO for correct ACE calculation and proper tie line monitoring. These tie lines also include any pseudo-tie lines modeled in the MISO network model (into or out of MISO). Based on the NERC standard, the modeling and telemetry requirements are defined for each LBA and Tier 1 BA separately in the following sections. All commissioning and decommissioning of facilities must follow the minimum requirements as stated in MISO Operating Procedure SO-P-NOP-00-446.

3.3.1. Tie Line Metering Location

A tie line metering location is a mutually agreed upon location between the MISO LBA and Adjacent Tier 1 BA. The Primary Tie Line measurement (TMW) is always received from the MISO Internal LBA, a Secondary Tie Line measurement (TMW1) is always received from the adjacent BA, and both are required to be provided to MISO. MISO may use either the Primary (TMW) or Secondary (TMW1) measurement in its ACE calculation, taking into consideration the meter location, RTU ownership, and accuracy or availability of the measurement.

- If the metering location is at the MISO end of the line, then the primary (TMW) and secondary (TMW1) tie line metering will be at this “Agreed Tie Metering Location” as shown in the Exhibit 3-2.
- If the metering location is at the Non-MISO end of the line, then the primary (TMW) and the secondary (TMW1) tie line metering will be at this “Agreed Tie Metering Location” as shown in Exhibit 3-3.

To the extent available, the non-metered tie point (i.e. metering available at the opposite end from the agreed-upon location) must be provided to MISO via ICCP. The non-metered end measurement (TMW2) will allow MISO to transition to the opposite side metering to continue monitoring and recording the MWhr flows for each hour should the primary RTU become unavailable due to routine maintenance or unscheduled outage. Please refer to Exhibit 3-1 and 3-2 for a representation of the non-metered end measurement location.

3.3.2. Existing BA Tie Line Requirements

3.3.2.1. LBA Responsibilities

- Inform MISO of any change in tie line modeling at least 4 months before implementation.
- Unique ICCP MW and MWH object IDs at the agreed metering location for each tie line.
- Unique ICCP MW and MWH object IDs at the non-metered end of the tie-line if available.
- Tie line measurements shall be read directly from the meter by the LBA and provided to MISO. The LBA shall not represent measurements received from the Tier 1 BA through MISO as their primary meter source. (ICCP data flow of Tier 1 BA → MISO → LBA → MISO is not allowed)
- Inform MISO of any ICCP data points change for tie line at least 1 month before implementation.
- The tie line measurement/ICCP object IDs should not be reused for another line.
- Unique ICCP object IDs for all available switching equipment statuses on either side of the tie line.

3.3.2.2. Tier 1 BA

- Unique ICCP MW object ID at the agreed metering location for each tie line.
- Unique ICCP MW object ID at the non-metered end of the tie-line if available.
- Tie line measurements shall be read directly from the meter by the Tier 1 BA and provided to MISO. The Tier 1 BA shall not represent measurements received from MISO as their primary meter source. (ICCP data flow of LBA → MISO → Tier 1 BA → MISO is not allowed)

3.3.3. New MISO BA Tie Line

3.3.3.1. LBA Responsibilities

- Accurate Modeling representation provided to MISO including all impedance parameters and ratings.
- Inform MISO of any change in tie line modeling at least 4 months before implementation.
- Create unique ICCP MW and MWH object IDs at the agreed metering location for each tie line.
- Create unique ICCP MW and MWH object IDs at the non-metered end of the tie-line if available.
- Tie line measurements shall be read directly from the meter by the LBA and provided to MISO. The LBA shall not represent measurements received from the Tier 1 BA through MISO as their primary meter source. (ICCP data flow of Tier 1 BA → MISO → LBA → MISO is not allowed)

- Inform MISO of any ICCP data points change for tie line at least 1 month before implementation.
- The tie line measurement/ICCP object IDs should not be reused for another line.
- Send zero (0) MW flow values for the new tie lines to MISO prior to the tie line coming in service.
- ICCP object IDs for all available switching equipment statuses on either side of the tie line.
- All commissioning and decommissioning of facilities must follow the minimum requirements as stated in MISO Operating Procedure RTO-OP-056.

3.3.3.2. Tier 1 BA

- Unique ICCP MW object ID at the agreed metering location for each tie line.
- Unique ICCP MW object ID at the non-metered end of the tie-line if available.
- Tie line measurements shall be read directly from the meter by the Tier 1 BA and provided to MISO. The Tier 1 BA shall not represent measurements received from MISO as their primary meter source. (ICCP data flow of LBA → MISO → Tier 1 BA → MISO is not allowed)

3.3.4. Double-modeled MISO BA Tie Line

A double-modeled tie line between an LBA and Tier 1 BA is one which comprises of the existing configuration and the new configuration of the tie line in the quarterly model update. Based on the effective date of the new configuration, switching between new tie line configuration and old tie line configuration will occur within the quarter.

3.3.4.1. LBA Responsibilities

- Accurate Modeling representation provided to MISO including all impedance parameters and ratings.
- Inform MISO of any change in tie line modeling at least 4 months before implementation.
- Create unique ICCP MW and MWH object IDs at the agreed metering location for each tie line.
- Create unique ICCP MW and MWH object IDs at the non-metered end of the tie-line if available.
- Tie line measurements shall be read directly from the meter by the LBA and provided to MISO. The LBA shall not represent measurements received from the Tier 1 BA through MISO as their primary meter source.
- Inform MISO of any ICCP data points change for tie lines at least 1 month before implementation.
- Once the new configuration is in service, the LBA is required to:

  - Send zero (0) flow values for the old tie MW and MWH ICCP object IDs
  - Send the actual flows on new MW and MWH ICCP object IDs
- The retiring tie line measurement/ICCP object IDs should not be reused for another line.
- Provide ICCP object IDs for all available switching equipment statuses on either side of the tie line.

3.3.4.2. Tier 1 BA

- Unique ICCP MW object ID at the agreed metering location for each tie line.
- Unique ICCP MW object ID at the non-metered end of the tie-line if available.
- Tie line measurements shall be read directly from the meter by the Tier 1 BA and provided to MISO. The Tier 1 BA shall not represent measurements received from MISO as their primary meter source.

Exhibit 3-2: Metering at MISO end of the tie line

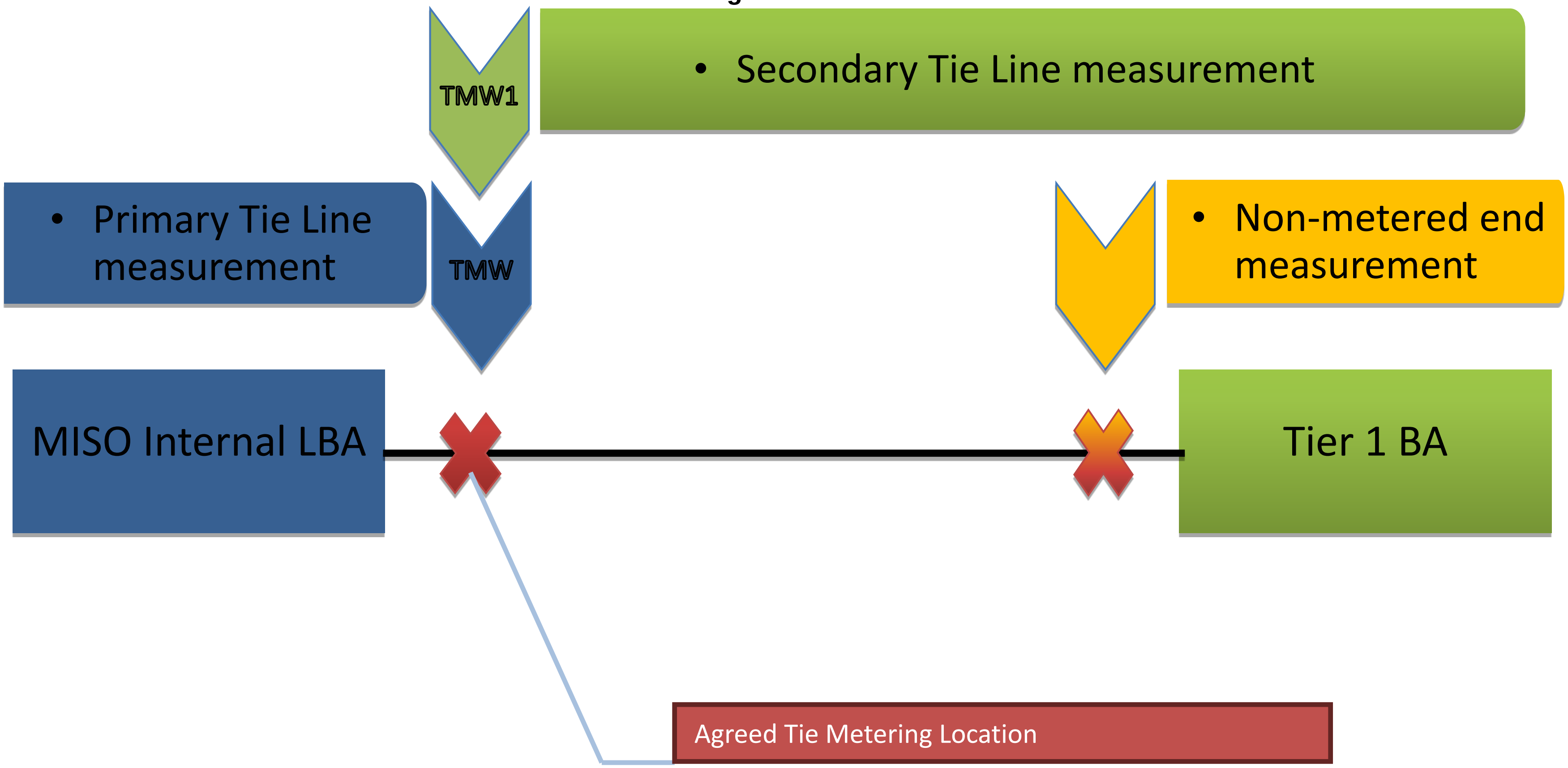
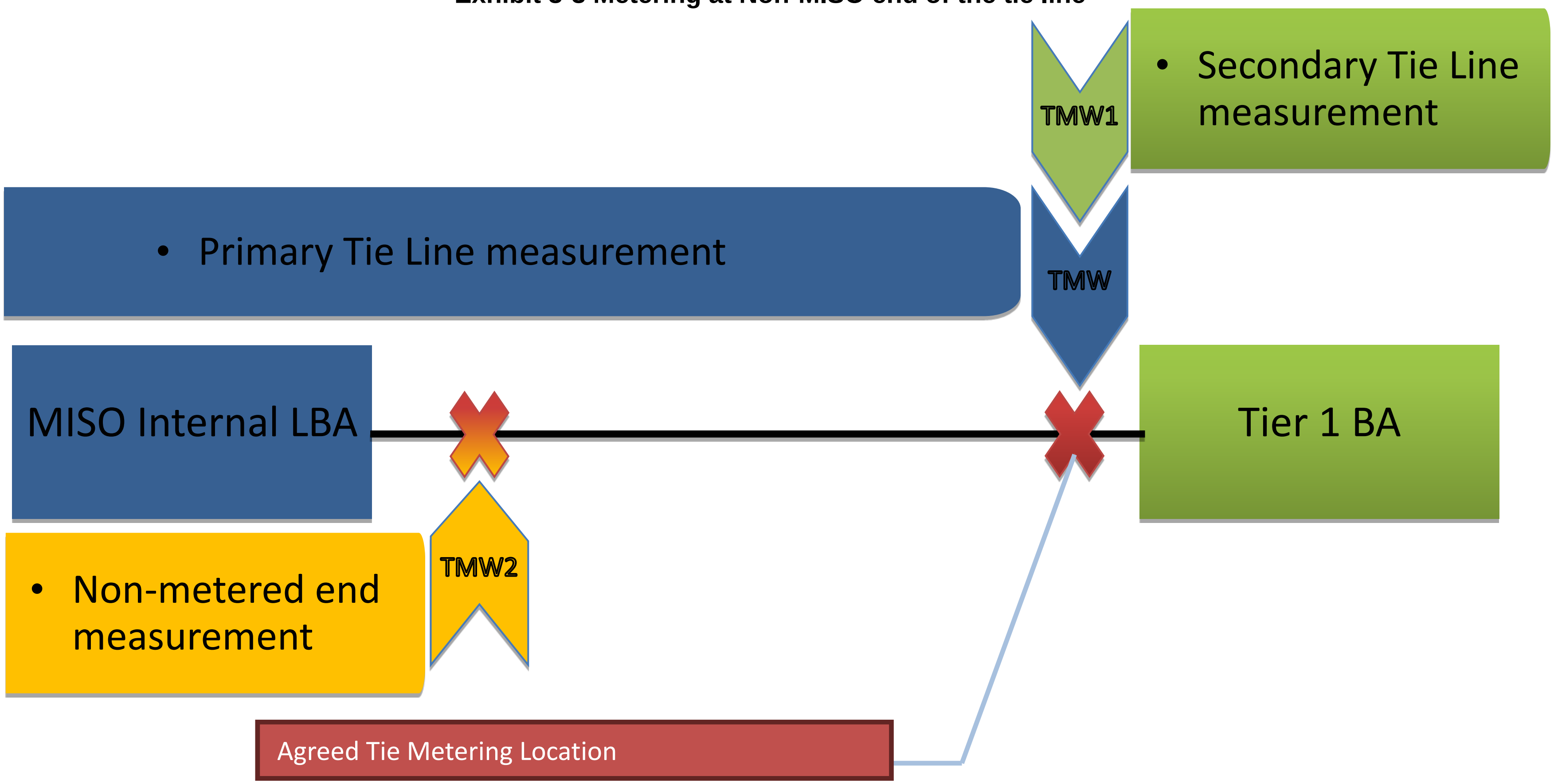
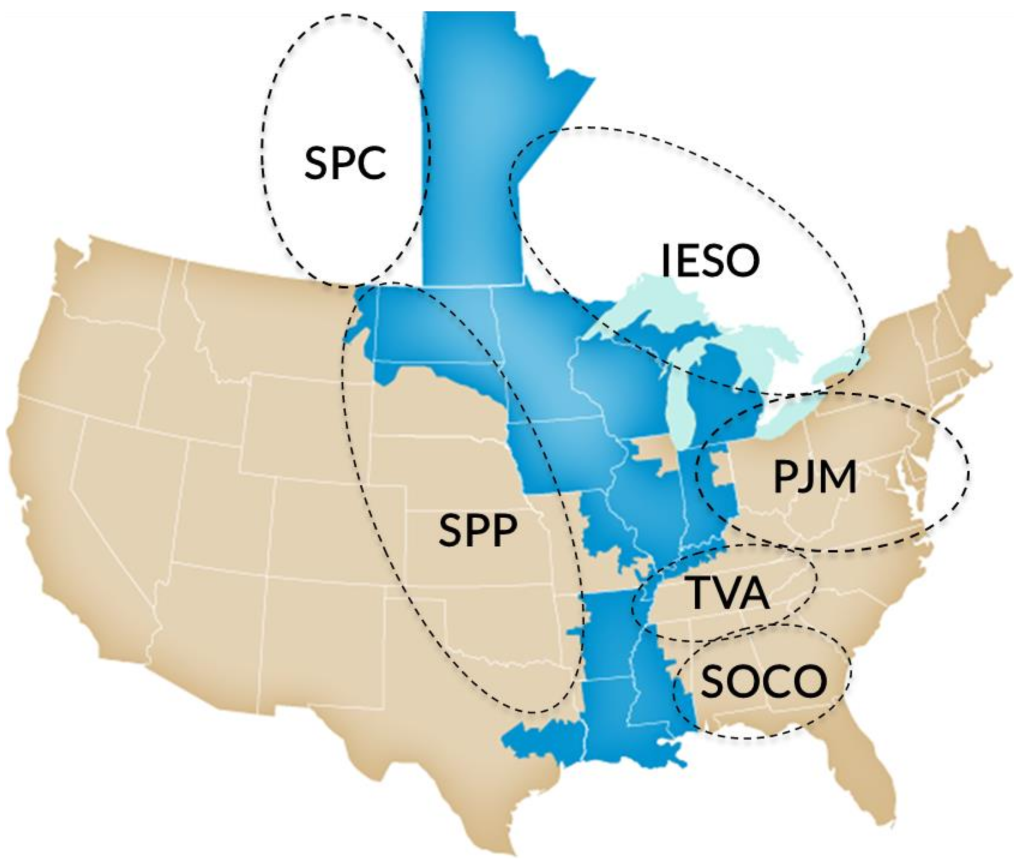


Exhibit 3-3 Metering at Non-MISO end of the tie line



3.4. Representation of Areas External to MISO

The MISO Reliability Coordinator Footprint is a portion of the Eastern Interconnection. To accurately analyze the MISO area covered by the Network Model and to accurately implement the various Joint Operating Agreements or other coordinated operations with various neighboring entities (some shown below), it is necessary that the Network Model include not only the electric system within the MISO Reliability Coordinator Footprint but also those portions of neighboring electric systems that will have an impact on the secure operation of MISO (and vice versa). Inclusion of the entire Eastern Interconnection would be impractical, so only selected external regions are considered. A combination of full circuit representations and equivalent circuits of the selected regions are used to complete the MISO Network Model.



