Manual No. 004

Business Practices Manual

Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR)

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Revision History

Doc Number	Description	Revised by	Effective Date
BPM-004-r26	Annual Review Completed. Corrected typographical errors.	D. Vasquez	JUN-06-2023
BPM-004-r25	Updated language in sections 4.10.1 and 4.10.2 to change the maximum acceptable price for FTR bids to +/- $150,000/MW and the minimum acceptable price for FTR offers to +/- $150,000/MW	J. Dannis	APR-06-2023
BPM-004-r24	Updated language in sections 4.10.1 and 4.10.2 to change the maximum acceptable price for FTR bids to +/- $250,000/MW and the minimum acceptable price for FTR offers to +/- $250,000/MW	J. Dannis	MAR-01-2023
BPM-004-r23	Annual Review Completed. Updated language in Section 2 (Exhibit 2-1 as well as 2.2) Updated references to MISO's Client Accounts and Readiness team Updated links to certain reference documents and templates 3.25: Removed the confusing statement regarding eligibility for network upgrades. 4.9: Removed the confusing statement regarding eligibility for network upgrades.	B. Buescher	JUN-01-2022
BPM-004-r22	Annual Review Completed 3.11.3: Updated to state that MISO could lower the Market Participant's pre-populated LTTRs down to the Stage 1A cap. 4.10.8.3: Removed the confusing table/example regarding eligibility of a self-Scheduled ARR in each round 6.2: Updated the example for ARR Clearing Price Calculation 7.2.3: Removed description of local transmission constraint management	B. Buescher	JUN-01-2021
BPM-004-r21	Annual Review Completed. • 3.11: Described Stage 1A infeasible LTTRs renomination in Stage 1B • 3.20: Updated infeasible LTTRs as the non-allocated Stage 1A infeasible LTTR candidates in stage 1B	B. Buescher S. Xu	JUN-01-2020
BPM-004-r20	• Annual Review Completed.Corrected typographical errors	P. Nathan	JUN-01-2019

Doc Number	Description	Revised by	Effective Date
	• Removal of references to ARR Administration Tool • Electronic signoff of PTP/GFA ARR Entitlements during Annual Registration How wholesale Load shift is reflected in absence of agreement among parties		
BPM-004-r19	Annual Review Completed. • Updated Disclaimer section • Updated hyperlinks to the new MISO website	P. Nathan	JUN-01-2018
BPM-004-r18	Annual Review Completed. Corrected typographical errors • Added MVP process to ARR/FTR Systems overview diagram • 3.8.3.5: Clarified the condition when a Category 2 ARR Zone is created for an Option B GFA conversion to tariff service • 3.9.1.4.2: Reiterated the circumstances when load EPNodes served by Option B will not be excluded from Category 1 ARR Zone • 3.24: Removed earlier reliance on 12 month load forecast used in calculation of NPLF • 3.24.1.1: Removed the requirement of retail choice suppliers from submitting Load forecast in the Module E tool • 3.25.1: Added clarity to the conditions to be met to qualify for ILTTRs • 3.25.2: Reduced the number of business days to choose the round from 5 days to 2 days • 3.25.3: Described the process of confirming the Network upgrade request • 3.25.5: Added clarity to the ILTTR Study process by describing the ILTTR Study model building process; Added language about network upgrades collectively funded by multiple market participants are studied as a single ILTTR study • Changed Section number of Multi-Value Project from 3.27 to 3.28 • 3.28: Evaluation of multi-segmented or combined projects as a single path • 4.9.1: Reduced the number of business days to choose the round from 5 to 2	P. Nathan	JUN-01-2017

Doc Number	Description	Revised by	Effective Date
	• 4.9.2: Described the process of confirming the Network Upgrade request • 4.9.4: Added clarity to the IFTR Study process by describing the IFTR Study model building process; added language about Network Upgrade collectively funded by multiple Market Participants will be studied as a single IFTR study • 4.10.2 FTR Offers: Acceptance of FTR Offers on same Bus FTRs • Added a section (4.10.10) to describe circumstances when an auction bidding window will be extended		
BPM-004-r17	Annual Review completed. Updated the following sections: • 3.9.1.1: Removed Exhibit 3-3 Category 1 ARR Zones • 3.9.2: Removed Exhibit 3-4 Interface CPNodes that can be specified as the Point of Receipt on the firm drive-in Network TSR • 3.10: Replaced references to three phases of the ARR Registration procedures with a single phase • 3.10.7: Stated the procedure for transferring the Self-Scheduled FTRs held on behalf of Carved-Out GFAs to Market Participants converting the GFA to Tariff service • 3.27: Updated the MVP ARR project in service date analysis procedure • 4.10.1; 4.10.8.4; and 4.10.9 Clarified the process of resettling cleared FTR bids on same Bus FTR paths • 4.10.4: Revised the language about the posted DA MCC • 4.10.6: Revised FTR Bid and Offer data posting schedule from 3 months to 90 days and how an individual entity's bids and offers can be tracked over time while still maintaining the confidentiality of the FTR Bidder and Offeror • 4.10.8.1 and 4.10.9.1: Specified what kind of data is posted in the FTR Auction results; Changed bid cap to 6000 Corrected typographical errors	P. Nathan B. Borissov	JUN-01-2016

Doc Number	Description	Revised by	Effective Date
BPM-004-r16	Corrected typographical errors Changed all email addresses to Client Relations to streamline the communication process Updated references to Module A Tariff definitions Updated the following sections: • Added SME.AZ to Category 1 ARR Zone and removed AMRN.AZ ARR Zone • 3.9.2.1: Described capacity factor data gathering process for registering PTP ARR Entitlements that has source residing outside MISO footprint • 3.9.2.8: Nomination eligibility of ARR Entitlements associated to a PTP commencing after applicable Reference Year in Stage 1 • 3.10.1: Accept digital signature in Phase 1 of the annual ARR registration and eliminate the manual signoff step • 3.10.5 and 3.10.6 Modified Entitlement registration sections to accommodate the Market Participant's ability to register PTP entitlements after year 1 • 3.21.1.1: Changes to RSP Termination Eligibility Rules ○ Removed following rule: Market Participant requesting termination is the same Market Participant whose ownership of or contractual relationship with the Generation Resource was the basis for original inclusion of the RSP • 4.3: FTRs does not protect against congestion charge from Real-Time LMPs • 5: Market Participant ability to transfer Transaction charges during a Secondary FTR Market transfer • 6.4: Clarified that MVP ARR is valued based on equal average of three rounds of Annual FTR Auction and they are in the nature of options.	P. Nathan	JAN-01-2016
BPM-004-r15	Annual Review completed by conforming the document to MISO standards	P. Nathan	JUN-01-2015

Doc Number	Description	Revised by	Effective Date
BPM-004-r14	Corrected typographical errors New Section describing Multi-Value Project ARR Entitlements Updated the following sections: • Section 4.6 – Added how Source and Sink of FTRs are remapped when CPNode types other than Generator; Load Zone; Interface and Hub terminates and situations when temporary CPNode are created for informational purpose • Changes to other sections impacted by MVP ARR Entitlements addition • Section 3.27.3 Included loopflow change as one of the model updates in section 3.27.3.1 for LTTR impact analysis due to member departure • Section 3.21.1.1 & 3.21.1.2 Changes to RSP Termination Eligibility Rules o Removed following rule: Market Participant's ineligibility to request RSP termination if Market Participant nominates from such a RSP in the current annual allocation. • Section 3.25.8: Clarified that the infeasible LTTR study is only designed as part of the MTEP process.	P. Nathan X. Wang	10-01-2014
BPM-004-r13	Annual Review Completed and no changes made	P. Nathan	06-01-2014
BPM-004-r12	Corrected typographical errors Updated the following sections: • Sections 3.8.2; 3.19; and 4.10.8.3 – refined the statement about allocated ARR and self-scheduled FTR(s) when a Market Participant doesn't exercise the PTP rollover rights, to MISO Tariff • Section 4.10.1.1 – New Section describes FTR Bid Curve characteristics • Section 4.10.2.1 – New Section describes FTR Offer Curve characteristics • Section 3.25.4 and 4.9.3 – Changed the PJM specific language regarding ILLTR and IFTR Request Process to include other external reciprocal entities • Section 4.6 – Clarified how temporary CPNodes is created to replace the terminating embedded BAs within external BAs that are integrating into MISO	P. Nathan X. Wang	FEB-21-2014

Doc Number	Description	Revised by	Effective Date
	• Added Category 1 ARR Zones defined during Entergy Integration		
BPM-004-r11	Updated Sections 3.21.4, 3.23.1, and 3.23.2 to reflect changes to RSP submittals via MUI for Round 1(Terminations), Round 2 (BRSS Addition/Replacement), Round 3 (PRSS Addition/Replacement). Removed references to the RSP Templates which are no longer used as part of the RSP Process. Added Appendix M reference to section 3.21 with an example of the Minimum Acceptance Ratio. Migrated Section 3.23 into Section 3.21 and made 3.23 "Reserved". Updated and changed "Monthly FTR Auction wording to "Multi-Period Monthly Auction". Updated Section 4.10.9 to include Multi-Period Monthly FTR Auction.	S. Sonti	OCT-17-2013
BPM-004-r10	Annual Review Completed and updated following sections: • Section 3.9.1.2 b 1– New Section clarifying Category 2 category requirements. Section 3.9.1.2 b i a is now Section 3.9.1.2 b 2 • Section 3.9.2.1 – Edited first paragraph to clarify capacity factor data gathering • Section 3.9.2.3.1 – New section describing HUFU RSP • Section 3.9.2.4 – New Section describing HUFU ARR Entitlements • Section 3.9.2.5 – New Section describing Reserved Source Points (RSPs) exception for BRSS • Section 3.9.2.6 – New Section describing the process of rejecting BRSS Entitlements created by Section 3.9.2.5 • Section 3.9.2.7.1 – New Section describing HUFU ARR Entitlement treatment in Stage 1A • Section 3.9.2.8.1 – New Section describing HUFU ARR Entitlement treatment in Stage 1B • Section 3.20.1 – New Section describing Transitional Infeasible ARRs Uplift • Section 3.21 – Updated to reflect HUFU RSPs • Section 3.24 – Load Growth – comprehensive rewrite to reflect updated procedures	S. Sonti	MAY-28-2013

Doc Number	Description	Revised by	Effective Date
	• Section 3.24.1 – Example demonstrating the conversion of Module E data to NPLF – comprehensive rewrite to reflect updated Section 3.24 • Section 3.25.6 – Network Upgrade Treatment from Integrating to the Transmission Provider • Section 3.27 – New Section describing the Assessment of the impact on LTTRs resulting from a departing Transmission Owner • Section 4.10.1 - Same-Bus FTR bid rules • Appendix L – New Section illustrating the of administration of Heat Rate Stack rule		
BPM-004-r9	Updated following sections: • Section 4.6.1 – CPNode replacement for LTTR • 4.10.6 – Masked bid data posting changed from 6 to 3 months • 4.10.8 and 4.10.9 – Changed bid cap to 4000	S. Sonti	APR-03-2012
BPM-004-r8	Section numbers corrected (all sections had slipped one number down in r7), exhibit references corrected for the appendices, page numbers corrected for certain sections	S. Sonti	Sep 15, 2011
BPM-004-r7	New section 4.6 for FTR remapping when CPNode terminates, Clarify section 5 for Secondary Market, Changed “The/ the Midwest ISO” to “MISO”, updated hyperlinks at several locations to replace with new MISO website location, changed the section numbers for the Appendix sections from alphabets to numericals, Revised section 3.21 describing the failed SFT of the BRSS RSP and its placement into PRSS, Added new subsection 3.21.3 describing the re-evaluation of the RSP into BRSS, Added new Appendix K with an example for RSP addition/ replacement process	S. Sonti	Sep 15, 2011
BPM-004-r6	Removed language throughout the BPM, particularly in section 4.6 referring to the previously offered service which enabled MPs to request FTRs associated with new PTP TSRs. This service is no longer available per FERC’s order on Docket No ER10-2393; changed logo	Z. Joundi	MAY-05-2011
BPM-004-r5	Clarified language addressing FTRs associated with mid planning year GFA conversion in section 3.8.3.6, included Category 1 ARR Zone BRPS.AZ in Exhibit 3-3, included timeline for acceptance of	A. Pewarski	MAR-08-2011

Doc Number	Description	Revised by	Effective Date
	GFA Change Templates in section 3.10.7, Updated Annual FTR Auction bid/offer limits in section 4.10.8.1-8, updated Monthly FTR Auction bid/offer limits in section 4.10.9.1-4		
BPM-004-r4	Pursuant to Feb 12, 2010 FTRWG comments and other Market Participant comments received by Feb 12 deadline on this version of BPM, following clarifications/ updates were made to these Sections - 3.20.2 (RSP addition for BRSS), 3.10.3.1 (Priority to LSEs), 3.12 (Stage 2 ARRs), Appendix G (Stage 2 example enhanced), 3.10.3 (prorate LTTRs in excess of Stage 1A cap, Year 2 vs. Year 3 clarification), LTTR termination flowchart (Exhibit 3-7) and vintage year location. Revisions to this version that were reviewed at the Feb 12, 2010 FTRWG meeting - Noted that Section 3.11 (ECCH) is no longer applicable and deleted the entire section leaving the section reserved, Provided details on BRSS check for JOUs in Section 3.8.2.1, Changed reference from Transmission Provider to MISO at various locations, Provided clarification to Section 3.12 (Stage 2 allocation) and Appendix G per Feb 12 FTRWG comments, Revised following sections pursuant to the Jan 11, 2010 Order on the LTTR and RSP termination — 3.10 (Stage 1A nomination), 3.10.5 (updated the section to reflect LTTR Restoration and Termination), 3.12 (Stage 2), 3.22 (Generator Resource retirement and PPA termination), Appendix C and H, Added new Appendix J	S. Sonti	MAR-08-2010
BPM-004-r3	BPM number in the header changed per MISO Control Documents process, BPM file name changed accordingly, Deleted the Issue Date column from this history table per MISO Control Documents process, Clarified Sections 3.24.4, 2.24.5, 3.24.7 and 4.9.3 per Ameren's comments, Revise Section 3.25 (LTTRs/FTRs for Network Upgrades) with more details, Update Section 3.24 and 3.9.6 to reflect the revised NPLF calculation as discussed at the Aug 17, 2009 special FTRWG, Remove Section 6.4 on the Settlement of Counterflow FTRs during FTR Source outage, Reflected Bid/Offer count cap at Sections 4.10.8 and 4.10.9, Reflected Bid/Offer price cap at Sections 4.10.1 and 4.10.2, Create section 3.20 and include 3.20 and 3.21 as its subsection. Added language to Section 3.20.1 (RSP	S. Sonti	Jan 12, 2010

Doc Number	Description	Revised by	Effective Date
	replacement) pursuant to Issue 40 of the FTRWG Issues List, Clarifications to Section 3.20.2 (RSP addition). Add section 3.20.3 for the timing of addition and replacement of RSP and PTP, Added Section 3.11.6 for Partial Year FTR Allocation, Clarifications to Section 3.9.7 (GFA Registration)		
MO-BPM-003-r2	Updated to reflect the new name of the ASM Tariff.	C. Tinch	JAN-06-2009
MO-BPM-003-r1	Changed the effective date from Sep 03, 2008 to Nov 21, 2008 when this final version was fully discussed with the FTRWG, Capitalized Allocation Period globally and defined it in Section 3.9.4, minor clarifications to Sections 3.20 and 3.21, updates to Sections 3.9.6.1, 3.9.6.2 and Appendix F per FTRWG conference call on Nov 21, 2008, expanded the definition of DNR in Section 3.8.2 Added Section 3.10.2, major revisions to Sections 3.9.6, 3.24 and Appendix F, minor revisions to Sections 3.8.2.1 (updated Deliverability Study results link), 3.9.5, 3.10.5 (bullet 9 to reflect the new deliverability results link referenced to section 3.8.2.1), 3.26.3.1 (provided the link for the RLS load shift template), 6.1, 6.2 and 6.3. Major revisions were made in the following sections: 6.1, 6.2 and 6.3. Section 6.4 new section for Counterflow FTRs Section 6.1 Distribution of FTR Annual Auction revenue Section 4.10.9.3 FTR monthly auction feasibility – new flowchart Section 6.2 ARR settlements in multi-round FTR auction Section 4.10.8.3 Self-Schedule Rollover Over ARRs Section 3.25 Network Upgrades and Eligibility of Network Upgrade Entitlement in Stage 1A, 1B as well as Stage 2 Section 4.9 FTRs for Network Upgrades – replace ARR with FTR-minor correction Section 3.11 The impact of ECCH treatment on Infeasible ARRs Section 3.7.3.4 Clarification on eligibility of GFA conversion and “year 1” Section 3.9.6 AE/LTTR reassignment methodology due to Load Shift (ARR Admin Tool Phase II design) Section 3.26 Revenue redistribution due to Load Shift (Settlements)	S. Sonti	NOV-21-2008

Doc Number	Description	Revised by	Effective Date
	Section 4.10.8.2 Determination of Available Transmission Capacity in multi-round Annual FTR Auction – new section Section 4.10.8.3 Determination of Self-scheduled ARR MW in multi-round Annual FTR Auction Changes on tables and chart in various sections to make the format consistent		

Contents

List of Exhibits:

1. Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM)* for Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) includes basic information about this BPM and other MISO BPMs. The first section (Section 1.1) describes the purpose of MISO BPMs. The second section (Section 1.2) is an introduction to this BPM. The third section (Section 1.3) identifies additional documents, which may be used by the reader as references when reading this BPM.

1.1 Purpose of 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

BPM-004 *FTR and ARR Business Practices Manual* focuses on guidelines, rules, and business processes used to comply with MISO and Market Participant obligations involving MISO's services regarding Financial Transmission Rights (FTR) and Auction Revenue Rights (ARRs).

MISO prepares and maintains the *FTR and ARR Business Practices Manual* as it relates to participation in the Energy and Operating Reserve Markets. The BPM conforms and complies with MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff), North American Electric Reliability Corporation (NERC) standards and policies, and the applicable Regional Entity or Regional Reliability Council reliability principles, guidelines, and standards, and is designed to facilitate administration of efficient Energy and Operating Reserve Markets.

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

1. What is an ARR?
2. How are ARRs created and processed?
3. How do Market Participants acquire or terminate ARRs?
4. What is an FTR?
5. How do Market Participants acquire FTRs?
6. What is the FTR auction process?

1.3 References

Other reference information related to this BPM includes:

- ARR Registration Business Rules
- BPM-001 Market Registration
- BPM-002 Energy and Operating Reserve Markets
- BPM-005 Market Settlements
- BPM-010 Network and Commercial Model
- BPM-012 Transmission Settlements
- BPM-020 Transmission Planning Business Practice Manual
- FERC (Docket Numbers ER04-691, ER04-106, EL04-104)
- Joint Operating Agreement between MISO and PJM Interconnection, L.L.C.
- Tariff

1.4 List of Acronyms

- **ADJ NPLF**: Adjusted NPLF
- **AEs**: ARR Entitlements
- **AO**: Asset Owner
- **ARRs**: Auction Revenue Rights
- **BA**: Balancing Authority
- **BAA**: Balancing Authority Areas
- **BD**: Business Day
- **BRP**: Baseline Reliability Project
- **BRSS**: Baseload Reserved Source Set
- **CARRs**: Candidate ARRs
- **CFTRs**: Candidate FTRs
- **CPF**: Coincident Peak Forecast
- **CPNodes**: Commercial Pricing Nodes
- **CSV**: Comma Separated Value file
- **DAM**: Day-Ahead Energy and Operating Reserve Market
- **DC**: Direct Current
- **DNRs**: Designated Network Resources
- **EDC**: Electric Distribution Company
- **EPNodes**: Elemental Pricing Nodes
- **EST**: Eastern Standard Time

- **FCA**: Facility Construction Agreement
- **FERC**: Federal Energy Regulatory Commission
- **FFE**: Firm Flow Entitlement
- **FRP**: Full Responsibility Purchase
- **FRS**: Full Responsibility Sale
- **FTR**: Financial Transmission Rights
- **GFAs**: Grandfathered Agreements
- **GIA**: Generator Interconnection Agreements
- **GIP**: Generator Interconnection Projects
- **HUFU**: High Utilization Factor Unit
- **HUFU RSP**: High Utilization Factor Unit Reserved Source Point
- **ICCS**: Integrated Control Center System
- **IFTRs**: Incremental FTRs
- **ILTTRs**: Incremental LTTRs
- **JOA**: Joint Operating Agreement
- **JOU**: Joint Operating Units
- **LBA**: Local Balancing Authority
- **LBAAs**: Local Balancing Authorities Areas
- **LMPs**: Locational Marginal Pricing
- **LP**: Linear Programming
- **LSE**: Load Serving Entity
- **LTTR**: Long-Term Transmission Rights
- **M2M CMP**: Market-to-Market Congestion Management Process
- **MCC**: Marginal Congestion Component
- **MECT**: Module E Capacity Tracking Tool
- **MEP**: Market Efficiency Projects
- **MLC**: Marginal Losses Component
- **ModE NPF**: Module E NITS Peak Forecast
- **MP**: Market Participant
- **MPMA**: Multi-Period Monthly FTR Auction
- **MTEP**: MISO Transmission Expansion Planning
- **MVP**: Multi-Value Project
- **MW**: Megawatts
- **NCPF**: Non-Coincidental Peak Forecast

- **NERC**: North American Electric Reliability Corporation
- **NITS**: Network Integration Transmission Service
- **NPLF**: NITS Peak Load Forecast
- **NU**: Network Upgrade
- **OASIS**: Open Access Same-Time Information System
- **OD**: Operating Day
- **OTDF**: Outage Transfer Distribution Factor
- **PAR**: Phase Angle Regulator
- **PF**: Participation Factor
- **PMax**: Rated Power or Maximum Power
- **POD**: Point of Delivery
- **POR**: Point of Receipt
- **PPA**: Power Purchase Agreement
- **PRM**: Planning Reserve Margin
- **PRSS**: Peak Reserved Source Set
- **PSU**: Pumped Storage Unit
- **PTDF**: Power Transfer Distribution Factor
- **PTP**: Point to Point Transmission Service
- **RCF**: Reciprocal Coordinated Flowgates
- **RSPs**: Reserved Source Points
- **SFT**: Simultaneous Feasibility Test
- **TAP**: Transmission Access Projects
- **TE**: Transmission Entitlements
- **TO**: Transmission Owner
- **TSR**: Transmission Service Request
- **WLS**: Weighted Least Squares

2. Overview of Auction Revenue Rights and Financial Transmission Rights

This manual provides Market Participants with information to understand the purpose and application of ARRs and FTRs. Exhibit 2-1 presents the FTR Systems Overview. It depicts the interfacing and the data movement between various internal systems, Market Participants and the FTR system.

Box 1 – represents the Annual ARR Registration system wherein the Market Participants register their existing transmission rights and convert those rights into ARR Entitlements. Section 3.10 provides additional details on the Annual ARR Registration procedures.

Box 2 – Main FTR system: MISO performs the following tasks on this system:

a. Simultaneous Feasibility Test for the Annual ARR Allocation (2a). Additional details for the Annual ARR Allocation are provided in Section 3.11.
b. Clears the Annual and Multi-Period Monthly FTR Auction (2b, 2c). Additional details are provided in Sections 4.10.8 and 4.10.9, respectively.
c. Processes the ARRs and FTRs for the Network Upgrades (2d). Additional details are provided in Sections 3.25 and 4.9 respectively.
d. Clears the Secondary FTR Market (2e). Additional details provided in Section 5.
e. Add/replace/terminate Reserved Source Points (2f). Additional details are provided in Section 3.21.
f. Processes ARRs for Multi-value Projects (2g). Additional details are provided in Section 3.28.

Box 3 – Energy Management System (EMS): FTR system receives the network topology and associated data elements such as outages, contingencies, monitored elements and flowgates to build the transmission model from the EMS.

Box 4 – Siebel System: FTR system receives the Commercial Model data such as the Commercial Pricing Nodes (CPNodes), Elemental Pricing Nodes (EPNodes), CPNode-EPNode relationship, weighting factors, Market Participants, Asset Owners and Market Participant-AO relationship from the Siebel System.

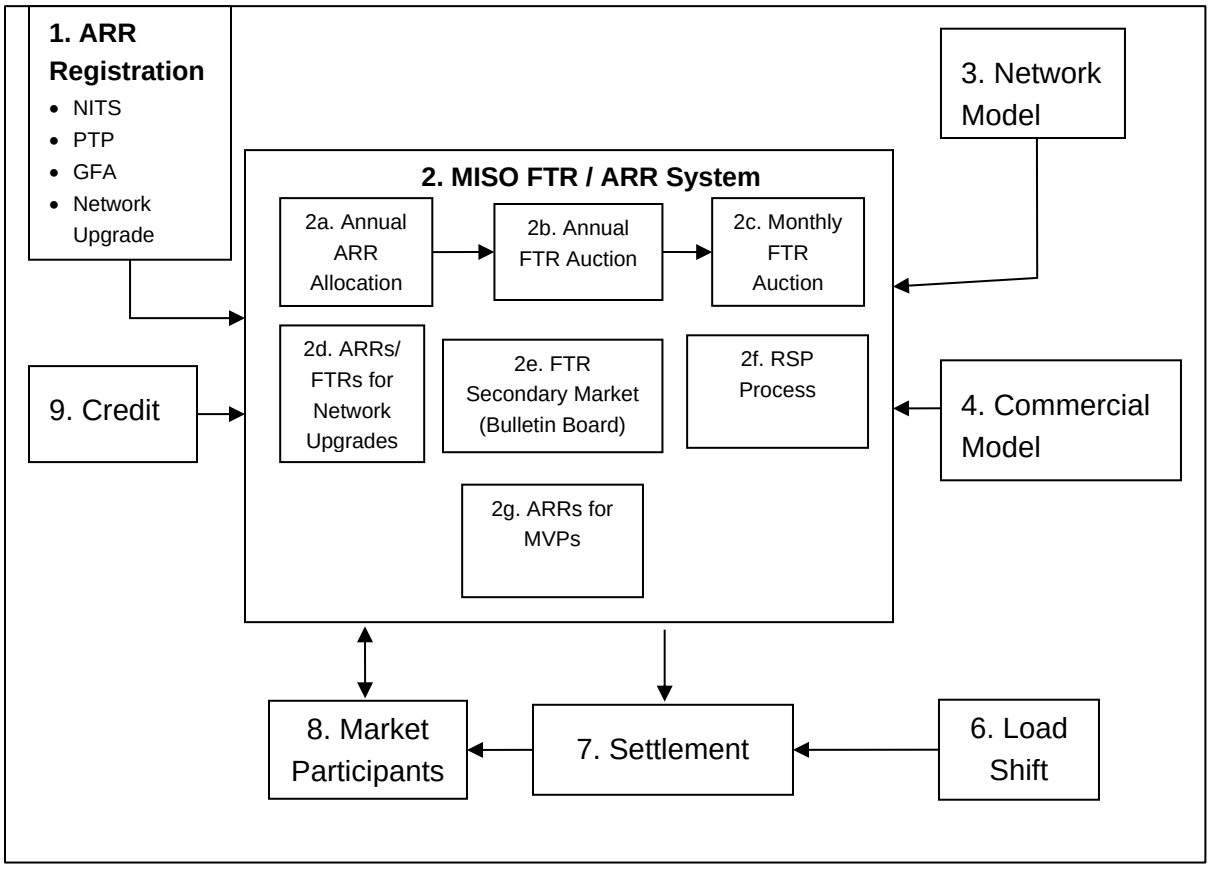
Box 6 – will represent the entities (to be determined) that will send the Load shift information to MISO Settlement system for the re-assignment of ARRs. Section 3.26 provides additional details on ARR re-assignment with Load switching.

Box 7 – Settlement System: FTR/ARR System sends the ARR and FTR information for settlement purposes.

Box 8 – represents the Market Participants that will interface with the FTR/ARR system via MISO Portal to submit ARR nominations, FTR bids and Secondary Market trades. They will receive network and market data via the same interface.

Box 9 – Credit System: FTR/ARR system obtains the credit data for the Market Participants for their participation in the auctions and the secondary market.

Exhibit 2-1: FTR/ARR Systems Overview



The following ARR and FTR topics are covered in this BPM:

a. Definition and Purpose;
b. Types;
c. Allocation;
d. Network Upgrades;
e. Auctions;
f. Secondary FTR and ARR Markets; and
g. Reserved Source Point (RSP) Process

2.1 Definition and Purpose of ARRs

ARRs are financial instruments that entitle their holders to a share of the revenue generated in the annual FTR Auction. ARRs are initially allocated to Market Participants based on firm historical usage of the transmission network. Incremental ARRs may be allocated for Network Upgrades, and for new and replacement Network Resources. The firm historic usage of the Transmission System is determined according to the guidelines presented in Section 3.8.