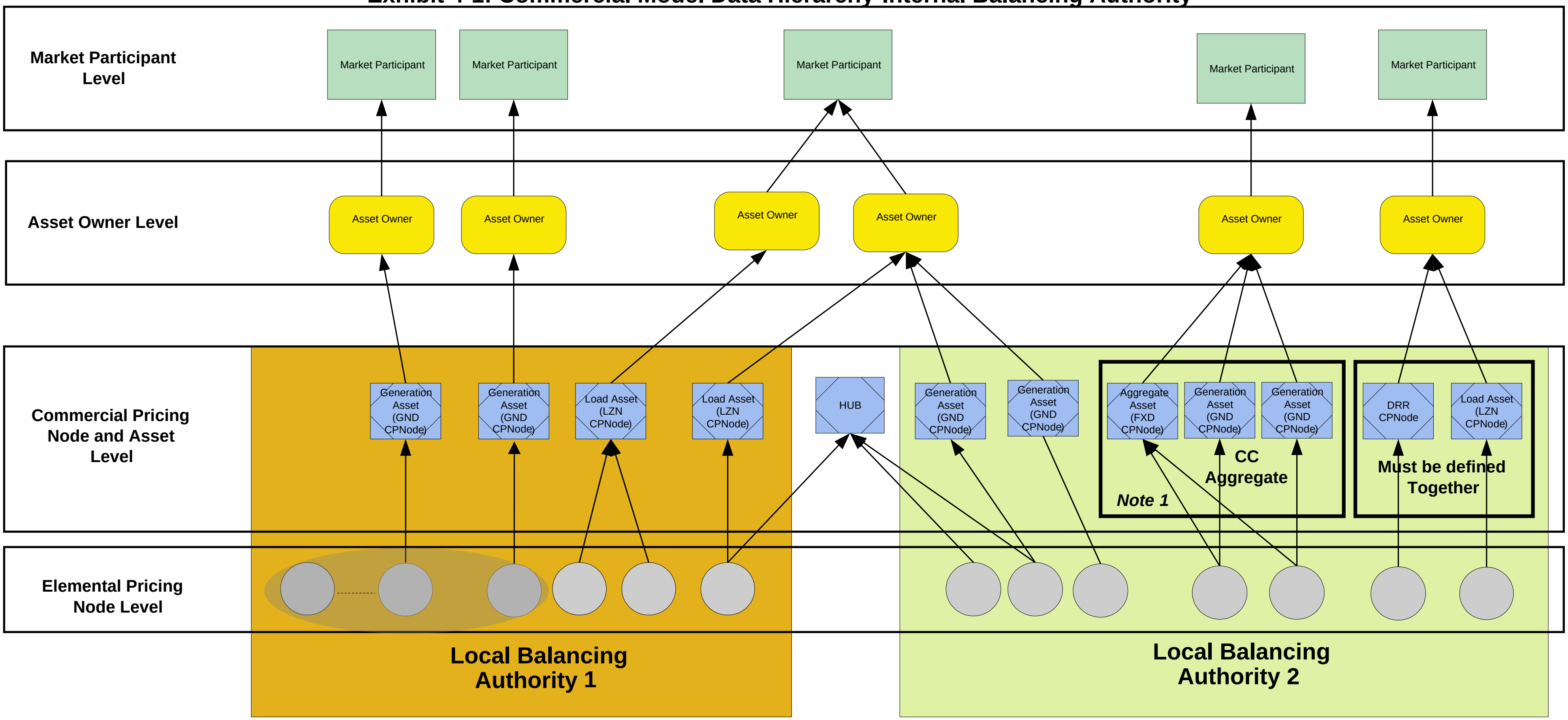
4. Commercial Model

The Commercial Model contains information used to identify assets, the owners of the assets, and the Asset Owner's representative Market Participant. It also defines all of the locations where prices are established and can be used for business transactions in the MISO markets. The data in the Commercial Model is stored in the following categories:

- Elemental Pricing Nodes (EPNodes)
- Commercial Pricing Nodes (CPNodes)
- Assets
- Asset Owners
- Market Participants (MPs)

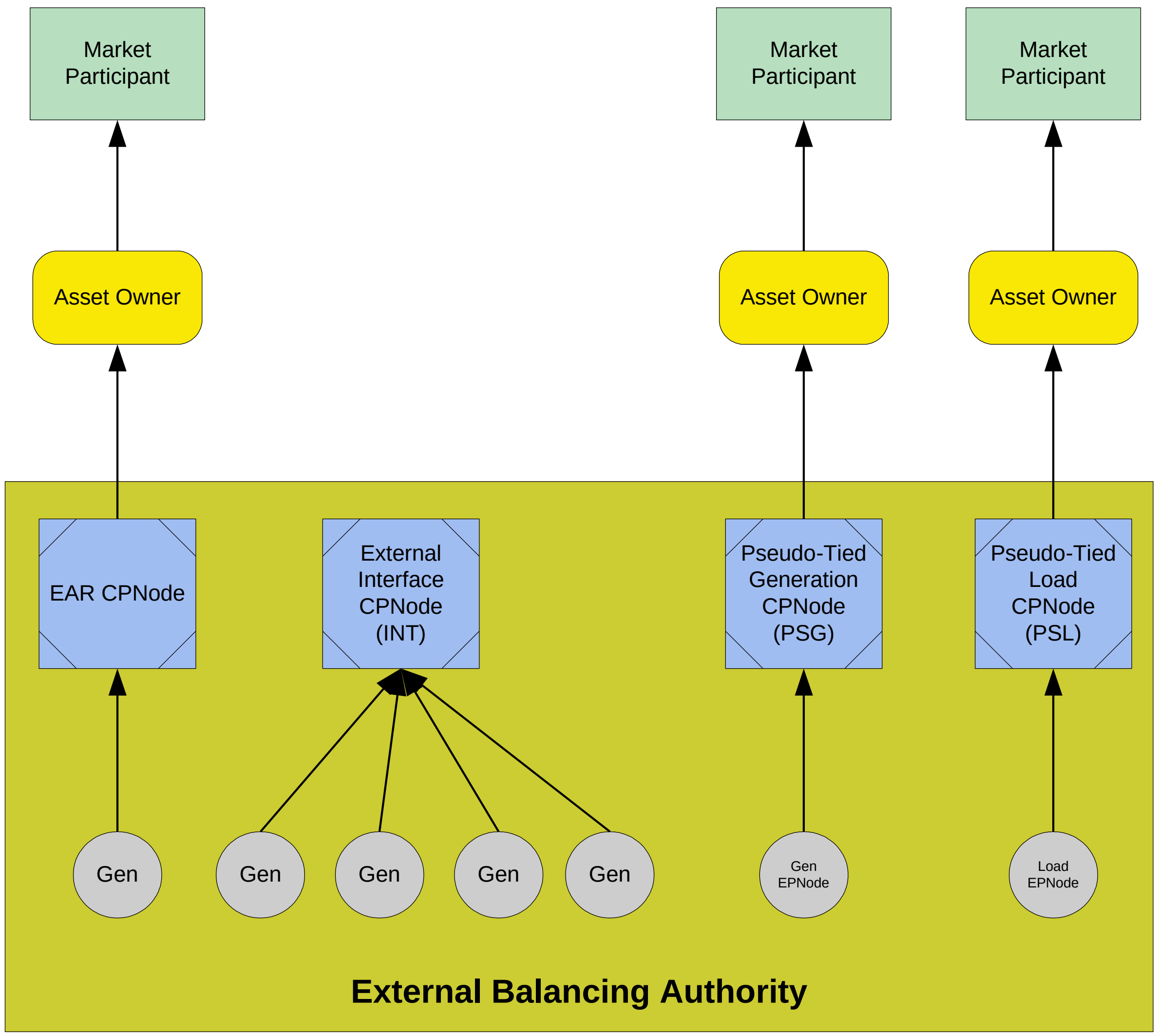
Exhibits 4-1 and 4-2 illustrate the data storage hierarchy of the Commercial Model.

Exhibit 4-1: Commercial Model Data Hierarchy-Internal Balancing Authority



Note 1: **CC assets can be offered either individually or as an aggregate .**

Exhibit 4-2: Commercial Model Data Hierarchy-External Balancing Authority



4.1. Elemental Pricing Nodes (EPNodes)

The EPNode is the lowest level of the hierarchy of data in the Commercial Model. EPNodes are directly related to the Network Model. EPNodes can either be Load EPNodes, Generation EPNodes, or Non-injection/Non-withdrawal (NINW) EPNodes. Load EPNodes have a one-to-one relationship to loads in the Network Model. Generation EPNodes have a one-to-one relationship with generating units in the Network Model. NINW EPNodes have a one-to-one relationship to a transmission node that does not have generation or load directly connected. In the Day Ahead and Real Time Energy & Operating Reserve Markets, a Locational Marginal Price (LMP) is calculated at each EPNode. Any Node in the Network Model can have an LMP. The price for generating electricity and consuming it are the primary concerns for Settlements so each generation and load location will have an EPNode associated with the electrical Node where it is connected. NINW EPNodes are created at select locations and may be used in the representation of Hubs, External Interfaces, below- threshold generation, and behind-the-meter loads.

EPNode names are established automatically based on LBA, station name, and equipment ID. The three types of EPNodes identified above are defined by a standard Network Model naming convention. Each has a four-part unique name. The convention for each is described as follows:

- ***Generation EPNodes*** – The letter “U” concatenated with the EMS LBA name, the EMS station name, and the EMS Unit ID.
  Example: U WEC PORTWAS0 PWASH_PW1
- ***Load EPNodes*** – The letter “L” concatenated with the EMS LBA name, the EMS station name, and the EMS Load ID.
  Example: L CIN 08OBRIEN LD
- ***NINW EPNodes*** – The letter “N” concatenated with the EMS LBA name, the EMS station name, and the node ID.
  Example: N CWLP EASTDALE 51

4.2. Commercial Pricing Nodes (CPNodes)

The CPNode is the next level of the hierarchy of the Commercial Model. Each CPNode consists of one or more EPNodes. MISO utilizes the CPNode to calculate the LMPs that are published and used for Settlement. The relationship of EPNodes to CPNodes determines how the LMP is aggregated for use by Market Settlements.

The standard naming convention for CPNodes is to have the NERC Registered BA or LBA acronym followed by a “.” and then an asset name of the MP’s choosing made up of with the rest of the characters. The only two special characters allowed are the dot "." and the underscore "_". The CPNode name cannot exceed 14 characters, and the effective date of a new CPNode must coincide with the first day of a month (as required by the FTR process).

A CPNode, other than ARR Zones, can't have its name end with ".AZ". The ".AZ" suffix is exclusively used by ARR Zones, which are geographic areas defined for the purpose of allocating ARRs based on where Market Participants served their load during the Reference Year. For more information on ARR Zones, refer to *BPM 004 – FTR and ARR*.

CPNodes may be designated one of the following types:

- Generation Resource
- DRR-Type I
- DRR-Type II
- Combined Cycle or Cross Compound Collection
- Load Zone
- External Interface
- Hub
- External Asynchronous Resource (EAR)
- External Pseudo-Tied Generator (PSG)
- External Pseudo-Tied Load
- ARR Zones
- Electric Storage Resource (ESR)
- Storage as a Transmission-Only Asset (SATOA)

A CPNode may be assigned to an asset that is in turn associated with an Asset Owner.

The Resource CPNode is for all market Generation Resources operating within the MISO Market Footprint only. External PSG CPNodes are for generators connected to the MISO Transmission System but Pseudo-Tied to an External BA. Both Resource CPNodes and External PSG CPNodes have one-to-one relationships to EPNodes.

A Combined Cycle (or Cross Compound) Collection CPNode has a one-to-many relationship with the associated EPNodes.

Load Zone, DRR-Type I, External Interface, Hub, ARR Zone, and External Pseudo-Tie Load CPNodes have one-to-one or one-to-many relationships with EPNodes.

EAR, DRR-Type II, ESR, and SATOA CPNodes have one-to-one relationships with EPNodes.

4.2.1. Generation Assets

CPNodes representing individual Generation Resources are considered Assets and must be assigned to an Asset Owner.
A single generation Asset will have one Asset Owner and will be represented for Market Settlements by one CPNode. The CPNode will contain the EPNode that is the direct representation of the generator. Generation Asset Owners may have multiple Generation Resources, each represented by a CPNode.

External PSG Nodes represent units that are telemetered into an External BA but that are connected directly to the MISO Transmission System and require Transmission Service from the MISO. These CPNodes are associated with an Asset Owner but are considered external to the MISO.

To register a generating asset in MISO's commercial model, all the parameters mentioned in Attachment E ("Asset Parameters for Commercial Model") of this Business Practices Manual must be provided by the application due date, along with all executed required legal documents and/or certifications as set forth in the Tariff and/or Business Practices Manuals or the generating asset will not be registered. The submitted "Maximum Output" parameter shall not exceed the asset's provided Interconnection Service as determined by MISO's generator interconnection process.

To terminate a registered generating asset from MISO's commercial model, an Attachment Y (Notification of Potential Resource/SCU Change of Status process) should be completed per Section 38.2.7 of the MISO Tariff. When an Attachment Y is submitted and resource retirement is approved by MISO, the generating asset will be removed from the Commercial Model per the date specified in the Attachment Y and MISO modeling data notification requirements.

4.2.1.1. Small Generators

Generators with a maximum output greater than or equal to 1 MW and less than 5 MW may not or are not required to be explicitly represented in the Network Model. However, if a Market Participant wishes to register such a generator, it will be modeled in the Commercial Model with a CPNode. For each generator of this type, a NINW type EPNode will be created in the Commercial Model corresponding to the Electrical Node where this generator will be injecting into the Transmission System. A Load Zone type CPNode will be created to calculate the Locational

Marginal Price at these Electrical Nodes. This CPNode will represent a Load type asset in the Commercial Model and that Asset will be associated with an Asset Owner. Market Participants can register more than one generator per CPNode as long as these locations are within one Local Balancing Area and the aggregated output of these generators is more than 1 MW.

Note: Participants that want capacity credits for the Small Generators registered in Commercial Model should also perform additional registration in the Capacity Markets. Additional details for registering in Capacity Markets are provided in the *BPM for Resource Adequacy (BPM 011).*

4.2.1.2. Behind-the-Meter Generation

Where the behind-the-meter facilities must remain in the Network Model for reliability purposes as described in Section 3.1.1.3, a commercial Load Zone will be created that will represent the net flow into or out of the behind-the-meter facilities.

The owner of the Load Zone may submit Day-Ahead Demand Bids for the net load and FTRs may be obtained by/for the Load Zone representing the net load. The load reported to the Market Settlements system by the MDMA for the MP of these load entities will the net of the behind-the-meter generation used to serve these loads. In the case where the after-the-fact metered net flow is an injection, the Load Zone would be settled as a price taker injection and receive a credit.

One consequence of this policy is that these generators that are effectively netted against load cannot be offered into the Energy and Operating Reserve Markets as a dispatchable Generation Resource and will not be explicitly settled by the Market Settlements system. However, there may be opportunity to participate in the Energy and Operating Reserve Markets as a DRR-Type II with this representation.

Examples of Behind-the-Meter and Below Threshold Generation Modeling are presented in Attachment D.

4.2.1.3. Jointly-Owned Unit Data

A JOU will have multiple Asset Owners. There are two different conditions that determine how a JOU will be handled in the Commercial Model. The CPNode to EPNode relationship will depend on which on the following options are chosen.

- ***Single Asset Owner to MISO*** – All Asset Owners agree contractually to allow one entity to Offer on behalf of all parties and settle for their shares through Financial Schedules or outside of the MISO Energy and Operating Reserve Markets. This results in one unit modeled in one LBA in the Network Model. There will be a single EPNode with a corresponding CPNode and Asset. The one Asset Owner will submit all relevant data and only that Asset Owner's MP settles financially with MISO. In essence, this unit would be represented exactly like any other unit that the Asset Owner owned outright.

- ***Pseudo-tie Units* –** A different CPNode can represent each portion of the JOU that is owned by a different Asset Owner. For JOU assets linked by Pseudo-Ties there will be a pseudo unit explicitly modeled in the Network Model representing each share, therefore, multiple EPNodes will exist in the Commercial Model related one-to-one to distinct Nodes in the Network Model. There will be a CPNode for each asset related to the EPNode for the Asset Owner's respective share. As the name implies in this case, a "Pseudo-Tie" line (modeled as a zero-impedance branch or ZBR) is also added to the Network Model and Energy flow is included in the actual Interchange reported/used in the LBA market load equation. There are some instances where the Pseudo-Tie representation is used within the same LBA. In that case, the JOU is modeled as described above with the exception that each share is not necessarily in a different station and LBA in the Network Model and the "Pseudo-Tie" line could actually be a pseudo bus-tie within the same station.

  MISO will perform SCADA calculations to represent the sum of the target base points for Pseudo-tied JOUs if requested by the unit owner/owners. This data will be provided for informational purpose only and will be transmitted, via ICCP, to the operator of the generating unit. For explicitly represented units in the network model, MISO calculates and sends setpoints for each unit. Settlements is done on each of the explicitly modeled units in the network model.

Note: JOU share that is represented explicitly in the network model must have a minimum output of 1 MW. MISO recommends all the JOUs shares that are less than 1 MW to include their share of the unit into a suitable other owner's share of the unit. ICCP data must be provided for all the shares that are explicitly represented in the network model. Also, each unit should be capable of receiving and responding to a dispatch signal from MISO.

Examples of JOU representations as Pseudo-Tie units are provided in Attachment A.

4.2.1.4. Pumped Storage Units

A pumped storage unit is a facility used to store energy during low load periods for the use of generation during high load periods. A pumped storage unit shall be modeled as single generation unit that has a positive output when generating and a negative output when pumping.

4.2.1.5. Aggregate Generation Assets

There are two types of units that can be modeled as independent units in the Network Model but due to the dependency of one or more units on the other, they may be combined for Offer purposes as aggregates. This decision is at the MP's discretion. These two types of units are the combined cycle and the cross compound. Refer to the *BPM for Energy and Operating Reserve Markets (BPM 002)* for definitions of these units. For operational purposes, if an aggregate Asset is created, the decision on whether to Offer as independent units or as an aggregate must be done on a daily basis. MPs will not be allowed to change their Offer basis from the aggregate to individual units on an hourly basis. If an aggregate Offer is made and cleared in the Day-Ahead Energy and Operating Reserve Market, the Real-Time Offers must also be submitted on an aggregate basis for that Operating Day. For more Offer details see the *BPM for Energy and Operating Reserve Markets (BPM 002).*

4.2.1.6. Combined Cycle Generation

Combined cycle plants have steam turbines that use the exhaust heat produced by one or more combustion turbine units to create the steam for the steam turbine. Although the combustion turbines can run independently, Offer curves are often developed for the plant as a whole. An EPNode will be assigned to each component unit. The number of component units varies per generator, but the aggregate should have at least one steam turbine and one combustion turbine. There will be one CPNode for each EPNode so that each component unit can be offered individually. One additional CPNode will be established to represent the aggregate of the component EPNodes. CPNodes representing combined cycle aggregates are considered Assets and must be assigned to an Asset Owner. The Asset Owner of the aggregate must also be the Asset Owner of each of the individual component generators.

4.2.1.7. Cross Compound Generation

Cross compound units have both a high and low-pressure turbine that is often represented as two separate units in the Network Model. These may also be represented as an aggregate for offering purposes. As with the combined cycle plant, the cross compound unit will have an EPNode and corresponding CPNode for each generator and if an aggregate is desired, a third CPNode will be defined representing the aggregate of the two. CPNodes representing cross compound aggregates are considered Assets and must be assigned to an Asset Owner. The Asset Owner of the aggregate must also be the Asset Owner of each of the individual component generators.