2.2 Definition and Purpose of FTRs

FTRs are financial instruments whose values are determined by the transmission congestion charges that arise in the Day-Ahead Energy and Operating Reserve Market, leading to differences in the Marginal Congestion Components (MCCs) of Ex-Post Day-Ahead Locational Marginal Prices (LMPs) at different locations. FTRs may be used to provide a financial hedge to manage the risk of congestion cost in the Day-Ahead Energy and Operating Reserve Market. Market Participants who hold FTRs are protected against paying congestion charges for scheduled injections (*e.g.*, generation, bilateral purchases, etc.) at one location, and withdrawals (*e.g.*, Load, bilateral sales) at a different location in the Day-Ahead Energy and Operating Reserve Market. If a Market Participant is buying (or selling) Energy in the Day-Ahead Energy and Operating Reserve Market, an FTR with the same source, sink, and MW quantity may hedge the congestion costs between the point of delivery (POD) and the point of receipt (POR) of the FTR. FTRs span the market footprint, including Interfaces.

3. Auction Revenue Rights (ARRs)

MISO will provide ARR Obligations. MISO shall maintain a list of eligible Baseload and Peak Reserved Source Points (RSPs) and ARR Zones that can be specified in the ARR Obligations.

Category 1 shall consist of Network Integration Transmission Service OASIS reservation Points of Delivery existing during the Reference Year, including Interface Commercial Nodes for PTP Exports. Category 2 shall consist of subzones within the Network Integration Transmission Service Points of Delivery that will be established where required to support state jurisdictional accounting obligations or where supported by transmission and Energy supply arrangements during the Reference Year, and that meet the qualification criteria.

3.1 Changes to ARR Zone and setting Reference Year

The Reference Year for all ARR Zones at the start of the first Annual ARR Allocation[1] shall comprise the four Seasons starting March 2004 and ending February 2005.

After an ARR Zone is defined during the year 1[2] Annual ARR Registration, the definition of the ARR Zone will not change over time to match changing Load Zone configurations. This implies that EPNodes will not be moved across ARR Zones. The constitution of an ARR Zone will generally remain fixed. However, EPNode changes resulting from Network Model updates will be appropriately reflected in the ARR Zone. Such EPNode changes may represent Load growth, system reconfiguration or additions. ARR Zones will not be reconfigured for Load "moving" from one Load Serving Entity (LSE) to another.

The Reference Year for any ARR Zone changes (addition or redefinition) after the first Annual ARR Allocation process as a result of an expansion of the Transmission Provider Region (hereinafter referred to as the "MISO Region") shall comprise the four most recent complete Seasons just prior to the Annual ARR Registration associated with the integration of the applicable ARR Zone.

[1] June 1, 2008 – May 31, 2009

[2] Year 1 is the first full Annual ARR Allocation period (6/1/XX - 5/31/XX+1) in which an ARR Zone is eligible and considered for that allocation period, A Market Participant's transmission rights existing during the Reference Year constitutes the basis for its eligibility to become part of that ARR Zone, and to participate in the year 1 Annual ARR Allocation.

A new ARR Zone may also be added to accommodate GFA carve-out or Option B conversion to NITS[3] or a new NITS[4]. Upon satisfactory review and verification by MISO, the addition of the new ARR Zone will only be accommodated at the time of Annual ARR Registration. The Market Participant must inform MISO at least one month prior to the commencement of the Annual ARR Registration of such changes. The Reference Year in these cases will be 12/1/(XX-1) – 11/30/XX, where XX is the year prior to the Annual ARR Allocation period for which the new ARR Zone is eligible and considered for addition.

3.2 ARR Obligations

Market Participants entitled to participate in the Annual ARR Allocation may nominate and receive ARRs, subject to simultaneous feasibility. ARRs allocated through the Simultaneous Feasibility Test (SFT) during Stage 1 of the Annual ARR Allocation are defined by their duration (validity dates), time of use (Peak or Off-Peak), source, sink and MW amount.

An ARR is settled based on the clearing price of its path from the annual FTR Auction for the corresponding season and time of use:

a. An ARR Obligation provides its holder with credits when the FTR Auction shadow price at the ARR Delivery Point is less than the FTR Auction shadow price at the ARR Receipt Point.
b. Conversely, an ARR Obligation will impose charges on its holder when the auction shadow price at the ARR Delivery Point is greater than auction shadow price at the ARR Receipt Point.

[3] A new ARR Zone will only be considered for addition if the request was made in the original ARR data gathering template when the corresponding GFA was registered.

[4] A new NITS corresponds to metered Load that began taking NITS that was previously behind the meter.

Exhibit 3-1: Credits (Charges) for ARR Obligations

Example	ARR MW Amount	Auction Path Price	ARR Credit
1	10 MW	50 $/MWh	Credit = 50 x 10 = $500
2	10 MW	-10 $/MWh	Credit = - 10 x 10 = -$100
Note: A negative credit is equivalent to a charge.			

Excess revenue from the annual FTR Auction will be distributed amongst ARR Entitlement holders based on the difference between their total ARR nomination eligibility and the amount allocated in Stage 1. The rights to receive a portion of this excess revenue are referred to as Stage 2 allocation.

3.3 ARR Specifications

An ARR is specified by:

a. ARR Receipt Point (ARR Source);
b. ARR Delivery Point (ARR Sink);
c. ARR MW;
d. ARR time of use (On-Peak/Off-Peak);
e. ARR Term;
f. Whether the ARR is an LTTR;
g. Whether the ARR is feasible or infeasible; and
h. Whether the ARR is a year 1 counter-flow LTTR

3.4 Key Characteristics of ARRs

ARRs are characterized as follows:

a. ARRs do not represent a physical right for delivery of energy.
b. Market Participants need not hold ARRs to schedule Physical or Financial Bilateral Transactions.
c. ARR Holders are not required to schedule Physical or Financial Bilateral Transactions by virtue of holding ARRs.

d. ARRs are settled based on the clearing prices from the annual FTR Auction prices. ARRs do not protect Market Participants from congestion charges in the Day-Ahead or Real-Time Energy and Operating Reserve Markets.
e. ARRs are allocated in the Annual ARR Allocation prior to the annual FTR Auction.

3.5 MISO Responsibilities

MISO's responsibilities are to:

a. Conduct the year 1 Annual ARR Registration to gather the historic rights and establish the ARR Entitlements for eligible Market Participants.
b. Conduct Annual ARR Registrations in future periods to realign the ARR Entitlements prior to the Annual ARR Allocation based on Load shifts, for addition or replacement of Reserved Source Points, addition of new Load or departure of existing Load.
c. Provide assistance in resolving disputes during the year 1 Annual ARR Registration process.
d. Conduct the Annual ARR Allocation ensuring the simultaneous feasibility of the allocated ARRs in Stage 1.
e. Settle the LTTRs and ARRs based on the clearing prices from the annual FTR Auction.
f. Guarantee the full allocation of the LTTRs by assigning infeasible ARRs as required in year 2 and beyond.
g. Distribute the residual annual FTR Auction revenue to the Stage 2 eligible Market Participants.
h. Process incremental ARRs/LTTRs for the Network Upgrades
i. Process MVP ARRs for Multi-Value Projects

3.6 Market Participant Responsibilities

Market Participants are responsible for the following:

a. Market Participants are responsible to perform their own congestion risk assessment and risk management with respect to ARR acquisition and disposition.
b. Market Participants representing the Transmission Customers (under Network Integration Transmission Service or NITS; PTP service; and service relating to Grandfathered Agreements or GFAs) active during the Reference Year are required to provide certain data for the initial Annual ARR Registration process as described in Section 3.9. These Market Participants constitute a subset of Market Participants that are eligible to participate in the Annual ARR Allocation process and to submit their ARR nominations. The Market Participants that take up the NITS Load responsibility

for every Annual ARR Allocation period will also be eligible to participate in the Annual ARR Allocation process.

c. In year 1, Market Participants that do not own but have supply contracts with Generation Resources are required to provide a written approval of the usage of those Resources from the corresponding asset owning Market Participants during the Annual ARR Registration data gathering process, and the owners are required to comply with such request.
d. Market Participants can initiate a request to MISO to invoke the supplemental rules to fill the baseload entitlement gap.

3.7 Overview of the Annual ARR Allocation

This section describes:

- How ARRs are initially created by MISO and allocated to eligible Market Participants
- The annual process for allocating ARRs

The allocation process addresses how Transmission Services under MISO Tariff and GFAs are converted to ARRs and related GFA congestion hedges. Transmission entitlements identify the transmission usages, upgrades, or other basis for Market Participants' definitions of ARR Entitlements. Transmission entitlements must be converted to ARR Entitlements in the ARR registration process. Tariff Customers may nominate to receive ARRs among their ARR Entitlements. The nominated ARR Entitlements are called Candidate ARRs (CARRs). The Annual ARR Allocation process determines the portion of the CARRs that is feasible to allocate to each Market Participant. The Market Participant for a Tariff Customer may hold ARR Entitlements for the following classes of service:

a. Firm PTP Transmission Service reservations of annual duration or longer, valid during the Reference Year (March 1, 2004 to February 28, 2005) and rolled over into the current or next ARR Allocation Period.
b. NITS for Network Load from qualifying Reserved Source Points (RSPs) valid during the Reference Year.
c. GFAs selecting treatment under Option A or Option B as defined in the Tariff.

For GFAs that are carved out per the Federal Energy Regulatory Commission's (FERC's) order ("Order Addressing Treatment of Grandfathered Agreements in MISO Energy Markets, and Establishing Hearing and Settlement Judge Procedures" Docket Numbers ER04-691-000, ER04-106-002, EL04-104-000), the Market Participant for the Responsible Entity will be required to

provide information on the GFA as well as historic usage. MISO will use this information to develop ARR Entitlements that will be used to reserve transmission capacity for the Carved-Out GFA.

ARR Entitlements may also be based on Market Participant-funded network expansion projects, to the extent of the incremental transmission capacity added by the upgrade.

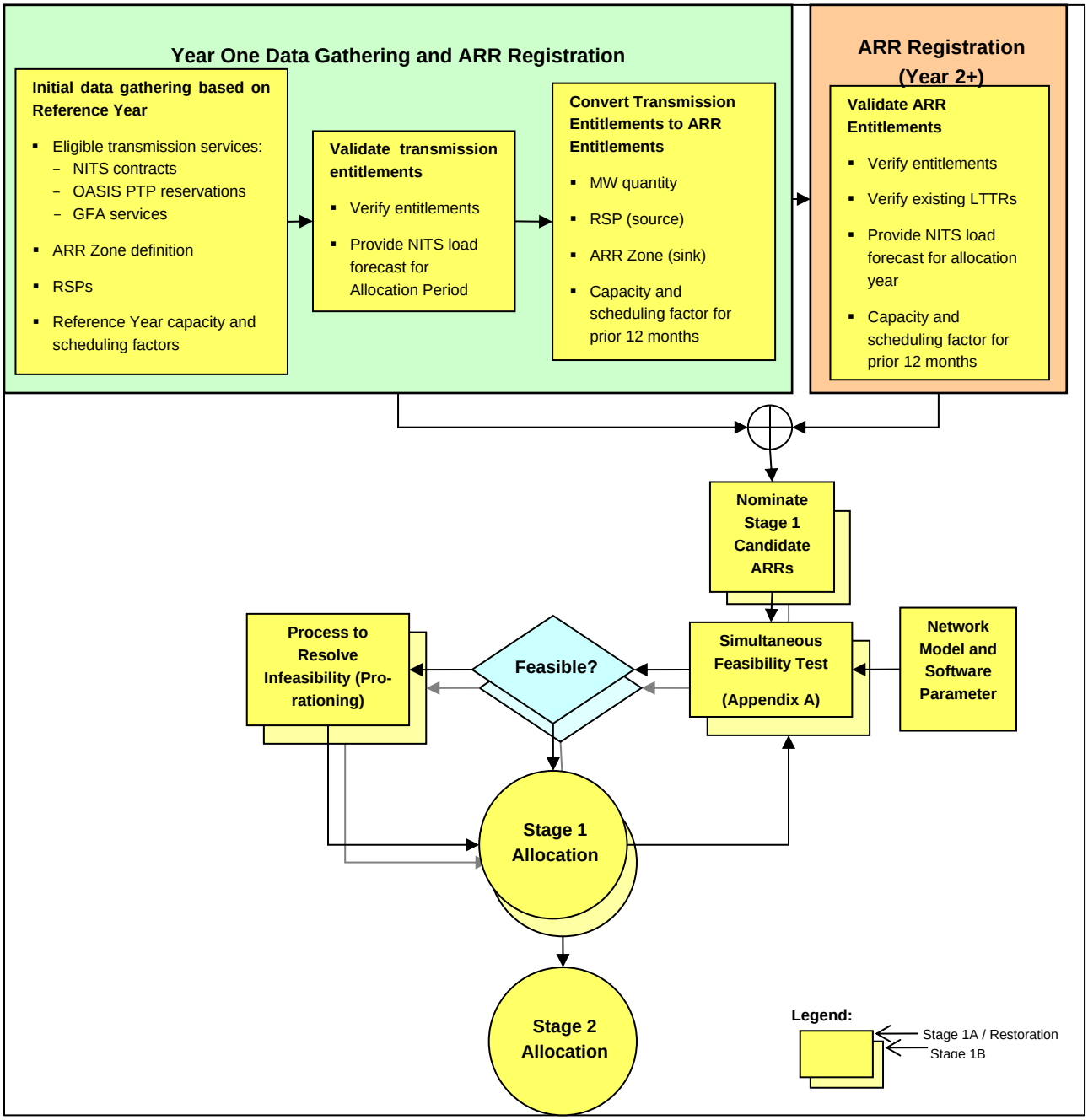
The allocation process has several important objectives:

a. To hold existing Transmission Customers whole compared to their firm historical use of the Transmission System with respect to congestion-related charges under MISO Day-Ahead Energy and Operating Reserve Market operation to the extent possible given the requirement of simultaneous feasibility, and to meet the reasonable needs of LSEs. To achieve this objective, the CARRs submitted for the allocation is based on entitlements to use MISO's Transmission System during the Reference Year, as described above.
b. To reserve capacity on the Transmission System for GFAs that FERC ordered to be carved-out.
c. To provide an allocation of ARRs that is simultaneously feasible in a security-constrained power flow that includes an appropriate representation of unscheduled loop flow from external Balancing Authority Areas ("BAA"), or a seams agreement with External BAAs. A Simultaneous Feasibility Test[5] (SFT) is needed to avoid over-allocating ARRs, which could lead to a situation in which the auction revenue collected by MISO in the FTR Auction is not sufficient to fund ARRs, or in which the congestion charges collected in the Day-Ahead Energy and Operating Reserve Market are insufficient to fund FTRs (revenue inadequacy). In case not all CARRs are simultaneously feasible, some CARR MW reduction is required to achieve a simultaneously feasible allocation of ARRs.
d. To provide an allocation of ARRs that is equitable and consistent with historical use of MISO's Transmission System (i.e., market footprint).

Exhibit 3-2 shows the principal steps in the allocation of ARRs.

[5] See Attachment A of this BPM for a detailed description of the SFT.

Exhibit 3-2: Allocation Process for ARRs



3.8 Transmission Service Eligible for Conversion to ARRs

Market Participants for Transmission Customers taking Transmission Service under the Tariff (whether PTP Transmission Service or NITS) during the Reference Year must convert such transmission rights to ARR Entitlements consistent with the procedures described here.

The Transmission Services listed in the following subsections are eligible for conversion to ARRs.

3.8.1 Network Integration Transmission Service (NITS)

NITS contracts valid during the Reference Year as well as GFAs converted to NITS since the Reference Year qualify for the ARR allocation. The contract should specify the associated set of Resources. Load pseudo-tied out of MISO must have an associated NITS contract valid during the Reference Year.

Market Participants serving Network Load during the Reference Year are responsible for registering the Load and Resources associated with their NITS during year 1 of the Annual ARR Registration.

3.8.2 Point-To-Point Transmission Service

Yearly, Firm PTP Transmission Service reservations on MISO OASIS active during the Reference Year and rolled over (or eligible to roll over) into the upcoming Annual ARR Allocation period are eligible for Annual ARR Allocation. GFAs converted to PTP Transmission Service since the Reference Year and rolled over (or eligible to roll over) into the upcoming Annual ARR Allocation period qualify for the Annual ARR Allocation as PTP Transmission Service. The path of the TSR active in the Reference Year will be the same path eligible for the Annual ARR Registration process. An active PTP Transmission Service Reservation during the Reference Year implies that the service had started prior to or during the Reference Year (i.e., with a start date prior to or within the Reference Year). A yearly confirmed Firm PTP Transmission Service that was active prior to and during the Reference Year will be eligible for ARRs as long as the underlying TSR has been rolled over into the current, upcoming or future Annual ARR Allocation period. In cases where the yearly redirected path became active in the Reference Year, the original path will continue to be eligible for the ARRs.

When an eligible PTP Transmission Service with rollover rights expires during the current or the upcoming Annual ARR Allocation period, the Market Participant may elect to register that service for the complete upcoming Annual ARR Allocation period. The Market Participant will then be eligible to nominate and be allocated ARRs during the Annual ARR Allocation for such PTP Transmission Service. If the Market Participant does not exercise rollover rights pertaining to that Transmission Service on MISO OASIS, allocated ARRs will be terminated when the PTP Transmission Service terminates.

For PTP Transmission Services that have been granted different MW amounts in different months, MISO will use the minimum granted volume in an allocation season as the ARR Entitlement amount for that season.

PTP Transmission Service Reservations that started after the Reference Year may be eligible for Stage 1 ARRs as described in Section 3.21 and may also be included in the calculation of the Stage 2 allocation.

3.8.3 Grandfathered Agreements

The GFA Responsible Entity (Market Participant) that intends to maintain service under GFAs must select one of three options, for scheduling and settlement of Costs of Congestion and Costs of Losses resulting in the Day-Ahead Energy and Operating Reserve Market, unless FERC has indicated that the GFA is to be carved-out. Parties selecting from among Options A, B and C must so indicate their election during the ARR Registration process. One and only one option must be selected for each GFA. A party to several GFAs may select different options for the different GFAs.

A Market Participant that is a GFA party may select between Options A and C for the GFA, unless the party is also eligible to select Option B for the GFA under FERC's relevant GFA orders (i.e., if the Market Participant had originally settled on a GFA treatment with MISO before July 28, 2004).

The selection is made annually as part of the Annual ARR Allocation process. The options are as follows:

3.8.3.1 Option A Grandfathered Agreements

a. ***Treatment of ARRs*** – The GFA Responsible Entity is entitled to nominate the Capacity under the GFA for allocation of ARRs. The GFA Responsible Entity is allocated ARRs. Such ARRs may or may not be converted to FTRs through the self-scheduling process described in Section 4.10.8.3. The GFA Responsible Entity holds the ARRs and/or FTRs and is accountable for all credits, debits, rights, and responsibilities associated with them.

b. ***Treatment of Transmission Congestion*** – MISO charges the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to Dispatch Instruction or Day-Ahead Schedules based on the designated Receipt Points and Delivery Points for the GFA.

c. ***Treatment of Transmission Losses*** – The GFA Responsible Entity is assessed (charged) the Cost of Losses for all transactions pursuant to the GFA based on the difference between the Marginal Losses Component (MLC) of the Day Ahead Ex-Post LMPs at designated Receipt Point and Delivery Point.

3.8.3.2 Option B Grandfathered Agreements

a. ***Treatment of ARRs*** – The GFA Responsible Entity will not nominate or receive ARRs or FTRs for the Capacity under the GFA but will instead receive a refund of the Cost of Congestion resulting from the Day-Ahead Schedules cleared in the Day-Ahead Energy and Operating Reserve Market. The GFA Responsible Entity is responsible for MISO's administrative costs associated with accounting for the proxy FTRs/ARRs under this option as set forth in Schedule 16, FTR Administrative Service Cost Recovery Adder, of the Tariff.

b. ***Treatment of Transmission Congestion*** – MISO charges the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to the GFA based on the designated Receipt Point and the Delivery Point under the GFA but credits back the full amount of the Cost of Congestion resulting from Day-Ahead Schedules cleared in the Day-Ahead Energy and Operating Reserve Market to the GFA Responsible Entity. This refund will only be provided if the GFA Scheduling Entity submits a Financial Bilateral Transaction Schedule according to the procedures described in *BPM 002 Energy and Operating Reserve Markets* for the Day-Ahead Energy and Operating Reserve Market for the GFA transaction(s) prior to the closing of the Day-Ahead Energy and Operating Reserve Market, consistent with the Receipt Point and the Delivery Point, and within the maximum MW Capacity permissible under the GFA. In the event that there is revenue inadequacy, MISO fully compensates the GFA Responsible Entity for the Cost of Congestion. The revenue inadequacy is funded through an assessment of debits on all Market Participants on a pro-rata basis, based on their Load Ratio Share across the Market Footprint. MISO accounts for GFAs under Option B in the FTR allocation process but does not actually allocate FTRs to the GFA Responsible Entity.

c. ***Treatment of Transmission Losses*** – MISO charges the GFA Responsible Entity the Cost of Losses for all transactions under the GFA based on the difference between the MLC of the Day Ahead Ex-Post LMPs at the designated Receipt Point and Delivery Point. MISO credits back to the GFA Responsible Entity the difference between Marginal Losses and actual cost of System Losses caused by the scheduled transaction at the designated Receipt Point and Delivery Point. The difference between costs based on Marginal Losses and System Losses is determined by MISO on an equitable basis[6]. This refund is only provided if the GFA Scheduling Entity submits a Financial Bilateral Transaction Schedule for the GFA transaction(s) the day prior to the Operating Day, consistent with the Receipt Point and Delivery Point and within the maximum MW Capacity permissible under the GFA. GFA Responsible Entities that receive such reimbursement for GFA transactions do not receive an allocation of the Marginal Losses Surplus Share.

3.8.3.3 Option C Grandfathered Agreements

a. ***Treatment of ARRs*** – The GFA Responsible Entity will neither nominate nor receive an allocation of ARRs or FTRs.

b. ***Treatment of Transmission Congestion –*** MISO charges the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to the GFA based on the designated Receipt Points and Delivery Points for the GFAs.

c. ***Treatment of Transmission Losses*** – The GFA Responsible Entity is assessed the cost of losses for all transactions pursuant to the GFAs based on the difference between the MLC of the Day Ahead Ex-Post LMPs at designated Receipt Points and Delivery Points. GFA Responsible Entities receiving such assessment for Marginal Losses receive an allocation of excess Marginal Losses revenue based on the Marginal Losses Surplus Share.

[6] See *BPM-005 Market Settlements*.

3.8.3.4 Carved-Out Grandfathered Agreements

A party with a GFA added to Attachment P after September 16, 2004, and that is eligible for carve out treatment per FERC Orders on GFAs (9/16/04, 4/15/05 and 12/15/09 Orders), also has the option to select treatment under Options A or C or conversion to Transmission Service under the Tariff. Once parties to Carved-Out GFAs voluntarily choose Options A or C treatment under the Tariff, or fully convert to Tariff Transmission Service, such GFAs can no longer revert to carve-out GFA treatment.

The maximum capacity associated with each Carved-Out GFA is reflected in MISO's ARR allocation model in a manner that reflects expected transmission usage under Carved-Out GFAs. The GFA billing entity is not assessed the Cost of Congestion and the Cost of Losses for all transactions pursuant to the Carved-Out GFAs.

3.8.3.5 ARRs for Grandfathered Agreements

Market Participants with GFAs that are not to be carved out must elect to schedule and settle for Costs of Congestion as described in Section 3.8.3 above. Market Participants under GFAs that select Option A define ARR Entitlements (as ARR Obligations) based on Transmission Service under GFAs from which they may nominate CARRs in the subsequent Annual ARR Allocation.

Eligible Market Participants under GFAs that select Option B define ARR Entitlements based on Transmission Service under GFAs as well. These define the maximum MW for Day-Ahead Schedules between defined pairs of Receipt and Delivery Points for which the Market Participant may receive refunds of Transmission Congestion Charges and refunds of a portion of the charges for Marginal Losses. The ARR Entitlements registered and defined for Option B GFAs may be for any MW quantity up to the maximum MW of service provided under the GFA.

The sink of an Option B GFA will be a valid Load Zone in the current Commercial Model, i.e., the sink will not be a Category 1 or 2 ARR Zone. If a current Load Zone is or will be served with an Option B GFA, the corresponding EPNodes or EPNode portions will be excluded from the Category 1 ARR Zone where they reside. If the Option B GFA is converted to NITS in the future, the corresponding EPNodes or EPNode portions will be used to define a Category 2 ARR Zone[7].

[7] A new ARR Zone will only be considered for addition if the request was made in the original ARR data gathering template when the corresponding GFA was registered.

It is essential that the GFA Responsible Entity try to maintain the current Load Zone definition, which can change when the constituent Load points change their name, expire or merge. If the Option B GFA serves a slice of a Category 1 ARR Zone, the corresponding EPNode portions will not be excluded from the ARR Zone. If that GFA is converted to NITS in the future, the sink for the NITS entitlements will be the same Category 1 ARR Zone.

3.8.3.6 Election of Conversion to Service under the Tariff

Market Participants intending to convert transmission rights contained in GFAs to Transmission Service under the Tariff and receive ARRs during the allocation must notify MISO of such intent during the Annual ARR Registration process. Procedures for such notification are specified in *BPM-001 Market Registration*. Market Participants requesting ARRs for GFAs that are converted to Tariff service must follow the nomination and allocation procedures established for service conversion under the Tariff and as further described in this BPM.

Market Participants that elect not to convert their existing rights under GFAs to service under the Tariff and receive ARRs in an Annual ARR Allocation period may elect to convert service at a future Annual ARR Allocation period. Market Participants may also elect to convert their existing rights under GFAs to service under the Tariff and receive FTRs between Annual ARR Allocation periods. In such a case, the amount of FTRs awarded following such belated conversion will be consistent with the FTRs assigned to the GFA during the most previous Annual ARR Allocation period. Market Participants intending to convert GFAs to ARRs must follow the nomination and allocation procedures established for service conversion under the Tariff as set forth in this BPM.

Once service under the GFA is converted to service under the Tariff, the Market Participant cannot revert to GFA status.

3.9 ARR Data Gathering During Year 1

The first stage of the Annual ARR Allocation process is the Annual ARR Registration, which converts eligible transmission rights into ARR Entitlements for nomination in the Annual ARR Allocation. The year 1 Annual ARR Registration will consist of two steps: the initial data gathering and the registration through the Market Portal.

The initial data gathering step prior to the commencement of the year 1 Annual ARR Registration will serve to establish the eligible network, PTP and GFA Transmission Services, as well as the qualified set of ARR Points of Delivery and Resources.

3.9.1 ARR Zones

ARR Zones represent areas within MISO's footprint defined for the purpose of allocating ARRs based upon locations where a Market Participant/Load Serving Entity (LSE) served Load during the Reference Year. This includes the Market Participants that lost the Load since the Reference Year. Market Participants that will be serving Load in the upcoming Annual ARR Allocation period will be required to provide their Peak Usage[8] on an annual basis.

ARR Zones are of the following two general categories.

3.9.1.1 Category 1

1. NITS OASIS reservation Points of Delivery existing during the Reference Year, including external interface CPNodes for PTP exports. The Category 1 ARR Zone will correspond to the Local Balancing Authorities Areas (LBAAs) specified in the NITS contract existing during the Reference Year. The Category 1 ARR Zone for the NITS customers will be one of MISO LBAAs. Non-jurisdictional Balancing Areas that do not utilize an OASIS system, but own transmission, can be classified as independent Category 1 ARR Zones pursuant to review of the supporting documentation. Otherwise, these non-jurisdictional Balancing Areas will be

[8] Tariff Section 1.P defines Peak Usage as follows: A Market Participant's Total Forecasted Peak Load in a given ARR Zone for the upcoming Annual ARR Allocation Period calculated using the immediate prior three year actual peak Loads. The Total Forecast Peak Load is the sum of the forecast Network Integration Transmission Service Peak Load for the upcoming allocation period plus peak Load served by Option A – Grandfathered Agreements plus peak Load served by Option B – Grandfathered Agreements.

included in the overall embedded LBAAs Category 1 ARR Zone. These Category 1 ARR Zones will be defined as HUB type CPNode in the Commercial Model.

2. The sink for a full requirement NITS customer will be one of the Category 1 ARR Zones if that NITS customer and the host LSE reside in the same MISO LBAA and that host LSE is not eligible to define a Category 2 ARR Zone. The host LSE is the LSE that has a contractual obligation to serve the full requirement NITS customer's Load with the same degree of reliability as it provides to its own native Load customers.
    i. The definition for the Category 1 ARR Zones is based on the LBAA-to-EPNode relationship from the Commercial Model at the start of the Annual ARR Registration data gathering process.

3.9.1.2 Category 2

a. Category 2 ARR Zones requested by a single or multiple Market Participants to satisfy state statutory or regulatory jurisdictional requirements to separate Load according to state boundaries will be considered valid subzones within a single Category 1 ARR Zone. The requesting Market Participant(s) must specify the native Load delivery points and the qualifying Generation Resources associated with the Category 2 ARR Zone requested to separate Loads according to state boundaries.
b. Requests for Category 2 ARR Zones for purposes other than to satisfy state jurisdictional requirements or partial requirements NITS customer must be supported by:
    1. PTP Transmission Service, NITS or GFA service agreements (including any relevant supporting documentation where transmission service agreements in effect are unclear) specifying delivery locations representing native Load delivery points. The Market Participant can request a Category 2 ARR Zone only if such separation is specifically defined by the service agreement or provided documentation. The documentation should clearly define the resource, the MW, the native load, the term of the agreement to be consistent with the RSP qualifications (inclusive of BRSS Gap), validity during the Reference Year, and signed and agreed upon by both parties.
    2. Market Participants must indicate the electrical representation of their native Load delivery points in terms of the EPNodes, which may necessitate or involve the sharing of EPNodes by agreement between or among affected Market Participants.
c. Requests to establish two or more ARR Zones that share identical or nearly identical EPNode definitions will not be permitted unless such definition is clearly supported by the effective transmission service agreements and any supporting documentation. This may be the case where, for example, two Market Participants' service territory is specified in their NITS contract

to be spread across a Category 1 ARR Zone and the mapping of their Load points happens to share identical or nearly identical sets of EPNodes.

i. Power supply contracts specifying the set of qualifying supply Resources and/or Generation Resources associated with those Load delivery locations
    a. Capacity and Energy contracts or ownership meeting the Resource Qualification Requirements.

ii. A Category 2 ARR Zone request that does not meet the criteria described in 2(i) and 2(ii) above will be defaulted into the qualifying ARR Zone(s) where such LSE's Load locations are electrically represented.

iii. A Category 2 ARR Zone request that otherwise qualifies, will be denied if it precludes or unduly limits a Market Participant(s) from receiving LTTRs.

iv. If a full requirements NITS customer and the host LSE providing the full requirements are in separate MISO LBAAs, the host LSE will need to request a Category 2 ARR Zone definition for the full requirements NITS customer in the LBAA where its Load resides and identify appropriate RSPs. The contractual documentation must be provided when requesting such a Category 2 ARR Zone definition.

The definition of the Category 2 ARR Zones will be based on the EPNode data from the Commercial Model at the start of the Annual ARR Registration data gathering process. After having been defined during the year 1 Annual ARR Registration, a Category 1 or 2 ARR Zone will not change over time to match the changing Load Zone configurations. Accordingly, EPNodes will not be moved across ARR Zones. The participation factors of EPNodes will generally remain fixed in the future allocations. However, incremental changes occurring in the Network/Commercial Model updates will be appropriately reflected in the ARR Zones. Such EPNode changes may represent Load growth, system reconfiguration or Load additions.

Refer to Section 3.1 for changes to ARR Zones and the establishing of the Reference Year.

3.9.1.3 ARR Zones for PTP Transmission Service

a. If the PTP Transmission Service is used to serve Load within MISO footprint, its sink may be a Category 2 (Non-POD) ARR Zone that is a Load Zone or a subset of the Load points (EPNodes) of a Category 1 ARR Zone as specified in the contract and specific Generation Resources (e.g., listed in power supply contracts) serving the Load Zone or the specific Load points. A Category 2 ARR Zone definition requires that the Market Participant provide contract language corresponding to the PTP Transmission Service, indicating the exact Load points (cities, substations or any such specific location) that were being served under that contract

during the Reference Year. Any ambiguity in the language may invalidate the Category 2 ARR Zone definition. MISO Legal and other appropriate Departments should be contacted to verify the contract language before establishing the requested Category 2 ARR Zone.

b. PTP rights can serve Load within MISO footprint only if that Load is not Network Load of MISO. Accordingly, such Load will be considered non-MISO market Load. In that case, if the Market Participant were delivering Energy to that non-MISO market Load, it could request the creation of a Category 2 ARR Zone composed of those Load points. All MISO market Load must have a valid NITS agreement with MISO. There must be a Market Participant responsible for the NITS contract and the Load. That Market Participant can request the creation of a Category 2 ARR Zone based on the NITS agreement. If a MISO NITS customer has a power supply (Capacity and Energy contract) from external areas, then it should have a designated network TSR from that external Interface point.
c. Category 2 ARR Zones for PTP Transmission Service will be defined pursuant to Section 3.9.1.2.

3.9.1.4 ARR Zones for GFAs

3.9.1.4.1 Category 1 ARR Zones for GFAs

A GFA entitlement can have a Category 1 (POD) ARR Zone as its sink when the following conditions are met:

a. The Category 1 ARR Zone for a GFA entitlement will correspond to the LBAAs specified in the GFA contract. The Category 1 ARR Zone for a GFA will be one of the LBAA within MISO footprint. These Category 1 ARR Zones will be defined as HUB type CPNode in the Commercial Model.
b. The sink(s) of the GFA contract must be identified in template filings. If the sink information is unclear or unspecified, the Responsible Entity will need to get an approval from the Transmission Owner (TO) for the sink that was specified for the GFA.

3.9.1.4.2 Category 2 ARR Zones for GFAs

a. The Category 2 ARR Zone(s) for a GFA contract will be established only during the initial Annual ARR Registration (year 1 registration). If a Category 2 ARR Zone was not requested for a Load served under a GFA during the year 1 Annual ARR Registration for the existing Market Participants, and the GFA was later converted to NITS, the corresponding NITS Entitlements will sink at one of the existing ARR Zones where the Load served under the converted GFA is electrically represented. The GFA Load and its Resources will be split in the ratio of the Load, if the electrical representation of the GFA Load spans multiple ARR

Zones. The GFA Resource portions and the existing RSPs within those ARR Zones will be apportioned in the load-ratio share between the Market Participant of the GFA and the Market Participants of the LSEs within those ARR Zones.

b. Category 2 ARR Zones for GFAs will be defined pursuant to Section 3.9.1.2.
c. The sink for the Option A entitlements will be one of the Category 1 or Category 2 ARR Zones. If the Responsibility Entity converted an Option B to an Option A, then the Responsible Entity must ensure that the sink is defined in one of the fixed Option B Load Zones, if the Responsible Entity chooses to convert back to Option B in any future Annual ARR Allocation periods.
d. Option B GFAs will be registered in a manner similar to the previous Annual ARR Allocation periods. The Market Participant/Responsible Entity must register the Option B entitlements sinking at one of the fixed Option B Load Zones defined during the data gathering effort to be able to bid Load schedules and FinScheds on such Load Zones in the Day-Ahead Energy and Operating Reserve Market, and to obtain the congestion benefit.
e. The sink for Option B and Carved-out GFA entitlements will be a valid Load Zone owned by the GFA Responsible Entity or billing entity, respectively, in the current Commercial Model. The EPNodes or EPNode portions served through Option B and Carved-Out GFAs will be excluded from the ARR Zone where they reside to avoid the double withdrawal at those EPNodes. If the Option B GFA serves a slice of a Category 1 ARR Zone, the corresponding EPNode portions will not be excluded from the ARR Zone.

3.9.2 Reserved Source Points (RSPs)

Reserved Source Points (RSPs) are Resources historically used by a Market Participant to serve Load in an ARR Zone. Only Designated Network Resources (DNRs) may qualify as RSPs. The RSPs will include specific Generators, System Purchase Contracts[9] and FRP (Full Responsibility

[9] Tariff Section 1.S defines System Purchase Contracts as follows: Agreements for the purchase of Energy that do not specify the Resource(s) that the seller shall select to supply such Energy at any particular time; provided, however, that such agreements may identify the group of Resources from which the seller may make its selection; provided, further that this term does not include agreements with Manitoba Hydro involving the supply of Energy from Generation Resources in Canada up to or at the U.S. border.

Purchase)[10] or FRS (Full Responsibility Sale)[11] within MISO footprint and Interface points for Network Resources outside the footprint (drive-in network TSR subclass "Designated"). The System Purchase Contracts and FRP/FRS may be considered as valid DNR only if the following conditions are met:

a. Buyer Market Participant (Market Participant claiming the RSP) should identify specific Generator Resource(s) and MWs within MISO footprint.
b. The MW quantities should add up to the contractual MW under the system purchase and FRP/FRS.
c. For the purposes of initial data gathering pursuant to Section 3.11.6, the Generator Resources should have TSRs on the previous transmission provider OASIS to demonstrate the DNR status for the RSP eligibility during the Reference Year. In the event that the Market Participant cannot provide a TSR, MISO can rely upon supporting documentation including the NITS contract that lists the DNRs clearly with MW amounts; any deliverability study (i.e. System Impact study or other) that the transmission provider conducted or any company report attested by a higher official that lists the DNRs clearly with MW amounts. If the DNR is listed in the supporting documentation but the MW amount is not, MISO will rely on the Deliverability Study. MISO will limit the MW amount to the minimum of the rated capacity (Pmax from Asset Registration) or the TSR-supporting documentation amount to establish the RSP eligibility for each applicable season.
d. For the purposes of RSP addition and replacement pursuant to Section 3.21, the Generator Resources should have TSRs on the previous transmission provider OASIS to demonstrate the DNR status for the RSP eligibility during the Reference Year. In the event that the Market Participant cannot provide a TSR, MISO can rely upon supporting documentation including the NITS contract that lists the DNRs clearly with

[10] Tariff Section 1.F defines Full Responsibility Purchases as follows: The total of all purchases coincident with the expected Demand of the LSE under which the seller is contractually obligated to deliver Energy plus reserves to the purchaser, expressed in MWs for the hour. Reserve provision by the seller as a percent must meet or exceed the PRM obligation for the purchasing LSE. Each purchaser and seller must agree on which of their transactions are to be reported under this heading.

[11] Tariff Section 1.F defines Full Responsibility Sales as follows: The total of all sales coincident with the expected Demand of the LSE under which the seller is contractually obligated to deliver Energy plus reserves to the purchaser, expressed in MWs for the hour. Reserve provision by the seller as a percentage must meet or exceed the PRM obligation for the purchasing LSE. Each purchaser and seller must agree on which of their transactions are to be reported.

MW amounts; any deliverability study (i.e. System Impact study or other) that the transmission provider conducted or any company report attested by higher official that lists the DNRs clearly with MW amounts. If the DNR is listed in the supporting documentation but the MW amount is not, MISO will rely on the Deliverability Study. MISO will limit the MW amount to the minimum of the rated capacity (Pmax from Asset Registration) or the TSR/ supporting documentation amount to establish the RSP eligibility for each applicable season.

e. The Seller Market Participant (Asset Owner of the Generation Resource(s)) shall approve the Generation Resources and the MW quantities for capacity and energy for a period of at least 5 years, including the Reference Year.
f. The MW quantities of the Generator Resources should not already be subscribed to another Market Participant for its ARR Entitlements.

Under the Generation Resource Qualification Requirements, for a supply Generation Resource to qualify for inclusion as an RSP, a qualified Market Participant must have had a Capacity and Energy ownership interest in, or a Capacity and Energy contract with, the supply Generation Resource that either began in the Reference Year, ended in the Reference Year, or remained in effect throughout the Reference Year for the applicable ARR Zone.

This ownership or contractual relationship must be for at least five (5) years. Contracts qualify if they include rollover rights that were exercised in such a way that the duration of the contracts was effective for a minimum of five (5) years.

If the Transmission Service for such owned Generation Resources or contracted for Generation Resources was approved, but was not in service during the Reference Year, or the Generation Resource was under construction, but was not in service during the Reference Year, the Generation Resource will qualify for inclusion in the BRSS or PRSS, if deliveries under the contracted for Generation Resource or owned Generation Resource began prior to December 31, 2005.

In the event the entire MW Capacity of the Generation Resource is greater than the Market Participant’s owned MW amount or contracted for MW amount, only the Capacity and Energy MW amount owned or contracted for shall qualify.

Any external Point of Receipt or Source for NITS will correspond to the Interface CPNode specified as the Point of Receipt on its firm drive-in network TSR.

Every source of a GFA service must be reported in the GFA template filings. If the source information is unclear or unspecified, the Responsible Entity will need to get an approval from the Transmission Owner (TO) for the source to qualify as an RSP.

If the source(s) is specified in a contract as one of the LBAAs qualifying as Category 1 ARR Zones, the specific RSPs will be determined during the Annual ARR Registration process under Section 3.9.3.

If two Market Participants had or have contracts that meet all of the above qualification requirements for the same MW quantity of a supply Resource, such that the Resource would otherwise qualify as an RSP for more than one ARR Zone, then the Market Participant that contracted the Resource most recently will be given priority in determining the ARR Zone for which the Resource will serve as an RSP.

3.9.2.1 Baseload Reserved Source Set (BRSS)

For an RSP to be part of the BRSS, its Capacity Factor must be at least 50% over a test period of three years, consisting of the Reference Year and two immediately preceding years. If the unit became commercially operational during or after the test period, the capacity factor information for the three consecutive years since commercial operation began will be used to establish the baseload eligibility. To the extent that the unit has not been in operation for the whole test period, MISO will utilize the available capacity factor data for the life of the unit. Alternatively, the Market Participant may request to use the class average for a similar technology type unit's capacity factor information. Similarly, for new Generation Resources, an average Capacity Factor based on the type of generation will be assigned to the Resource.

For Joint Operating Units (JOU), the baseload eligibility will be established based on the aggregated capacity (minus any JOU share pseudo-tied out of MISO footprint) during the test period. If the aggregated capacity does not meet the baseload eligibility requirements, the capacity of the individual JOU shares will be considered for the test period. The JOU owner with the largest share shall supply the capacity factor information when the aggregated capacity is considered. Individual JOU owners shall supply the capacity factor information when the individual shares are considered.

In determining Capacity Factors for supply Generation Resources, data from the single month of the 36-month period with the lowest Capacity Factor for that supply Generation Resource will be excluded.

The Generator asset owning Market Participants must provide the Capacity Factor data where the non-Generator owning Market Participants (those with power purchase agreements) are relying upon them. If the owner fails to provide the Capacity Factor data, the Generation Resource will be deemed as non-baseload supply.

The Capacity Factor will be calculated as:

$$Capacity\ Factor = \frac{Total\ Net\ Generation\ MWh}{Generator\ Capacity\ MW\ \times\ Period\ Hours}$$

Generator Capacity should reflect the maximum seasonal output for the season if the baseload status is calculated on a seasonal basis and the rated capacity (Pmax from Asset Registration)

For RSPs external to MISO, Market Participants may choose to use the scheduling factor of the associated drive-in TSR for baseload qualification. Scheduling data of the import path as determined to be eligible and valid in the Reference Year will be used to determine the baseload status. Scheduling data on re-directed paths cannot be used to determine the baseload status. A drive-in network TSR must have three years of data to be eligible for inclusion in the BRSS.

The formula for the scheduling factor calculation is shown below.

$$Scheduling\ Factor = \frac{Total\ Scheduled\ MWh\ for\ the\ Period}{Granted\ TSR\ MW * Period\ Hours}$$

In determining scheduling factors for a PTP service, data from the single month of the 36-month period with the lowest scheduling factor will be excluded.

Market Participants registering PTP ARR Entitlements or NITS entitlements where the source resides outside MISO footprint may still choose to provide Capacity Factor information of the underlying Resource for baseload qualification. Market Participants must provide the following data to determine the Capacity Factor:

a. Rated Power (Pmax) of the resource residing outside MISO footprint

b. Monthly net generation MWh of the resource over a test period of three years, consisting of the Reference Year[12] and the two immediately preceding years. Generation data for the life of the resource would be sufficient if the resource has not been in operation for the whole test period. For Joint Operating Units (JOU), generation data for the aggregate and individual JOU share are required.

Load factor will be used in place of Capacity or Scheduling factor to determine the baseload status for Loads that are pseudo-tied out of MISO.

3.9.2.2 Peak Reserved Source Set (PRSS)

All sources qualified as RSPs, including those in the BRSS, make up the PRSS.

3.9.2.3 HUFU Reserved Source Point (HUFU RSP)

High Utilization Factor Units (HUFU) Reserved Source Points are RSPs with an RSP utilization factor[13] of seventy percent (70%). These resources do not meet the BRSS capacity factor requirement of 50%, but instead have a high utilization factor as they are very often relied upon and can be dispatched frequently at any capacity level.

3.9.2.3.1 HUFU ARR Entitlements

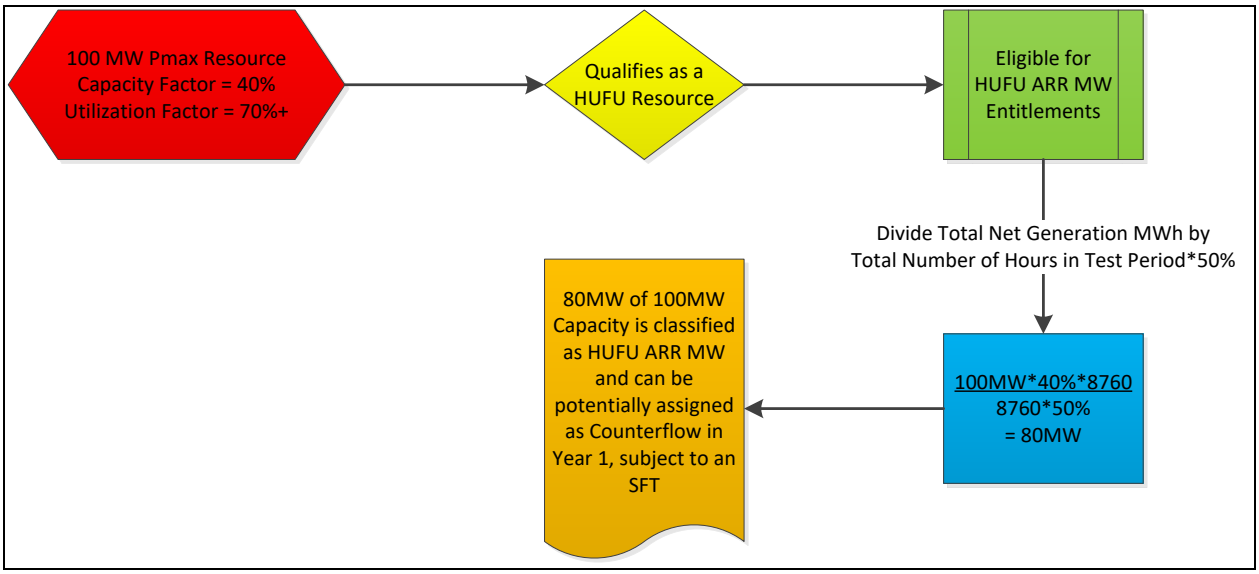
HUFU ARR Entitlements are PRSS in nature with the special eligibility of being available for counterflow assignment (pursuant to section 3.9.2.7.1) as part of the year 1 allocation. HUFU ARR Entitlements are defined from the qualified HUFU Network Resource to the applicable ARR Zone using the HUFU RSP MW that has been identified at a 50% implied capacity factor. The HUFU ARR Entitlement is calculated as follows:

$$HUFU\ MW\ Level = \frac{Total\ Net\ Generation\ MWh}{50\% * Total\ Hours\ in\ Test\ Period}$$

[12] The Reference Year is the Annual ARR Allocation period subsequent to the year of the RSP request to add or replace the PTP ARR Entitlement.

[13] RSP Utilization Factor corresponds to the percentage of hours that an RSP was on-line during the test period, which is defined for the MISO Southern Region to be June 1, 2010 through May 31, 2012. For MISO Midwest Region the test period is during the Reference Year and two years prior to the Reference Year.

Exhibit 3-3: HUFU ARR Entitlement Example



3.9.2.4 Reserved Source Points (RSPs) Exception for PRSS

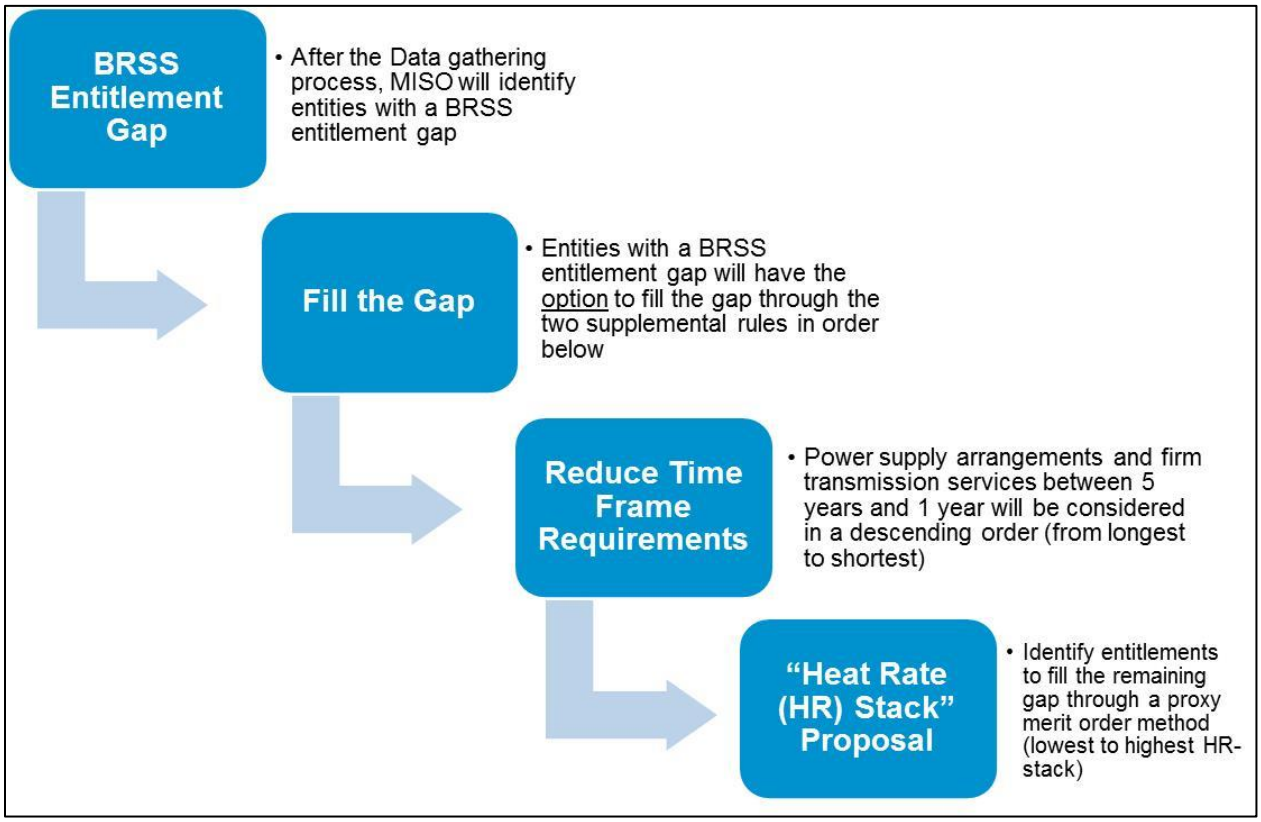
For the purposes of Year 1, if a Market Participant has insufficient Capacity in its PRSS to meet its Baseload Usage, the five-year ownership/contract requirement will be reduced to one year for the PRSS up to the Baseload Usage amount. RSPs determined under this exception will not be eligible for LTTRs, i.e., the entitlements corresponding to these RSPs will not be eligible for Stage 1A nomination.

3.9.2.5 Reserved Source Points (RSPs) Exception for BRSS

A Market Participant that has a total of BRSS entitlement MWs below its Baseload usage can invoke the supplemental rules to determine whether any new BRSS entitlement can be created to fill the BRSS gap. This multistep process is illustrated in

Exhibit 3-4: Supplemental Rules Process below and further discussed in this section.

Exhibit 3-4: Supplemental Rules Process



The supplemental rules to fill the BRSS gap apply during; (1) the initial data gathering and registration (pursuant to Section 3.9.2.1) of the BRSS entitlements for areas integrating into the Transmission Provider Region after the effective dates of these supplemental rules, and (2) during the first Annual ARR Registration following the effective date of these supplemental rules for areas integrated into the Transmission Provider Region prior to the effective date of these rules. Market Participants that choose to not invoke these supplemental rules during the eligibility period will be ineligible to request the creation of BRSS entitlements under these supplemental rules in periods thereafter.

Market Participants can qualify for supplemental BRSS entitlements by utilizing one of two exceptions to fill in the BRSS Entitlement Gap. The first exception is called Term Reduction, which reduces the Market Participant ownership or contract requirement and maintains the 50% capacity factor requirement for baseload supply resources. The second exception is called the Heat Rate Stack, which maintains the ownership or contractual requirement of five (5) year

duration while considering lower capacity factor thresholds. This supplemental rule intends to capture resources that would have otherwise qualified as Baseload given different operational factors. In either scenario the BRSS entitlements will not exceed the maximum capacity of the resource and BRSS entitlements will not exceed the Baseload usage. Additional details on these exceptions are described below.

Term Reduction: During the period after conversion of Transmission Service to ARR Entitlements but before Nomination for Allocation, the supplemental rules that the Transmission Provider will implement based on requests by the Market Participant(s) for a reduction of the ownership or contractual duration for a given RSP will be effective. The RSPs for the requesting Market Participant will be reviewed from the longest term required, five (5) year duration, to the shortest term required, one (1) year duration, for PPAs that serve load in the Market Participant's ARR Zone.

Rolling twelve months of firm transmission that are valid during the Reference Year will be eligible for ARR Entitlements if the monthly services are continuous and converted into a confirmed long-term firm transmission service. Market Participants should be able to demonstrate the continuity of the monthly services into firm long-term service and provide confirmation of the firm long-term service at the time of initial ARR registration.

- If the 12 monthly services make up the Reference Year in its entirety, the minimum MW of the 3 months that make up the Season in the Reference Year will be the eligible ARR Entitlement MW.
- If the 12 monthly services only partially overlapped with the Reference Year, the minimum MW amount across the months in the Reference Year will be the eligible ARR Entitlement MW.

ARR Entitlements created per this section will be defined from the longest duration transmission service to the shortest duration transmission service in sequential order.