4.2.1.8. External Asynchronous Resources

EARs represent an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid. The EAR output is represented within the MISO Region through a Fixed Dynamic Interchange Schedule. EARs are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid. Qualified EARs are eligible to provide Regulating Reserve, Spinning Reserve, and Supplemental Reserve in addition to Energy.

A special EAR EPNode and CPNode is created that is modeled internal to the MISO BA. An EAR CPNode is not the same as an Interface CPNode,.

EAR Fixed Dynamic Interchange Schedules are a special type of Dynamic Interchange Schedule that needs to be specifically linked to an EAR CPNode. The Fixed Dynamic Interchange Schedule is required to provide a mechanism to move EAR Energy into the MISO BA when dispatched. EAR Settlement is based upon the EAR Resource dispatch and not on the Fixed Dynamic Interchange Schedule Energy.

To register an EAR asset in the MISO's commercial model, all the parameters specific to an EAR in Attachment E ("Asset Parameters for Commercial Model") must be provided.

For additional information about the operation and settlement of the EAR, please refer to the *BPM for Energy and Operating Reserve Markets (BPM 002)* and the *BPM for Market Settlements (BPM 005).*

4.2.1.9. External Pseudo-Tie Generation

External PSG Nodes represent units that are electronically telemetered into an External BA but that are connected directly to the MISO Transmission System and require Transmission Service from MISO. These CPNodes are associated with an Asset Owner but are considered external to the MISO Market. They are only used for Settlement of MISO congestion and losses charges for the Asset Owner to move Energy from the Resource to the External Interface.

The following conventions will be followed. Assume the unit is connected to the Transmission System of BA 1 (BA1) and is metered into a different BA 2 (BA2).

- If BA1 is in the MISO Market Footprint and BA2 is outside the MISO Market Footprint then the portion in BA1 is assigned to a generator CPNode. The portion outside the MISO will be registered for congestion and loss only as an external Pseudo-Tie generation CPNode. An EPNode must be defined for the Asset Owner's share (AO2) in BA2 in order to create the external PSG CPNode.

- If BA1 is outside the MISO Market Footprint and BA2 is in the MISO Market Footprint then the portion in BA2 will be assigned to a generator CPNode and that portion of the Asset needs to have Transmission Service arrangements with the Transmission Provider of BA1. The portion in BA1 need not be registered and is not considered in the MISO Commercial Model.

Graphical examples of External Pseudo-Tie Generation are provided in Attachment B.

4.2.2. Load Assets

The following types of load assets are described in this section:

- Load Zones
- External Pseudo-Tie Loads

4.2.2.1. Load Zones

CPNodes representing Load Zones are considered assets and must be assigned to an Asset Owner. The CPNode to EPNode relationship for these is typically one to many except for isolated municipal or industrial load assets that have only one elemental load point in the Network Model. A Load Zone is represented by a CPNode that contains an aggregate of EPNodes. One EPNode can be divided among multiple Load Zone CPNodes with the percent of Node ownership defined for the amount in each Load Zone CPNode. Individually owned loads can also be aggregated in a single Load Zone CPNode.

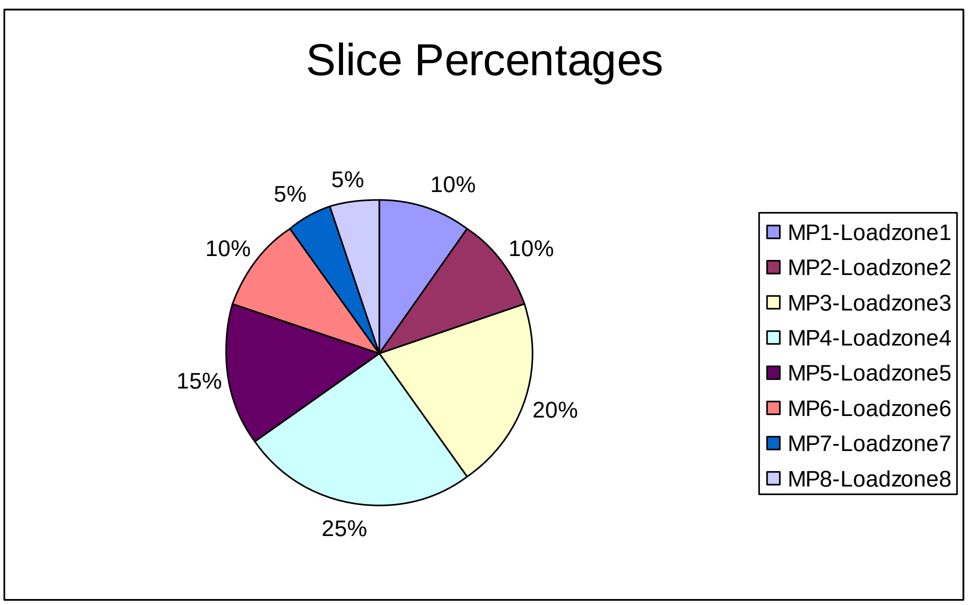
*Note: Any request to create a Load Zone shall have approvals from the Local Balancing Authority.

Load Zones are typically defined as dedicated Load Zones (Option 1 described below) or slice of system Load Zones (Option 2 described below).

Option 1: Defines a new Load Zone consisting of specific load EPNodes. This approach is typically used for large industrial loads that have long-term supply contract relationships and loads where the supplier is easily identifiable.

Option 2: Define new Load Zones using slice of system. A "slice of system" is simply a percentage of one or more load EPNodes. This approach is typically utilized by Market Participants that cannot identify the load EPNodes in advance (e.g. in retail choice states) but still have a requirement to create their own CPNodes for participation in the Energy and Operating Reserves Market. When the EPNodes defined in each slice of system Load Zone CPNode are the same and have uniform slice percentages defined across each slice of system, the LMP will be the same at each of the CPNodes. The slice of system percentages can be adjusted on a quarterly basis. All Market Participants that participate in the slice of system definition should coordinate with the corresponding Local Balancing Authority and shall agree to the slice percentages defined by them. MISO will request the Local Balancing Authority to redefine the slice whenever there are additions or terminations to the Load Zones in the slice definition. Adding or terminating Load Zones may change the slice definition of all or many participants in the slice. Market Participants participating in the slice definition shall be aware that they may need to confirm the changes to the Commercial Model even though they did not request a change. If the Market Participant and/or Local Balancing Authority do not perform the confirmation by MISO's published deadline, then MISO will proceed to model the changes as posted.

Exhibit 4-3: Slice of System Definition



In the figure above, total load of the load EPNode is divided among eight Load Zones. In retail choice states the Load can shift from one MP to another or a new participant can register load. Slice percentages can be changed with every network model update to reflect the change in the amount of Load served by each Load Zone. The LMP for loads in the slice of system Load Zone are the same, so load shifts can occur daily and are reflected through the meter data used for settlement calculations. The example below describes the weighting factor calculation for the uniform slice of the system.

Load Zone (LZA) for MP1

EPNode	Ownership Percentage
EPL1	70
EPL2	70
EPL3	70

Load Zone (LZB) for MP2

EPNode	Ownership Percentage
EPL1	30
EPL2	30
EPL3	30

Assume the Loads at the EPNodes, obtained from the State Estimator solution or Power Flow case are as follows: EP1: 300MW, EP2: 400MW and EP3: 100MW.

Weighting Factor calculation for Load Zone LZA is:

EPNode	Ownership Percentage	Weighting Factor Calculation	Weighting Factor
EPL1	70%	300*0.7 / (300*0.7 + 400*0.7 + 1000*0.7) = 300/1700	3/17
EPL2	70%	400*0.7 / (300*0.7 + 400*0.7 + 1000*0.7) = 400/1700	4/17
EPL3	70%	1000*0.7 / (300*0.7 + 400*0.7 + 1000*0.7) = 1000/1700	10/17

Weighting Factor calculation for Load Zone LZB is:

EPNode	Ownership Percentage	Weighting Factor Calculation	Weighting Factor
EPL1	30%	300*0.3 / (300*0.3 + 400*0.3 + 1000*0.3) = 300/1700	3/17
EPL2	30%	400*0.3 / (300*0.3 + 400*0.3 + 1000*0.3) = 400/1700	4/17
EPL3	30%	1000*0.3 / (300*0.3 + 400*0.3 + 1000*0.3) = 1000/1700	10/17

LMP Calculation:

$$\mathrm{LMP_{LZA}} = \frac{3}{17}\mathrm{LMP_{EPL1}} + \frac{4}{17}\mathrm{LMP_{EPL2}} + \frac{10}{17}\mathrm{LMP_{EPL3}}$$

$$\mathrm{LMP_{LZB}} = \frac{3}{17}\mathrm{LMP_{EPL1}} + \frac{4}{17}\mathrm{LMP_{EPL2}} + \frac{10}{17}\mathrm{LMP_{EPL3}}$$

Settlement Calculation:

$$\$\mathrm{LZA} = \mathrm{LMP_{LZA}}(\mathrm{Actual\ Meter\ Value})_{\mathrm{LZA}}$$

$$\$\mathrm{LZB} = \mathrm{LMP_{LZB}}(\mathrm{Actual\ Meter\ Value})_{\mathrm{LZB}}$$

With the implementation of Resource Adequacy requirements, load zones in retail choice programs should provide the Electric Distribution Company (EDC) at the time of registration. The process for registration of an EDC is explained in *BPM 001 – Market Registration.*

4.2.2.2. External Pseudo-Tie Load Zone

External Pseudo-Tie Load Zone CPNodes are associated with an Asset Owner but are considered external. As with internal Load Zones, the CPNode to EPNode relationship is typically a one to many type relationships. If a load is represented by Pseudo-Ties, the following conventions will be followed:

- If the load is physically in LBA1 that is within MISO but pseudo-tied to BA2 that is outside the MISO Market Footprint, then the load is considered in BA2. The load will be represented in the Network Model in BA2 and be registered as a Pseudo-Tie Load Zone for congestion and loss charges.
- If the load is physically in BA2 which is outside the MISO Market Footprint but pseudo-tied to LBA1 that is within the MISO Market Footprint, then the load is considered in LBA1 and assigned to a Load Zone in LBA1. However, appropriate Transmission Service arrangements must be in place with the Transmission Provider of BA2.

Note: All requests to Pseudo-Tie Load from one Control Area to another shall be approved by both Local Balancing Authorities. For more information on pseudo-tied load and related processes, refer to the *BPM for Dynamic Transfers: Pseudo-ties and Dynamic Interchange Schedules (BPM 030).*

If a load is represented by a Dynamic Schedule, the following conventions will be followed:

- If the load is physically in LBA1 that is within the MISO Market Footprint with a Dynamic Schedule from BA2 that is outside the MISO Market Footprint, then the load is considered in BA1 and assigned to a Load Zone in BA1.
- If the load is physically in BA1 that is outside the MISO Market Footprint with a Dynamic Schedule from BA2 that is either in or out of the MISO Market Footprint, then the load is considered in BA1 and will not be included in the Commercial Model and need not be registered. There will be a Physical Bilateral Transaction (PBT) Schedule out of the MISO to serve the load.

Graphical examples of external pseudo-tied loads are presented in Attachment C.

4.2.3. Modeling of Demand Response Resources – Type I

Customer programs such as industrial interruptible load programs, controlled appliance programs and other load reduction programs registered by Aggregators of Retail Customers (ARC) can register as DRR-Type I Resources to provide a specific amount of Energy or Contingency Reserve into the MISO Market through physical load interruption. Commercial modeling of DRR-

Type I is done using a special DRR-Type I (DRRNODE1) CPNode. This CPNode is modeled similar to the Load Zone CPNode. The following rules apply to modeling DRR-Type I Resources.

- A DRR-Type I Resource CPNode may have the same EPNode relationship as the EPNodes that make up a Load Zone of a Market Participant.
- Multiple DRR-Type I CPNodes owned by the same Market Participant can be created to represent different Demand Reduction Programs. An Asset Owner can submit offers for target demand reduction through the Market Portal for participation in the Day Ahead and Real Time Markets.
- A DRR-Type I must have a capacity of at least 1 MW to be included in the Network and Commercial models.

To register a DRR-Type I asset in the MISO's commercial model, all the parameters specific to DRRs-Type I in Attachment E must be provided by the Commercial Model due date, along with all executed required legal documents and/or certifications as set forth in the Tariff and/or Business Practices Manuals(including, but not limited to, Asset Registration - Section XIX and Section XIV, if applicable) or the DRR-Type I asset will not be registered. The process for registration of ARCs is explained in *BPM 026 – Demand Response,* provided at the link below:

https://www.misoenergy.org/legal/business-practice-manuals/

For qualification requirements to register DRR-Type I Resources and modeling examples, please refer *BPM for Energy and Operating Reserve Markets (BPM 002)*.

4.2.4. Modeling of Demand Response Resources – Type II

Behind the meter generators or highly controllable load processes that are capable of receiving electronic (via ICCP) dispatch instructions from MISO can register them as DRR-Type II Resources in MISO Energy and Operating Reserve Market to supply a range of Energy and/or Operating Reserves. The Commercial modeling of a DRR-Type II Resource is similar to that of modeling the Generator. The following rules apply to modeling of DRR-Type II.

- A single Resource EPNode/DRR-Type II CPNode representation is used to model a DRR-Type II Resource in the Commercial Model. If the DRR-Type II is not committed, the net metered output will be used as load consumption for Settlement purposes. If the DRR-Type II is committed, the hourly Economic Minimum limit represents the DRR-Type II Load Forecast for Settlement purposes.
- A DRR-Type II must have a capacity of at least 1 MW to be included in the Network and Commercial models

To register a DRR-Type II asset in MISO's Commercial Model, all the parameters specific to a DRRs-Type II in Attachment E must be provided by the Commercial Model due date, along with all executed required legal documents and/or certifications as set forth in the Tariff and /or Business Practices Manuals (including, but not limited to, Asset Registration - Section XIX and Section XIV, if applicable) or the DRR-Type II asset will not be registered.

For qualification requirements to register DRR-Type II Resources and modeling examples please refer *BPM for Energy and Operating Reserve Markets (BPM 002*).

4.2.5. Electric Storage Resource (ESR)

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

An Electric Storage Resource must:

1. Be capable of injecting and withdrawing a minimum of 0.1 MW
2. Be capable of complying with MISO's Setpoint Instructions
3. Have the appropriate metering equipment installed
4. Be physically located within the MISO Balancing Authority Area

To register an Electric Storage Resource asset in MISO's Commercial Model, all the parameters specific to ESRs listed in Attachment E of this Business Practices Manual must be provided by the Commercial Model due date, along with all executed required legal documents and/or certifications as set forth in the Tariff and/or Businesses Practices Manuals (including, but not limited to, Asset Registration - Section XIX and Section XIV, if applicable) or the Electric Storage Resource will not be registered.

4.2.6. Storage As Transmission Only Asset (SATOA)

CPNodes representing Storage As Transmission Only Assets are used for settlement with MISO. A SATOA is an Electric Facility connected to and part of the Transmission System and approved for inclusion in Appendix A of the MTEP, that is capable of receiving Energy from the Transmission System and storing it for injection to the Transmission System. It is operated only to support the Transmission System.

A SATOA shall not participate in MISO's markets except to the extent necessary to receive or inject Energy to provide the services for which it was included in the MTEP. Therefore, CPNodes representing SATOAs must be created and are used for settlement of these injections and/or withdrawals of Energy. A SATOA is represented as a Generator in the Network Model, and a SATOA-type CPNode in the Commercial Model.

4.2.7. External Interfaces

CPNodes representing External Interfaces are used for Settlement of Interchange Schedules with MISO. The CPNode to EPNode relationship is typically one to many with each EPNode representing a location within an External BA. These CPNodes and the relationships to EPNodes are established and maintained by MISO and are not related to any specific Asset Owner. The weighting factors for each EPNode are established by MISO as equal weighting in Interface LMP calculations.

The naming convention for interfaces follow the NERC registered acronym for all BAs in the Eastern Interconnection. If an External BA has more than one External Interface CPNode defined, it will have the BA acronym followed by a dot "." followed by a unique identifier developed by MISO.

4.2.8. Trading Hubs

Hub-type CPNodes are defined by MISO using a process that seeks to create a group of nodes that are electrically and geographically close and have similar prices over time. Hubs are considered an approximation of the region they are meant to represent, and have a one to many CPNode to EPNode relationship. The weighting factors for each EPNode are established by MISO as equal weighting in Trading HUB LMP calculations.

Hub CPNodes are not related to any specific Asset Owner. All Participants are allowed to submit Virtual Supply Offers and Virtual Demand Bids at these locations as well as use them as a delivery points for trading.

There are other types of CPNodes (ARR zone, etc.) administered as Hub type in the system. However, they are different from the Trading Hubs and serve different business purposes. ARR zones will have weighting factors defined by MISO similar to load zones. For more information on ARR Zones, refer to *BPM 004 – FTR and ARR*.

4.2.9. Aggregated Pricing Nodes

MPs will be allowed to define Aggregated Pricing Nodes (APNode) that may be used for MP reference. The prices for these aggregate nodes will be viewable in the MISO Portal publicly and can be downloaded. All EPNodes assigned to the APNode must be owned by a single MP.

4.3. Asset Owners

The next level of the Commercial Model hierarchy above CPNodes represents the Asset Owners. An Asset Owner must represent each Asset. This is the operating entity level where all Bid and Offer data submittals, Settlement Statement aggregation, and Bilateral Transactions are conducted. Asset Owners are commonly referred to as Load Serving Entities (LSEs) or Generation Owners but an Asset Owner can own any combination of generation and load.

However, not all Asset Owners must have physical Assets of load and generation. The operating entities associated with Bilateral Transactions and FTRs are also considered Asset Owners. All Energy and Operating Reserve Markets transactions for generation, load, FTRs and bilateral schedules are settled to the level of the Asset Owners and then invoiced to the MP. Asset Owners must be represented by one MP, but a MP may have or represent multiple Asset Owners. This second entity layer allows for full flexibility for a MP to manage its users' access and to separate internal business units or provide MP services for multiple entities with separate settlements for each.

4.4. Market Participant

The Market Participant (MP) represents the highest-level data component of the Commercial Model. The MP is the entity that is financially obligated to MISO for Market Settlements. The MP must have associations with at least one Asset Owner. The Local Security Administrator for the MP is the sole authority responsible to the MISO for establishing the security roles for its Asset

Owners to submit all operating information. Refer to the *BPM for Market Registration (BPM 001)* for details on the data required to register a MP.