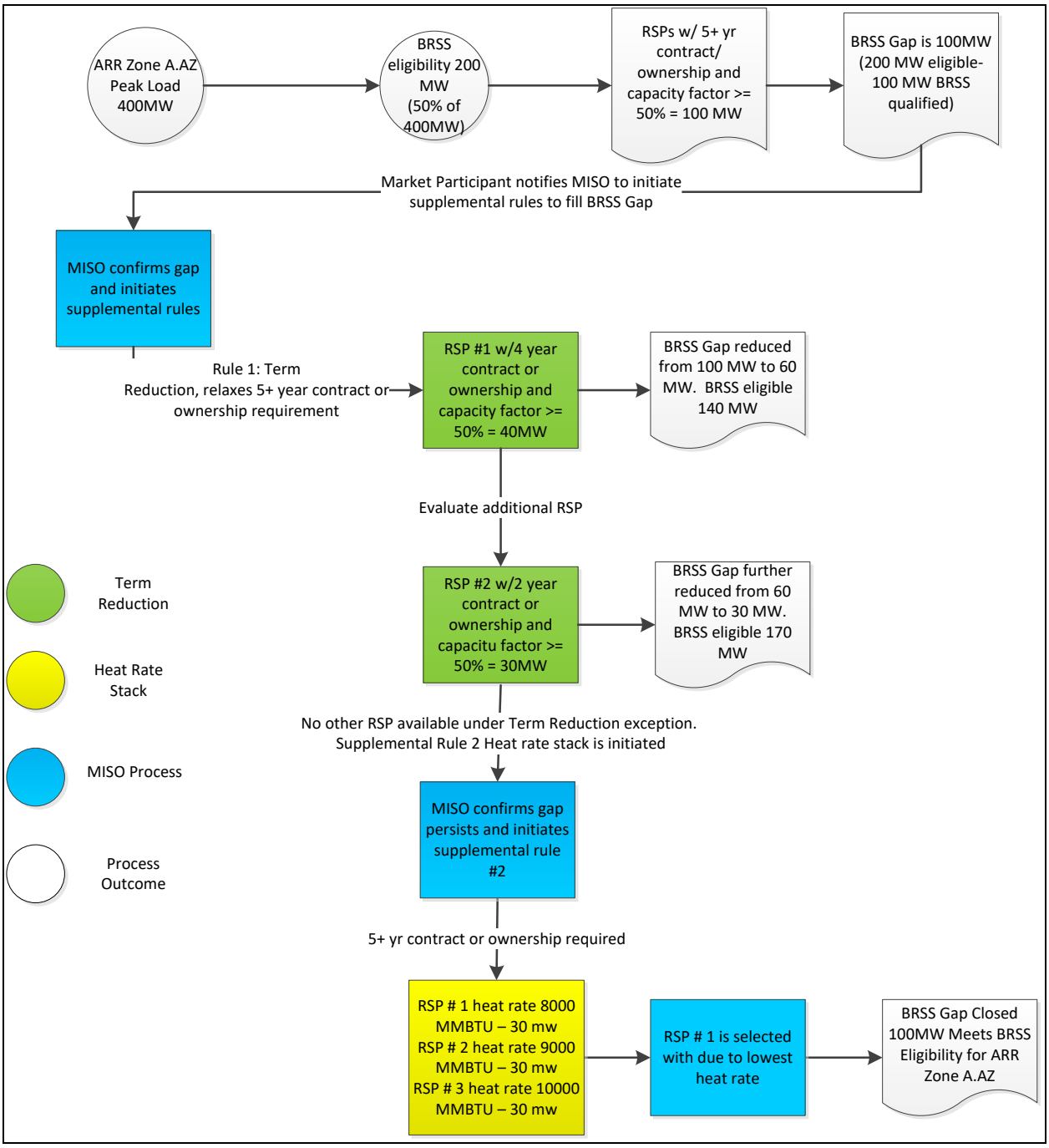
For the ARR Entitlements determined based on terms of ownership or contractual duration of three (3) years or less, Market Participants shall provide the capacity factor data for the RSP for the full length of the ownership or contract.

Heat Rate Stack: If the first supplemental rule, Term Reduction, does not provide sufficient RSPs to fill the BRSS entitlement gap satisfying the Market Participant's Baseload Usage, the Market Participant may then utilize the Heat Rate Stack rule. BRSS entitlements created under this rule

will be determined using the most recent annual average heat rate data, generally the full year immediately preceding that of the initial data gathering and ARR Registration. The remaining BRSS entitlement deficiency may be mitigated by adding these RSPs from the one with the lowest to the highest heat rates to the applicable ARR Zone up to the Baseload Usage such that the BRSS gap is filled. Heat Rates will be determined by MISO using publicly available information, including the U.S. Energy Information Agency (EIA) and the Department of Energy, unless otherwise provided by the Market Participant.

An example of a Heat Rate Stack process can be found in Appendix L of this BPM.

Exhibit 3-5: Example of Supplemental rule application



3.9.2.6 Rejecting BRSS Entitlements created by Term Reduction and/or Heat Rate Stack

Following the creation of the BRSS entitlements due to the Term Reduction or Heat Rate Stack rules described above, a Market Participant can review and reject the BRSS entitlements created using the exception rules. If the Market Participant wishes to reject the BRSS entitlement, the Transmission Provider will process such requests in the reverse order of the entitlement creation. For example, suppose that the Term Reduction exception was used to create the BRSS entitlement that the Market Participant wishes to reject. The Transmission Provider processes such rejection requests of the BRSS entitlement in the order of the shortest ownership contract to the longest contract ownership. If a Heat Rate Stack entitlement is requested for rejection, the Transmission Provider will process such request by removing the highest heat rate RSP first then moving to a lower RSP heat rate.

Market Participants that reject BRSS entitlements created under the term reduction, or the heat rate stack can use the exception under RSP for insufficient PRSS.

3.9.2.7 Stage 1A (LTTR) PTP service

For a PTP service to be considered in Stage 1A, the scheduling factor of the corresponding path must be at least 50% over the Reference Year and two immediately preceding years. The path that existed during the Reference Year will be used to define the LTTR and will not change in subsequent years.

If multiple sources are defined for the PTP service, then the scheduling factor must be the same for all sources of that PTP service. The tag information for the PTP service that was used to compute the scheduling factor would be the same for all paths. In this case, all paths will become eligible for Stage 1A if the scheduling factor equals or exceeds 50%. Only the scheduling data of the tags associated with the path as determined to be eligible and valid in the Reference Year will be used to determine the baseload status. Scheduling data of the tags on re-directed paths cannot be used to determine the baseload status. If less than three years of scheduling factor data is available, the PTP service will not qualify for Stage 1A nomination.

In determining scheduling factors for a PTP service, data from the single month of the 36-month period with the lowest scheduling factor will be excluded.

3.9.2.7.1 HUFU ARR Entitlement – Stage 1A

Market Participants cannot nominate on a HUFU ARR Entitlement in Stage 1A of the Annual ARR Allocation. However, as part of the restoration phase during the Year 1 allocation, MISO may use HUFU ARR Entitlements to the extent that they provide counterflows and increase allocation of LTTRs only during Year 1 of the Annual ARR Allocation. HUFU ARR assigned counterflow as part of the restoration will reduce the HUFU ARR Entitlement nomination eligibility for Stage 1B.

Any assigned HUFU MW allocated in year 1 can be requested for termination in subsequent Annual ARR Allocations and would undergo the same process as any LTTR termination request. Successful termination of HUFU ARRs will result in a HUFU ARR Entitlement with similar characteristics to a non-BRSS entitlement.

3.9.2.8 Stage 1B PTP service

All PTP services that meet the qualification requirements as described in Section 3.8.2 and 3.21.3.2 will be included in the set of PTP services eligible for Stage 1B.

3.9.2.8.1 HUFU ARR Entitlement – Stage 1B

Market Participants can nominate on any available HUFU ARR Entitlements in Stage 1B. The nomination and megawatt quantity of the HUFU ARR Entitlements associated with HUFU RSPs eligible for nomination in Stage 1B are subject to the same rules and nomination caps as other Stage 1B entitlements.

3.9.2.9 Stage 1A Option A GFA entitlements

For a GFA entitlement to be considered in Stage 1A, the capacity or the scheduling factor of the corresponding source points must be at least 50% over the Reference Year and two immediately preceding years (or the life of the unit if it had not been in operation for three years).

If multiple sources are defined for the GFA, then the scheduling factor must be the same for all sources of that GFA. The electronic tags (“e-Tags”) information for the GFA that is used to compute the scheduling factor would be the same for all paths. In this case, all paths will become eligible for Stage 1A if the scheduling factor equals or exceeds 50%. Scheduling data of the e-Tags associated with the primary GFA path will only be used to determine the baseload status. Scheduling data of the e-Tags on re-directed paths cannot be used to determine the baseload. If less than three years of scheduling factor data is available, all paths of the GFA will not qualify for Stage 1A nomination.

Market Participants/GFA Responsible Entities must use the Capacity Factor data to establish the baseload characteristics, where the contracted (i.e., not owned) or owned Generator Resource was within MISO footprint. The Generator asset owning Market Participants must provide the Capacity Factor data where the non-generator owning Market Participants are relying upon them. If the owner fails to provide the Capacity Factor data, the Generation Resource will be deemed as non-baseload supply.

The formula for the Capacity Factor calculation is shown in Section 3.9.2.1. For new Generation Resources, an average Capacity Factor based on the type of generation will be assigned to the Resource. In determining Capacity Factors for supply Generation Resources, data from the single month of the 36-month period with the lowest Capacity Factor for that supply Generation Resource will be excluded. If the unit became commercially operational during the three applicable years, all available Capacity Factor information must be provided. If less than three years of data is available, a class average of the same technology type will be used to compare the unit's Capacity Factor information. A unit that became commercially operational prior to the three applicable years will not qualify for inclusion in the BRSS if less than three years of data is available.

Market Participants and GFA Responsible Entities may choose to use either capacity or scheduling factor data to establish the baseload characteristics, where the contracted (i.e., not owned) or owned Generator Resource is outside MISO footprint. If the Market Participant or Responsible Entity fails to provide the scheduling or Capacity Factor data, the Generator Resource will be deemed as non-baseload supply. An import network service must have three years of data to be eligible for inclusion in the BRSS.

The formula for the scheduling factor calculation is shown in Section 3.9.2.1. In determining scheduling factors for a PTP service, data from the single month of the 36-month period with the lowest scheduling factor will be excluded.

3.9.2.10 Stage 1B Option A GFA entitlements

All GFAs that pass the qualification requirements as described in Section 3.8.3, including those that fall under Stage 1A, will constitute the Stage 1B GFA entitlements.

3.9.3 Registration of Local Balancing Authority Area as Points of Receipt of ARR Entitlements

During year 1 of the Annual ARR Registration, if the Points of Receipt for a PTP Transmission Service reservation, NITS reservation, or GFA reservation are specified as an LBAA, the existing entitlement shall be defined in terms of RSPs within the LBAA or the Interface as described in this section.

If the Point of Receipt of an eligible NITS, GFA or PTP service is external to MISO, the source of the entitlement will be the corresponding Interface CPNode. For example: If the NITS contract indicates an external Balancing Authority (BA) as the supporting DNR and the DNR meets RSP requirements, then the RSP must be specified in terms of an Interface CPNode. The MW quantity claimed from the Interface must be equal to the MW specified on the corresponding DNR (sub-class “designated”) TSR. MISO will provide the eligible list of CPNodes during the registration process.

For NITS contracts with a LBAA as Point of Receipt:

1. If either the POR or the source for a NITS contract match specific generation CPNodes internal to MISO, such Resources may be claimed as the sources of the corresponding entitlements. For example: If the NITS contract indicates a specific Generator within MISO footprint as the supporting DNR and the DNR meets the RSP requirements, then the RSP must be specified in terms of a Generator CPNode. The MW claimed from that Generator must be equal to the contracted MW with the Generator owner. MISO will provide the eligible list of CPNodes during the registration process.
2. When both the POR and the source are specified as an LBAA, the source of the corresponding entitlements may be specific Generation CPNodes within that LBAA. For example: If the NITS contract indicates a system purchase of an LBA within MISO footprint as the supporting DNR and the DNR meets the RSP requirements, then the RSP must be specified in terms of one or more Generator CPNodes. The sum total of the MWs claimed from those Generators must be equal to the contracted MW under the system purchase. MISO will provide the eligible list of CPNodes during the registration process.

In both cases (1 and 2 above), the registering Market Participant of the qualifying DNR must provide a written approval from all relevant Asset Owners to MISO during the Annual ARR Registration data gathering process. The Resources should be present in MISO Commercial Model (active or expired Generator CPNodes). MISO will map the expired Generator CPNodes

to the nearest electrically equivalent CPNode to define the ARR Entitlements. A new HUB type CPNode will be created at the high-side transmission Bus of the expired Generator with a non-injection/non-withdrawal EPNode in case an electrically equivalent CPNode cannot be identified accurately, and as determined to be feasible by MISO Commercial Modeling Team.

Where there is no agreement between the Market Participant registering the NITS entitlement and the Market Participant for the sources used in defining the ARR Entitlement, all RSPs in the PRSS of the Category 1 ARR Zone corresponding to the POR LBAA of the NITS contract will be used as the default definition. The default will be calculated based on the ratio of the Ptest values of those RSPs. Only RSPs internal to the LBAA will be used for this definition. If the Category 1 ARR Zone is completely subdivided into multiple Category 2 ARR Zones, the default will be based on the RSPs of all the Category 2 ARR Zones that make up the LBAA. The MW amount of the resulting entitlements will be deducted from the corresponding RSPs and the remaining available Capacity is split among the NITS customer(s) of the Category 1 ARR Zone.

If the POR for a PTP or GFA is specified as a Local Balancing Authority Area (LBAA), the entitlement shall be defined as a set of Generator CPNodes within the LBAA. Those CPNodes should be present in MISO Commercial Model as active Generator CPNodes. Written approval must be obtained from all relevant Asset Owners and provided to MISO during the Annual ARR Registration data gathering process.

Where there is disagreement between the GFA Responsible Entity and the Market Participant for the Source Points used in the definition of a GFA entitlement, the default definition described above for rejected NITS entitlements will be used.

Where there is disagreement between the Market Participant registering the PTP service and the Market Participant for the entitlement's source points:

a. For Capacity backed PTP Transmission Services, all RSPs in the PRSS of the Category 1 ARR Zone corresponding to the POR LBAA of the PTP service will be used as the default definition. Only RSPs internal to the LBAA will be used for this definition. If the Category 1 ARR Zone is completely subdivided into multiple Category 2 ARR Zones, the default will be based on the RSPs of all Category 2 ARR Zone(s) that make up the LBAA. The MW amount of the resulting entitlements will be deducted from the corresponding RSPs and the remaining available Capacity will be split among the NITS customer(s) of the Category 1 ARR Zone.

b. The Category 1 ARR Zone corresponding to the POR LBAA of the PTP Transmission Service will be used as the default definition for the non-Capacity backed PTP Transmission Service. If the Category 1 ARR Zone is completely subdivided into multiple Category 2 ARR Zones, the default will be based on the Load Ratio Share of all such Category 2 ARR Zone(s) that make up the LBAA.

A Hub or an ARR Zone internal to MISO will be used as the source for ARR Entitlements if MISO determines that there are two or more existing entitlements representing hubbing transactions in which a set of existing entitlements is used to deliver power to the relevant LBA while another set of existing entitlements is used to transport that power from it. In this case, the Hub or an ARR Zone will be used as the ARR sink for the first set of existing entitlements that deliver power to the LBA and as the ARR source for the second set of existing entitlements that transport the power from the LBAA. A Hub will be used as a source/sink of ARR Entitlements only where the receipt or the delivery point of the existing entitlements is consistent in terms of nodal definition with an LBA.

3.10 ARR Registration Procedures

This section describes the procedures for the yearly registration of qualifying transmission entitlements. Eligible Market Participants (see section 3.10.5) are required to participate in the Annual ARR Registration as described in this section. The year 1 Annual ARR Registration will be a two-step process. Step 1 will consist of the initial data gathering as described in Section 3.9. Step 2 will consist of reviewing and approving ARR Entitlements through the Market Portal. The Annual ARR Registration in year 2 and beyond will consist only of Step 2.

Additional details on Step 2 can be found in the FTR Market Participant User's manual and in the sections below.

Market Participants perform the following actions to review and approve ARR Entitlements:

- Validate and sign off ARR Entitlements for GFA and PTP Transmission services
- Asset Owner (AO) approve asset usage (year 1 only)
- Review Network ARR Entitlements

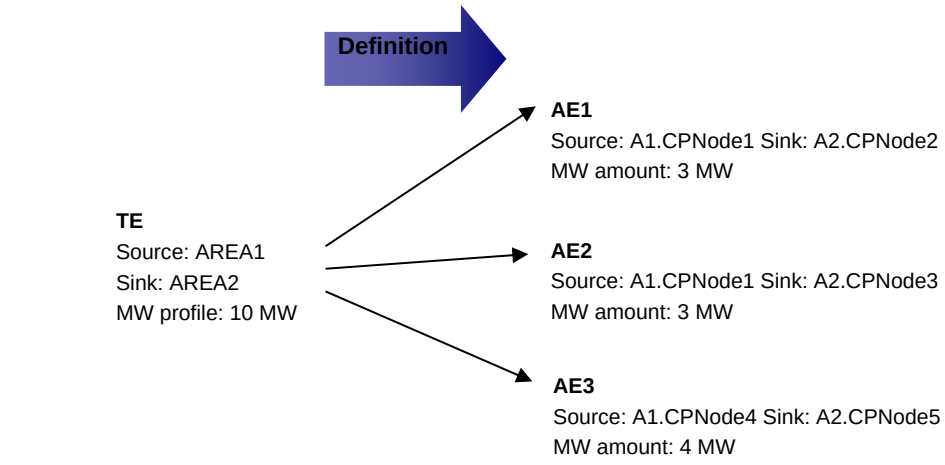
3.10.1 Validate and Sign Off ARR Entitlements for GFA and PTP Transmission Services

Market Participants will validate and electronically sign off transmission entitlements, and the definition of GFA and PTP entitlements.

When defining the ARR Entitlements, Market Participants will select valid CPNodes as sources and sinks for their ARR Entitlements (AEs). The definition process is illustrated in

Exhibit 3-6.

Exhibit 3-6: ARR Entitlement Definition



TE: Transmission Entitlement

AE: ARR Entitlements

3.10.2 Asset Owner Approval of Asset Usage

Once GFA and PTP entitlements are defined, the Asset Owners (AOs) of the Resource used in the entitlement definitions must approve such usage. Approval is done at the TE level; the TE is rejected if any of the AOs of the Resources used for the definition rejects it.

Where there is no agreement between the Resource owner and the Market Participant registering the entitlements, rejected entitlements will be re-defined by MISO as described in Section 3.9.3.

3.10.3 Review Network ARR Entitlements

The network ARR Entitlements are created during the year 1 Annual ARR Registration. The Network ARR Entitlements will be calculated based on the following information:

1. Capacity of the Generation Resource associated with an ARR Zone
2. Usage of each Generation Resource in PTP and GFA transmission service
3. NITS Peak Load Forecast (NPLF) of the Market Participant in an ARR Zone

Appendix 11.1.1 contains an example describing the creation of network entitlements.

Market Participants will only review the Network ARR Entitlements during the Annual ARR Registration in year 2 and beyond.

3.10.4 Timing of the Annual ARR Registration

Market Participants with firm historical transmission rights, are eligible to receive ARRs. To acquire ARRs, such Market Participants, as well as those assigned LTTRs for Network Upgrades as established in Section 46.1 of MISO Tariff and Section 3.25 of this BPM must participate annually in the ARR registration process, which is a prerequisite to the Annual ARR Allocation (nomination and allocation).

Every Annual ARR Registration and Allocation covers a period of one year (four seasons) from June 1 through May 31 of the following year. The period of June 1 through May 31 of the next year is considered as the Annual ARR Allocation period. At least ninety (90) days prior to the beginning of each Annual ARR Allocation period, MISO initiates a process to allocate ARRs to Market Participants. (Refer to Section 3.11 of this BPM.)

3.10.5 Registration of Existing Entitlements

The set of Transmission Services eligible for allocation of ARRs is determined during the year 1 Annual ARR Registration (refer to Section 3.9). Only during the year 1 Annual ARR Registration, ARR entitlements for PTP and GFA services will be defined by Market Participants based on their historical transmission usage. The GFA and PTP ARR Entitlements will remain static after year 1, barring changes in MISO footprint, expiration of PTP Transmission Services or conversion of GFAs to Tariff service.

ARR Entitlements associated with NITS and PTP will be adjusted pursuant to Section 3.10.6 for the next Annual ARR Allocation period.

All Market Participants that have existing entitlements or Option A GFAs and are eligible to nominate and hold ARRs must participate in the ARR registration process as specified in this section to preserve their entitlements under the Service Agreement. Market Participants with GFAs that select Option B must also participate in the ARR definition process. For Market Participants with Option B GFAs, the "ARR Entitlements" specify the MW level between defined pairs of Receipt (source) and Delivery Points (sink) for which they will receive refunds of Transmission Congestion Charges for schedules submitted in the Day-Ahead Energy and Operating Reserve Market (DAM). The Market Participant or registered entity must register the Option B entitlements sinking at one of the fixed Option B Load Zones defined during the data gathering effort to be able to bid Load schedules and FinScheds on such Load Zones in the DAM to obtain the congestion benefit.

During the ARR registration period, Market Participants must register their existing entitlements by providing and/or confirming the information to MISO via MISO market system as described in the applicable user guides, which includes:

a. Information about the Open Access Same-Time Information System (OASIS) reservation number(s), term of service, POR (source) and POD (sink) associated with the identified Transmission Service, and the MW capacity under PTP Transmission Service.
b. In the case of existing entitlements under GFAs, information pertaining to the GFA number, GFA option, Receipt (source) and Delivery (sink) Points and reserved MW capacity.
c. Network Load Forecast by ARR zone and associated RSPs.

MISO verifies such information as consistent with the terms of the Transmission Service for which the existing entitlement is claimed. Any Market Participant that fails to provide and/or confirm all of the information requested for a transmission entitlement during the ARR registration period is deemed to have waived any rights to obtain ARRs for that transmission entitlement but may remain subject to counterflow ARR assignment.

3.10.6 Adjustment of ARR Entitlements and LTTRs for the next ARR Allocation Period

ARR Entitlements and Long-Term Firm Transmission Rights (LTTRs) remain fixed after the year 1 Annual ARR Allocation for all Market Participants that participated in the year 1 Annual ARR Registration and Allocation. Only under the following scenarios can the ARR Entitlements and

LTTRs be adjusted among existing and/or new Market Participants in an ARR Zone for the next Annual ARR Registration and Annual ARR Allocation period. The four scenarios described are not mandatory. As long as MISO receives the requested data for these four scenarios by the prescribed deadlines, and the requests are approved by MISO, the ARR Entitlements will be defined and the LTTR adjustments will be performed pursuant to this section.

3.10.6.1 Annual Adjustment based on request for the addition of New RSP

This section is applicable if a new RSP was requested to be added into an ARR Zone, was studied and approved by MISO pursuant to Section 3.21 of this BPM. In this case, the network ARR Entitlements for the new RSP will be added to the Market Participants in that ARR Zone based on the ratio of the NPLF[14] from the current allocation period.

3.10.6.2 Annual Adjustment based on request for the Replacement of RSP

This section is applicable if an existing RSP was requested for replacement in an ARR Zone, was studied and approved by MISO pursuant to Section 3.21 of this BPM. In this case, the network ARR Entitlements for the replacement RSP will be adjusted among the Market Participants in that ARR Zone based on the ratio of the NPLF from the current allocation period.

3.10.6.3 Annual Adjustment within the ARR Zones Representing Retail Load in Retail Choice States

This section is applicable to the Market Participants within the ARR Zones representing retail load in retail choice states, particularly IP.AZ, CIPS.AZ, CILC.AZ, DECO.AZ and CONS.AZ. In this case, the network ARR Entitlements will be adjusted among the prospective Market Participants in that ARR Zone in the ratio of the annual NPLF for the next Annual ARR Allocation period pursuant to Section 3.24. The ARR Entitlements and LTTR adjustments pursuant to Section 3.10.6.1 will be performed before proceeding with the adjustments specified above in this paragraph.

3.10.6.4 Annual Adjustment associated with Future Load Shift Reporting

This section is applicable if future Load shift was reported among Market Participants within an ARR Zone. Future Load shift is referred to as the Load that is expected to shift between Market

Participants in an ARR Zone and is in effect for the next Annual ARR Allocation period. In this case, the network ARR Entitlements will be adjusted among the Market Participants in that ARR Zone based on the ratio of the future NPLF[15] submitted via predefined request template. The location of the template for future Load shift and the deadline for its submission will be communicated to the Market Participants prior to the start of the next Annual ARR Registration.

MISO will utilize the information reported in this template by the published deadline to adjust the ARR Entitlements and LTTRs among the Market Participants serving Load in the relevant ARR Zone. If no Load-shift is reported by the published deadline, no adjustment of the ARR Entitlements or LTTRs will occur for the Market Participants in that ARR Zone for the next Annual ARR Registration and Allocation.

3.10.6.4.1 Timing

If a Market Participant elects to have its ARR Entitlements and LTTRs adjusted pursuant to the future Load shift reporting, it shall submit the future Load shift template to Client Services and Readiness by the published deadline. The location of the template for future Load shift and the deadline for its submission will be communicated to the Market Participants prior to the start of the next Annual ARR Registration.

3.10.6.4.2 Submission details for future load shift template

Market Participants reporting future Load shift for wholesale and retail Load should submit the data in the following manner.

3.10.6.4.2.1 Future load shift data for retail load

Typically, MISO would not expect future Load shift information for ARR Zones representing retail Load in a retail choice state since such information may not be known or available so far in advance to the Market Participants gaining or losing load. But if such a situation arises, where Market Participants become aware of Load shifts in the next Annual ARR Allocation period, then the affected Market Participants in that ARR Zone may initiate the future Load shift request pursuant to section 3.10.6.4.2.2 below (Future Load shift data for wholesale load).

[15] Future NPLF is the expected future Load shift between the Market Participants in terms of the current NPLF in that ARR Zone, i.e., the sum of the current NPLF should equal the sum of the future NPLF for the Market Participants reporting future Load shift.

3.10.6.4.2.2 Future load shift data for wholesale load

A single template must be submitted by only Market Participants that expect to have a Load switch among them. MISO can receive the template from any one of the affected Market Participants. Typically, MISO expects that there are two parties involved in the shift of wholesale load in a retail or non-retail state, where one Market Participant is expecting to lose Load and the other to gain Load. In such a case, the two Market Participants should coordinate the Load shift data among themselves and submit one template to MISO in the specified format. One party shall initiate the template by completing all fields, and then forward it to the counterparty. The counterparty shall review, approve, and forward the template to MISO. Because both parties have reviewed, accepted, and forwarded the template, MISO will consider the contents of the template to be valid and accurate. MISO will only verify the template data to ensure that the sum of the NPLFs of the two Market Participants remain the same for current and future periods. In case of disagreement among parties about the Load shift, MISO will reflect the Load shift based on the relevant Market Participant's submitted Meter Data or other reliable data sources.

Market Participants that lose Load (future NPLF is less than the current NPLF) will see a decrease in the ARR Entitlements and/or LTTRs for the next Annual ARR Allocation period as compared to the current Annual ARR Allocation period. Market Participants that acquire Load (future NPLF is greater than the current NPLF) will see an increase in the ARR Entitlements and/or LTTRs for the next Annual ARR Allocation period as compared to the current Annual ARR Allocation period.

The future Load shift data must align with the start of the season in the next Annual ARR Allocation period. If that is not the case, MISO will reflect the ARR Entitlement and LTTR adjustments aligning with the following season in the next Annual ARR Allocation period subject to review and verification. The Market Participants can avail themselves of Section 3.26 for ARR revenue redistribution for those partial months of the season when the Load shift was effective.

3.10.6.5 Illustration of Annual Adjustments of ARR Entitlements and LTTRs

Appendix E illustrates an example of the re-calculation of the network ARR Entitlements and LTTRs prior to each Annual ARR Registration.

3.10.7 Registration of Grandfathered Agreements

In an "Order Addressing Treatment of Grandfathered Agreements in MISO Energy Markets, and Establishing Hearing and Settlement Judge Procedures" (Docket Numbers ER04-691-000, ER04-

106-002, EL04-104-000) issued on September 16, 2004,[16] FERC divided the GFAs into three categories:

a. GFAs that had settled before July 28, 2004, and for which the Responsible Entity may choose treatment under Option A, B, or C or choose conversion to service under the Tariff
b. GFAs that had not settled but determined to be subject to a "just and reasonable review" standard and for which the Responsible Entity may choose treatment under Option A or Option C or choose conversion to service under the Tariff.
c. GFAs that had not settled but ordered to be carved-out since these GFAs either are expressly subject to the Mobile-Sierra standard of review, are silent on the review standard, or involve a transmission provider that is not under the jurisdiction of the Federal Energy Regulatory Commission (FERC), and for which the billing entity may choose "Carve Out", Option A, Option C treatment, or conversion to service under the Tariff.

To protect their rights, parties to GFAs must participate in the Annual ARR Registration process. During the registration period, Market Participants must register their existing service contained in GFAs by providing information requested by MISO, including information about contractual source, sink, term, MW quantity, and OASIS reservation numbers where appropriate. A GFA Responsible Entity is entitled to specify multiple Receipt and Delivery Points, consistent with its existing entitlements.

Regarding GFAs involving multiple Receipt and Delivery Points electing treatment under Option A or Option B or conversion to service under the Tariff, the GFA Responsible Entity must provide information identifying each Receipt Point and Delivery Point combination as well as MW of service between them. The total MW summed over all Receipt Point/Delivery Point pairs may not exceed the MW of service identified by FERC in Appendix B to its September 16, 2004 Order or subsequent Orders with updates to the Appendix B. MISO verifies such information as consistent with the terms of the GFA for which the existing entitlement is claimed.

[16] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236 (2004), *order on reh'g*, 111 FERC P61,042 (2005), *order on reh'g*, 112 FERC ¶ 61, 311 (2005), *aff'd sub nom.*, ***Wis. Pub. Power, Inc. v. FERC*, 2007 U.S. App. LEXIS 17257 (D.C. Cir., July 20, 2007**).

For GFAs that are to be carved out, the Responsible Entity must provide the information on Sources, Sinks, and historic use requested by MISO in the registration process for Carved-Out GFAs.

Market Participants wishing to update previously provided GFA information (where the GFA Contract language specifically allows for the update), for example to reflect new eligible sources or sinks, or higher GFA MW quantities to reflect Load growth, must submit, in accordance with the Annual FTR Registration, Allocation and Auction timeline noted in the FTR and ARR Calendar, the GFA Change Template and supporting documentation, as requested by MISO and approved by the Transmission Owner (see latest FTR and ARR Calendar and GFA Change Template at the MISO website under Markets and Operations > ARR and FTR Market >> Guides and References). Upon review and verification of the template and the supporting documentation, MISO will allow the requested change to the GFA data. MISO will notify the Market Participant via email of the outcome of the review of the change request. If MISO deems the request to be valid, the change will be reflected in the next Annual ARR Registration and Allocation. The Market Participant must follow Section 3.21.2 to properly request the addition of Resources under the GFA (Option A or B).

For purposes of allocating ARRs or granting Option B GFA congestion refunds, the ARR Zones or Option B Load Zones defined during the initial data gathering will remain static after year 1. Other changes, such as Load growth provisions and inclusion of new RSPs, when allowed by the terms of the GFA, will be reflected in the Annual ARR Allocation period following the registration of the change. For scheduling purposes (*i.e.*, submission of physical schedules for imports, exports, or Carved-Out GFAs), changes will be implemented once the GFA Change Template has been approved.

Documentation required to support requested changes will include, at a minimum, citations and copies of relevant GFA contract language, and the agreement of both GFA counterparties that the change is consistent with the terms of the contract. MISO will evaluate the requested change with the supporting documentation and other relevant sources, such as the information provided by the GFA parties during the FERC GFA fact-finding process and related FERC orders and will determine if the change may be accepted.

ARR eligibility for Load served by GFAs that expire during an Annual ARR Allocation period is based on the replacement Tariff service in place as of the ARR registration cutoff date for the period in which the GFA expires. For example, Load served by a GFA that expires at the end of

the Summer season will be eligible to register and nominate ARRs for the Fall and subsequent seasons to the extent that a NITS agreement has been executed for the Fall and subsequent seasons as of the ARR registration cutoff date. RSPs may be added to the PRSS of the ARR Zone served by the new NITS contract if they meet the Resource qualification criteria for new RSPs.

An Option A and Option B GFA Transmission Service that expires during an ARR season and for which a NITS agreement has been executed as of the cutoff date, will be treated as a Tariff rollover of Transmission Service for the purpose of ARR allocation for only the remainder of the season in which the GFA expires. ARRs allocated for such GFAs will remain in effect for the remainder of the ARR season in which the GFA service terminates. For Option A GFAs, allocated ARRs or self-scheduled FTRs associated with the GFA service will remain in the portfolio of the Market Participant for the remainder of the season in which the GFA expires. For Option B GFAs, self-scheduled FTRs associated with the Option B GFA but held by MISO for such Option B service will be transferred to the Market Participant at the time of the GFA's expiration, for the remainder of the season in which the GFA expires. Market Participants with GFAs that expire during an ARR season and that otherwise meet the requirements for rollover of the associated GFA congestion hedge, must notify MISO no later than 30 days prior to the GFA expiration date to request rollover treatment. For the remaining seasons of the ARR Allocation Period, the ARRs for the Load served by the expiring GFA can be registered and nominated towards the replacement Tariff service.

Carved-Out GFAs that expire during an ARR season and that are replaced by Tariff service during the same season will register and nominate ARRs for the Tariff service for that season in place of MISO's carved-out treatment. The Tariff agreement must have been executed for such Carved-Out GFA as of the ARR registration cutoff date. Allocated ARRs associated with the new Tariff service will have an effective date based on the effective date of the service. The self-scheduled FTRs associated with the Carved-Out GFA but held by MISO for such Carved-Out service that are replaced by Tariff service will be transferred to the Market Participant at the time of the GFA's expiration, for the remainder of the season in which the GFA expires.

3.11 Nomination and Allocation of Candidate ARRs and Termination of LTTRs

Prior to the start of each Annual ARR Allocation period, MISO initiates a process to allocate ARRs to Market Participants. The allocation of ARRs is based on the overarching principles that:

a. ARRs are allocated to entities based on their historic transmission entitlements to the use of the Transmission System administered by MISO;
b. Market Participants have the ability to select, or nominate, within limits, those historic transmission entitlements they wish to convert to ARRs;
c. Market Participants can request the termination of LTTRs; and
d. The total set of allocated ARRs is simultaneously feasible to increase the likelihood that the ARRs are fully funded by annual FTR Auction revenue.

The multi-stage process described in this section will be applied during each Annual ARR Allocation.

MISO facilitates the allocation of LTTRs to the Market Participants through a multi-stage allocation/nomination process during which Market Participants may also request the termination of their existing LTTRs. In each stage, MISO provides Market Participants with the opportunity to nominate, and be allocated, ARRs from RSPs up to their NPLF,[17] plus ARRs for Option A and Option B GFAs from GFA sources to sinks. MISO also provides Market Participants with the opportunity to be allocated ARRs based on Firm PTP Transmission Service of annual duration or longer. In Stage 1A, Market Participants likewise may request the termination of LTTRs allocated to them in prior years.

MISO determines stage sizes for two categories of ARR Entitlements:

i. The first category consists of a Market Participant's NPLF in an ARR Zone and all of that Market Participant's GFAs sinking in the ARR Zone (excluding GFAs for which the Market Participant elects Option C or that are to be carved out). Stage size for each ARR Zone will be calculated separately.

[17] Refer to Section 3.24

ii. The second category consists of all a Market Participant's PTP Transmission Service of an annual duration or longer that is valid and rolled over to the upcoming Annual ARR Allocation period.

MISO determines two nomination and allocation stages. For each stage and each category (either total of a Market Participant's forecast pro-rata Load share in each ARR Zone and all of its GFAs sinking to the ARR Zone, or all of the Market Participant's PTP Transmission Service), ARR nomination eligibility is equal to the maximum nomination eligibility multiplied by an ARR Stage Factor less the MW quantity of ARRs allocated for the category in previous stages. For the combination of NITS and GFA, maximum nomination eligibility is defined by the sum of a Market Participant's NPLF served under NITS, plus its GFA for which the Market Participant elects Options A or B. For PTP Transmission Service, maximum nomination eligibility is defined by the sum of a Market Participant's PTP reservation amounts. The nomination eligibilities for Stage 1A in both categories (NITS and PTP) are predetermined by the current set of LTTRs[18], where the LTTRs are available for a Market Participant. The nomination procedure is described in Section 3.11.3 below. The ARR Stage Factors are:

- Stage 1A: 50% of Peak Usage; otherwise, the Candidate Baseload ARR Rights
- Stage 1B: 100% of Peak Usage; otherwise, the Candidate Peak ARR Rights

A process described in Section 3.11.5 is available that may allow the restoration of CARRs that are curtailed in Stage 1A. CARRs that are curtailed in Stage 1A will be restored, if possible, by MISO in full or in part to the candidate MW quantity.

MISO allocates ARRs only to Market Participants in each stage to the extent that MISO determines that such ARRs satisfy its SFT. The LTTR termination requests are also processed subject to SFT in the LTTR Restoration and Termination stage described in Section 3.11.5.

Any infeasible ARRs assigned, following the LTTR Restoration and Termination Stage, are deemed included in the Stage 1B nomination.

[18] The current set of LTTRs is composed of the feasible and Stage 1A infeasible LTTRs that were allocated to a Market Participant in the current Annual ARR Allocation period. These LTTRs include the Stage 1A as well as the Restoration and Counterflow ARRs.

3.11.1 Time Periods and Seasons for Existing Transmission Entitlements

The Annual ARR Allocation performed by MISO considers time of use and season when allocating ARRs for entitlements (existing terms of Transmission Service or terms under the GFA for Market Participants that elected Option A), irrespective of whether the historic transmission entitlements vary by time period or season.

a. The annual allocation of ARRs is performed separately for time of use Peak and Off-Peak in each of four seasons prior to the start of each Annual ARR Allocation period.
b. The four seasons are:
    i. ***Winter****:* December, January and February
    ii. ***Spring****:* March, April and May
    iii. ***Summer****:* June, July and August
    iv. ***Fall****:* September, October and November
c. Peak is defined as period of time from 0700 hours EST through 2200 hours EST Monday through Friday excepting New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day, or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
d. Off-Peak is any period of time not classified as Peak.

The ARRs awarded to a Transmission Customer cover only current periods that correspond to the seasons or months when the transmission entitlement was found to have historically existed. ARRs are withheld in expectation of rollover rights and only awarded to Transmission Customers after the rights are renewed. Thus, the ARRs awarded for the Spring season to a Market Participant with annual NITS are valid for the entire Spring season, whereas the ARRs awarded to a Market Participant with Firm PTP Transmission Service for the period from March 1st through April 30th are only valid for the months of March and April and not for the full Spring season.

3.11.2 Transferring Candidate ARR Rights

Prior to the start of every Annual ARR Allocation, Market Participants with Candidate Baseload or Candidate Peak ARR Rights may request MISO to transfer ownership of such rights in its entirety to another Market Participant for the purposes of participating in the Annual ARR Allocation, Annual/Multi-Period Monthly FTR Auction and the secondary market. The receiving Market Participant ("receiving MP") will hold the ARRs and FTRs but the Load will remain with the original Market Participant. If the original Market Participant loses its Load to another Market Participant, then the ARR revenue will be shifted from the ARR-receiving Market Participant to the Load-gaining Market Participant.

3.11.3 Stage 1A Nomination and Allocation Procedures

Market Participants are eligible to nominate CARRs from among all of their NITS and GFA Option A ARR Entitlements. For each sink, Market Participants may nominate up to 50% of the Peak Usage (the sum of their NPLF for the upcoming Annual ARR Allocation period, plus Option A and Option B GFAs at that sink). Option B GFA entitlements are automatically fully nominated. Nominated ARR Entitlements will constitute the Candidate Baseload ARR Rights for each Market Participant. The source of the Candidate Baseload ARR Rights will be any of the RSPs in the BRSS for each of the corresponding ARR Zones up to the qualified Market Participant's pro rata Load share of the ARR Zone. The calculation of ARR Entitlements associated with NITS and Option A GFA services is illustrated in Appendix 11.1.1.

a. In the next year and each ensuing year after the LTTR termination procedure is first implemented, MISO will pre-populate the current set of LTTRs into the Stage 1A nomination process. Market Participants wishing to terminate LTTRs shall do so by marking those LTTRs for termination during the Stage 1A nomination process. Those requests are processed subject to SFT as described in Section 3.11.5. It is possible that the pre-populated LTTRs may exceed the Stage 1A cap, and so Market Participants need to ensure that the Stage 1A cap is not violated. This can be achieved by marking LTTRs for termination so that the Stage 1A nominations are within or at the Stage 1A cap. In cases where a Market Participant does not take action to prevent a violation of the Stage 1A cap at the conclusion of the Stage 1A nomination, MISO will lower the Market Participant's pre-populated LTTRs down to the Stage 1A cap for the affected cases (4 seasons x 2 time of use). If possible, MISO will prorate the MW amount according to the pre-populated LTTR MW amounts. When strict proration is not possible due to small exceedance values, MISO will lower the pre-populated MW as necessary to respect the Stage 1A cap. Appendix H illustrates an example for requesting LTTR termination and its processing.
b. Market Participants are eligible to nominate CARRs from the ARR Entitlements defined for PTP Transmission Service for up to 50% of the total reservation MW quantity over all annual or longer Firm PTP Transmission Service Entitlements.
c. Nominations of CARRs equal to 100% of the registered MW quantity of Option B GFAs are automatically included in Stage 1A, even if these nominations exceed the Stage 1A cap. MISO does not allocate to Market Participants ARRs representing Option B GFAs that are determined to be feasible.
d. Option B ARRs are used by MISO as an accounting mechanism to offset possible revenue inadequacy resulting from any congestion cost refunds to Option B GFAs.

e. Stage 1A includes eight independent nominations: one for each of four seasons and two time of use (Peak and Off-Peak).
f. MISO performs an SFT for each season and time period for Stage 1A CARRs for a total of 8 cases (4 seasons x 2 time of use). CARRs are curtailed in each season and time of use as required to achieve simultaneous feasibility.
g. CARRs for service under the Tariff and for Option A GFAs may be nominated up to the Stage 1A cap for CARRs for NITS plus GFAs less the CARRs nominated by MISO to account for Option B GFAs.
h. Where the MW quantity of Option B GFAs exceeds the Stage 1A limit for -CARRs for NITS plus GFAs, Stage 1A nominations for NITS plus GFAs will include only Option B GFAs. Any Option B GFAs over the Stage 1A limit for CARRs for NITS plus GFAs are considered in a subsequent stage by reducing the size of the subsequent stage for the purpose of determining nomination eligibility for CARRss for NITS plus GFAs.
i. Where a PTP Transmission Service Entitlement is zero MW in some months, the corresponding ARRs Entitlements will be set to the minimum MW of the three months that make up a season.
j. Where a GFA provides for service in one direction during part of the year and in the other direction for the rest of the year, ARR Entitlements may be defined separately for the two directions and nominated separately. Where a GFA is zero MW in the specified direction during some months, the corresponding ARR Entitlements will be set to the minimum MW of the three months that make up a season.
k. For a Carved-Out GFA, MISO will define ARR Entitlements that will be used to reserve transmission capacity for the GFA in the ARR allocation process. MISO will include these entitlements as CARRs in Stage 1A of the allocation process.

3.11.3.1 Priority to LSEs with Long-term rights under transmission system scarcity

The Market Participants were determined to be in Category 1 or Category 2 ARR Zone based on their long-term rights valid in the Reference Year as described in Sections 3.8 and 3.9. Market Participants that did not have long-term rights but were serving Load during the Reference Year were put into the Category 1 ARR Zone by default,and allowed to share the RSPs of the LSEs with long–term rights, i.e., those that had brought the RSPs into the Category 1 ARR Zone. This section describes the process by which the LSEs with long-term rights are eligible to request for priority under system scare conditions. To process the request, the Market Participant shall use MISO's dispute resolution process under Attachment HH of the Tariff to file a claim that its LTTRs were impacted due to the participation of LSEs with short-term or no rights in its ARR Zone. The

impact on the LTTRs is determined based on whether or not the requesting Market Participant's reasonable needs were met in the most recent Annual ARR Allocation. MISO will process the dispute if all the following conditions are met:

a. The Market Participant has Load within MISO Region and is represented in one of the existing ARR Zones.
b. The Market Participant participated in the most recent Annual ARR Allocation, and the Stage 1 allocation was less than its reasonable needs. While a Market Participant may nominate ARRs up to 50% of its Peak Usage, its reasonable need shall be determined with reference to 50% of its total nominations in Stage 1A and 1B of the recent Annual ARR Allocation.
c. The Market Participant making such request shall be the same Market Participant who's RSPs made up the PRSS for that ARR Zone.

3.11.4 Stage 1B Nomination and Allocation Procedures

a. Market Participants are eligible to nominate CARRs from among all their NITS, GFA Option A, and HUFU ARR Entitlements, defined up to 100% of the Peak Usage, less ARRs allocated in Stage 1A for NITS and Option A GFAs and less Option B GFAs. Such ARR and HUFU Entitlements will constitute the Candidate Peak ARR Rights for each Market Participant. The source of the Candidate Peak ARR Rights will be any of the RSPs, or HUFU RSPs, in the PRSS for each of the corresponding ARR Zones up to the qualified Market Participant's pro rata Load share of the ARR Zone.
b. Market Participants are eligible to nominate CARRs from the ARR Entitlements defined for PTP Transmission Service up to 100% of the sum of the reservation MW quantity over eligible annual or longer Firm PTP Transmission Service Entitlement, less ARRs allocated in Stage 1A. Stage 1B includes eight independent nominations: one for each of four seasons and two time of use (Peak and Off-Peak)[19].
c. If Option B GFAs exceeded the Stage 1A limit for NITS and GFAs, the amount by which the Option B GFAs exceeded the Stage 1A limit will automatically reduce the Stage 1B nomination limit for NITS and Option A GFAs. MISO performs an SFT for each season and time of use for Stage 1B CARRs. MISO curtails CARRs in each season and time of use as required to

[19] See Section 3.10.4 of this BPM for the definition of Seasons and Peak and Off-Peak.

achieve simultaneous feasibility. Previously allocated Stage 1A ARRs are fixed (not subject to curtailment) in the Stage 1B process.

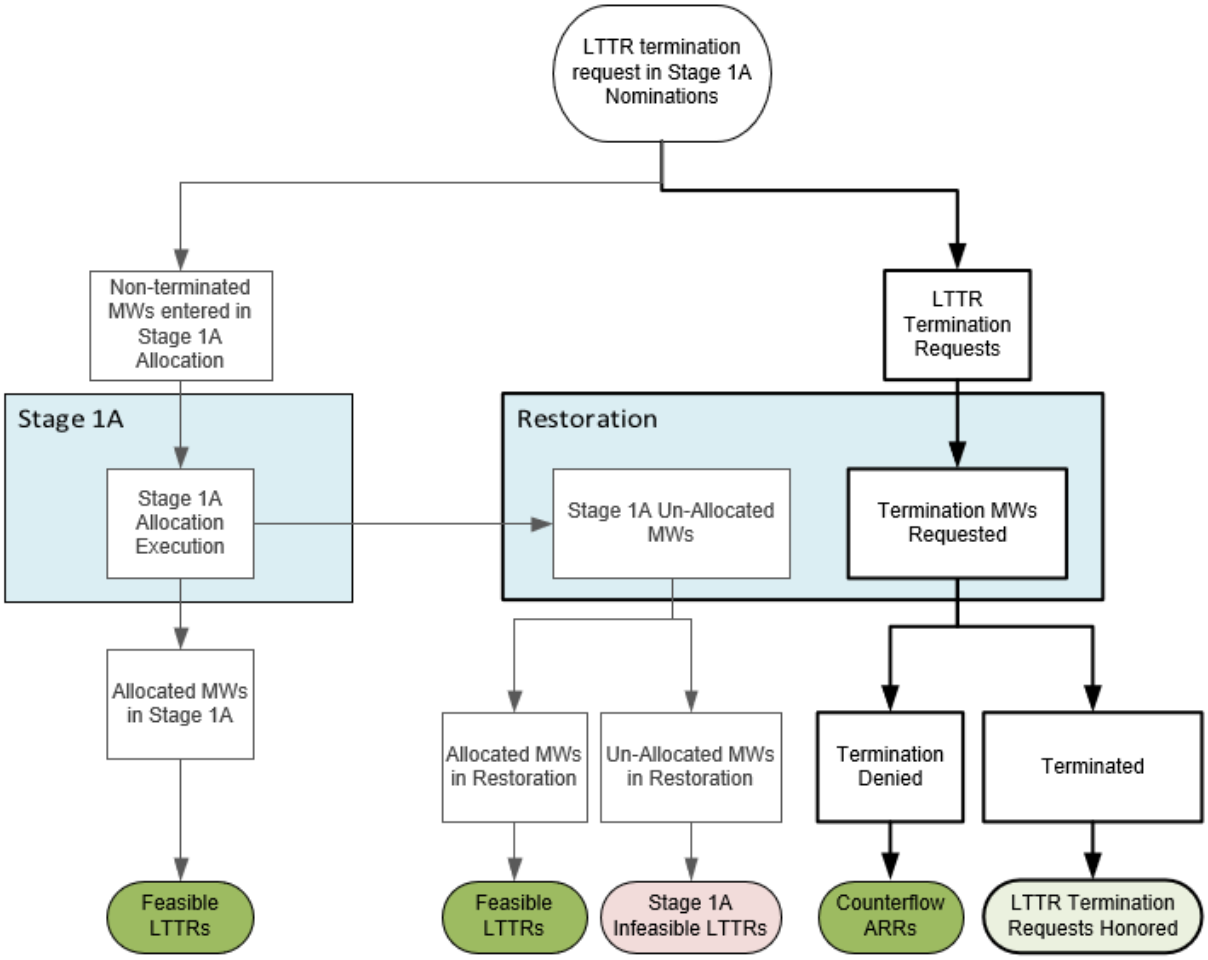
d. MISO will fully nominate assigned infeasible ARRs following LTTR Restoration and Termination Stage as Stage 1B CARRs, which are ineligible for modification by the Market Participants. These infeasible ARRs will remain LTTRs whether or not made feasible in Stage 1B. Infeasible ARRs not rendered feasible in Stage 1B remain infeasible LTTRs for the current Annual ARR Allocation.
e. MISO will fully nominate MVP CARRs as Option CARRs. The allocated ARRs are not guaranteed in the subsequent Annual Allocations.

3.11.5 LTTR Restoration and Termination Stage

This Section describes the restoration of curtailed Stage 1A CARRs and candidate LTTRs,[20] using any available Counterflow ARR Entitlements, HUFU ARR Entitlements and LTTR termination requests. The restoration process involves an SFT that maximizes the restoration, and also maximizes the termination of the LTTRs for which LTTR termination requests were made during Stage 1A. The restoration process is conducted after Stage 1A is concluded and before the Stage 1B nominations are accepted. The flowchart below depicts the LTTR Restoration and Termination Stage.

[20] A “Candidate LTTR” is an LTTR carried over from the previous year and re-nominated into Stage 1A of the current Annual ARR Allocation. An “LTTR” refers to the Stage 1A ARR (i.e., a granted Stage 1A CARR) and Counterflow ARR for the current Annual ARR Allocation period.

Exhibit 3-7: Flowchart of LTTR Termination Process



Market Participants need to ensure that their LTTR termination requests are made during the Stage 1A nomination stage. There is no Market Participant involvement during the subsequent restoration/termination stage. MISO will utilize the restoration candidates and counterflow candidates described below as inputs to process this stage.

3.11.5.1 Restoration Candidates

The following may be restored:

a. The candidate ARRs (CARRs) curtailed during Stage 1A of a Market Participant's participation in its year 1 of the Annual ARR Allocation (Year 1 Stage 1A CARRs). As implied, the Year 1 Stage 1A CARRs are only applicable in year 1. The curtailed Year 1 Stage 1A CARRs will be eligible for restoration to their CARR MW quantity.
b. The candidate LTTRs curtailed in Stage 1A. The curtailed candidate LTTRs will be eligible for restoration to their current Annual ARR Allocation period's MW quantity.

3.11.5.2 Counterflow Candidates

a. Counterflow ARR Entitlements – The MW quantity of a Stage 1A eligible ARR Entitlement that was not nominated in Stage 1A of a Market Participant's year 1 Annual ARR Allocation.
b. LTTR Termination requests made during Stage 1A.
c. HUFU ARR Entitlements – The MW quantity of the ARR Entitlement defined from a HUFU RSP will be an eligible counterflow candidate.

During a Market Participant's year 1 Annual ARR Allocation, the Counterflow and HUFU ARRs[21] may be assigned from any of its Counterflow and HUFU ARR Entitlements. In a Market Participant's year 2 and ensuing Annual ARR Allocation, the Market Participant can request the termination of LTTRs pursuant to this Section. An example illustrating the year 1 versus year 2 restoration and counterflow eligibility is included in Appendix H.

3.11.5.3 Process for restoring the Restoration Candidates

The restoration of candidate ARRs/LTTRs shall be attempted, using the counterflow and HUFU ARR candidates, by computing the optimization problem that minimizes an objective function that is the weighted sum of two components:

a. The first component of the objective function is the weighted sum of squares of the megawatt amount of the curtailed candidate LTTRs and a Market Participant's curtailed year 1 Stage 1A CARRs that could not be restored based on the inclusion of counterflow and HUFU ARR entitlements and processing of LTTR termination

[21] Counterflow and HUFU ARRs are those allocated during this stage resulting from Counterflow and HUFU ARR Entitlements and LTTRs.

requests. The weights in the weighted sum of squares will be equal to the inverse of the MW of curtailed candidate LTTRs and curtailed year 1 Stage 1A CARRs.

b. The second component of the objective function is the weighted sum of squares of any LTTR megawatt amount whose termination was requested but not granted, and the counterflow and HUFU ARRs that are added to restore curtailed candidate LTTRs and curtailed year 1 Stage 1A CARRs. The weights in the weighted sum of squares will be equal to the inverse of the MW of the corresponding LTTR termination requests and counterflow and HUFU ARR entitlements.
c. Appendix C of this BPM illustrates the restoration process using counterflow candidates.

3.11.5.4 Outcome of the Restoration process

The outcome of the above optimization problem results in the restoration of all or a portion of curtailed candidate LTTRs and curtailed Year 1 Stage 1A CARRs, the allocation of counterflow and HUFU ARRs, and the processing of LTTR termination requests. The LTTR termination requests can be partially or fully accepted. If partially accepted, the unaccepted portion will remain as an LTTR for the future allocations. The accepted portion of the LTTR termination request will cease to exist as an LTTR for future allocations. The underlying RSP and ARR Entitlement of an accepted LTTR Termination request will remain in the requesting Market Participant's portfolio for the future ARR Registrations. The Market Participant may invoke Section 3.21 to terminate RSPs and ARR Entitlements, which is applicable under limited circumstances.

a. Counterflow and HUFU ARRs shall be allocated and assigned directly to the owner of the corresponding CARR(s). Counterflow and HUFU ARRs and any LTTR megawatt quantity whose termination was requested but not accepted are subject to the same settlement terms and conditions as other allocated Stage 1A ARRs (i.e., LTTRs).
b. Counterflow and HUFU ARRs and any LTTR megawatt quantity whose termination was requested but not accepted will not be considered toward the Stage 1B ARR nomination eligibility cap of such Market Participant.

3.11.5.5 10 Year clock on LTTR Termination Requests

A Market Participant's LTTR whose termination was requested but not accepted shall nonetheless expire after such termination requests are made for ten (10) consecutive Annual ARR Allocation

periods[22]. The termination will take effect on the eleventh (11th) Annual ARR Allocation period after the vintage year. The vintage year[23] is (i) the year when that LTTR was first requested for termination, or (ii) Year 1 in the case of counterflow and HUFU ARRs assigned to a Market Participant. This 10-year timeline shall be reset if the megawatt volume that remains un-terminated after the processing of an ensuing request is greater than the megawatt volume that remained un-terminated after the processing of the immediately preceding request[24]. The MW quantity covered by a request for termination of an LTTR during the 2009-10 Annual ARR Allocation shall be deemed to constitute the un-nominated MW quantity of that LTTR (i.e., the difference between the 2008-09 LTTR MW and the 2009-10 Stage 1A CARR corresponding to that LTTR). Requests for LTTR termination for the 2010-11 allocation and beyond should be made during the corresponding Stage 1A nomination window.

3.11.6 Partial-Year FTR Allocation

A Partial-Year FTR Allocation will be conducted for the Market Participant in new ARR Zones added because of the expansion of MISO footprint that becomes effective after the start of the Annual ARR Allocation period. The Partial-Year FTR Allocation will cover the period when the new ARR Zones become effective up to the start of the next Annual ARR Allocation. For the partial year period, the Market Participants in new ARR Zone(s) may request an allocation of FTRs, which will be in lieu of an allocation of ARRs. As part of the integration of new ARR Zones, MISO will conduct a mid-cycle Annual ARR Registration for the Market Participants in the new ARR Zone(s). The ARR registration process will be held according to Section 3.10, with the Reference Year comprised of the four full seasons prior to the Annual ARR Registration associated with the integration of the applicable ARR Zones. Market Participants must provide data pursuant to Section 3.9. The Partial-Year FTR Allocation and the ensuing Annual ARR Allocation will use the ARR Entitlements from the mid-cycle ARR registration.

The Partial-Year FTR Allocation will consist of a single-round nomination and allocation using the SFT like that of the Annual ARR Allocation process. Market Participants with NITS or Option A

[22] Once the difference between the vintage and the current year reaches 10 years, the LTTR will expire.

[23] The vintage year of an ARR Entitlement can be found out from the "LTTR Export" download located in the ARR Definition page of the ARR Admin Tool.

[24] In other words, the vintage year will be reset to the current year whenever the allocated unterminated LTTR amount increases from the previous year.

GFA Transmission Service may nominate up to the Peak Usage (less the portion of the Load served under Carved-Out or Option C GFAs) of the remaining seasons of the current Annual ARR Allocation period. Market Participants of PTP Transmission Service may nominate up to the eligible PTP Transmission Service MW amount. The Partial-Year FTR Allocation and the allocated FTRs will cover the peak and off-peak for each of the remaining seasons of the partial year. The process will be conducted with base loading from the latest annual FTR Auction models to ensure the Simultaneous Feasibility of all existing FTRs.