4.5. Common Bus

A Common Bus is a single nominal Bus to which two or more Resources (Generator and DRR-Type II) are connected in an electrically equivalent manner when all breakers are placed in their normal status. Multiple Resources connected to a single Common Bus are treated as a single Resource for NERC Standard compliance monitoring purpose. Common Buses are nominated by a Market Participant during the asset registration process. Each Common Bus nominated by a Market Participant will be checked and verified against the Network Model with all breakers in their nominal or normal position. The accepted Common Bus definitions will be implemented in the Commercial Model and will remain active unless a network model change reconfigures the nominal bus or a Market Participant chooses to terminate it. All combined cycle child nodes will automatically be defined on a common bus to monitor Contingency Reserve Deployment Compliance.

Common Bus information is used in calculating:

- Contingency Reserve Deployment Failure Charge
- Excessive/Deficient Energy Calculation
- Excessive/Deficient Energy Deployment Charge

For more information on Common Bus implementation details please refer to *BPM 005 - Market Settlements*.

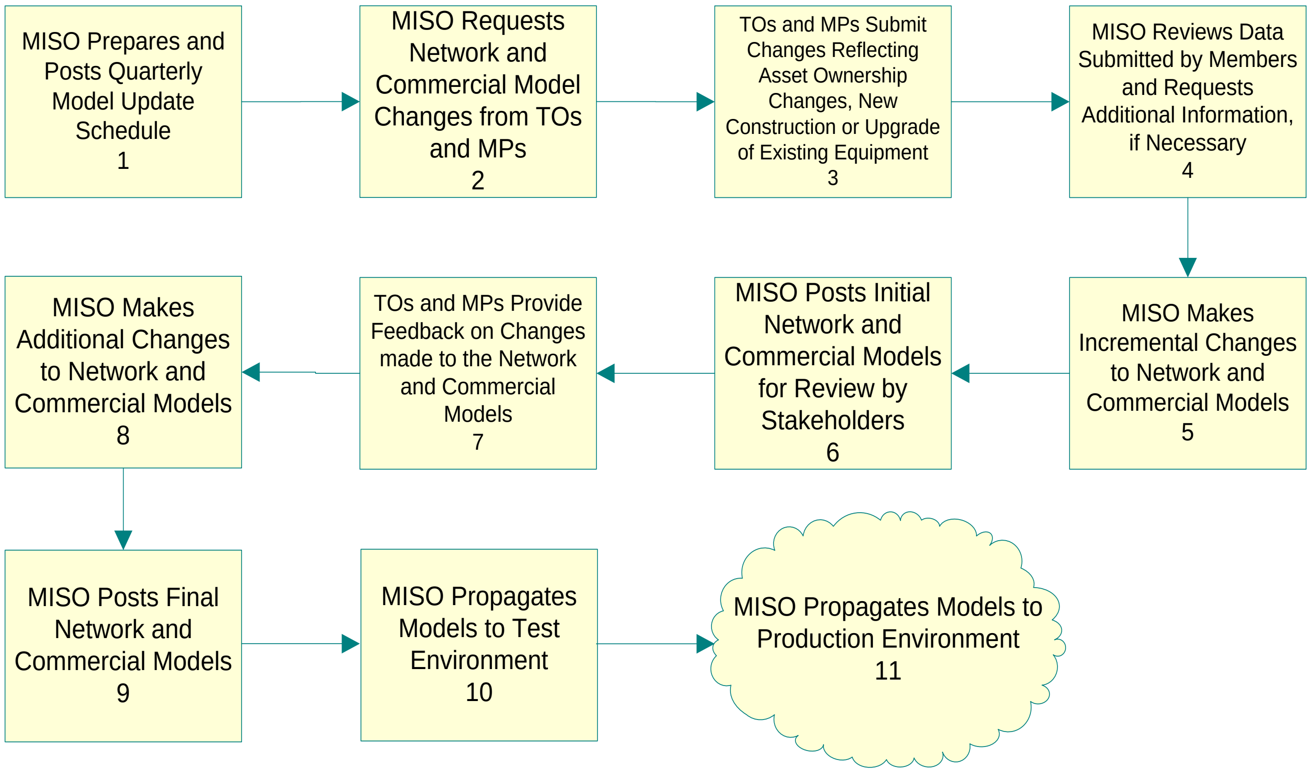
5. Model Maintenance

Both the Network Model and the Commercial Model must be kept current in order to support the reliable and economic operation of the power system and the Energy and Operating Reserve Markets. Any additions, deletions, or other changes in electric power system components or asset registration and commercial model information must always be reflected in the models.

MISO Transmission Owners and Market Participants must submit all Network and Commercial Model additions, modifications, and deletions to MISO via the MISO Model Manager (MMM) application. All additions, modifications, and deletions must include all executed required legal documents and/or certifications as set forth in the Tariff and/or Business practices Manuals or the changes will not be processed. The MISO Model Manager Data Requirements document describes the required equipment information needed to ensure accurate equipment representation within the MISO models. Application introduction and use case training videos can be found on the MISO Learning Center, https://miso.csod.com/ui/lms-learning-details/app/course/85fbff8f-2c2f-48d5-86e9-36cc83c12d41.

Changes to the Network and Commercial Models are initially made on a MISO test system. Once the changes have been verified during a period of testing, the changes are then made on the MISO Production System following the published model update schedule.

Exhibit 5-1 Process diagram for Network and Commercial Model Updates:



5.1. Network Model Change Times

MISO currently follows a quarterly Network Model update cycle, with updates made effective March 1, June 1, September 1, and December 1 of each year. Minimally, MISO shall perform a model update at least 90 days prior to the annual ARR allocation. During the three months, any Network Model changes that will become effective during the three month window will be included in the Network Model. Those changes that are not effective immediately at the loading time of the Network Model will be inactivated through outages until such time as the equipment is energized. Likewise, once a configuration is switched in, any old configurations will be switched out until the next Network Model update, when they will be terminated and removed from the Network Model. This practice is generally referred to as double-modeling. Given the three-month update cycle, all Network Model changes must be submitted to MISO through the MISO Model Manager at least 150 days in advance of their operational or termination date in order to be included in the appropriate Network Model update. As shown in Exhibit 2-1, many MISO applications use or depend on the Network Model. Therefore, sufficient time must be allowed to implement changes into the Network Model, test all the applications that will use the new Network Model and coordinate with all the users of the applications before the new Network Model is put into production. At least one month must be allowed for the testing, coordination and data propagation. MISO reserves the operational authority to keep any new equipment connected to MISO Transmission System out of service if:

- The information is submitted later than 150 days in advance of the expected start date; and
- The equipment has the potential to disrupt reliability assessment and/or Energy and Operating Reserve Market operations if activated in the field without updating all relevant models including the Network and Commercial models, the FTR model, and the Day-Ahead and Real-Time market databases.

In the event a model change is required that is deemed an emergency correction necessary to ensure reliable operation of MISO Transmission System and Market Operations, the Model Team will make the necessary corrections and apply the model changes between the normal quarterly updates. Any such change requires the Transmission Owner and/or MP to supply all relevant data for the Network and Commercial Model changes as soon as they are known. All steps for validation and testing of the models must still be concluded according to MISO's change management process for propagating models to production. The model update schedule for each year is available on the MISO website at the link below:

https://www.misoenergy.org/markets-and-operations/#nt=/marketsandopstype:Network%20and%20Commercial%20Model%20Schedule

5.2. Commercial Model Changes and Timeline

MISO updates the Commercial Model to coincide with Network Model changes. Both topology and non-topology dependent changes are made during these quarterly model updates. MISO also provides four more opportunities in the months following quarterly model update to perform non-topology based changes. MPs are obligated to confirm Asset changes with each Commercial Model update.

During the non-topology dependent updates for the months beginning April, July, October and January the following Commercial Model changes will be allowed:

- Creation of new Market Participant / Asset Owner

- Termination of Market Participant / Asset Owner
- Asset transfer / Asset transfer termination
- Scheduling and Metering Agent change
- Asset parameter updates (Default values)

The Commercial Model is kept in sync with the Network Model. Whenever the Network Model is changed, the Commercial Model, if impacted, is also updated to reflect the Network Model changes. Some changes that occur in the Network Model which require corresponding Commercial Model changes are:

- Substation name changes
- adding loads/generators
- adding a new substation
- moving loads/generators to a new substation
- moving loads/generators at a higher KV level
- moving loads/generators to a lower KV level
- moving loads/generators from one transformer to the other

These types of changes require that EPNodes be added, terminated or changed. These changes will be communicated to the MP for review and confirmation.

During quarterly model updates Market Participants can request a transfer of load EPNodes from one CPNode to another with an effective date coinciding the quarterly model update or beyond. In the event a CPNode is transferred between Market Participants or Asset Owners, then submittals via the MMM tool are required from both parties involved in the transfer and should reflect the same requested change to the Commercial Model.

Ad hoc Asset Ownership transfer - In the event of asset ownership changes for which Market Participants and/or Asset Owners are not able to confirm a transfer date by the established model data submittal deadlines, MISO has the following procedure in place.

1. Both Asset Owners must submit Commercial Category Model Change Requests (MCRs) via the MMM tool during a Commercial Model update with a suggested transfer date well into the future (more than 3 months out). The MCR effective date should reflect the model this transfer will be applied to. The description in the MCR should state that "This is an anticipated change happening in the future. The actual transfer date will be communicated to MISO.", and also include the suggested transfer date. (For example, if the suggested

transfer date is January 1st next year and the change needs to be reflected in September model this year, the MCR effective Date should be within 9/1 ~12/1 this year and the 1/1 date should be provided in MCR description). A separate ICCP category MCR must be submitted if the telemetry provider is changing.

2. MISO implements the asset transfer with future effective date.
3. Both Asset Owners will review and confirm the asset ownership changes.
4. When the actual ownership transfer date is firmly established, both asset owners must inform MISO Client Services and Readiness team via e-mail, and update their MCRs' effective date to the actual transfer date in the MMM tool **at least 14 calendar days in advance of the date.**
5. MISO will update all the impacted systems to respect the actual transfer date.

Note: Provisions must be made so the real-time telemetry (ICCP data) required for the Asset per *BPM for ICCP Data Requirements (BPM 031)* continues to be available after the asset has been transferred. Failure to provide the required data may delay market participation.

In the event the anticipated asset ownership transfer is cancelled or not successful, both asset owners must inform MISO Client Services and Readiness team via e-mail and withdraw their respective MCRs at least 14 calendar days prior to the tentative transfer date.

- Note: Both parties (Asset Owners) utilizing this approach for asset transfer shall inform MISO Commercial Modeling team via CommercialModeling2@misoenergy.org to either cancel the tentative transfer or extend the date of the tentative transfer at least 14 calendar days prior to the tentative transfer date. If such a communication is not received in time MISO will proceed with the transfer as scheduled.

5.3. ARR Allocation and FTR Auction Model Changes

The following sections describe the Quarterly and Annual FTR model changes for both the Network and Commercial models.

5.3.1. FTR Models Changes

FTR models are derived from the Network Model by adding all known future equipment that will be in service on the first day of the season to the Network Model that is used for real-time operations. The resulting modified Network Model is converted to a bus-branch model in the PTI PSS/E format and used as the FTR model. The main difference between the Network Model and bus-branch model formats is that circuit breakers are not represented in the FTR model. The timeline and criteria for submitting model changes for the FTR models are the same as those described in Section 6.1 for the Network Model updates.

The Annual ARR Allocation and FTR Auction will be conducted on a seasonal basis and MISO will develop four Network Models to represent the Transmission System topology for the following seasons:

1) Winter ARR and FTR Models effective from Dec 1 to Feb 28/29
2) Spring ARR and FTR Models effective from Mar 1 to May 31
3) Summer ARR and FTR Models effective from Jun 1 to Aug 31
4) Fall ARR and FTR Models effective from Sep 1 to Nov 30

Transmission System Equipment that goes into each ARR and FTR Model is as described below:

- The Spring ARR and FTR model will include all equipment that will be operational by March 1.
- The Summer ARR and FTR model will include all equipment that will be operational by June 1.
- The Fall ARR and FTR model will include all equipment that will be operational by September 1.
- The Winter ARR and FTR model will include all equipment that will be operational by December 1.

Transmission Owners submit their future projects for various planning studies via the Model On Demand (MOD) tool. MISO will utilize these projects in MOD tool to incrementally update the seasonal FTR models. For each model update, Transmission Owners should identify the Project IDs in MOD to be included for different FTR Models. Only projects that have been planned, budgeted, and have received regulatory approval should be submitted for FTR models. If project expected in-service dates change, then the associated MOD project in-service date should also be updated in MOD to reflect the new expected in-service date.

5.4. Network and Commercial Model Reviews

MISO has developed processes and methods that allow Transmission Owners and MPs to review the Network Model and provide feedback to MISO. The feedback provided is used to improve and keep the Network Model up-to-date. The following processes and methods currently exist for reviewing the MISO Network and Commercial models:

- ***On-site Model Review***: Transmission Owners, LBAs and Reliability Coordination Customers who have a Non-Disclosure Agreement (NDA) on file are able to perform on-site review of the Network Model and the SE solution by visiting one of the MISO office locations. The NDA is required for the on-site review of the Network Model since the SE solution represents Real-Time system data.
- ***Members Delivered Applications***: Transmission Owners, LBAs and Reliability Coordination Customers who have **UNDA Appendix A** (Transmission/Reliability) and **CEII** confidentiality agreements on file are able to perform off-site review of the Network Model and the SE solution via remote terminals installed at their sites by MISO.
- ***Using the Posted State Estimator Models****:* Transmission Owners, LBAs, MPs, and Reliability Coordination Customers who have the appropriate non-disclosure and confidentiality agreements in place are able to perform off-site review of the Network

Model and the SE solution by downloading snapshots of MISO's State Estimator model posted on the MISO's Extranet The SE snapshots are created four times per day and can be found in the following locations:

- ***1-13 days old: Reliability Authority → EMS Models***
- ***14-30 days old: Models → SE Models***
- ***Older than 30 days: Models → SE Models → Archived SE Models***

- ***Reviewing Commercial Model Data***: The Commercial Model is updated whenever the Network Model is updated, to be consistent with the Network Model. The updated Commercial Model changes are posted for review by Transmission Owners and MPs at the following MISO Extranet site (Path: Home > EMS Model Information >Network and Commercial Models).

Attachment A

PSEUDO-TIE JOU EXAMPLES

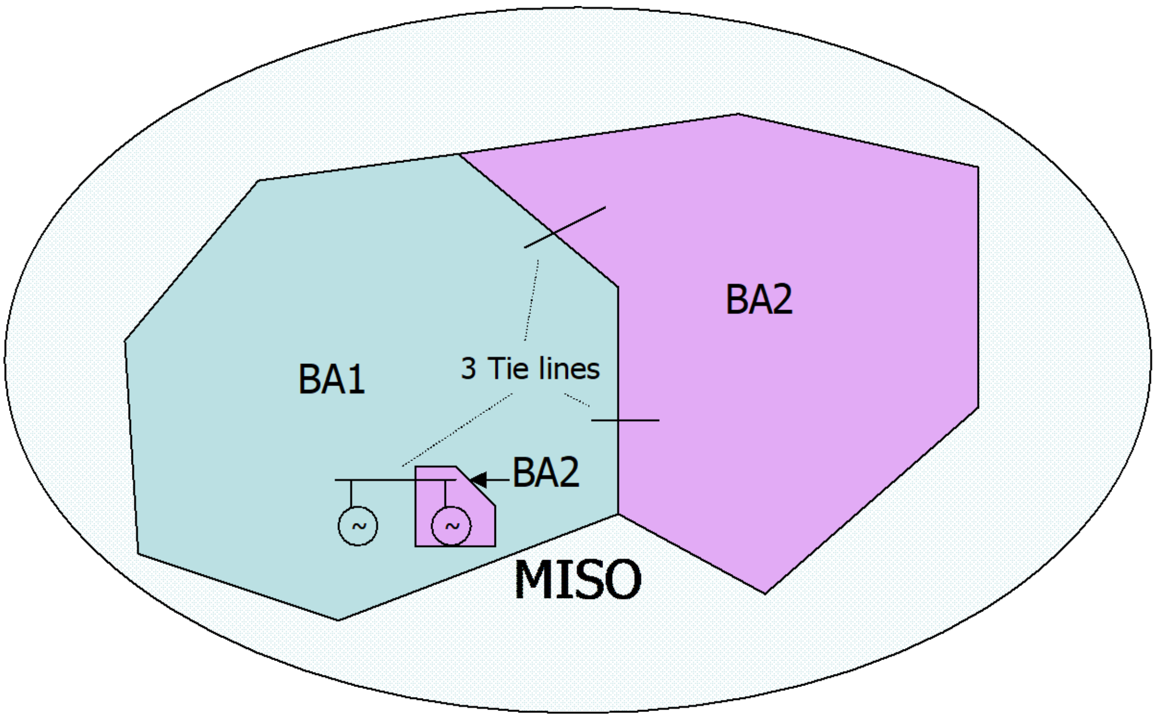
A. Pseudo-Tie JOU Examples

JOU representations as Pseudo-tie In these examples, a JOU with Pseudo-Tie arrangements will be represented as two Pseudo Units in the Network Model.

- For Pseudo-Tie arrangements between LBAs, both portions need to be claimed by appropriate Asset Owners.
- If the unit is physically located in LBA1 within MISO and BA2 is not in MISO, then the portion in LBA1 needs to be claimed by Asset Owners. The portion in BA2 needs to be registered for congestion and loss only.
- If the unit is physically located in BA2 out of the MISO and LBA1 is within the MISO, then the portion in LBA1 needs to be registered. The portion in BA2 is considered out of the MISO Market Footprint both physically and electrically and it does not need to be registered. The generator share for LBA1 must have appropriate transmission arrangements with these external entities and the MISO is not a party to these arrangements.