MISO will build seasonal allocation models to be used in the Partial-Year FTR Allocation from data submitted for the Network and Commercial Models that includes the information submitted by Market Participants in the new ARR Zone(s). Transmission capacity resulting from updating the loopflow assumptions will also be used for allocating FTRs to the Market Participants in the new ARR Zone(s) during the Partial-Year FTR Allocation process.

Market Participants in the new ARR Zone(s) may participate in the multi-period monthly FTR Auctions pursuant to Section 4.10.9, following the Partial-Year FTR Allocation, for each complete month beginning with the integration date. In subsequent Annual ARR Allocation periods, the Market Participants shall follow the nomination and allocation procedures specified in Section 3.11 for the allocation of ARRs. The Year 1 Annual ARR Allocation process for the Market Participants in the new ARR Zones will be the first full Annual ARR Allocation period that begins immediately after the end of the partial year period.

3.12 Reserved

3.13 Stage 2 Allocation

After Stage 1B of the Annual ARR Allocation, MISO will inform each Market Participant of its Stage 2 allocation based on the difference between that Market Participant's Stage 1 allocation amounts and its Stage 1 nomination cap. MISO will further inform each Market Participant of its Stage 2 allocation as a percentage of the Stage 2 allocation of all applicable Market Participants. Each Market Participant will then receive the corresponding percentage share of the dollar value of the system capability sold in the Annual FTR Auction that was not otherwise disbursed to holders of ARRs allocated in Stage 1 of the Annual ARR Allocation.

MISO will determine the Stage 2 allocation for each Market Participant after the completion of the Stage 1 allocation. The Stage 2 allocation will be calculated as described below:

a. For each Season and time of use of the Annual ARR Allocation, the Stage 2 MW amount for each Market Participant will be calculated as the difference between the Stage 1 nomination cap[25] and the Stage 1 ARRs[26] The Stage 2 MW amount for a Market Participant is determined in each ARR Zone in which that Market Participant has a Stage 1 cap and/or Stage 1 allocations.
b. Exception for Counterflow and HUFU ARRs: The MW amount of the Counterflow and HUFU ARRs that were requested for termination will not be included in the Stage 1 ARRs when determining the Stage 2 allocation MW amount. The Market Participant must request the LTTR termination of the Counterflow and HUFU ARRs to continue getting the benefit of this exception for each subsequent year until the Counterflow and HUFU ARR is successfully terminated or the 10-year clock runs out, whichever is less. Only the unaccepted MW amount of the LTTR termination request will be considered towards the exception calculation. The rules for the 10-year clock are described in Section 3.11.5.5.
c. The Stage 2 MW amount will also be determined separately in a similar manner as described in (1) and (2) above for the PTP Transmission Services. Non-Reference Year firm yearly PTP Transmission Services are fully eligible for Stage 2 allocation, even if not found feasible for Stage 1B inclusion.
d. The sum of the Stage 2 MW amounts from (1) and (3) determines the total share of the Stage 2 revenue for a Market Participant.

Appendix G shows an example of the Stage 2 allocation.

MVP ARRs will not receive Stage 2 allocations.

[25] NPLF + Sum of Option A ARR Entitlements + Sum of Option B ARR Entitlements.

[26] Stage 1A NITS and GFA Option A ARRs + Restoration NITS and GFA Option A ARRs + Infeasible NITS and Option A ARRs + Unaccepted MW amount of NITS and Option A LTTR Termination Requests + Stage 1B NITS and GFA Option A ARRs – Unaccepted MW amount of NITS and Option A LTTR Termination Requests corresponding to Counterfow ARRs - Sum of Option B ARR Entitlements.

3.14 ARRs for Pumped Storage Units

A pumped storage unit (PSU) is a unique type of Resource that can act as a Generator or a Load. The following definitions apply to PSUs:

- ***Pumped Storage Generating Unit*** – A hydroelectric generating facility producing electricity from water that has been pumped and stored.
- ***PSU Existing Entitlement*** – An existing entitlement that is used for Transmission Service from a PSU in hours in which the PSU is generating and for Transmission Service to a PSU in hours in which the PSU is pumping.

The procedure for Transmission Service that is currently used in two directions, in connection with the operation of a PSU, differs in limited ways from the procedures for service that is not currently used in connection with the operation of a PSU.

3.14.1 Treatment of Entitlements To/From Pumped Storage Generating Units

The rules in this section apply only in situations in which the same existing entitlement is used for Transmission Service from the PSU in hours in which it is generating and for Transmission Service to the PSU in hours in which it is pumping. Such existing entitlements are referred to as PSU existing entitlements. Existing entitlements to or from a PSU that are not "bi-directional," are not subject to the rules in this section.

The rules for establishing ARR Entitlements and nominating CARRs for Transmission Customers with PSU existing entitlements are the same as for other existing Transmission Entitlements, with the exception that ARR Entitlements and corresponding nominated CARRs specify the CPNode for the PSU as a Receipt Point during Peak hours (Peak CARRs) and CARRs specify the CPNode for the PSU as a Delivery Point during Off-Peak hours (Off-Peak CARRs).

3.14.2 Pumped Storage Unit Existing Entitlements

For PSU existing Transmission Entitlements, the rules that apply to other service for determination of the megawatt quantity, Receipt Point and Delivery Point of Peak ARR Entitlements and Off-Peak ARR Entitlements, apply with the clarifications and modifications described next.

Candidate Network Service ARRs cover the following time of use:

- ***Peak ARRs*** – The PSU is treated like any other designated Resource for purposes of nominating CARRs. The maximum megawatt nomination of Peak CARRs with the PSU as a source is the generating capacity of the PSU that is a designated Resource.

Peak CARRs based on network service Delivery Point at a pre-existing Load Zone CPNode.

- ***Off-Peak ARRs*** – The PSU may be a Delivery Point, if consistent with the underlying Network Service Agreement or GFA. The maximum megawatt nomination of Off-Peak CARRs with the PSU as a Delivery Point is the pumping capacity of the PSU. Off-Peak CARRs with the PSU as a Delivery Point have a source at a CPNode for a designated Resource.

3.15 Seams Agreements in ARR Simultaneous Feasibility

MISO has seams agreements with external entities. A set of Reciprocal Coordinated Flowgates (both internal to MISO and external to MISO) will be defined and a Firm Flow Entitlement for MISO and for the other party pursuant to the Joint Operating Agreement (JOA) will be defined on the Reciprocal Coordinated Flowgates. In allocating ARRs, MISO will calculate the impact of the ARRs on each Reciprocal Coordinated Flowgate and limit the impact based on MISO's allocated Firm Flow Entitlement. MISO will address such impacts consistent with any executed seams agreements with external entities (*e.g.*, with PJM as listed in Section 1.3 of this BPM).

3.16 Service Confirmed after Allocation Process Cutoff Date

TSRs that have not been confirmed by the cutoff date established for each Annual ARR Registration period are not considered existing Transmission Service for purposes of ARR allocation and will not be eligible for inclusion in the ARR allocation process.

3.17 Firm Point-to-Point Transmission Service Less Than Annual Duration

Only Firm PTP Transmission Service of annual duration or longer are eligible to receive ARRs in the annual allocations. Monthly or shorter-term Firm PTP Transmission Service will not be allocated ARRs in the annual allocation process. Section 3.8.2 describes the eligibility criteria for PTP services.

3.18 Network Resources Eligibility Criteria

Only Network Resources designated for firm network Transmission Service for a season or longer are eligible to be used in defining ARR Entitlements and for receiving ARRs in annual allocations.

3.19 Treatment of Rollover Rights

Long-Term Firm PTP Transmission Service that has renewal rights does not have to be exercised prior to the cutoff date for inclusion in the Annual ARR Allocation. The Market Participant will be eligible to nominate and receive ARRs in the allocation process as if the rollover right had been exercised prior to the cutoff date, provided the rollover right has been registered during the Annual ARR Registration process. Rollover ARR Entitlements will be created with the start date equal to the stop date of the existing Transmission Entitlement plus one day and the stop date as the end of the Annual ARR Allocation period.

When the renewal request is made and confirmed, the rollover allocated ARRs will be assigned to the Market Participant. Assignment of ARRs is automatic and mandatory upon service renewal and is not at the option of the Market Participant. If the rollover right is not exercised, the corresponding rollover ARRs will be terminated.

MISO will reassign the ARRs allocated against rollover entitlements or terminate these ARRs based upon requests by the Market Participant and validation against OASIS. Further, prior to every monthly auction, MISO will review the existing Firm PTP Transmission Service Entitlements that will expire at the start of the month for which the monthly allocation is performed and will process the ARRs allocated against rollover rights as described above.

The source and sink CPNode(s) chosen for renewal request(s) on OASIS for pre-EMT Transmission Service Reservations containing a generic (LBAA level) source and sink, will be used to define ARR Entitlements during future ARR registration processes. Market Participants are advised to work with the source and sink Asset Owners prior to selecting source and sink CPNodes because the use of those CPNodes for the purpose of defining ARRs will require Asset Owner approval. Absent such approval, ARR definitions will be based on the default methodology described in this BPM.

3.20 Infeasible ARRs

In year 2 of the Annual ARR Allocation and beyond, Market Participants are guaranteed to maintain their LTTRs up to the amount allocated in current Annual ARR Allocation period and not requested for termination in the next Annual ARR Allocation period. Where the SFT with counter-flow assignment and Stage 1B nomination is unable to fully allocate such CARRs, MISO will allocate as infeasible ARRs the MW portion of the nominated previous year LTTRs found to be infeasible.

The allocated infeasible ARRs shall be subject to the same settlement terms and conditions as other allocated ARRs. The cost, if any, of allocated infeasible ARRs will be funded by all LTTR holders in the ratio share of the MW quantity of LTTRs allocated in the current Annual ARR Allocation in the planning area. The allocated LTTRs for each Market Participant will be the sum of the allocated Stage 1A ARRs, ARRs assigned as counter-flow following the restoration stage, and Stage 1A infeasible LTTRs.

3.20.1 Transitional Infeasible ARRs Uplift

The Transmission provider will, for the first five Annual ARR Allocations following the integration of the Second Planning Area, determine and settle LTTR infeasibility separately from those LTTRs in the First Planning Area.

The following criteria will be used to determine the appropriate planning area to which the infeasible ARR uplift will be applied:

If the applicable LTTR sources in one Planning Area and sinks in the same Planning Area, then the entire cost of settling the infeasibility shall be allocated to that Planning Area.

If the applicable LTTR sources in one Planning Area and sink in a different Planning Area, then the cost of settling infeasibility shall be allocated equally to the Planning Areas.

3.21 Termination, Addition, and Replacement of Reserved Source Points and Point-To-Point Services

Market Participants can request the termination of an existing RSP corresponding to a retiring (or retired) Generation Resource or an expiring (or expired) long-term power purchase agreement (PPA), which is described in 3.21.1. Market Participants can also request to replace an existing RSP or PTP service, including any associated ARR Entitlements, ARRs and LTTRs with a new RSP or PTP service either via contractual agreement or ownership in the Annual ARR Allocation periods after the year in which the request was made, which is described in Sections 3.21.2 and 3.21.3. Market Participants can also request the inclusion of a new RSP either via contractual agreement or ownership in the Annual ARR Allocation periods after the year in which the request was made, which is described in the Sections 3.21.2 and 3.21.3. The total MW subscription of the Generator, taking into consideration all existing ARR Entitlements and all the requests, cannot exceed the rated Capacity of the corresponding Generator. Market participants can submit requests for changes to RSP's in rounds as part of the RSP process.

Round 1 – RSP Terminations for the retirement of Generation Resources and expiration of Long-Term PPA's;

Round 2 – BRSS addition or replacement of a BRSS RSP or Stage 1A Eligible Point-To-Point Service;

Round 3 – PRSS addition or replacement of a PRSS RSP or Point-To-Point Service.

Section 3.21.4 illustrates the timing for such requests.

3.21.1 Round 1 – RSP Terminations for the Retirement of Generation Resources and Expiration of Long-Term PPA's

This section describes the Market Participants' termination eligibility rules, review and verification of the RSP termination requests, and the process for requesting the termination of an RSP corresponding to a retiring (or retired) Generation Resource or an expiring (or expired) long-term power purchase agreement (PPA).

3.21.1.1 RSP Termination Eligibility Rules

a. The submitted supporting documentation shall clearly establish the PPA expiry or Generator retirement.
b. The request for RSP, including a HUFU RSP and associated Year 1 Counterflow and/or HUFU ARRs, termination must be made 5 years before the expected retirement or expiration. This

is applicable to RSP, including a HUFU RSP and associated HUFU ARRs, terminations tied to a Generator that is retiring or PPA that is expiring during the 2016 Annual ARR Allocation period and beyond (i.e. 6/1/2016 – 5/31/2017 and beyond). If the request is made within the 5-year expiry period, the RSP or HUFU RSP termination will be effective, subject to review and approval, in the fifth Annual ARR Allocation period counting from the Annual ARR Allocation period when the request was made. The 5-year notice period may be waived and the RSP or the HUFU RSP (including any associated HUFU ARRs) terminated immediately for a Generator retirement or associated PPA, if the Generation Resource was rendered inoperable immediately and permanently due to a catastrophic failure of the Generation Resource. There is no waiver of the 5-year notice period for the expiration of a PPA unless it is tied to a Generator that is deemed inoperable. Appendix J illustrates several examples of the requesting and effective periods.

c. The transitional period (involving a notice period shorter than 5 years) for the RSP or HUFU RSP termination requests is described in Sections 3.21.1.4.1 and 3.21.4.2 below.

3.21.1.2 Review and verification of the RSP termination request

MISO will begin the review process by verifying the details submitted and the supporting documentation. MISO may follow up with the Market Participant for any missing details before denying the request on case-by-case basis. MISO will deny the RSP or HUFU RSP termination request if MISO determines that the request is not eligible for termination pursuant to the rules described in section 3.21.1.1.

3.21.1.3 Process for effecting the RSP termination

Upon satisfactory review and approval, MISO will terminate the RSP, as well as the underlying AEs and LTTRs, from the corresponding ARR Zone effective with the next full Season following the actual occurrence of such Generator retirement or PPA expiration. All Market Participants within that ARR Zone will no longer be able to nominate the AEs and LTTRs beginning with the next full Season. If the Market Participant intends to retain the RSP, or HUFU RSP and the underlying AEs but terminate the LTTRs, it should reference and follow Section 3.11.5.

During Annual ARR Registration, the affected Market Participants will not see AEs corresponding to the RSP or HUFU RSP that is the subject of an RSP or HUFU RSP termination request, indicating that the RSP or HUFU RSP termination has been affected beginning with the next full Season. These AEs will not be available for the nomination process for all ensuing Annual ARR Allocation periods beginning with the next full Season following the actual occurrence of the retirement or termination.

The corresponding FTRs acquired through self-scheduling will remain in effect through the end of the current Annual ARR Allocation period. The source or sink of the ARRs and FTRs shall continue to be given effect through the end of the current Annual ARR Allocation period by mapping the retired Generator Resource to the nearest electrically equivalent CPNode, as described in Section 4.6.

If the Market Participant eligible to request RSP termination does not make such a request upon the retirement of a Resource, the RSP, including associated ARRs and LTTRs, will be kept in the subsequent Annual ARR Allocation periods by mapping the CPNode for the retired Generation Resource to the nearest electrically equivalent CPNode, as described in Section 4.6.

3.21.1.4 Transitional period (shorter than 5-years) for requesting RSP termination

Generally, the request for RSP termination must be made 5 years in advance as described in the eligibility rules in Section 3.21.1.1 above. Under the following circumstances, however, the Market Participant is eligible for a shorter (less than 5 years) request period. This is a transitional mechanism and expires with the start of the 2016 Annual ARR Allocation period. Appendix J illustrates several examples of the request and effective periods.

3.21.1.4.1 Generator Retirement or PPA Expiry during or prior to 2010 Annual ARR Allocation Period

A Market Participant that meets the eligibility rules for RSP termination tied to a Generator that has retired (or is retiring) or a PPA that has expired (or is expiring) prior to or during the 2010 Annual ARR Allocation period (i.e., 6/1/2010 – 5/31/2011) shall request the termination of the associated RSP prior to the 2010 ARR registration per the posted timeline (see section (c) of Section 3.21.1.1). Upon satisfactory review and approval, MISO will terminate the RSP, as well as underlying AEs and LTTRs, from the corresponding ARR Zone effective with the next full Season following the actual occurrence of such retirement or expiration. The process for effecting the RSP termination is described in Section 3.21.1.3 above.

3.21.1.4.2 Generator Retirement or PPA Expiry during 2011 through 2015 Annual ARR Allocation Periods

A Market Participant that meets the eligibility rules for RSP termination tied to a Generator that is retiring or a PPA that is expiring during the 2011 through 2015 Annual ARR Allocation periods (i.e., 6/1/2010 – 5/31/2016) shall request the termination of the associated RSP prior to the ARR

registration for the Annual ARR Allocation period when such retirement or expiration is scheduled to occur, in accordance with the timeline that will be posted per Section 3.21.1.1 (3). For example, if a PPA is terminating on December 31, 2014, the request for RSP termination must be made at the 2014 ARR registration. Review Appendix J for additional examples. Upon satisfactory review and approval, MISO will terminate the RSP, as well as underlying AEs and LTTRs, from the corresponding ARR Zone effective with the next full Season following the actual occurrence of such retirement or expiration. The process for effecting the RSP termination is described in Section 3.21.1.3 above.

A Market Participant may request the termination of an RSP tied to a Generation Resource that is retiring or retired, or a long-term PPA that is expiring or expired, and has no associated LTTRs in the current Annual ARR Allocation period. The termination shall be effective in the next full Season following such retirement or expiration.

3.21.2 Round 2 – Addition or Replacement of a BRSS RSP or Stage 1A Eligible Point-To-Point Service

In Round 2 of the RSP process, Market Participants can submit requests to add Baseload resources or replace existing BRSS RSPs with Baseload resources. Market Participants can also submit requests to add Stage 1A eligible PTPs or replace the existing Stage 1A PTPs.

3.21.2.1 Addition or Replacement of a BRSS RSP

RSPs may be added to the BRSS if the total MW capacity of the existing BRSS in a given ARR Zone is less than 115% of the Baseload Usage[27] (“BRSS RSP addition cap”) of the requesting Market Participant. The new RSP can either be an existing Resource or a new Resource that should be commercially operational by the start of the new Annual ARR Allocation period. The new RSP must meet the Resource Qualification Requirements. The subsequent Annual ARR Allocation period will take the place of the Reference Year for determining whether the new resource meets the Resource Qualification Requirements. The subsequent Annual ARR Allocation period will take the place of the Reference Year for purposes of evaluating the Baseload RSP eligibility of the replacement Resource.

[27] Baseload Usage is the Stage 1A nomination cap.

Megawatts from an existing RSP may also be removed from the BRSS to free up more system capability for the feasibility of ARRs from a new RSP to be added to BRSS based on a new Baseload Supply Resource.

The new RSP can be an existing Resource or a new Resource that should be commercially operational by the start of the new Annual ARR Allocation period. The new Resource must meet the Resource Qualification Requirements with two exceptions: i) the Capacity and Energy Contract can also be with another entity that has a Capacity and Energy contract directly with the Generation Resource, provided that both contracts have the same termination date; and ii) the Capacity and Energy ownership interest, or the Capacity and Energy contract should remain in effect throughout the Seasons for which the replacement RSP is requested in the upcoming Annual ARR Allocation for the applicable ARR Zone. The subsequent Annual ARR Allocation period will take the place of the Reference Year required for the replacement Resource to meet the Resource Qualification Requirements. The replacement Baseload RSP must also meet Baseload Supply Resources qualifications pursuant to Section 3.9.2 of this BPM. The subsequent Annual ARR Allocation period will take the place of the Reference Year required for the replacement resource to meet Baseload RSP eligibility.

3.21.2.2 Stage1A Eligibility Point-to-Point Service

A Firm Point-To-Point Transmission Service with annual or longer duration that commences after the Reference Year is eligible to be requested as an addition to Stage 1A or to replace an existing Stage 1A Point-To-Point Transmission Service. This new Stage 1A Eligible Point-To-Point Transmission Service must be active by virtue of rollover provisions or extant in the upcoming Annual ARR Allocation period by the closing date provided by the Transmission Provider prior to each Annual ARR Registration.

The Market Participant requesting Stage 1A Eligible Point-To-Point Transmission must also meet the following requirements:

a. The Market Participant must be an LSE serving load with the portion of the new Stage 1A Eligible Point-To-Point Transmission Service for which Stage 1A Eligible Point-To-Point is requested.
b. The Market Participant must demonstrate the existence of a firm network contract with the transmission provider for the network load.
c. The duration of the Market Participant's entitlement to service under the network contract (source and sink) by virtue of rollover rights or extant, in the upcoming Annual Allocation Period by the closing date provided by the Transmission Provider prior to

each Annual ARR Registration, must be equal to or greater than that of the Stage 1A Eligible Point-To-Point Transmission Service.

d. The Point of Receipt of the new Stage 1A Eligible Point-to-Point Transmission Service must correspond to a Local Balancing Authority Area and the Point of Delivery must correspond to the Local Balancing Authority or external Balancing Authority Area for the load identified in the network contract.
e. The Market Participant must demonstrate a Capacity and Energy interest through a contract or ownership of the Resource corresponding to the source of the new Stage 1A Eligible Point-To-Point Transmission Service.
f. The Resource or the new Stage 1A Eligible Point-To-Point Transmission Service must meet the Baseload Supply Resource qualification requirements pursuant to Section 3.9.2.

The remainder of the Stage 1A Eligible Point-To-Point Transmission Service MW, that did not pass the SFT for Stage 1A inclusion, shall be entitled to Stage 2 ARR compensation pursuant to Section 3.13. The rollover provisions described in Section 3.19 will also apply to the new Stage 1A Eligible Point-To-Point Transmission Service.

3.21.2.3 Validation Process

Market Participants shall submit the requests with the order in which those requests will need to be studied. The SFT can result in ARR Entitlements for a MW quantity of the replacement RSP or Stage 1A Point-To-Point that is less than, equal to, or greater than the terminated MW quantity of the existing RSP or Stage 1A Point-To-Point. The requesting Market Participant must submit the Minimum Acceptance Ratio for the replacement request. (Appendix M illustrates examples of the Minimum Acceptance Ratio). If the ratio of the replacement RSP or Stage 1A Eligible Point-To-Point to existing RSP or Stage 1A Point-To-Point being replaced is less than the Minimum Acceptance Ratio, determined by SFT, MISO will deny the replacement request. The ensuing SFT results will be considered pre-confirmed by the Market Participant (*i.e.*, with an advance commitment to accept the ensuing SFT results) so that the next request in queue can be processed with the previously studied requests as base-loading in the SFT case. This will ensure that the SFT results for the completed requests do not affect the results of the requests further down the queue. The SFT will be performed sequentially, and the outcome of the previous requests will be fixed for the following request SFT study. At the request of the Market Participant, the MW portion of the request that fails the SFT can be included in Stage 1B without having to undergo or pass any further SFT and will also be processed as base-loading in the SFT case for the subsequent Round 3 RSP study and will take precedence over any request to add an RSP to

the PRSS in counting the additional RSPs towards the PRSS RSP Addition Cap (115% of the ARR Zone NPLF). Any unallocated portion from the SFT study can be requested for addition[28] or replacement in any future Annual ARR Allocation period if the Resource meets the Resource Qualification Requirements for that Annual ARR Allocation period. The study will be performed on a first come, first served basis. The results of the SFT will set the new ARR Entitlement MW amount for subsequent Annual ARR Allocation periods for the requesting Market Participant. Each following Annual ARR Allocation period, the Market Participant will then be able to request ARRs and LTTRs from the resulting ARR Entitlements. No ARRs/LTTRs from the new RSP will be granted in the current Annual ARR Allocation period.

The Round 2 request will be subject to SFT wherein the allocation of the new RSP or Stage 1A Eligible Point-To-Point and the termination of the existing RSP or Stage 1A PTP (for a replacement request) will be maximized. The SFT for a new Baseload RSP will protect the feasibility of all LTTRs from the current Annual ARR Allocation period without the infeasible ARRs. The SFT will be conducted on a market-wide, non-ARR Zone basis. The termination and replacement of LTTRs must be associated with the same Load within or outside MISO footprint that was served in the current Annual ARR Allocation period and will be served in the future Annual ARR Allocation periods.

3.21.2.4 Request RSP for re-evaluation into BRSS

A Market Participant may request that an existing RSP that is in the PRSS but not in the BRSS be included in the BRSS if the RSP meets all the qualifications for inclusion in the BRSS and passes the SFT for such inclusion. In assessing such a request, MISO shall reevaluate the baseload status of an RSP that it has previously determined to have that status. It must meet Baseload Supply Resources qualifications pursuant to Section 3.9.2 of this BPM. The portion that doesn't pass this study will remain in the PRSS. Market Participant cannot request re-evaluation of a failed RSP for another ARR Zone in the same year.

A Market Participant may not request that an RSP be removed from an ARR Zone and then later request that such RSP be re-included in the same ARR Zone, within the same year.

[28] Pursuant to Section 3.21.2.

3.21.3 Round 3 – Addition or Replacement of a PRSS RSP or Point-To-Point Service

In Round 3 of the RSP process, Market Participants can submit requests to include Baseload or non-Baseload resources into non-BRSS RSP as additions or by replacing existing RSPs. Market Participants can also submit requests to add new PTPs or replace the existing PTPs.

3.21.3.1 Addition and Replacement of a PRSS RSP

Megawatts from an existing Reserved Source Point may be removed from the PRSS to free up system capability for the feasibility of ARRs from a new Reserved Source Point eligible to be added to the non-BRSS RSP. The Market Participant may also request to replace an existing BRSS RSP with a non-Baseload Supply Resource in an ARR Zone in which the requesting Market Participant's total PRSS MW do not exceed 115% of the requesting Market Participant's Peak Usage, provided that no LTTRs have been allocated to the existing BRSS RSP for the portion to be replaced. Once allocated, the replacement RSP will be considered a non-BRSS RSP, and the replaced Baseload Supply Resource can only be submitted for subsequent re-inclusion in the BRSS pursuant to Section 3.21.2.

RSPs may also be added to the non-BRSS RSP if the total MW capacity of the existing PRSS in an ARR Zone is less than 115% of the Peak Usage[29] ("PRSS RSP Addition Cap"). The new RSP can either be an existing Resource or a new Resource that should be commercially operational by the start of the new Annual ARR Allocation period. The new RSP must meet the Resource Qualification Requirements. The subsequent Annual ARR Allocation period will take the place of the Reference Year for purposes of determining whether the new resource meets the Resource Qualification Requirements. The non-Baseload RSP must meet the qualifications pursuant to Section 3.9.2.2. The subsequent Annual ARR Allocation period will take the place of the Reference Year for purposes of evaluating the Baseload RSP eligibility of the replacement Resource.

Market Participants can request up to 115% of the Peak Usage to add a qualifying non-Baseload Resource to the PRSS.

[29] Peak Usage is the Stage 1 (Stage 1A + Stage 1B) nomination cap.

3.21.3.2 Addition and Replacement of a PRSS Point-To-Point Service

PTP Firm Transmission Service of annual or longer duration that commences after the Reference Year can be added to Stage 1A or Stage 1B of the upcoming Annual ARR Allocation for the amount that is determined to be feasible in SFTs, and subject to the following conditions. Only PTP Transmission Services that required construction of new transmission capacity and associated payments by the Market Participant are eligible for Stage 1A inclusion, whose feasibility will be studied through Network Upgrade Process pursuant to Section 3.25. Other qualifying PTP Services are eligible for inclusion in Stage 1B. The eligible PTP Services for Stage 1A or Stage 1B must be active by virtue of their renewal in the upcoming allocation year by the cut-off date provided by MISO prior to each Annual ARR Registration. The remainder of the PTP MW that did not pass the SFT for Stage 1B shall be entitled to Stage 2 ARR compensation pursuant to Section 3.13. The ARR Receipt Points for all existing ARR Entitlements along with these PTP Services cannot exceed the rated Capacity of the corresponding Generator.