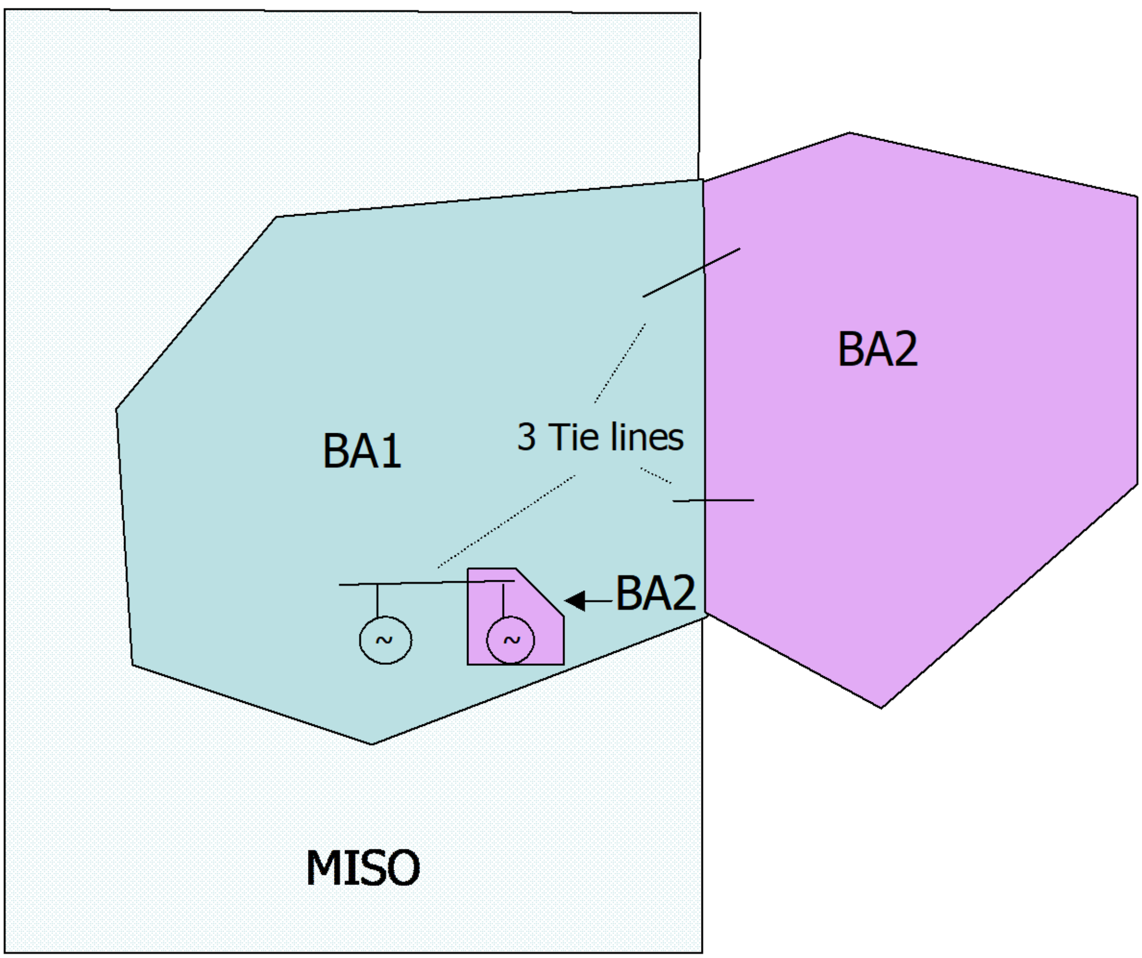
Example A1: The JOU is physically in LBA1 (within the MISO) with Pseudo-Tied second party share to LBA2 (within the MISO)

- Each share is physically modeled in the Network Model as a separate generator
- Each share also has a CPNode and asset created for the respective owner.



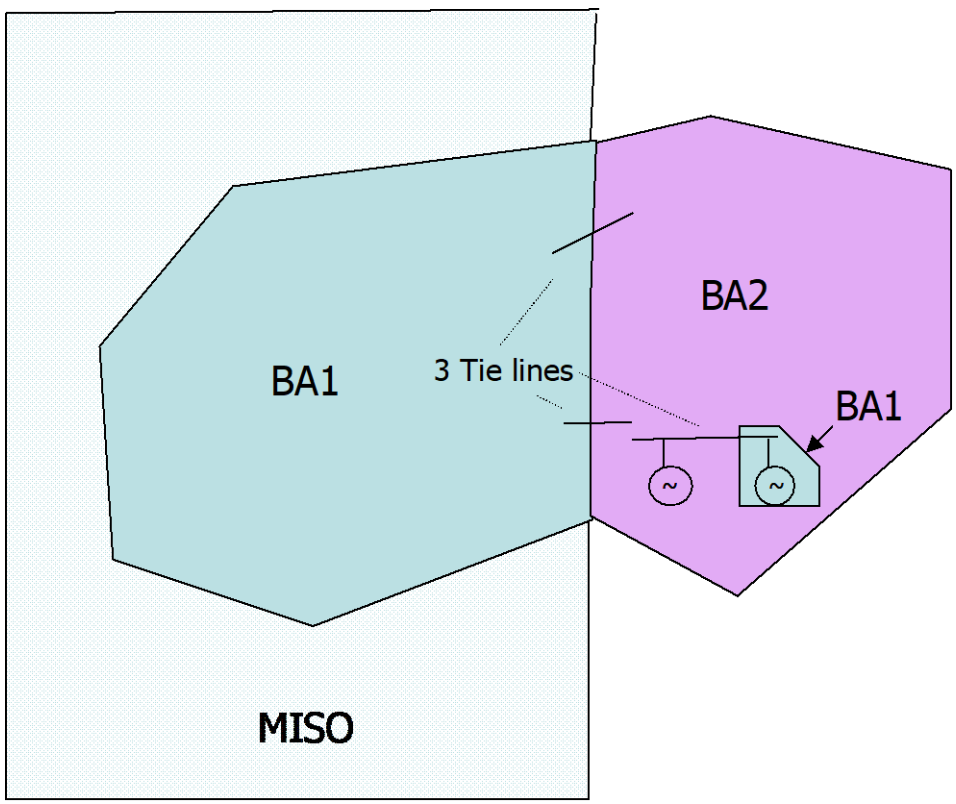
Example A2: The JOU is physically in LBA1 (within the MISO) but the BA2 owner share is Pseudo-Tied to BA2 (out of the MISO). This share falls under the same rules identified earlier for Pseudo-Tie units. Again it must be registered for congestion and loss charges only.

- Generator share in LBA1 treated as any other MISO Energy and Operating Reserve Markets Resource
- Generator share in BA2 is a special CPNode BA2.xxxx PSG
- Generator share for BA2 falls under Pseudo-Tie rules previously stated.
- Only generator share in LBA1 is subject to the MISO Energy and Operating Reserve Markets dispatch.



Example A3: The JOU is physically in BA2 (outside the MISO) and one share is Pseudo-Tied to LBA1 (inside the MISO).

- All shares represented in the Network Model
- Generator share in LBA1 treated as any other MISO Energy and Operating Reserve Markets Resource
- Only the generator share in LBA1 is subject to the MISO Energy and Operating Reserve Markets dispatch.
- Same rules apply for the generator share in LBA1 as discussed previously for a Pseudo-Tied Resource physically outside the MISO Market Footprint.



Attachment B

EXTERNAL PSEUDO-TIE GENERATION EXAMPLES

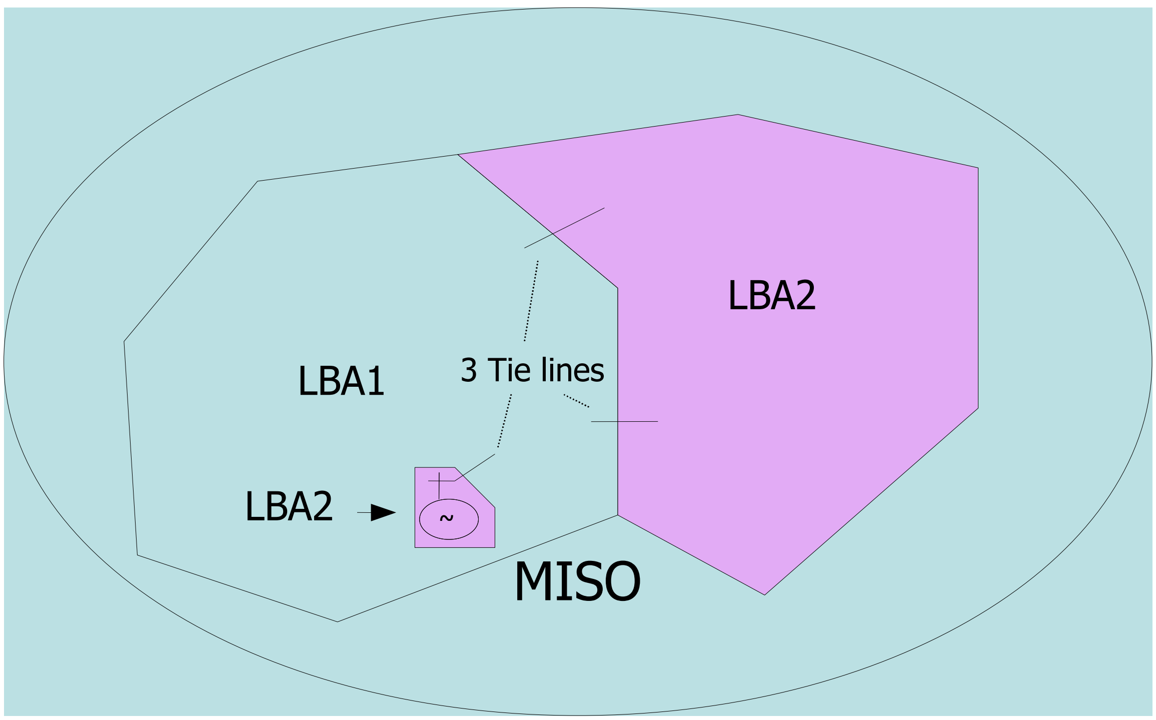
B. External Pseudo-Tie Generation Examples

Pseudo-Tie and Dynamic Schedule Generators

- A generator physically in LBA1 (within the MISO) but Pseudo-Tied to LBA2 (within the MISO) will be considered in LBA2 and assigned as a Generation Resource in LBA2
- Generator physically in LBA1 (within the MISO) but Pseudo-Tied to BA2 (out of the MISO) will be considered in BA2. The generator must be registered for congestion and loss charges only.
- A generator physically in BA1 (out of the MISO) but Pseudo-Tied to LBA2 (within the MISO) will be considered in LBA2 and assigned as a Generation Resource in LBA2.
  - The generator will be a Resource for the MISO Energy and Operating Reserve Markets and accounted for in the centralized dispatch
  - The generator is subject to Transmission Service requirements of the external Transmission Service Providers in order to move the Energy from the generator into the MISO Transmission System. The MISO is not a party to these arrangements but will verify that appropriate service exists to bring Energy in from this Resource.
- A generator physically in LBA1 (within the MISO) supplying a Dynamic Schedule to BA2 (out of the MISO) will be considered in LBA1 and assigned as a Resource defined in LBA1

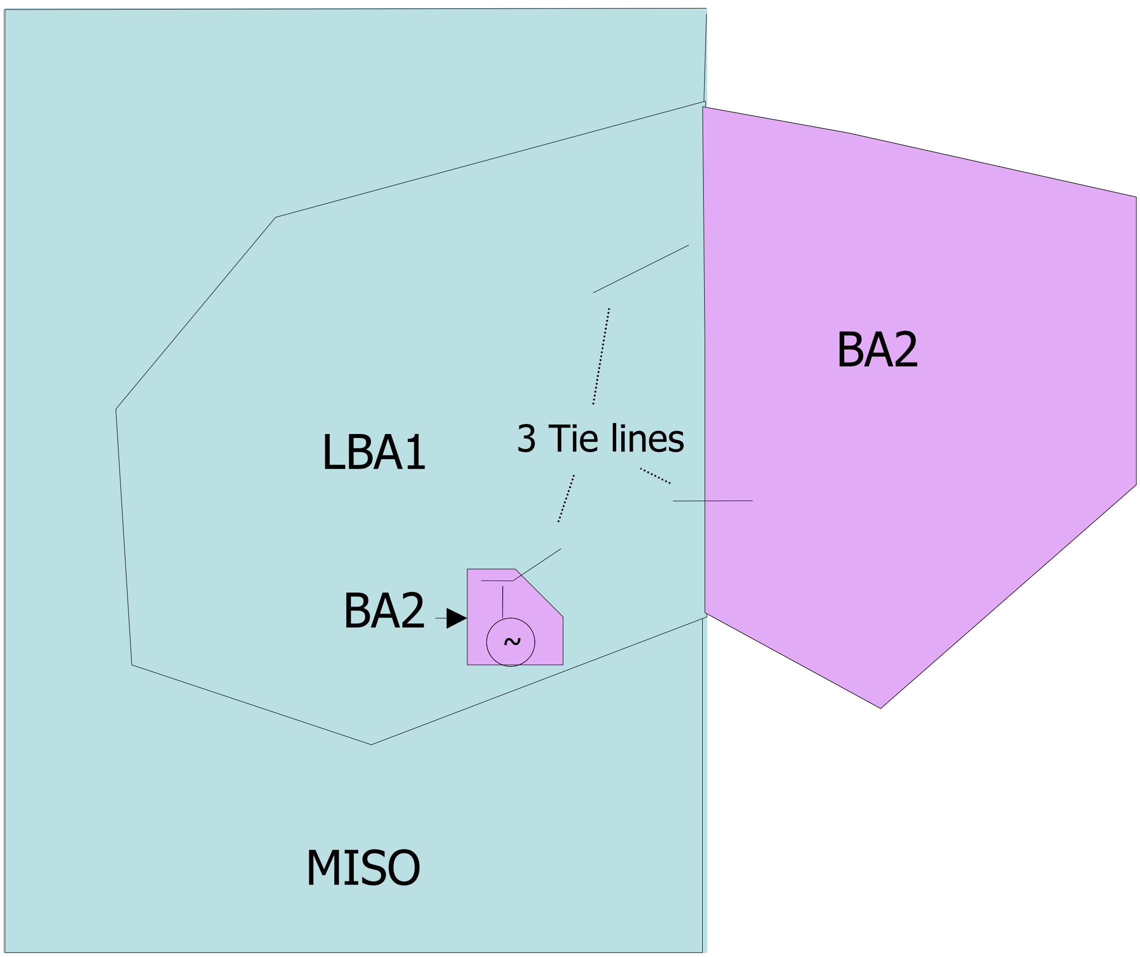
Example B1: A generator physically in LBA1 (within the MISO) but Pseudo-Tied to LBA2 (within the MISO) will be considered in LBA2 and assigned as a Generation Resource in LBA2

- Generator is a LBA2.xxxx Resource
- Looks like and acts like all other LBA2 Resources.



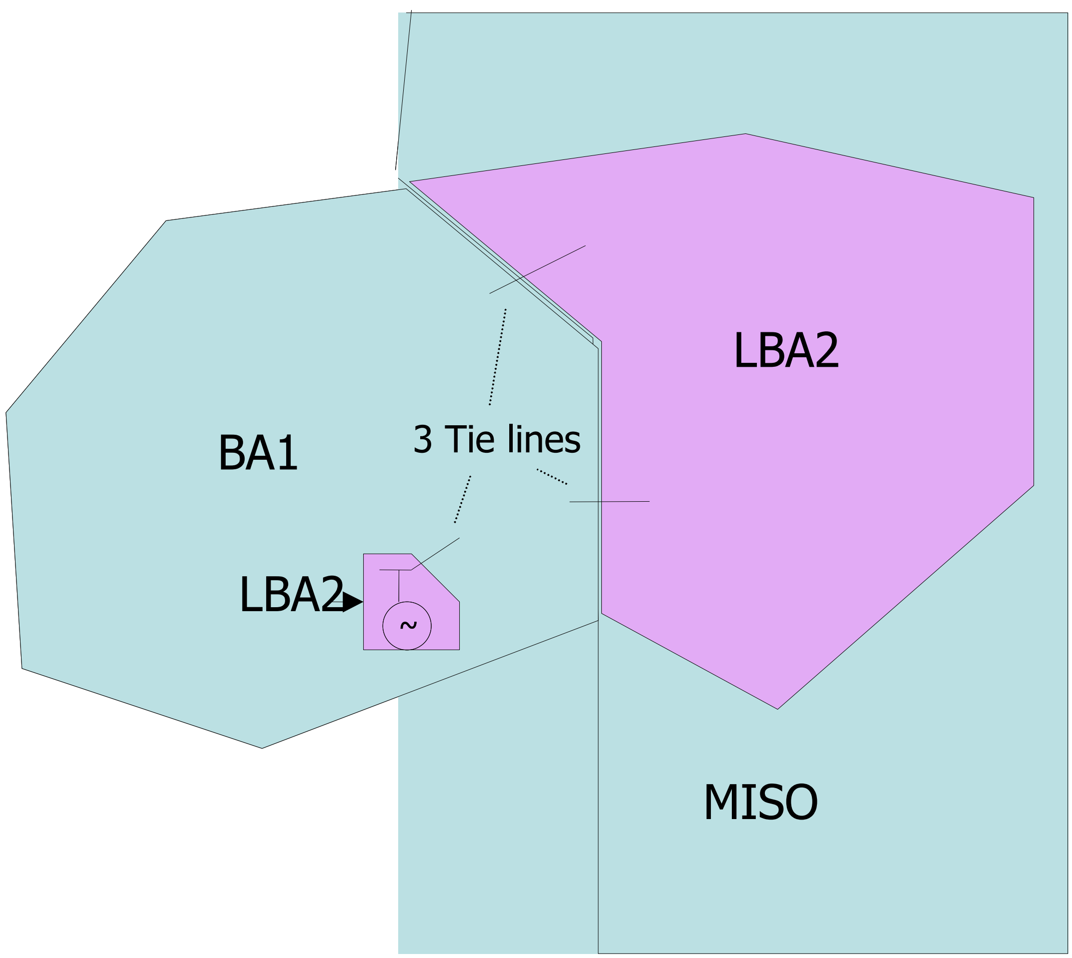
Example B2: A generator physically in LBA1 (within the MISO) but Pseudo-Tied to BA2 (out of the MISO) will be considered in BA2. The generator must be registered for congestion and loss charges only.

- Generator is a special CPNode BA2.xxxx PSG
- Registered for the MISO congestion and losses only
- Settled for LMP difference between PSG and BA2 Interface
- Financial schedule should be set up for settlements.
- MDMA upload on the CPNode is not needed for settlements.



Example B3: A generator physically in BA1 (out of the MISO) but Pseudo-Tied to LBA2 (within the MISO) will be considered in LBA2 and assigned as a Generation Resource in LBA2.

- Generator is a normal LBA2.xxxx Resource
- Subject to the MISO Energy and Operating Reserve Markets dispatch and Settlement
- Transmission Service across adjoining Transmission Service Provider to the MISO Market Footprint handled separately from the MISO Energy and Operating Reserve Markets and Transmission Service
- The MISO will verify applicable service arrangements that exist for these Resources.



Attachment C

EXTERNAL PSEUDO-TIED LOAD EXAMPLES

C. External Pseudo-Tied Load Examples

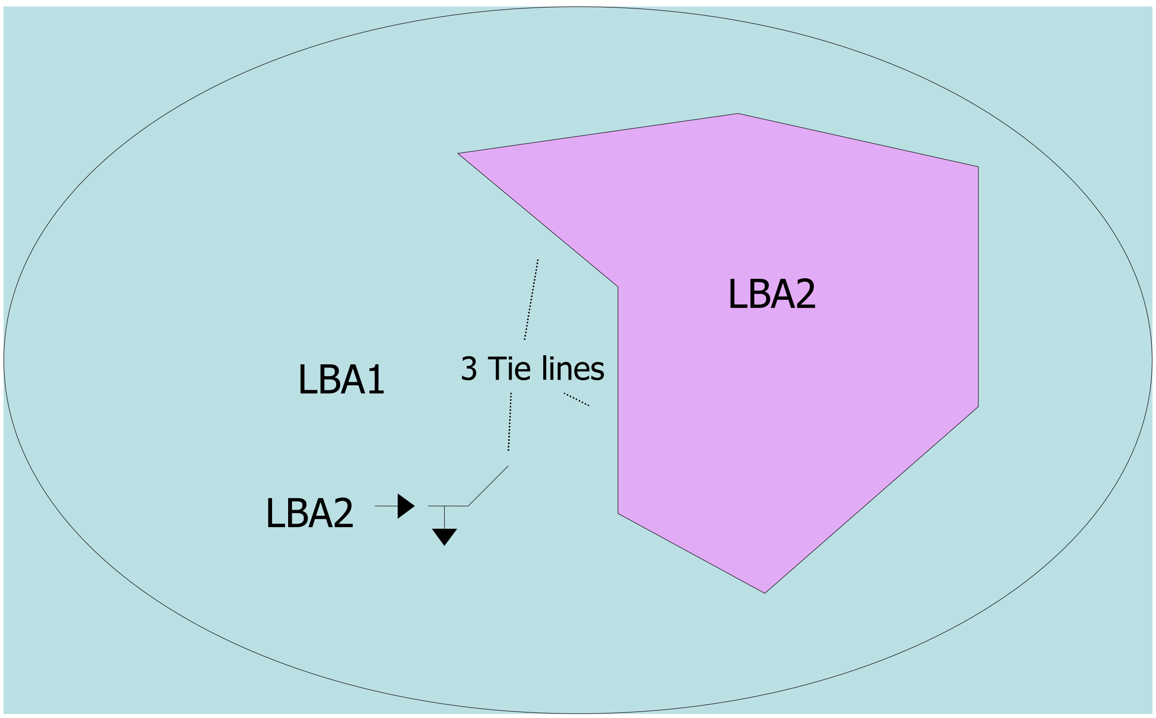
Pseudo-tie and Dynamic Schedule Loads

- A Load physically in LBA1 (within MISO) but Pseudo-Tied to LBA2 (also within MISO) will be considered in LBA2 and assigned to Load Zones defined in LBA2
- A Load physically in LBA1 (within MISO) but Pseudo-Tied to BA2 (not in MISO) will be considered in BA2. The Load must be registered for congestion and loss charges only.
- A Load physically in BA1 (not in MISO) but Pseudo-Tied to LBA2 (within MISO) will be considered in LBA2 and assigned to Load Zones defined in LBA2.
    - The Load will be subject to the MISO Energy and Operating Reserve Markets and accounted for in the centralized dispatch.
    - The Load is only subject to Transmission Service arrangements it has with these external entities and the MISO is not a party to these arrangements.
- A Load physically in LBA1 (within MISO) with Dynamic Schedule to BA2 (out of MISO) will be considered in LBA1 and assigned to Load Zones defined in LBA1
- A Load physically in BA1 (out of MISO) with Dynamic Schedule to LBA2 (within MISO) will be considered in BA1 and need not be registered.

The following examples help to illustrate these different scenarios.

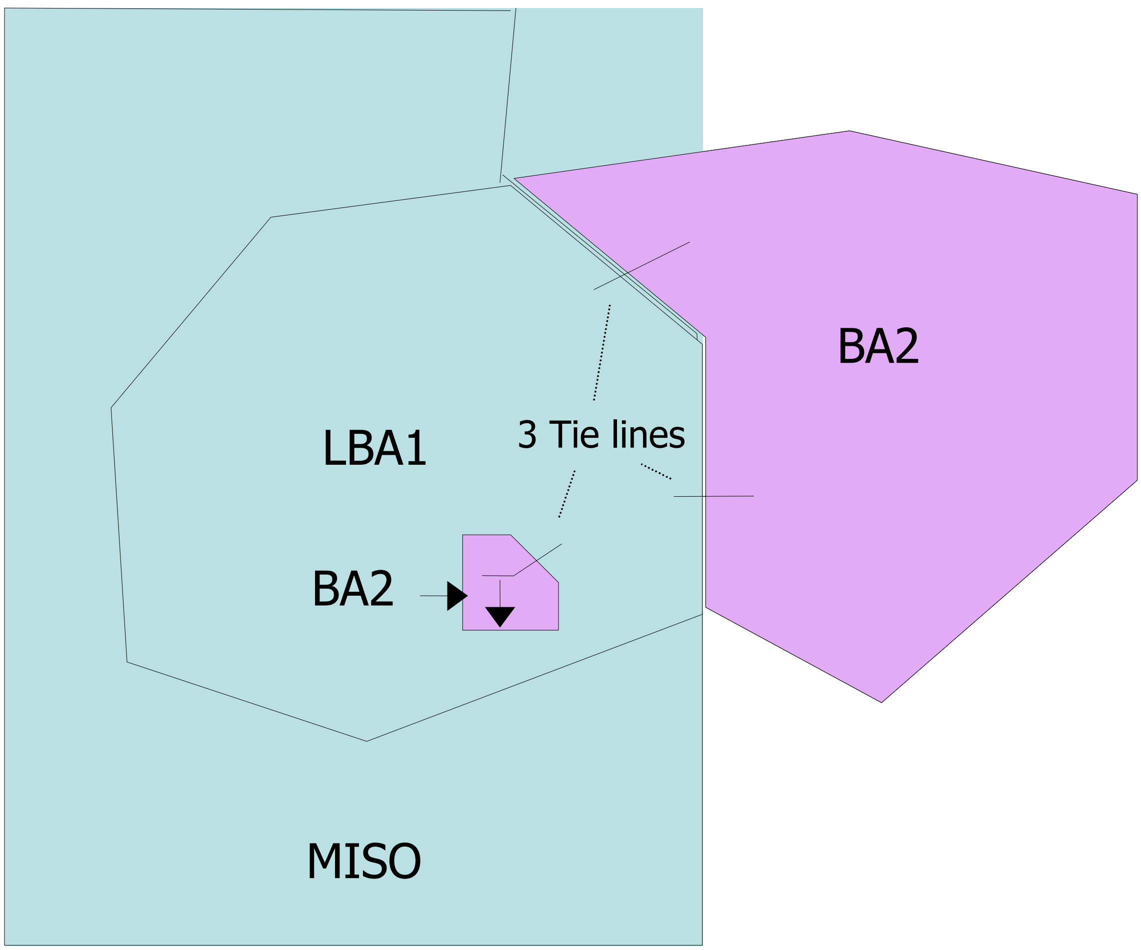
Example C1: A Load physically in LBA1 (within MISO) but Pseudo-Tied to LBA2 (also within MISO) will be considered in LBA2 and assigned to Load Zones defined in LBA2

- Load in LBA2.xxxx Load Zone
- Can be part of larger LBA2 Load Zone aggregated with load in primary LBA2 area
- Load in Pseudo-Tie area included in LBA2 Load Forecast.



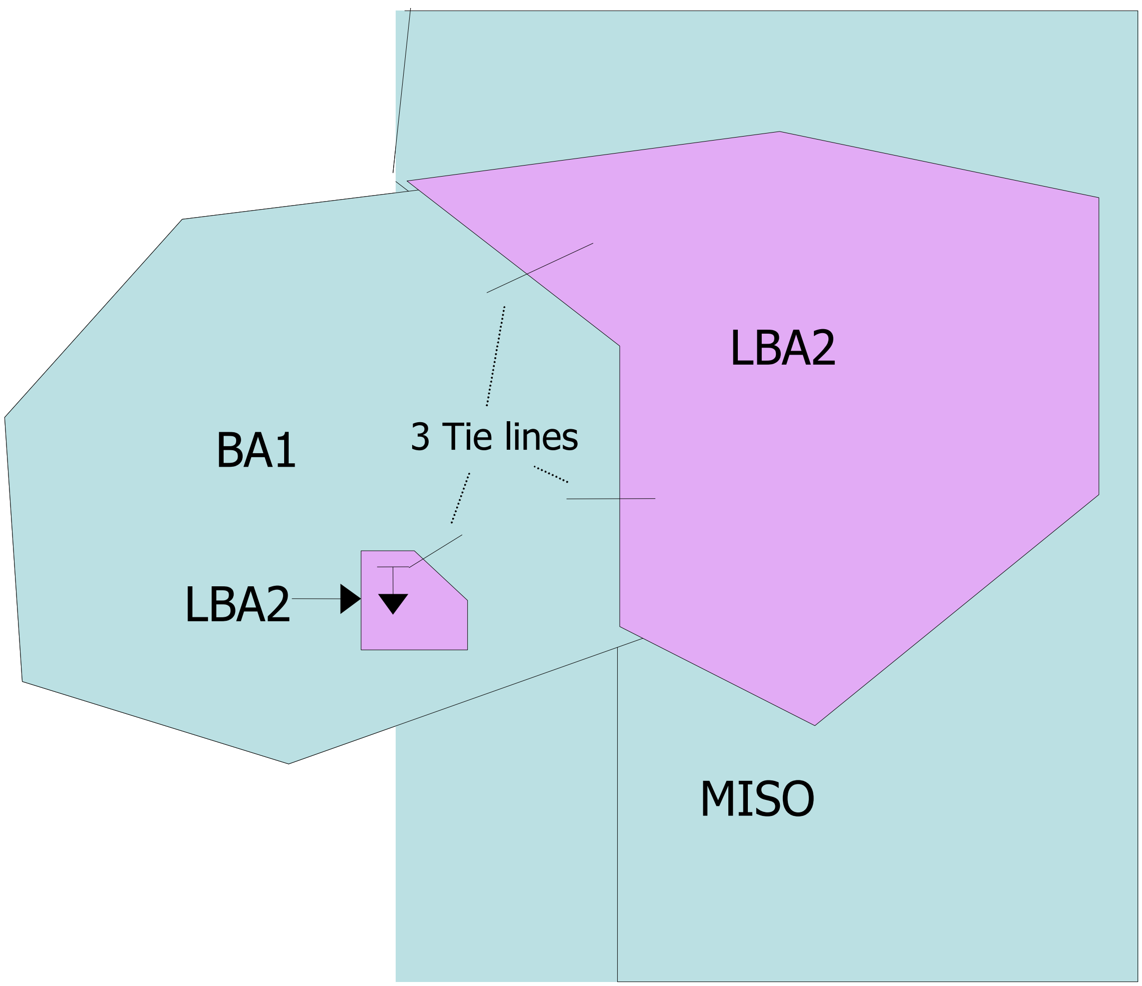
Example C2: A Load physically in LBA1 (within MISO) but Pseudo-Tied to BA2 (out of MISO) will be considered in BA2. The Load must be registered for congestion and loss charges only.

- Load in special BA2.xxxx Pseudo-Tie Load Zone (PSL)
- Registered for the MISO congestion and losses only
- Load not included in LBA1 Load Forecast
- Settled for LMP difference between BA2 interface and PSL
- Financial schedule should be set up for settlements.
- MDMA upload on the CPNode is not needed for settlements.



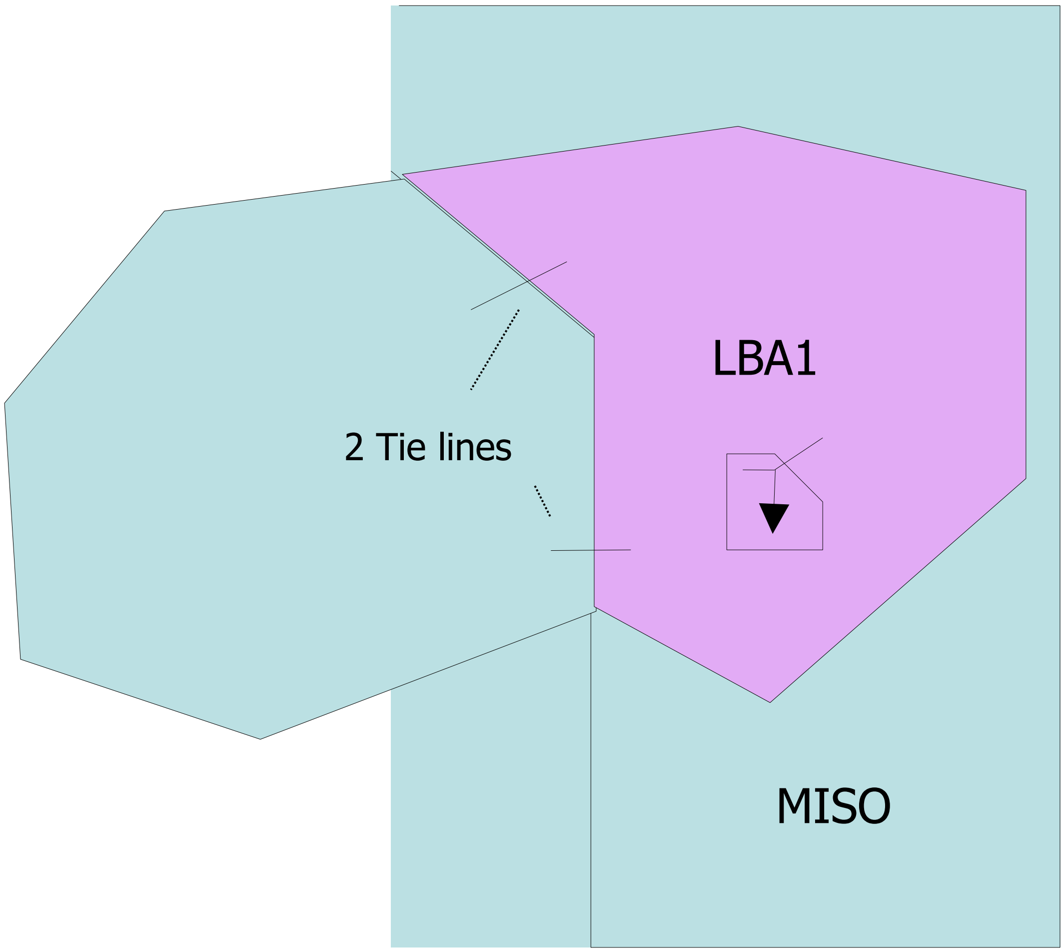
Example C3: A Load physically in BA1 (out of MISO) but Pseudo-Tied to LBA2 (within MISO) will be considered in LBA2 and assigned to Load Zones defined in LBA2.

- Load in normal LBA2.xxxx Load Zone
- Subject to the MISO Energy and Operating Reserve Markets dispatch and Settlement
- Load included in LBA2 Load Forecast
- Transmission Service from MISO to adjoining Transmission Service Provider handled separately from the MISO Energy and Operating Reserve Markets.



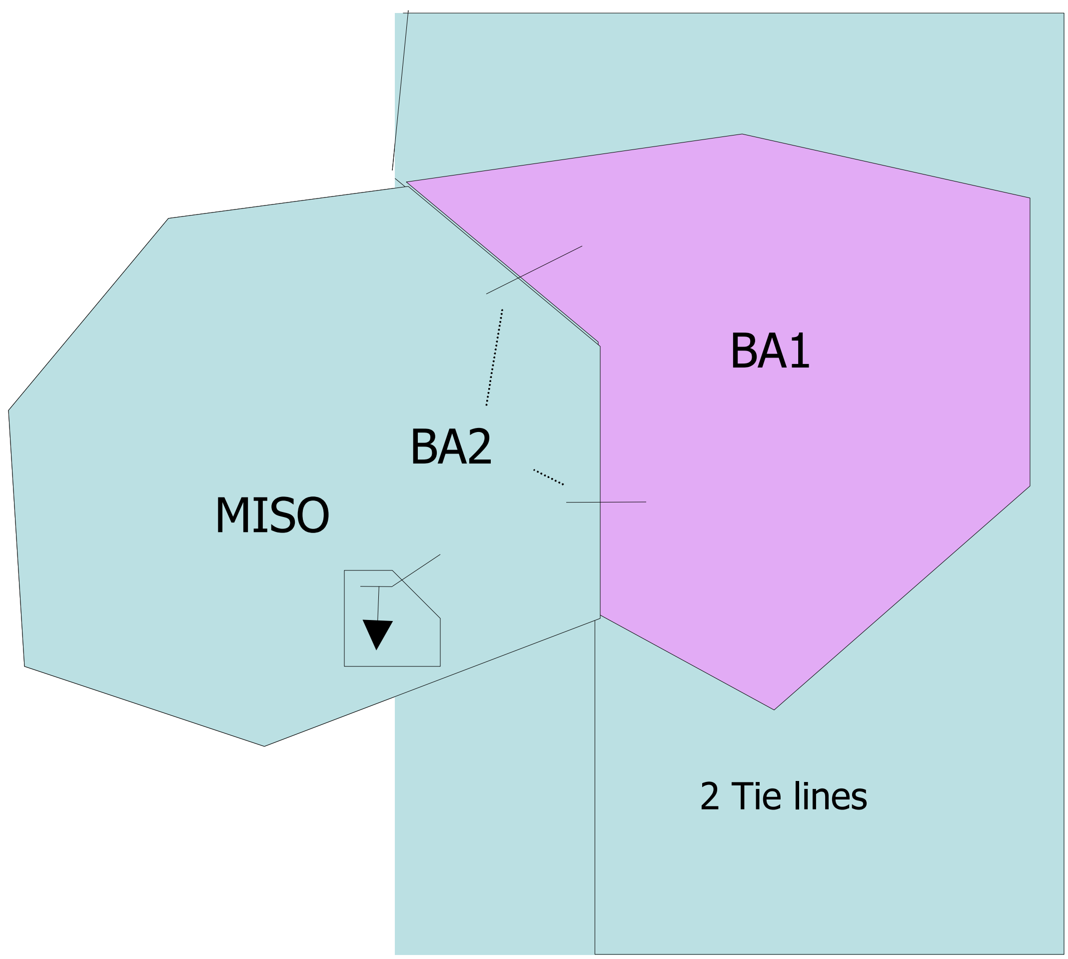
Example C4: A Load physically in LBA1 (within MISO) and dynamically scheduled to BA2 (not in MISO) will be considered in LBA1 and will be required to be registered for the MISO Energy and Operating Reserve Markets.