3.21.3.3 Validation Process

An SFT will be conducted and ARRs sourcing at the new Baseload or non-Baseload Supply Resource will be eligible to be added to the BRSS or PRSS up to the quantity determined to be feasible in the most recent Annual ARR Allocation. Market Participants can request that any unallocated portion be used for additions or replacements[30] in any future Annual ARR Allocation period if the Generator Resource meets the Resource Qualification Requirements for that period. The SFT for the non-Baseload RSP will protect the feasibility of all Stage 1A and Stage 1B ARRs of the most recent Annual ARR Allocation without the infeasible ARRs. The SFT will be conducted on a market wide, non-ARR Zone basis. The results of the SFT will set the new ARR Entitlement MW amount for subsequent Annual ARR Allocation periods for all Market Participants within that ARR Zone based on the ratio of the NPLF[31] from the current Annual ARR Allocation period. In each ensuing Annual ARR Allocation period, the Market Participants will then be able to request ARRs and LTTRs from the resulting ARR Entitlements. No ARRs/LTTRs will be granted in the current Annual ARR Allocation period.

[30] Pursuant to Section 3.21.

Market Participants shall request the designation of new RSPs, and that request should indicate the order and the ARR Zones in which the RSPs will need to be studied. The SFT will be performed sequentially on a first-come, first served basis and the outcome of an ARR or LTTR will be fixed for the following RSP study. The request for designation will be considered pre-confirmed by the Market Participant, meaning that the outcome of the SFT for the new RSP will be automatically accepted by the Market Participant so that the next request in queue can be processed with the previously studied requests as base-loading in the SFT case. This will ensure that the SFT results for the completed requests do not affect the results of the requests further down the queue.

The designation of a new RSP pursuant to this section may also involve, but does not require, the termination, retirement, or replacement of any of the requestor's existing RSPs.

3.21.4 Timing for Termination, Addition, or Replacement of Reserved Resource Point or Point-To-Point Service

The request for termination, addition and/or replacement of an RSP or a PTP service pursuant to the foregoing conditions must be made no later than the published deadline of each year for the upcoming Annual ARR Allocation period using the web-based Market User Interface (MUI). The deadline dates for each of the rounds will be posted by June 15th of each year for the current RSP process.

Market Participants are required to submit their RSP requests using the MUI when the specified window is open which consists of the following rounds:

Round 1 – Termination Requests
Round 2 – BRSS Addition or Replacement Requests
Round 3 – PRSS Addition or Replacement Requests

For each round, Market Participants can include all the requests in one submission using a .csv template or the requests can be submitted individually via the MUI. Market Participants can make any changes to the submitted requests during the open window for each round of each year; however, any such change will reset the queue date of the requests. For each round, requests for an RSP termination, addition, or replacement will be evaluated sequentially in the order they are received.

3.22 Expiration of Point-to-Point Service Contracts

For PTP Transmission Service Agreements, any allocated ARRs terminate when such Service Agreement expires. PTP Transmission Service with annual service or longer that terminates during the Annual ARR Allocation period is included in the annual allocation for the seasons containing months during which the service is in effect.

Section 3.21 describes the replacement of LTTRs associated with a PTP service.

3.23 Reserved

3.24 Load Growth

Market Participants will be provided an opportunity to nominate additional CARRs in Stage 1A and Stage 1B to reflect incremental load growth for the planning year for which MISO is conducting the annual ARR Auction process.

To determine the nomination cap for a given Market Participant, MISO will rely on the Non-Coincidental Peak Forecast (NCPF) amount submitted by MPs as part of the Module E Capacity Tracking Tool (MECT) document submission by November 1st of the year prior to the planning year. In accordance with the current Resource Adequacy design, this forecasted amount will be associated with a specific LBA (Local Balancing Authority) and reported by Asset Owner (AO).

The LBAA non-coincidental peak Load Forecast determined using the Module E submitted Load Forecast data (described in A below) will be validated against the LBAA non-coincidental peak Load Forecast developed by MISO, which is based upon the yearly LBAA coincident peak of the most recent three years (described in B below). The two LBAA Load Forecasts will be developed as described below and a validation check will be performed prior to using the NCPF to establish the Network Peak Load Forecast (NPLF):

A. LBAA Peak Usage using Module E Load Forecast data
    1. The sum of each Asset Owner's Module E Non-Coincidental Peak Forecast (NCPF) in a given LBA, and, if applicable, the Module E GFA Peak Load corresponding to the Module E NCPF month in an LBAA will be determined.
    2. The total Load value calculated in 1 above will be aggregated for all Market Participants in that LBAA Level

B. LBAA Peak Usage using actual three-year MISO's State Estimator data

1. For each LBAA, the average of the Load growth will be calculated from the three most recent LBAA non-coincident yearly peak demands. The Load growth will be computed as follows:

$$Load\ Growth\ \% = Load\ \frac{(Year\ X)}{(Year\ X-1)}$$

Where Load is equivalent to the historical LBAA non-coincident peak, *year X* is one of the three years under consideration, and *year X-1* is the year immediately preceding.

The two resulting Load growth percentages will be averaged to calculate the combined Load growth factor.

2. The most recent full year's LBAA peak demand will be multiplied by the average Load growth factor calculated in Step 1 and the result compared to the current Module E forecast submission.

The validation checks will involve the flagging of meaningful differences between the MP submitted forecast and the historical data, and the investigation of any inconsistencies. When unexplained inconsistencies are found, Market Participants will be required to justify the forecasted NCPF or to submit revised data. If a Market Participant fails to provide adequate justification, and acknowledges that new data cannot be provided, the prior year's nomination cap allocation will be used to develop the NPLF for the upcoming allocation.[32]

Once the data is validated, the NCPF will be converted into each Market Participant's share of each ARR Zone (NPLF) as described in the example in Section 3.24.2. NPLF is defined as the Market Participant's network Load Forecast portion (NITS) of its Peak Usage[33] (demand forecast)

[32] Retail choice providers are required to confirm their individual forecasts with the appropriate EDC prior to MISO submission.

[33] Tariff Section 1.P defines Peak Usage as follows: A Market Participant's Total Forecasted Peak Load in a given ARR Zone for the upcoming Annual ARR Allocation Period calculated using the immediate prior three-year actual peak Loads. The Total Forecast Peak Load is the sum of the forecast Network Integration Transmission Service peak Load for the upcoming allocation period plus peak Load served by Option A – Grandfathered Agreements plus peak Load served by Option B – Grandfathered Agreements.

for an ARR Zone as computed from the NCPF. This number will constitute the Market Participant's total nomination eligibility associated with network ARR Entitlements sinking at the ARR Zone. The following section sets forth the data requirement responsibilities of ARR Market Participants and MISO.

3.24.1 Example demonstrating the conversion of Module E data to NPLF

The data requirements discussed in this section are separated according to the party responsible for gathering, submitting and/or calculating the load growth input data.

As part of the annual Module E Capacity Tracking Tool (MECT) submission process, Market Participants will submit non-coincident peak[34] by Asset Owner (AO) demand forecasts as part of the calculation used to determine the Coincident Peak Forecast (CPF).[35] Market Participants will submit one non-coincident peak megawatt value for each LBA they are serving. The forecasted values should be based on a predefined set of techniques and methodologies. A white paper on Peak Forecasting Methodology Review can be found at: https://cdn.misoenergy.org/Peak%20Forecasting%20Methodology%20Review%20Whitepaper173766.pdf

The non-coincident peak demand forecast data will cover the planning period (June 1 to May 31) for the next Annual ARR Allocation. The non-coincidental peak demand forecast data will be based on the AO's demand (not the LSE's Planning Reserve Margin Requirement[36]) and will be utilized in the ARR/FTR process for the purposes of incorporating load growth, if any, into the nomination cap of the next Annual ARR Allocation period. This NCP forecast should not be adjusted for any Load Modifying Resources (LMR) or transmission line losses.

Load registered as a Demand Resource, such as Interruptible Load, Direct Control Load Management, or other resources, should be included in a Market Participant's NCP forecast.

[34] The non-coincident peak demand forecast determination and methodology is discussed and covered as part of the re-design of the Resource Adequacy market.

[35] The deadline for submitting these forecasts will be the first of November of the year prior to the planning year for which these forecasts will be used.

[36] For more information refer to Resource Adequacy BPM 011 Sections 2 and 3

3.24.1.1 Retail Choice Zone Reporting Requirements

The aggregated non-coincident peak demand forecast in a Retail Choice area is to be provided by the Electric Distribution Company (EDC) on behalf of the participating retail choice suppliers (LSEs) engaging in business in that area. LSEs shall work with applicable EDCs to report their annual share of the EDC's area Non-Coincidental Peak Forecast (NCPF) to MISO on an aggregated level. The deadline for the EDC's forecast remains November 1st of the year prior to the planning year. LSEs with demand in a retail choice area shall work with the applicable EDC to confirm and report their share in MWs of the EDC's service territory's NCPF no later than 11:59 p.m. January 15th.

It should be noted that individual retail choice supplier forecasts will not change the EDC's area NCPF amount but may result in an adjustment of shares of that amount amongst providers. MISO will work with the EDC to determine allocation percentage changes for the upcoming planning year, if warranted. If no load change data is received from an individual LSE by January 15th of the planning year, MISO will assume that the entity is no longer serving load in that area. If there is excess demand within the LBA unclaimed by any LSE, MISO will allocate the unclaimed amount to the Provider of Last Resort within the specific EDC's area.

If after receipt of all LSE allocation submissions by January 15th, the total MW share for an LBA exceeds that of the original EDC submission from the previous November, MISO will alert the EDC of the inconsistency and direct them to resolve the discrepancy with the appropriate LSEs.

On occasion, a new retail choice supplier will petition to begin serving an existing Retail Choice zone. In this case, the new supplier will not have historical data on which to base their own individual load forecast. Thus, any allocation of ARRs to the new supplier for the upcoming planning year would come at the discretion of the EDC, who would also consider any future supply contracts executed by a new LSE and a purchaser. It may be appropriate to direct a first-year supplier to participate in the ARR/FTR monthly load shift process as they accumulate ongoing data of their load levels.

3.24.2 Nomination Cap Assignment based on NPLF to ARR Zones

The non-coincident peak load forecast for a given LBA may be different from the ARR Zone that the AOs nomination cap is assigned to. To derive the ARR Zone NPLF from LBA NCPF, the set of ARR Zones registered by the Market Participant are compared to the LBA used for forecast submission. When comparing the LBAs and ARR Zones for a given MP, the following four cases

may be identified. The Market Participant's ARR zone nomination cap (NPLF) is determined differently for each of the four cases:

a. *Within an LBA, the Market Participant registered Load in only one ARR Zone*: the NCPF reported for the LBA will be equivalent to the NPLF.
b. *Within an LBA, the Market Participant registered Load in several ARR Zones:* The NCPF will be allocated among the multiple ARR Zones in the same ratio of the previous year's allocation to determine the NPLF for each ARR Zone.
c. *Within an LBA*, *the Market Participant registered Load in an ARR Zone but submitted no NCPF data*: This is an inconsistency to the extent that the Market Participant registered an ARR Zone during the year 1 registration process but did not report Load in the annual submission process. MISO will need to resolve such an inconsistency with the help of the Market Participant. Alternatively, the Market Participant may have lost the Load in its entirety after the creation of the ARR Zone during the year 1 registration, and therefore did not report any Load Forecast. The NCPF submitted by the Market Participant gaining that Load will be used to establish the NPLF for this ARR Zone.
d. *Within an LBA, the Market Participant did not register Load in an ARR Zone but submitted a NCPF for that associated LBA*: This is an inconsistency to the extent that the Market Participant did not register an ARR Zone during the year 1 registration process but submitted an annual NCPF figure. Again, MISO will need to resolve such an inconsistency with the help of the Market Participant. Alternatively, the Market Participant may have gained the Load in entirety from the Market Participant that created the ARR Zone during the year 1 registration. The NCPF reported by the Market Participant gaining that Load will be used to establish the NPLF for such Market Participant in that ARR Zone.

Once the NPLF is established for an LBA, the individual ARR Zone allocation of the overall NPLF can be performed.

Exhibit 3-8: ARR Zone Allotment Example

ARR Zone Name	Previous Year Load Percentage of LBA	Associated LBA NPLF	Apportioned ARR Zone MW Value
A_1.AZ	20%	135	27
A_2.AZ	35%	135	47
A_3.AZ	45%	135	61
B_1.AZ	53%	260	138
B_2.AZ	47%	260	122

3.24.3 New Network Integration Transmission Service Customers

New NITS is defined as a new Load registered to a Market Participant that was not included in any previous Annual ARR Allocation or in the Load of another Market Participant for purposes of establishing nomination eligibility in the current Annual ARR Allocation.[37] The Reference Year for new NITS shall be comprised of the four most recent complete Seasons just prior to its integration into MISO. The ARR Zone and RSPs for the new NITS will be determined pursuant to sections 3.9.1 and 3.9.2. The source and sink for the ARRs and FTRs of the new NITS will use those RSPs and ARR Zone.

New NITS that begins after the cutoff date for an Annual ARR Allocation is eligible to receive FTRs. FTRs will be granted to the extent feasible for the period beginning with the commencement of the new service and terminating at the end of the current Annual ARR Allocation period. The FTR eligibility for this period will equal the ARR nomination eligibility. The feasibility of requested FTRs will be evaluated based on the latest available model for each season. The FTR allocations

[37] Such service may be associated, for example, with a new Transmission Owner Member, the expiration of a GFA or of a wholesale power supply contract prior to an Annual ARR Allocation period cutoff, such that no Market Participant represents the Load as of the cutoff date of the Annual ARR Allocation.

for new NITS customers will follow the Annual ARR Registration and nomination procedures described in this BPM for the Annual ARR Allocation with two exceptions:

1) Market Participants nominating Candidate FTRs (CFTRs) under this section may elect to nominate in a single stage up to the total nomination eligibility rather than in multiple stages, and
2) No restoration phase will be performed other than in the Annual ARR Allocation.

The new NITS customer will be eligible for ARRs and Long-Term Transmission Rights from the next Annual ARR Allocation period.

3.25 Incremental LTTRs (ILTTRs) for Network Upgrades

Market Participants that fund Network Upgrades[38] may request the allocation of Incremental LTTRs (ILTTRs) resulting from such Network Upgrade pursuant to Attachment FF of the Tariff. MISO will issue such ILTTRs: (i) equal to the capability created by the Network Upgrade(s) (the incremental capacity created by the Network Upgrade will be agreed upon by MISO and Market Participant(s) funding the upgrade), and (ii) consistent with the existence of LTTRs previously issued. Market Participants may request Incremental FTRs (IFTRs) associated with the Network Upgrade in accordance with Section 4.9 of this BPM.

3.25.1 Network Upgrades Eligible for Requesting ILTTRs

A Market Participant is eligible to request ILTTRs if the following conditions are met:

a) Market Participant is funding the Transmission Access Projects (TAP), Market Efficiency Projects (MEP) or "Other Projects" as defined in Section 2.4 of the Transmission Planning BPM (BPM 020). A Market Participant providing funding to advance the schedule of a Baseline Reliability Project (BRP) is also eligible.

b) Electric Facilities added to the Transmission System that are associated with Generator Interconnection Projects (GIP) are eligible only if those Facilities are used to interconnect to MISO's Transmission System and provide incremental transfer capability.

c) A Network Upgrade required for granting Firm PTP Transmission Service (Section 19 of the Tariff) is eligible only if the in-service date of the Network Upgrade coincides with the start date of the PTP Transmission Service.

d) The eligibility to request ILTTRs is limited to the portion of the project cost that is unrecoverable through cost allocation pursuant to Attachment FF of the Tariff.

e) The planned in-service date of the Network Upgrade is in the current or the upcoming Annual ARR Allocation period.

f) Facility Construction Agreement (FCA) for the Network Upgrade associated with the request for ILTTRs is executed with applicable Transmission Owner(s) and is filed with FERC no later than September 15th of each year.

[38] Tariff Section 1.N defines Network Upgrades as follows: All or a portion of the modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all Users of such Transmission System.

g) Network Upgrade is qualified to be included in the MISO Network Model (see BPM 010 - Network and Commercial Models).

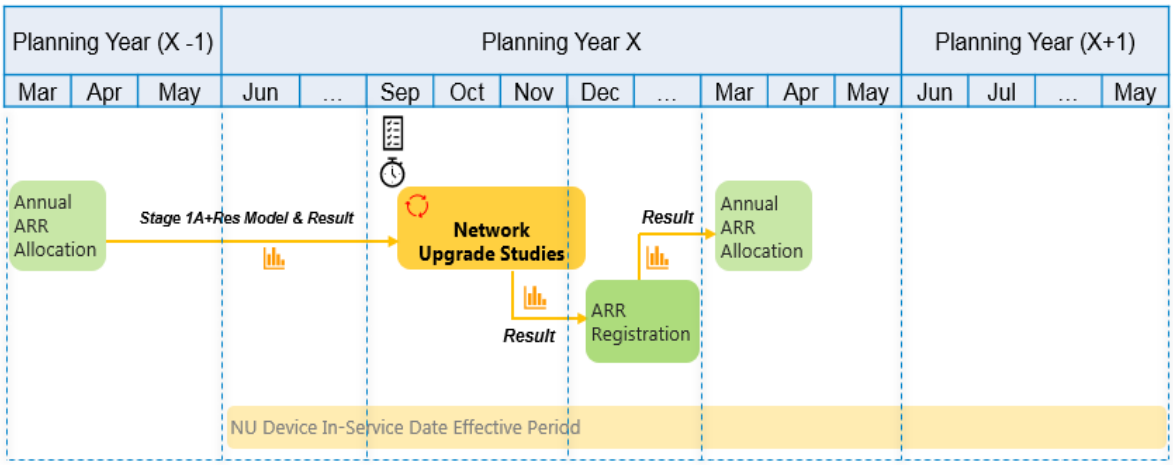
Network Upgrade required for granting Firm PTP Transmission Service Requests (Section 19 of the Tariff) will also be eligible to receive Stage 1B ARRs (IARRs) or Stage 2 compensation in addition to the ILTTRs, if the ARR Receipt Point and ARR Delivery Point of the requested ILTTRs match exactly the Source and Sink of the Firm PTP Transmission Service. Otherwise, they will be eligible to receive only Stage 1A ARRs (LTTRs).

3.25.2 Timing for requesting Incremental LTTRs (ILTTRs)

The request for ILTTRs associated with Network Upgrades must be made no later than September 15th of each year for such Network Upgrades that will be operational in the current or the next Annual ARR Allocation period. MISO, however, will not issue the ILTTRs or IFTRs until the Network Upgrade is reflected in the Network Model and has been determined to be physically operational in the Transmission System. The ILTTR study is performed sequentially on a first come, first served basis. The request must be made using the "LTTRs-FTRs for Network Upgrades" template located on the ARR and FTR Market page via the MISO website.
The completed template must be submitted via email to Client Services and Readiness. The date and time recorded on this email will establish the queue position.

MISO will provide a Market Participant-specific timeline approximately a week prior to the completion of the ILTTR study for the Market Participant that is ahead in the queue. MISO typically expects to have a 2 BDs nomination window for each round and 3 BDs to clear each round. If the study duration takes as long as planned, the three-round study process will be completed in 15 BDs. The Market Participant will have up to 2 BDs to determine the choice of the round after MISO sends the third and final round study results. The timeline is illustrated in Exhibit 3-9 below.

Exhibit 3-9: Network Upgrade Studies Timeline



- Sep 15th is the deadline for submitting NU requests to be studied for Planning Year (X +1)
- Verify Eligibility: ARR/FTR BPM 3.25.1
- MISO performs NU studies on a first come, first served basis
- It takes approximately one month to study NU for each Market Participant
- NU studies use the most recent ARR Allocation Stage 1A & Restoration models and results posted during Planning Year (X – 1)
- The NU study results become inputs into the Annual ARR Registration process for Planning Year (X +1)

The Market Participant should submit the IFTR request in conjunction with ILTTR request in the same template, if it qualifies to and wishes to request IFTRs pursuant to Section 4.9. MISO may increase the nomination period to 3 BDs, and the study period to 5 BDs, per round if ILTTRs and IFTRs are both requested.

3.25.3 Confirmation of the Network Upgrade

Upon receiving the completed template, MISO will verify the request's validity against the eligibility rules stated in Section 3.25.1 of this BPM. MISO will confirm or deny the request via an email to the requestor. Once the request is confirmed by MISO, the Market Participant must collaborate with the relevant Transmission Owners to submit the Network Upgrade information to MISO at least one week prior to the start of the ILTTR study. If relevant information is not submitted on time, MISO will utilize the best available information in consultation with the upgrade's Transmission Owners.

3.25.4 ILTTR Request Process

A Market Participant may submit the ILTTR requests for any MW amount on any number and combination of paths using the CPNodes that were active at the time of the last Annual ARR Allocation. The ILTTR requests can be submitted differently for each of the eight (8) cases (4 seasons times peak/ off-peak time of use). The Market Participant should review the Network/Commercial Model corresponding to the last Annual ARR Allocation and the latest Network/Commercial Model, and then submit the ILTTR requests using active CPNodes. If the Market Participant submits the ILTTR request using an expired CPNode, MISO will replace such CPNode with an electrically equivalent CPNode.

A Market Participant may also request the creation of one new pair of source and sink CPNodes that map directly to the Network Upgrades completed and energized in MISO Region at a construction cost more than $1.0 million. The Market Participant can then use the newly created CPNodes for the ILTTR requests. The Market Participant cannot create new pairs of source and sink CPNodes separately for IFTR and ILTTR requests.

A Market Participant is allowed to submit the ILTTR requests in three (3) rounds iteratively using the MUI. After the conclusion of the three-round study, the Market Participant is allowed to choose all resulting paths from one of the three rounds without the ability to pick specific paths of that round. The same round will be awarded to the Market Participant for the ILTTR results. The same round will be awarded for the IFTR if the IFTR request was made in conjunction with the ILTTR request. MISO will issue all the granted MWs on all of the requested paths of that round to the Market Participant as ILTTRs for future Annual ARR Allocation periods. The Market Participant cannot request any additional ILTTRs in future Annual ARR Allocation periods for the same Network Upgrade. If the Market Participant fails or decides not to choose any results from any of the rounds, MISO will consider the ILTTR rights waived for all future Annual ARR Allocation periods. The Market Participant will not be allowed to request ILTTRs in future Annual ARR Allocation periods for the same Network Upgrade.

Market Participants funding the upgrade of the facilities that make up Reciprocal Coordinated Flowgates (RCF) described in section 3.15 may request the ILTTRs under the Tariff of MISO and/or other external reciprocal entities under the agreement. If a Market Participant also requests ILTTRs in other reciprocal entities, the Market Participant should inform MISO via email of the share of the FFE distributed to MISO. More detail information of FFE determination can be found in the corresponding M2M CMP provision in the JOA between MISO and other reciprocal entities.

Market Participants must coordinate with MISO and other reciprocal entities to enter the respective queues for requesting, studying, and obtaining the results of the ILTTRs.

3.25.5 ILTTR Study Process

MISO will perform the SFT on the ILTTR study for the submitted requests on a first come first served basis. The Market Participant may submit varying sets of ILTTR requests for each of the eight (8) cases. MISO will perform the study for the eight (8) cases separately and the ILTTRs may vary for each of the eight (8) cases.

3.25.5.1 ILTTR Study Model

The ILTTR Study model will use the most recent Annual ARR Allocation models (restoration cases). If a Market Participant funded Network Upgrade is contingent upon a Transmission Owner upgrade, MISO will model the Transmission Owner's upgrade in the ILTTR Study model prior to performing any study. To ensure that any previously allocated feasible LTTRs are not degraded, the SFT will treat them as non-curtailable.

3.25.5.2 ILTTR Pre-Upgrade Study

MISO will prepare eight (8) "pre-network upgrade ILTTR" cases by saturating the ILTTR Study model. This saturation ensures that the unused capacity in the model isn't available as ILTTR during the study.

3.25.5.3 ILTTR Post-Upgrade Study

The Network Upgrades of the Market Participant under study will then be inserted into the eight (8) "pre-network upgrade ILTTR" cases, along with the ILTTR requests, to prepare eight (8) "post-network upgrade ILTTR" cases, and the SFT will be performed on these cases. The resulting allocation of the ILTTR requests from the eight (8) "post-network upgrade ILTTR" cases will be the ILTTRs that are awarded to the Market Participant.

The ILTTRs issued by MISO based on Network Upgrades will be eligible for nomination by aligning with the full season of the next Annual ARR Allocation period in which that Network Upgrade becomes physically operational in the Transmission System. The nomination and allocation will be performed pursuant to Section 3.11.3. All the rules of an LTTR will also apply to an ILTTR when the ILTTR becomes eligible for nomination.

The year 1 of the ILTTRs will be the current Annual ARR Allocation period during which the request was made.

A Network Upgrade collectively funded by multiple Market Participants will be studied as a single ILTTR study. Please see section 3.25.7 regarding how the allocation of the ILTTR will be done among the Market Participants upon the study completion.

3.25.6 Network Upgrade Treatment from Integrating to the Transmission Provider

Market Participants that funded network upgrades that were not rolled into the transmission rate in another transmission provider's territory prior to integrating into MISO may be eligible to receive ARR entitlements beginning with the first full Annual ARR allocation period following integration with the Transmission Provider. Similarly, Market Participants that integrate into the Transmission Provider on a date other than June 1 may be eligible for FTRs for the balance of the Annual ARR Allocation.

To qualify for LTTR treatment due to funding a network upgrade in another Transmission Provider's territory prior to integration, the Market Participant must acknowledge that:

a. The network upgrade cost would not be rolled into the transmission rate.
b. The network upgrade would be in service prior to the end of Year 1 of the Annual ARR Allocation.

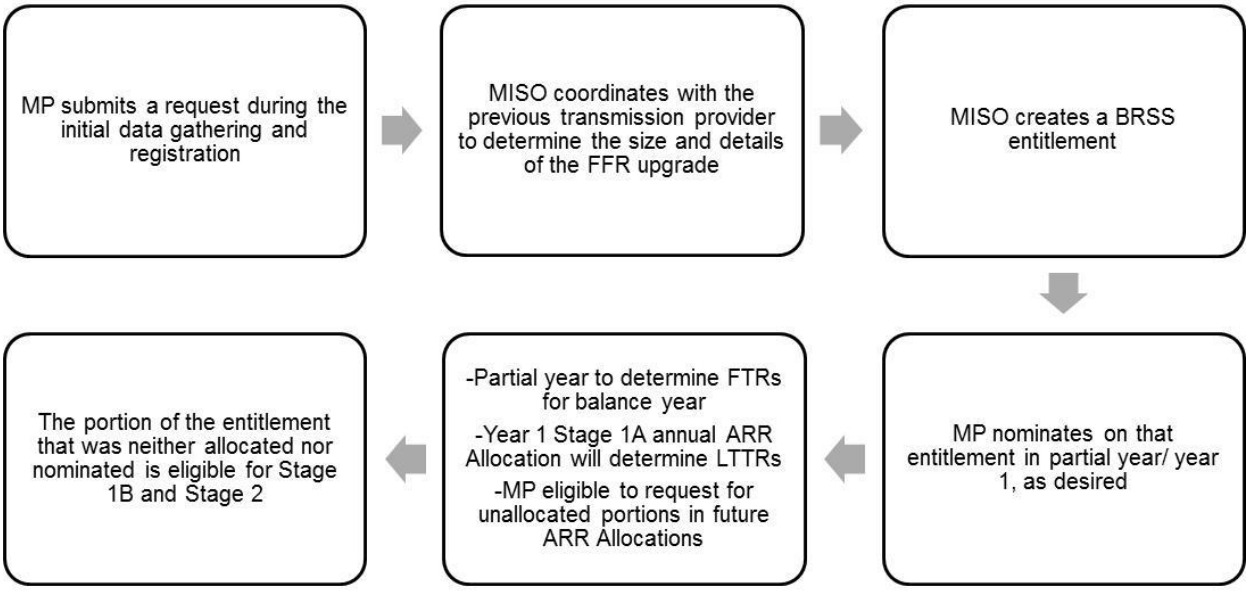
MISO will work with the previous Transmission Provider to identify the capacity created by the network upgrade and establish the incremental capacity created by the network upgrade study while netting out any of that capacity used for or by that Market Participant to be granted its transmission service. The net incremental capacity will be converted to BRSS entitlements by the Transmission Provider. These BRSS entitlements will not be considered for counterflow ARR Entitlements and will have a start date that corresponds with the first full Season following the in-service date of the network upgrade.

To represent the network upgrade in the network and commercial model, the Transmission Provider will establish CPNodes on each side of the network upgrade. Market Participants can use the CPNodes that represent the network upgrade as ARR Receipt Points and ARR Delivery points to establish the BRSS Entitlement. These BRSS entitlements can be nominated in Stage 1A. The Network Upgrade's incremental capacity that is not nominated or allocated in Stage 1A will be eligible for Stage 1B or for inclusion in Stage 2.