- Load is part of LBA1.XXXXX load zone
- Load is subject to the MISO Energy and Operating Reserve Markets dispatch and Settlement
- Load expected to be included in LBA1 Load Forecast.
- Must have Physical Bilateral Transaction (PBT) Schedule
- Delivery settled at the interface like all PBT Schedules
- The LBA is responsible for updating the actual values of the dynamic schedule after the fact in webTrans



Example C5: A Load physically in BA1 (not in MISO) and dynamically scheduled to LBA2 (within the MISO) will be considered in BA1 and not required to be registered for the MISO Energy and Operating Reserve Markets.

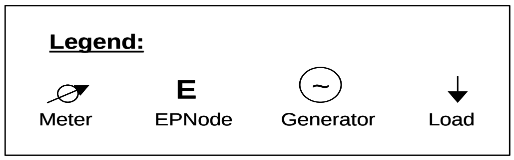
- Load not in the MISO Energy and Operating Reserve Markets
- Must have PBT Schedule
- Delivery settled at the interface like all PBT Schedules
- Load expected to be accounted for in BA1 NERC System Data Exchange (SDX) Load Forecast.



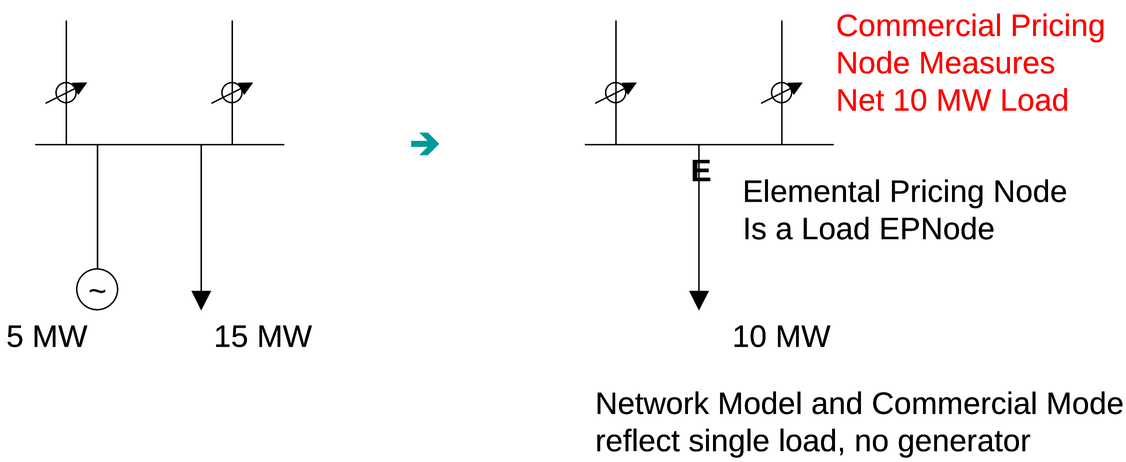
Attachment D

BEHIND-THE-METER AND BELOW THRESHOLD GENERATION MODELING EXAMPLES

D. Behind-the-Meter and Below Threshold Generation Modeling Examples

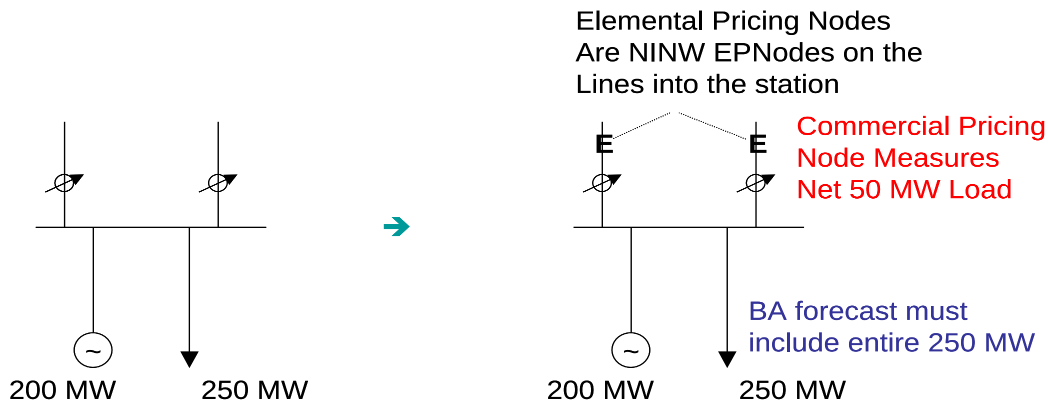


Example D1: Behind-the-Meter Modeling using a load EPNode: Small generator, not necessary for reactive support.



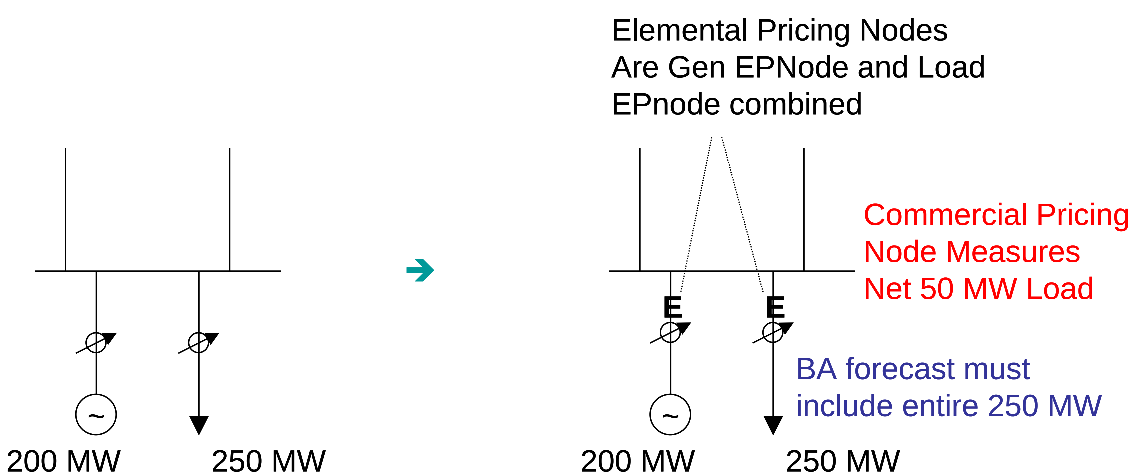
Note: Small generators here are less than 5MW and greater than 1 MW.

Example D2: Behind-the-Meter Modeling: Large generator, necessary for flexible reactive support – NINW Node option.



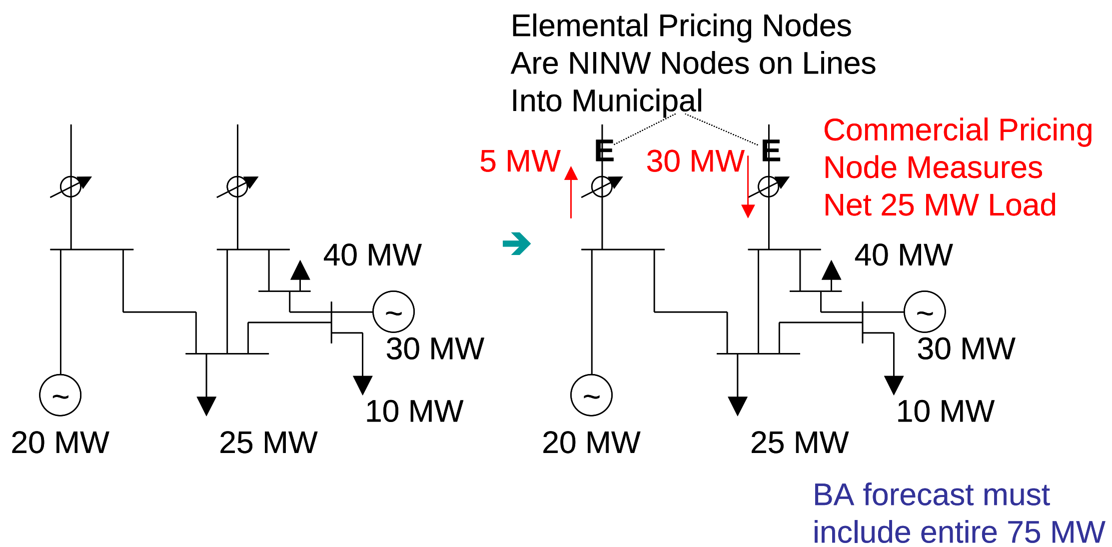
Network Model maintains Generation and Load while Commercial Model reflects aggregate of NINW EPNodes as a single Load Zone

Example D3: Behind-the-Meter Modeling: Large generator, necessary for flexible reactive support – Unit/Load option.



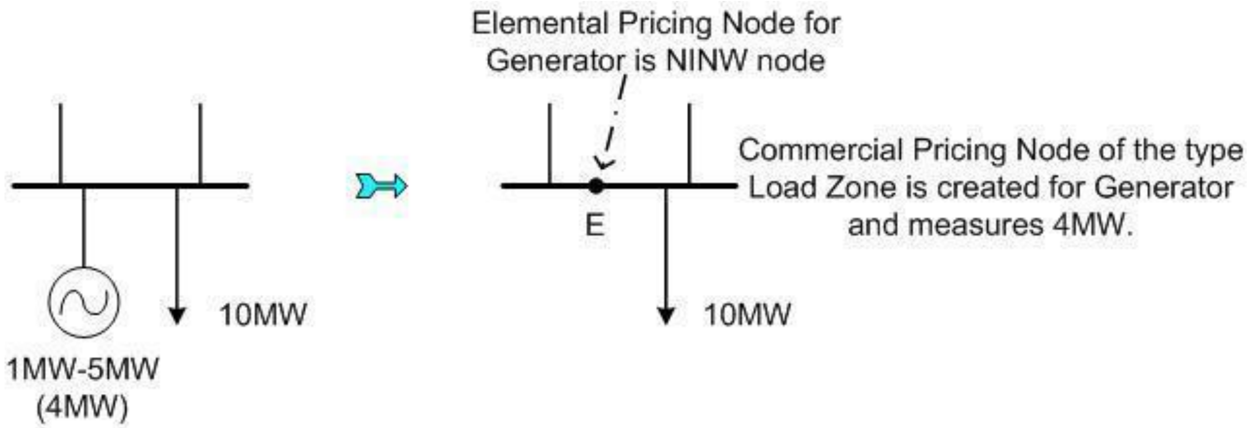
Network Model maintains Generation and Load while Commercial Model reflects aggregate of Gen EPNode and Load EPNode as single load zone.

Example D4: Behind-the-Meter Modeling: Networked large Municipal, need flexible reactive support and flow through representation.



Network Model maintains all Generation and Load while Commercial Model reflects aggregate of Net Line Flows into Municipal as a single Load Zone.

Example D5: Below Threshold Generation Modeling using a NINW EPNode: Generators (>= 1MW but < 5MW)



Attachment E

ASSET PARAMETERS FOR COMMERCIAL MODEL

Note on Dispatch Status:

The following default dispatch statuses are set during the Asset Registration for various asset types by the participants. All of these fields can be updated on an hourly basis, independently for the Day-Ahead and Real-Time Markets.

Energy Dispatch Status:

The Energy Dispatch Status determines if energy will be dispatched economically on a Resource by the SCED algorithm (Economic) or if the energy will be a fixed value specified by the participant (Self-Scheduled). Valid values are

- Economic
- Self-Schedule

Regulation Reserve Dispatch Status:

The Regulation Reserve Dispatch Status determines if regulating reserve capacity will be dispatched economically on a Resource by the SCED algorithm (Economic), be set to a fixed value specified by the participant (Self-Scheduled), or be made unavailable by the participant (Not Qualified/Not Participating). This field applies only to Resources that have the Regulation Qualified Resource set to "TRUE". Valid values are

- Economic
- Self-Schedule
- Not Qualified
- Not Participating

Spinning Reserve Dispatch Status:

The Spinning Reserve Dispatch Status determines if spinning reserve will be dispatched economically on a Resource by the SCED algorithm (Economic) or if the spinning reserve will be a fixed value specified by the participant (Self-Scheduled) or be made unavailable by the participant (Not Qualified). This field applies only to on-line Resources that have the Spin Qualified Resource Flag set to "TRUE". Valid values are

- Economic
- Self-Schedule
- Not Qualified

Supplemental Reserve Dispatch Status:

The Supplemental Reserve Dispatch Status (Online Supplemental Reserve) determines if supplemental reserve will be dispatched economically on an ON-LINE Resource by the SCED algorithm (Economic) or if the supplemental reserve will be a fixed value specified by the participant (Self-Scheduled) or be made unavailable by the participant (Not Qualified). This field applies only to those on-line Resources that are defined with the Spin Qualified Resource Flag set to "FALSE" and Supplemental Qualified Resource Flag set to "TRUE". Valid values are

- Economic
- Self-Schedule
- Not Qualified

Off-line Supplemental Reserve Dispatch Status:

The Off-line Supplemental Reserve Dispatch Status determines if supplemental reserve on an off-line or uncommitted quick-start Resource will be dispatched economically by the SCED algorithm (Economic), dispatched only under emergency conditions (Emergency), specified by the participant (Self-scheduled) or be made unavailable by the participant (Not Qualified). This field applies only to those off-line Resources that are defined with the Quick Start Qualified Resource Flag set to "TRUE" and Maximum Offline Limit of the Resource is defined with a positive value. Valid values are

- Economic
- Emergency
- Self-Schedule
- Not Qualified

Resources such as Generators, DRR - Type II's that are Spin Qualified must also be Supplemental Qualified to allow cleared on-line Spin Reserves to be substituted for Supplemental Reserves. Also, such Resources that are Regulation Qualified must also be Spin and Supplemental Qualified to allow cleared on-line Regulating Reserves to be substituted for Spinning or Supplemental Reserves.

The following table describes parameters that should be provided to model a Generation Resource in the Commercial Model:

Parameter Name	Values	Required	Description
Commercial Node Name	CPNode Name (Character)	Required	Commercial Node Name. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Maximum Output	Number(MW)	Required	Default unit maximum output submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI). Should not exceed a resource's interconnection service.
Minimum Output	Number(MW)	Required	Default unit minimum output submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI).
UNITTYPE	Name	Required	Unit type (Diesel, Steam Turbine, Combustion Turbine, Combined Cycle ST, Combined Cycle CT, Hydro, Wind, Pumped Storage, Other Peaker, Solar, Other)
FUELTYPE	Name	Required	Fuel type (Coal, Coal/Gas, Coal/Oil, Gas, Nuclear, Oil, Oil/Gas, Pet Coke, Waste, Water, Wind, Solar, Other)
Weather Point	Name	Optional	
Intermittent	Yes/No/DIR	Required	Intermittent flag indicates whether the unit is dispatchable or not. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Intermittent flag is set only for a Resource that qualifies as described in section 3.1.1.6.
DIR Forecast Feasibility Limit	MW	Optional/Required	A MW value is expected when Intermittent Flag is set to DIR. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
EIA Plant No	Name	Required	
EIA Unit No	Name	Required	

Parameter Name	Values	Required	Description
Default Status	Name	Required	Default Commit Status of the unit (Economic, Emergency, Must Run, Outage, Not Participating). Default value can be overridden by MP via Market Portal (DART MUI).
Default Ramp Rate	Number (MW/min)	Required	Default Ramp Rate of the unit. This single value applies to Hourly Ramp Rate, Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-Directional Down Ramp Rate for both Day-Ahead and Real-Time Schedule Offer. Separate default values for each individual ramp rate for Day-Ahead and Real-Time may be entered via the Market Portal (DART MUI).
MDMA	Metering Agent	Required	
24 Hour Contact Email		Optional	
24 Hour Contact Mobile		Optional	
24 Hour Contact Name		Required	
24 Hour Contact Primary Phone		Required	
24 Hour Contact Secondary Phone		Optional	
City		Required	
Facility Address		Required	
State		Required	
Zip Code		Required	
Regulation Max Limit	Number (MW)	Optional	The maximum output for which a Regulation Qualified Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit. Applies to regulating Resources only. Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Regulation Min Limit	Number (MW)	Optional	The minimum output for which a Regulation Qualified Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than the day-ahead / real-time Regulation Maximum Limit. Applies to regulating Resources only. Default value set

Parameter Name	Values	Required	Description
			in asset registration may be overridden by MP via Market Portal (DART MUI).
Max Offline Limit	Number (MW)	Required	The maximum amount of capacity that can be loaded in the lesser of ten minutes or the Contingency Reserve Deployment Period from a cold-start. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit and greater than or equal to the day-ahead / real-time Economic Minimum Limit. Applies only to Quick Start Resources qualified and available to supply supplemental reserve as off-line units. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
Regulation	Yes / No	Required	Regulation Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Regulation Qualified must also be registered as Spin Qualified and registered as Supplemental Qualified.
Spinning	Yes / No	Required	Spin Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Spin Qualified must also be registered as Supplemental Qualified.
Supplemental	Yes / No	Required	Supplemental Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Quick Start	Yes / No	Required	This value is set and updated through asset registration only. And cannot be changed via the Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Energy Dispatch Status	Economic/Self-Schedule	Required	Energy dispatch status of this unit. Default value may be overridden by MP via Market Portal (DART MUI).
Regulation Reserve Dispatch Status	Economic/Self-Schedule /Not Qualified/Not Participating	Required	Default Regulating Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Spinning Reserve Dispatch Status	Economic/Self-Schedule/Not Qualified	Required	Default Spinning Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Supplemental Reserve Dispatch Status	Economic/Self-Schedule/Not Qualified	Required	On-Line Supplemental Reserve Dispatch Status of the unit Default value may be overridden by MP via Market Portal (DART MUI).
Off-line Supplemental Reserve Dispatch Status	Economic/Self-Schedule/Not Qualified/Emergency	Required	Off-Line Supplemental Reserve Dispatch Status of the unit. This value may be overridden by MP via Market Portal (DART MUI).
Online STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Qualified	Yes / No	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Maximum Offline STR Response Limit	Number (MW) >= Minimum Output	Required	Not applicable for non-qualified resources. Default/registered value may be overridden via Market Portal (DART MUI).
Common Bus	Common Bus Name	Optional	If this generator becomes part of the Common Bus definition then the name of such Common Bus should be defined with this parameter. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Interconnection Agreement Number	Number	Required	Generation Interconnection Agreement Number (G123 or H012). This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Use Limited Resource	Yes/No	Required	Use Limited Resource - Please refer to Resource Adequacy BPM for explanation of how this parameter is used. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).

The following table describes parameters that should be provided to model **DRR Type I** in the Commercial Model

Parameter Name	Values	Required	Description
Commercial Pricing Node Name	CPNode name	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Common Bus	Common Bus Name	Optional	Two or more Demand Reduction Programs attached to the same host Load Zone can be defined on a Common Bus for compliance monitoring. The name of such Common Bus should be defined with this parameter. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Contingency Reserve Dispatch Status	Economic/Self-Schedule/Emergency/Not Qualified/Not Participating	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). MP may enter default values for Spinning Reserve Dispatch Status via the Market Portal (DART MUI) if Spin Qualified. MP may enter default values for Supplemental Reserve Dispatch Status via the Market Portal (DART MUI) if Supplemental Qualified.
Contingency Reserve Status	Offline/Online	Required	The Contingency Reserve Status determines whether the DRR – Type I will be considered to clear and deploy Spinning Reserves, or whether it will be considered to clear and deploy Supplemental Reserves. This value is initially set through asset registration and may be overridden by MP via Market Portal (DART MUI).
Default Status	Economic/Emergency / Not Participating	Required	Default Energy Commit Status. Default value may be overridden by MP via Market Portal (DART MUI).
MDMA	Metering Agent Name	Required	Meter Data Management Agent

Quick Start	Yes/No	Required	Whether the Resource can come online and produce output in 10 minutes (Quick Start Capable – Yes or No). This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Spinning	Yes / No	Required	Spin Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Spin Qualified must also be registered as Supplemental Qualified.
Supplemental	Yes / No	Required	Supplemental Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Target Demand Reduction Level	MW	Required	Default value for Targeted Demand Reduction Level. This value is initially set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
UNITTYPE	Name	Required	Unit type (DRR1)
MaxDailyCRDeployment	MWh	Optional	The maximum amount of contingency reserve deployment that may be supplied by the DRR during one operating day in the Real Time Energy & Operating reserve market. Default value set in asset registration may be overridden by MP via Market Portal (DARTMUI)
Offline STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Qualified	Yes / No	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Maximum Offline STR Response Limit	Number (MW) = Target Demand Reduction Level	Required	Not applicable for non-qualified resources. Default/registered value may be overridden via Market Portal (DART MUI).

The following table describes parameters that should be provided to model an **External Asynchronous Resource** (EAR) in the Commercial Model:

Parameter Name	Values	Required	Description
Commercial Pricing Node Name	CPNode name	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
UNITTYPE	Name	Required	Unit type (EAR)
MDMA	Metering Agent	Required	
Maximum Limit	Number (Mw)	Required	The maximum output attainable by an external market generation Resource under emergency / economic conditions in the Day-ahead / real-time market. Maximum limit submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI).
Regulation	Yes / No	Required	Regulation Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Regulation Qualified must also be registered as Spin Qualified and registered as Supplemental Qualified.
Spinning	Yes / No	Required	Spin Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Spin Qualified must also be registered as Supplemental Qualified.
Supplemental	Yes / No	Required	Supplemental Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Regulation Min Limit	Number (MW)	Optional	The minimum output for which a Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than the day-ahead / real-time Regulation Maximum Limit. Applies to regulating Resources only Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Regulation Max Limit	Number (MW)	Optional	The maximum output for which a Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit. Applies to regulating Resources only. Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Default Ramp Rate	Number (MW/min)	Required	Default Ramp Rate of the unit. This single value applies to Hourly Ramp Rate, Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-Directional Down Ramp Rate for both Day-Ahead and Real-Time Schedule Offer. Separate default values for each individual ramp rate for Day-Ahead and Real-Time may be entered via the Market Portal (DART MUI).
Energy Dispatch Status	Economic/Self-Schedule	Required	Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Regulation Reserve Dispatch Status	Economic/Self-Schedule /Not Qualified/Not Participating	Required	This value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Spinning Reserve Dispatch Status	Economic/Self-Schedule/Not Qualified	Required	This value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Supplemental Reserve Dispatch Status	Economic/Self-Schedule/Not Qualified	Required	This value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Online STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).

The following table describes parameters that should be provided to model a **DRR-Type II** Resource in the Commercial Model:

Parameter Name	Values	Required	Description
Commercial Pricing Node Name	CPNode name	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Regulation Max Limit	Number (MW)	Required	The maximum output Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit. Applies to regulating Resources only. Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Regulation Min Limit	Number (MW)	Required	The minimum output Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than the day-ahead / real-time Regulation Maximum Limit. Applies to regulating Resources only. Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Max Offline Limit	Number (MW)	Required	The maximum amount of capacity that can be loaded in the lesser of ten minutes or the Maximum Contingency Reserve Deployment Time from a cold-start. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit and greater than or equal to the day-ahead / real-time Economic Minimum Limit. Applies only to quick-start type 2 demand response Resources qualified and available to supply supplemental reserve as off-line Resources. Default value is set through asset registration only and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
Regulation	Yes / No	Required	Regulation Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via

Parameter Name	Values	Required	Description
			the Market Portal (DART MUI). Resources that are registered as Regulation Qualified must also be registered as Spin Qualified and registered as Supplemental Qualified.
Spinning	Yes / No	Required	Spin Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Spin Qualified must also be registered as Supplemental Qualified.
Supplemental	Yes / No	Required	Supplemental Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Quick Start	Yes / No	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
24 Hour Contact Email	Email Id	Required	
24 Hour Contact Mobile	Mobile Number	Required	
24 Hour Contact Name	Name of the person	Required	
24 Hour Contact Primary Phone	Phone number	Required	
24 Hour Contact Secondary Phone	Phone number	Required	
City	Address	Required	
Facility Address	Address	Required	
MDMA	Metering Agent	Required	
State	Address	Required	
Zip Code	Address	Required	
UNITTYPE	Type of the unit	Required	
FUELTYPE	Fuel type	Required	
Commercial Node Name	CPNode name	Required	
Minimum output	MW	Required	Default unit minimum output submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI).
Maximum output	MW	Required	Default unit maximum output submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Default Ramp Rate	Number (MW/min)	Required	Default Ramp Rate of the unit. This single value applies to Hourly Ramp Rate, Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-Directional Down Ramp Rate for both Day-Ahead and Real-Time Schedule Offer. Separate default values for each individual ramp rate for Day-Ahead and Real-Time may be entered via the Market Portal (DART MUI).
Default Status	Name	Required	Default Commit Status of the unit (Economic, Emergency, Must Run, Outage, Not Participating). Default value may be overridden by MP via Market Portal (DART MUI).
Energy Dispatch Status	Economic/Self-Schedule	Required	Energy dispatch status of this unit. Default value may be overridden by MP via Market Portal (DART MUI).
Regulation Reserve Dispatch Status	Economic/Self-Schedule / Not Qualified /Not Participating	Required	Default Regulating Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Spinning Reserve Dispatch Status	Economic/Self-Schedule	Required	Default Spinning Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Supplemental Reserve Dispatch Status	Economic/Self-Schedule	Required	On-Line Supplemental Reserve Dispatch Status of the unit Default value may be overridden by MP via Market Portal (DART MUI).
Off-line Supplemental Reserve Dispatch Status	Economic/Self-Schedule/Not Qualified / Emergency	Required	Off-Line Supplemental Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Online STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Qualified	Yes / No	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Maximum Offline STR Response Limit	Number (MW) >= Minimum Output	Required	Not applicable for non-qualified resources. Default/registered value may be overridden via Market Portal (DART MUI).
Common Bus	Common Bus Name	Optional	If this DRR becomes part of the Common Bus definition then the name of such Common Bus should be defined with this parameter. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
ICCP Available	Yes/No	Required	If DRR Type II Resource cannot provide ICCP Data then it will not be eligible to provide Regulation Reserves.
MaxDailyCRDeployment	Number(MWh)	Optional	The maximum amount of contingency reserve deployment that may be supplied by the DRR during one operating day in the Real Time Energy & Operating reserve market. Default value set in asset registration may be overridden by MP via Market Portal (DARTMUI)
MaxDailyRegUpDeployment	Number(MWh)	Optional	The maximum amount of net regulation reserve deployment that may be supplied by the DRR in the up direction during one operating day in the Real Time Energy & Operating Reserve market. Default value set in asset registration may be overridden by MP via Market Portal (DARTMUI)
MaxDailyRegDownDeployment	Number(MWh)	Optional	The maximum amount of net regulation reserve deployment that may be supplied by the DRR in the down direction during one operating day in the Real Time Energy & Operating Reserve market. Default value set in asset registration may be overridden by MP via Market Portal (DARTMUE)

The following table describes parameters that should be provided to model a **Combined Cycle Aggregate** Resource in the Commercial Model:

Parameter Name	Values	Required	Description
Commercial Node Name	CPNode name	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Maximum Output	Number(MW)	Required	Default unit maximum output submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI). Should not exceed a resource's interconnection service.
Minimum Output	Number(MW)	Required	Default unit minimum output submitted to asset registration initially is transferred as default Economic and Emergency limits to DART. These default limits can be changed via the Market Portal (DART MUI).
UNITTYPE	Name	Required	Unit type (Combined Cycle Aggregate, Other)
FUELTYPE	Name	Required	Fuel type (GAS, Water, Other)
Weather Point	Name	Optional	
Intermittent	No	Required	Intermittent flag indicates whether the unit is dispatchable or not. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Intermittent flag is set only for a Resource that qualifies as described in section 3.1.1.6.
DIR Forecast Feasibility Limit	N/A	Optional/Required	A MW value is expected when Intermittent Flag is set to DIR. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
EIA Plant No	Name	Required	
EIA Unit No	Name	Required	
Default Status	Name	Required	Default Commit Status of the unit (Economic, Emergency, Must Run, Outage, Not Participating). Default value may be overridden by MP via Market Portal (DART MUI).
Default Ramp Rate	Number (MW/min)	Required	Default Ramp Rate of the unit. This single value applies to Hourly Ramp Rate, Hourly Bi-Directional Ramp Rate, Hourly Single-Directional-Up Ramp Rate and Hourly Single-

Parameter Name	Values	Required	Description
			Directional Down Ramp Rate for both Day-Ahead and Real-Time Schedule Offer. Separate default values for each individual ramp rate for Day-Ahead and Real-Time may be entered via the Market Portal (DART MUI).
Regulation Max Limit	Number (MW)	Optional	The maximum output for which an Internal Market Generation Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit. Applies to regulating Resources only. Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Regulation Min Limit	Number (MW)	Optional	The minimum output for which an Internal Market Generation Resource can immediately respond to automatic control signals in the day-ahead / real-time market. Must be less than the day-ahead / real-time Regulation Maximum Limit. Applies to regulating Resources only. Default value set in asset registration may be overridden by MP via Market Portal (DART MUI).
Max Offline Limit	Number (MW)	Required	The maximum amount of capacity that can be loaded in the lesser of ten minutes or the Maximum Contingency Reserve Deployment Time from a cold-start. Must be less than or equal to the day-ahead / real-time Economic Maximum Limit and greater than or equal to the day-ahead / real-time Economic Minimum Limit. Applies only to quick-start internal market generation Resources qualified and available to supply supplemental reserve as off-line units. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Regulation	Yes / No	Required	Regulation Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Regulation Qualified must also be registered as Spin Qualified and registered as Supplemental Qualified.
Spinning	Yes / No	Required	Spin Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI). Resources that are registered as Spin Qualified must also be registered as Supplemental Qualified.
Supplemental	Yes / No	Required	Supplemental Qualified Resource Flag. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Quick Start	Yes / No	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Energy Dispatch Status	Economic/Self-Schedule	Required	Energy dispatch status of this unit. Default value may be overridden by MP via Market Portal (DART MUI).
Regulation Reserve Dispatch Status	Economic/Self-Schedule / Unavailable	Required	Default Regulating Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Spinning Reserve Dispatch Status	Economic/Self-Schedule	Required	Default Spinning Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).
Supplemental Reserve Dispatch Status	Economic/Self-Schedule	Required	On-Line Supplemental Reserve Dispatch Status of the unit Default value may be overridden by MP via Market Portal (DART MUI).
Off-line Supplemental Reserve Dispatch Status	Economic/Self-Schedule/Unavailable / Emergency	Required	Off-Line Supplemental Reserve Dispatch Status of the unit. Default value may be overridden by MP via Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Online STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Dispatch Status	Economic / Not Participating / Not Qualified	Required	Default/registered value may be overridden via Market Portal (DART MUI).
Offline STR Qualified	Yes / No	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).
Maximum Offline STR Response Limit	Number (MW) >= Minimum Output	Required	Not applicable for non-qualified resources. Default/registered value may be overridden via Market Portal (DART MUI).
Common Bus	Common Bus Name	Required	Parent and child nodes of the combined cycle will automatically be defined as part of the Common Bus definition. This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).

The following table describes additional parameters that should be provided to model an **Electric Storage Resource** (ESR) in the Commercial Model:

Parameter Name	Values	Required	Description
MinEnergyStorageLevel	Number (MWHr)	Required	The minimum amount of Energy that may be stored by an ESR on a sustained basis, expressed in MWHr, equivalent to the minimum State of Charge. Default value is set through asset registration only and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MaxEnergyStorageLevel	Number (MWHr)	Required	The maximum amount of Energy that may be stored by an ESR on a sustained basis, expressed in MWHr, equivalent to the maximum State of Charge. Default value is set through asset registration only and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MaxChargeLimit	Number (MW)	Required	The maximum withdrawal MW level at which an Electric Storage Resource may operate. Default value is set through asset registration, initially transferred to DART as Economic and Emergency values, and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MaxDischargeLimit	Number (MW)	Required	The maximum injection MW level at which an Electric Storage Resource may operate. Default value is set through asset registration, initially transferred to DART as Economic and Emergency values, and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MinChargeLimit	Number (MW)	Required	The minimum withdrawal MW level at which an Electric Storage Resource may operate. Default value is set through asset registration,

Parameter Name	Values	Required	Description
			initially transferred to DART as Economic and Emergency values, and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MinDischargeLimit	Number (MW)	Required	The minimum injection MW level at which an Electric Storage Resource may operate. Default value is set through asset registration, initially transferred to DART as Economic and Emergency values, and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MaxRegulationChargeLimit	Number (MW)	Required	The maximum withdrawal MW level at which an Electric Storage Resource can respond to automatic control signals. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MaxRegulationDischargeLimit	Number (MW)	Required	The maximum injection MW level at which an Electric Storage Resource can respond to automatic control signals. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MinRegulationChargeLimit	Number (MW)	Required	The minimum withdrawal MW level at which an Electric Storage Resource can respond to automatic control signals. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
MinRegulationDischargeLimit	Number (MW)	Required	The minimum injection MW level at which an Electric Storage Resource can respond to automatic control signals. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).

Parameter Name	Values	Required	Description
Charge Ramp Rate	Number (MW per Minute)	Required	The MW/minute response rate for an ESR moving from zero output to its Hourly Economic Maximum Charge Limit and/or from the Hourly Economic Maximum Charge Limit to zero output, in response to Setpoint Instructions. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
Discharge Ramp Rate	Number (MW per Minute)	Required	The MW/minute response rate for an ESR moving from zero output to its Hourly Economic Maximum Discharge Limit and/or from the Hourly Economic Maximum Discharge Limit to zero output, in response to Setpoint Instructions. Default value is set through asset registration and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).
Electric Storage Efficiency Factor	Number (between 0 and 1 with 0.0001 precision)	Required	An operating characteristic of an ESR that is the amount of increase in Energy Storage Level for each 1 MWh of Charge Energy withdrawn by that Resource. Default value is set through asset registration only and may be overridden by MP via the Schedule Offer submittal via Market Portal (DART MUI).

The following table describes parameters that should be provided to model a **Load Zone** in the Commercial Model:

Parameter Name	Values	Required	Description
Load Zone/Pseudotied load zone Name	CPNode Name	Required	This value is set and updated through asset registration only and cannot be changed via the Market Portal (DART MUI).

MDMA	Metering Agent	Required	Abbrev name of the Metering Data Management Agent for this Resource. For Pseudo-tied load zones this is just a place holder only and the actual transaction is settled based on financial schedule. Please refer to *BPM 005 - Market Settlements*. This value is set through asset registration process only
Percentage	Number	Required	Percentage of the EPNode that is assigned to the CPNode. The number should be >= 0.001% and <= 100%. This value is set through asset registration only
Participate in Retail Choice	Boolean (0-No/1-Yes)	Required	Yes - Load switch occurs between Asset Owners as in Retail Choice Market, No - Load Switch does not occur between Asset Owners.
Energy Distribution Company (EDC)	EDC Abbrev name	Dependent	Yes for Retail Choice- Provide Energy Distribution Company (EDC) Mapping. This value is set through asset registration only

Attachment F

ICCP REQUIREMENTS FOR TIE LINES

The inputs required for a market tie in the model are shown in the table below. The inputs that would are requested from an LBA are as following. Primary Tie Line measurement (TMW) is always received from MISO Internal LBA

Input Name	Values	Required	Input Description
Tie Ordering Location	Station name	Required	Matching the order of the LBA system tie ordering
Tie Metering Location	Station name	Required	The metering point that both the LBA and the adjacent tier 1 BA agree to measure the exchange flow at.
Preferred Tie ID	14 characters limit	Required	Matching the name LBA is using in their system and accustomed with.
Tie Long Common Name (60 characters limit)	60 characters limit	Required	Providing the description of the tie line
TMW measurement	MW	Required	Metered MW tie line measurement indicating the flow at the agreed metering location provided by the MISO LBA (internal)
MWH measurement	MW	Required	Hourly aggregated MW tie line measurement indicating the aggregated hourly flow at the metering location provided by the MISO LBA (internal)

Following are the inputs that should be provided by Tier 1 BA for a market tie line. Secondary Tie Line measurement (TMW1) is always received from Tier 1 BA.

Input Name	Values	Required	Input Description
TMW1 measurement	MW	Required	Metered MW tie line measurement indicating the flow at the agreed metering location provided by the External Balancing Authority (external to MISO)
Agreed Tie Metering Location	Station name	Required	Mutually agreed upon location between the two adjacent areas