Finally, Market Participants that have Network Service with an in-service date after the end of Year 1 of the Annual ARR Allocation will be eligible for LTTRs based on the Network Upgrade Sections defined in this BPM.

Exhibit 3-10 summarizes the process of requesting supplemental upgrades and processing of such upgrades by MISO. Note Year 1 in the exhibit refers to June 1, 2014 to May 31, 2015.

Exhibit 3-10: Supplemental Upgrade Process



3.25.7 Allocation among Multiple Market Participants

Market Participants collectively funding a Network Upgrade are encouraged to agree in writing among themselves and submit the details of such agreement along with the ILTTR request pursuant to Section 3.26.2, including how such ILTTRs are to be allocated following completion of the Network Upgrade ILTTR study. Where such agreement does not exist, ILTTRs will be prorated consistent with each Market Participant's financial contribution to the Network Upgrade (including construction, research, and development costs).

3.25.8 Identifying Network Upgrades for Infeasible ARRs

As part of the MTEP process, MISO will provide the impact of the infeasible ARRs to the binding constraints of the most recent FTR Annual Auction.

3.25.8.1 Study of Infeasible ARRs

MISO will perform a contingency analysis after inserting the infeasible ARRs into the base cases for which the request is made. MISO will present the results of the study to the Market Participant by identifying:

- Branches over their normal ratings
- Overloaded PTDF / OTDF flowgates
- Post-contingency branches over their emergency ratings
- Nomograms above their ratings
- The sensitivities of each binding constraint to the set of infeasible ARRs

The Market Participant can use this information to work with MISO Planning Group to identify the Network Upgrades to be considered to address any identified constraint violations. Please refer to section 4.5.3 of BPM 020 - Transmission Planning for detail information.

3.26 ARR Revenue Re-assignment to Reflect Load Switching

3.26.1 Background

ARRs associated with NITS will be re-assigned to reflect Load switching under state retail choice programs, such other state auction programs or other transactions under which Load switches between Market Participants. On an annual basis, each Market Participant's nomination eligibility and the allocation of ARR(s) will be based on its Peak Usage within an ARR Zone and the NITS ARRs will be re-assigned to reflect Load switching. Each month, MISO will determine the ARR re-distribution based on the NPLF[39] reported to have shifted between Market Participants within an ARR Zone for the previous month. The ARR revenues are calculated using the clearing prices from the annual FTR Auction, based on the source, sink and MW value of the ARRs. Please refer to Section 3.10.6 for information regarding the transfer of ARR Entitlements and LTTRs due to Load Shift for the next Annual ARR Registration.

3.26.2 Key Points about Load Switching

1. The revenue collected by the Market Participant acquiring Load due to Load switching can be a net credit or charge to that Market Participant.
2. The NITS ARR must stay among the Market Participants within the sink ARR Zone and cannot be transferred into another ARR Zone following a Load shift.
3. Market Participants may serve Load in an ARR Zone one month and not the next (and vice versa). The ARR revenue re-assignment will be the same as the previous month's re-assignment when no Load data or inaccurate load data has been submitted.
4. ARR revenue re-assignment will not appear on the S7 or S14 Settlement Statements. Retail Load switching is performed once a month and occurs after the month is over. ARR revenue re-assignment will first appear on the S55 Settlement Statement or the S105 Settlement Statement at the latest.
5. The retail Load shift process has no effect on and is not affected by the method or CPNode that Market Participants chose to bid their Load into the Energy and Operating Reserves Market, or monthly changes in Resource Adequacy for Load adjustments.

[39] NPLF refers to Network Peak Load Forecast, as described in Section 3.24 of this BPM.

6. In case of disagreement among parties about the wholesale Load shift, MISO will reflect the Load shift based on the relevant Market Participant's submitted Meter Data or other reliable data sources.

3.26.3 Designated Entity Registration

All Market Participants serving (or served) Load under NITS in an ARR Zone that elect to have their ARR revenues redistributed due to the Load shift should designate a reporting entity and have that entity registered with MISO. The designated entity acquires and processes the Load shift data for all Market Participants serving (or served) NITS in its ARR Zone and submits such data in the required format and in a timely manner as described below to MISO. The Load shift data submitted by a designated entity for an ARR Zone will be the evidence relied upon by MISO that all Market Participants agree with such representation by the designated entity and that the reported Load shift data is accurate and complete. If all Market Participants located in an ARR Zone do not designate and register with one designated entity on a monthly basis, then MISO will not process the Load shift data for that month. If Market Participants agree to designate one designated entity, then the following provisions shall apply.

3.26.3.1 Timing

The designated entity for the ARR Zone must submit Load shift data in terms of the NPLF (adjusted NPLF[40]) for the previous month by 11:59 pm of the 10th calendar day of the current month. That entity should submit the Load shift data to Client Services and Readiness in the ARR Registration Load Shift template located on the MISO website under Markets and Operations > ARR and FTR Market >> Guides and References.

3.26.3.2 Submission

MISO will review the adjusted NPLF data file. The sum of all Market Participants' adjusted NPLF should equal the NITS portion of the Peak Usage of the ARR Zone (ARR Zone annual NPLF) for which the adjusted NPLF is being submitted. MISO will use Load ratios from the previous accurate month in the event that the sum of all Market Participants' adjusted NPLF does not equal the ARR Zone annual NPLF (or if no data was submitted). This process ensures that the ARR revenue re-

[40] Adjusted monthly NPLF is the individual Market Participant's NPLF within an ARR Zone with the Load switching reflected for the reporting month. The NPLF of the ARR Zone must remain the same for all months and must be equal to the annual ARR Zone NPLF used in the Annual ARR Allocation.

distribution remains balanced with the Market Participant's Load Ratio Share corresponding to the most recent load shift.

The ARR revenue re-distributions will be reflected on the S55 settlement of the first Operating Day of the month for which the Load shift data was reported. If the S55 does not reflect the expected distribution of the ARR revenue, the designated entity can re-submit the Load shift data by the 10th calendar day of the following month. In this case, the settlement will be reflected on S105 statement. Please refer to the Market Settlements Business Practices Manual (BPM-005) for the settlements billing schedule details.

Market Participants that lose Load (adjusted NPLF is less than the annual NPLF) will receive an obligation to fund ARRs equal to a pro-rata share of all NITS ARRs received by the Market Participants in the Annual ARR Allocation. Market Participants that acquire Load (adjusted NPLF is greater than the annual NPLF) will receive a pro-rata share of Load gained during the month multiplied by the total ARR funding obligations allocated to the Market Participants that lost Load during that month.

Please see Appendix I for examples of the retail Load shift mechanism.

3.27 Assessment of the Impact on Long Term Transmission Rights (LTTR) Resulting from a Departing Member

When a Transmission Owner (TO) and/or a Market Participant (MP), collectively referred to as "members," withdraw from the MISO market, a study is triggered to assess the impact of suddenly terminating the associated LTTRs on the feasibility of remaining LTTR holders. LTTRs are coupled with a full funding guarantee characteristic which is maintained through the performance of a restoration stage as part of the Annual ARR Allocation processes where termination requests for LTTRs are processed. The termination of LTTRs resulting from a member's departure occurs outside of the Annual ARR Allocation process and hence requires a separate study process described in this BPM section to assess the feasibility impact of such termination. This analysis will be performed by MISO no earlier than three months before the exit date. This limitation is due to the unavailability of key input data for the analysis before this time frame.

3.27.1 Study Period used for the LTTR Impact Determination

The list of eligible LTTRs to be reviewed and considered will be taken from the most recent applicable Annual ARR Allocation prior to the scheduled member departure from MISO. For example, if a member's exit was scheduled for June 1st, 2013, the 2012 allocation case would be used. The sample June exit date is used to reflect the instance where the most recent allocation, which in this example would be the allocation performed in March-April 2013, would not be used. Instead, the eligible and awarded LTTRs from the 2012 allocation would be used in the analysis, as it constitutes the more recent allocation where the LTTRs associated with the departing member are still valid.

3.27.2 Types of LTTRs Affected by a Member Departure

The following types of LTTRs have been identified as likely candidates to be affected by a member departure:

1. A LTTR sinking in the departing Transmission Owner's LBA Area (TO departure only).
    a. LTTR will no longer be valid after the departure of the Transmission Owner if the source of the LTTR is also in the departing Transmission Owner's LBA Area.
    b. LTTR will be converted to a point-to-point entitlement with a new sink at the interface with the asset owner if the source remains in MISO.
2. A LTTR sourcing from a member's resource in the departing Transmission Owner's LBA Area (TO departure only).

a. LTTR will no longer be valid after the departure of the Transmission Owner if the sink of the LTTR is also in the departing Transmission Owner's LBA Area.
b. LTTR will be updated to reflect the new CPNode at the interface with the asset owner as the new source if the sink is in the MISO Balancing Authority Area.

3. A LTTR owned by the Market Participant(s) leaving MISO.

MISO will determine the list of affected LTTRs and determine the appropriate reconfiguration, which might either require removing the LTTR or updating either the source or sink to reflect the expected change.

3.27.3 Methodology for Assessment of Impact on LTTR Holders of a Member Departure

The study to capture the impact requires several changes to the models to ensure that key inputs to the allocation process reflect appropriately any changes associated with the member's departure. The section below captures the details of the specifics changes that MISO performs as well as description of the analysis.

3.27.3.1 Inputs and Modeling Changes

The following changes capture the key modeling changes that MISO will perform.

1. Updates to LTTRs
    a. Remove all LTTRs that have both their source and sink in the service area of the departing Transmission Owner, as they are no longer valid after the exit date (TO departure only).
    b. Update the sink of the LTTRs with the appropriate asset owner interfaces if the sources remain in MISO and the sinks are located within the service area of the departing member.
    c. Remove all LTTRs owned by the departing member.
2. Allocation Case Changes and Nominations
    a. The most recent applicable annual ARR restoration allocation cases prior to the member departure will be used.
    b. All the existing LTTRs will be modeled as nominations with the actual allocation LTTR amount representing the nomination values.
3. Commercial Model Update
    Changes to the Commercial Model will be made to reflect the termination of CPNodes and either the introduction of new CPNodes for the new interface(s) or an update to the definition of current interfaces if this information can be provided by the MISO

modeling team at the time of analysis. In the case where the information is not readily available at the time of analysis, the most up-to-date model information will be used as a proxy.

4. Flowgates
    a. Update reciprocal coordinated flowgates (RCFs), including potential new RCF flowgates and the removal of the existing RCF flowgates. This will require coordination with entities external to MISO.
    b. Any updates to the loopflow data set will be added.
    c. Any updates to the Firm Flow Entitlement (FFE) data set will be added.
5. Contingencies
   Any updates to the contingency list will be added to reflect changes related to the member's departure.
6. Update loopflows to reflect the removal of the departing member, which involves but is not limited to, updating the Reciprocal Coordinated Flowgates (RCFs) and Firm Flow Entitlements (FFEs) to reflect the impacts related to the departure.

3.27.3.2 Analysis

Once all necessary inputs and changes have been made, an allocation study will be performed that reflects all changes and updates discussed in the previous section. MISO will run the Stage 1A and restoration phase using the new models which only encompass changes related to the departing member. The allocation results will then be compared with the results from the annual allocation results used as the baseline. Any incremental infeasibilities and feasibilities in the allocation study will be considered as impacts to the existing members due to the member departure. This comparison is done at the entitlement level for each of the periods that are analyzed.

The incremental infeasibilities and feasibilities for each LTTR will subsequently be priced using a methodology based on the clearing prices at the relevant source and sink CPNodes from the average of the last three annual FTR auction clearing prices. In the situation where a path does not have three years of data, MISO will then rely on the best available clearing prices for that path.

3.27.3.3 LTTR Impact Due to Departing Members

The impact analysis will be performed once prior to the member departure, and the associated cost (determined by the allocation study) will be calculated for a ten (10) year period so it can be

incorporated into the exit fee and paid in accordance to the departure schedules. During the following ten annual auctions after the exit of the member, the total social uplift of the infeasible LTTRs will be adjusted by the yearly impact from the departing member as identified in the one-time study.

The annual exit fee will be subject to a discount factor calculated by dividing the percentage of infeasible LTTRs relative to all LTTRs in the particular annual ARR allocation by the percentage of the infeasible LTTRs relative to all LTTRs in the study case. The exit fee will be reduced by the discount factor in each year where the overall LTTR infeasibility of the transmission system is less than the infeasibility determined in the study case. The exit fee will not be reduced by the discount factor in each year where the overall LTTR infeasibility of the transmission system increases relative to the level of infeasibility determined in the study case. The exit fee will be due yearly once the annual auction is complete, and MISO has calculated the discount factor.

When the withdrawal of a TO is calculated to have a positive net impact on the feasibility of existing LTTRs of the Stage 1A ARR holders that remain after the withdrawal, the funds related to this impact will not be credited to the withdrawing TO and MPs in its ARR Zone.

3.28 Multi-Value Projects

A new class of ARR Entitlements ("MVP ARR Entitlements") is established to reflect the incremental transfer capability made available by MVP projects.

Every year prior to the annual ARR Registration, MISO will identify eligible MVP projects and perform an MVP ARR analysis for the first four consecutive full seasons after the MVP comes into service. If less than four of such full Seasons are in an upcoming Annual ARR Allocation period, the MVP ARR analysis will be performed for the full Seasons(s) within that period. Finally, the MVP ARR analysis will be performed for the other full Seasons within the next Annual ARR Allocation period.

Exhibit 3-7 below illustrates how the MVP ARR analysis will be performed based on the in-service date of the MVP projects during the 2015-16 Annual ARR Allocation periods.

Exhibit 3-71 : MVP ARR Project in-service date schedule example

Project in-service date	Upcoming Annual ARR Allocation period (2015-16)				Next Annual ARR Allocation period (2016-17)			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
06/01/2015	✓	✓	✓	✓				
Any date in period 06/02/2015-09/01/2015		✓	✓	✓	✓			
Any date in period 09/02/2015-12/01/2015			✓	✓	✓	✓		
Any date in period 12/02/2015-03/01/2016				✓	✓	✓	✓	
Any date in period 03/02/2015-05/31/2016					✓	✓	✓	✓

(Checks indicate each Season for which the MVP ARR analysis will be performed.)

A pre- and post-upgrade SFT (i.e. incremental SFT) on seasonal basis is performed to identify incremental capacity created by the MVP projects and associated congestion rights for the newly created paths. The constraint set for the incremental SFT will primarily include the binding constraints in the base model derived from the most recent Stage 1B ARR allocation model. The performed incremental SFT will treat previously allocated feasible ARRs as fixed. At the conclusion of each MVP project study, MISO will establish seasonal MVP ARR Entitlements that will be used in the upcoming Annual ARR Allocation for the relevant Seasons. The created MVP ARR Entitlement will shadow the electrical nodes on the two ends of the transmission facility. Additionally, if the MVP project involves multiple upgrade segments and/or two or more combined

MVP projects, the whole project will be evaluated to create the source(s) and sink(s) in determining the incremental capacity.

The MVP ARRs will not be self-scheduled in the Annual FTR Auction.

The MVP ARR Entitlement will terminate at the end of the life of the associated MVP facility.

4 Financial Transmission Rights (FTRs)

MISO currently issues obligation type PTP FTRs (Receipt Point-to-Delivery Point FTR Obligation) to the Market Participants.

4.1 FTR Obligations

For a given hour that falls within the FTR Period and Term, an FTR Obligation confers on its FTR Holder appropriate charges or credits:

- In an applicable hour, an FTR Obligation provides the FTR Holder with credits when the Marginal Congestion Component (MCC) of the Day-Ahead Ex-Post LMP at the FTR Delivery Point is greater than the MCC of the Day-Ahead Ex-Post LMP at the FTR Receipt Point.
- Conversely, in an applicable hour, an FTR Obligation will impose on its holder charges when the MCC of the Day-Ahead Ex-Post LMP at the FTR Delivery Point is less than the MCC of the Day-Ahead Ex-Post LMP at the FTR Receipt Point.

Exhibit 4-1 illustrates the credits (charges) for an FTR Obligation.

Exhibit 4-1: Credits (Charges) for FTR Obligations

Example	MCC @ Receipt Point	MCC @ Delivery Point	Congestion Credit
1	50 $/MWh	60 $/MWh	Credit = 60 - 50 = 10 $/MWh
2	10 $/MWh	- 5 $/MWh	Credit = - 5 - 10 = -15 $/MWh
Note: A negative credit is equivalent to a charge.			

4.2 FTR Specifications

An FTR is specified by:

a. FTR Receipt Point (FTR Source);
b. FTR Delivery Point (FTR Sink);
c. FTR MW Quantity;
d. Whether the FTR is an Obligation or an Option;
e. FTR Period (Peak/Off-Peak); and
f. FTR Term.

The FTR Receipt Point (FTR Source) and FTR Delivery Point (FTR Sink) specified in a given FTR (Obligation or Option) may be any one of the following CPNodes:

a. Node for the relevant Generation Resource
b. ARR Zone
c. Hub
d. Load Zone
e. Interface

MISO maintains a list of FTR Receipt Points and FTR Delivery Points for the FTR specifications. The list is posted in the MISO FTR MUI.

4.3 Key Characteristics

FTRs are characterized as follows:

a. Only Market Participants can hold FTRs; however, Market Participants can be agents for other entities.
b. FTRs do not represent a physical right for delivery of energy.
c. Market Participants need not hold FTRs to schedule Physical or Financial Bilateral Transactions.
d. FTR Holders are not required to schedule Physical or Financial Bilateral Transactions by virtue of holding FTRs.
e. FTRs will not protect Market Participants from congestion charges related to Hourly Real-Time Ex Post LMPs.
f. FTRs do not provide any physical scheduling priority in the Day-Ahead Energy and Operating Reserve Market.

g. FTRs do not protect Market Participants from Transmission Congestion Charges related to scheduling power in the Real-Time Energy and Operating Reserve Market or deviating from the amounts that they scheduled in the Day-Ahead Energy and Operating Reserve Market.

4.4 MISO Responsibilities

MISO's responsibilities are to:

a. Make available and facilitate FTRs which can provide the FTR Holder with a hedge against future costs of congestion;
b. Ensure that the set of FTRs that are self-scheduled and awarded in the FTR Auctions is simultaneously feasible from a transmission network point of view; and
c. Ensure that the collection of congestion charges is sufficient to cover the payments to FTR Holders to the extent possible given the uncertainties regarding future power system conditions

4.5 Market Participant Responsibilities

a. Market Participants are responsible for their own congestion risk assessment and risk management through the acquisition and disposition of FTRs.
b. Market Participants are responsible for submitting Bids and Offers into the annual and multi-period monthly FTR Auction.
c. Market Participants are responsible to present the required credit to participate in the auction and secondary market trade. These requirements are addressed in Attachment L of the Tariff (Credit Policy).

Entities who intend to acquire FTRs must register as a Market Participant with MISO as described in the *BPM for Market Registration (BPM-001)*. Market Participants who wish to enter the FTR Auctions and post FTR information on MISO's FTR Bulletin Board must do so using MISO's Market Portal.

4.6 FTR Remapping Process for Terminated CPNodes

During the network/commercial model update, Market Participants may terminate CPNodes, which may impact outstanding FTRs sourcing or sinking at the terminated CPNodes. This section describes the process MISO will take in finding replacement CPNodes for the impacted FTRs.

The replacement CPNode may be an existing active CPNode, or a new temporary CPNode, that may need to be created during the quarterly model update process. All FTRs sourcing or sinking at the terminating CPNode will be remapped for the remainder of the FTR's term. The following subsections describe instances where the remapping may be required and the process for replacing these different types of terminated CPNodes.

a. When a Generator CPNode terminates, including a Pseudo-tie out Generators and Stored Energy Resource
   MISO will remap the terminating CPNode to an existing generator type CPNode at the same station and/or same voltage level, if available. When such remapping does not exist, a temporary CPNode will be created at the same or nearest station[41] as the terminating CPNode.
b. When Load CPNode terminates
   MISO will not create a temporary CPNode when a Load CPNode terminates. MISO will use engineering judgment to find a CPNode that closely resembles the terminating CPNode by evaluating the underlying EPNodes of the terminating load CPNode versus existing CPNodes.
c. When Interface CPNode terminates
   MISO will create a temporary CPNode to replace the terminating Interface CPNode. In situations where interfaces are terminating due to integration, MISO will determine the proper mapping of these interfaces to minimize the impact on the expanded transmission footprint. For example, interfaces representing embedded BA and its integrating host BA will be mapped to a temporary CPNode with the same definition.
d. When Hub CPNode terminates
   MISO will not create a temporary CPNode when a Hub CPNode terminates. MISO will use engineering judgment to find a CPNode that closely resembles the terminating Hub CPNode by looking at the underlying EPNodes of the terminating Hub CPNode versus existing CPNodes.

Other than for the types of CPNodes listed in this section, MISO will not be creating temporary CPNode. MISO will use engineering judgment to find a CPNode that closely resembles the expiring terminating CPNode by looking at the underlying EPNodes of the expiring terminating CPNode versus existing CPNodes.

[41] Nearest station will be determined based on electrical proximity.

This process only applies for terminated CPNodes and no remapping will be applied in any other situations, including CPNode definition changes.

4.6.1 Duration of the temporary CPNode

The temporary CPNode will be set to expire at the end of the current FTR planning year (5/31/XX). If a temporary CPNode is tied to an LTTR, the temporary CPNode will be made permanent if no active electrically equivalent CPNode is found during the ARR Registration for the next planning year.

4.6.2 Dispute of the CPNode replacement

A Market Participant shall use MISO's dispute resolution process under Attachment HH of the Tariff to dispute that its FTRs were impacted due to CPNode replacement when it has been mapped to a different station as described above in this section.

4.6.3 Reserved

4.7 Reserved

4.8 Reserved

4.9 Incremental FTRs (IFTRs) for Network Upgrades

Market Participants that fund Network Upgrades[42] and have not elected to receive refunds or are ineligible for the refunds under Attachment FF of the Tariff, may request the allocation of Incremental FTRs (IFTRs) resulting from such Network Upgrade. MISO will issue such IFTRs: (i) equal to the capability created by the Network Upgrade(s) (the incremental capacity created by the Network Upgrade will be agreed upon by MISO and Market Participant(s) funding the upgrade), and (ii) consistent with the existence of FTRs previously issued. Market Participants may request Incremental LTTRs (ILTTRs) associated with the Network Upgrade in accordance with Section 3.25 of this BPM.

To the extent that a network upgrade has been funded by a Market Participant in a different Transmission Provider region prior to integrating with the Transmission Provider, the MP may be eligible for FTRs for the balance of the Annual ARR Allocation period. For more details on the qualification requirements, please review the section on Network Upgrade Treatment from Integrating to the Transmission Provider in this BPM.

Network Upgrades or Direct Assignment Facilities associated with Firm PTP Transmission Service Requests (Section 19 of the Tariff) will be eligible to receive IFTRs. The in-service date of the Network Upgrades or Direct Assignment Facilities must coincide with the start date of the PTP Service for which the IFTRs are requested pursuant to this Section.

Network Upgrades that qualify for IFTRs must qualify to be included in the Network Model (see *BPM for Network and Commercial Models, BPM-010*). Market Participants shall collaborate with the relevant Transmission Owners to submit the Network Upgrade information to MISO prior to the cut-off date for incorporating such data into the model release so that the IFTRs can be released at the same time.

Market Participants shall be permitted to elect any set of FTR Receipt Points and Delivery Point for the incremental FTRs request. Market Participants may also request the creation of a new pair

[42] Tariff Section 1.N defines Network Upgrades as follows: All or a portion of the modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all Users of such Transmission System.

of source and sink CPNodes that map directly to the transmission upgrades completed and energized in MISO region at a construction cost greater than $1.0 million. Market Participants can then use the newly created CPNodes that are requested, as the FTR Receipt Points and Delivery Points.

4.9.1 Timing for requesting Incremental FTRs (IFTRs)

The request for IFTRs associated with Network Upgrades must be made no later than September 15th of each year for such Network Upgrades that will be operational in the current Annual ARR Allocation period. The IFTRs study is performed sequentially on a first come first served basis. The request must be made using the
"LTTRs-FTRs for Network Upgrades" template located on the ARR and FTR Market page via the MISO website.

The completed template must be submitted via email to Client Services and Readiness. The date and time recorded on this email will establish the queue position.

MISO will provide a Market Participant-specific timeline approximately a week prior to the completion of the IFTR study for the Market Participant that is ahead in the queue. MISO typically expects to have a 2 BDs nomination window for each round and 3 BDs to clear each round. If the study duration takes as long as planned, the 3-round study process will be completed in 15 BDs. The Market Participant will have up to 2 BDs to determine the choice of the round after MISO sends the third and final round study results.

A Market Participant should submit the IFTR request in conjunction with ILTTR request in the same template, if it qualifies for and wishes to request ILTTRs pursuant to Section 3.25. MISO may increase the nomination period to 3 BDs and the study period to 5 BDs per round if requests are made for both ILTTRs and IFTRs.

A Market Participant may submit the IFTR request prior to the Network Upgrade becoming operational if the request is submitted prior to September 15 and MISO is able to confirm the validity of the Network Upgrade as described in Section 4.9.2. MISO, however, will not issue the ILTTRs or IFTRs until the Network Upgrade is reflected in the Network Model, and has been determined to be physically operational in the Transmission System.

4.9.2 Confirmation of the Network Upgrade

Upon receiving the completed template, MISO will verify the request's validity against the eligibility rules stated in the Section 3.25.1 of this BPM. MISO will confirm or deny the request via an email to the requestor. Once the request is confirmed by MISO, the Market Participant must collaborate with the relevant Transmission Owners to submit the Network Upgrade information to MISO at least one week prior to the start of the IFTR study. If relevant information is not submitted on time, MISO will utilize the best available information in consultation with the upgrade's Transmission Owners.

4.9.3 IFTR Request Process

A Market Participant may submit the IFTR requests for any MW amount on any number and combination of paths using the CPNodes that are active in the latest quarterly Network and Commercial Models. The IFTR requests can be submitted differently for each of the eight (8) cases (4 seasons times peak/ off-peak period). The IFTR requests can also be different from the ILTTR requests. The Market Participant should review the latest Network and Commercial Models and submit the IFTR requests using the active CPNodes. If the Market Participant submits the IFTR request using an expired CPNode, MISO will replace such CPNode with an electrically equivalent CPNode.

Market Participants may also request the creation of one new pair of source and sink CPNodes that map directly to the Network Upgrades completed and energized in MISO Region at a construction cost greater than $1.0 million. Market Participants can then use the newly created CPNodes for the ILTTR and/ or IFTR requests. Market Participants cannot create new pairs of source and sink CPNodes separately for IFTR and ILTTR requests.

A Market Participant is allowed to submit the IFTR requests in three (3) rounds iteratively as described in Section 4.9.4. After the conclusion of the 3-round study, the Market Participant is allowed to choose all resulting paths from one of the three rounds without the ability to pick specific paths of that round. The same round will be awarded to the Market Participant for the IFTR and ILTTR results. MISO will issue all the granted MWs on all the requested paths of that round to the Market Participant as IFTRs for the remainder of the current Annual ARR Allocation period. Market Participant cannot request any additional IFTRs in the current or future Annual ARR Allocation periods. If the Market Participant fails or decides not to choose any results from any of the rounds, MISO will consider the IFTR rights waived for the current or future Annual ARR

Allocation periods. The Market Participant will not be allowed to request IFTRs in future Annual ARR Allocation periods for the same Network Upgrade.

Market Participants funding the upgrade of the facilities that make up Reciprocal Coordinated Flowgates (RCF) described in section 3.15 may request the IFTRs under the Tariff of MISO and/or other external reciprocal entities. When a Market Participant also requests IFTRs in other reciprocal entities, the Market Participant should inform MISO via email of the share of the FFE distributed to MISO. More detail information of FFE determination can be found in the corresponding M2M CMP provision in the JOA between MISO and other reciprocal entities. Market Participants must coordinate with MISO and other reciprocal entities to enter the respective queues for requesting, studying, and obtaining the results of the IFTRs.

4.9.4 IFTR Study Process

MISO will perform the SFT on the IFTR study for the submitted requests on a first come first served basis, using the most recent annual and monthly FTR Auction models. To ensure that any previously awarded FTRs are not degraded, the SFT will treat them as non-curtailable. The Market Participant may submit varying sets for each of the remaining auction periods. MISO will perform the study and the IFTRs may vary for each of those periods.

MISO will apply the IFTR requests to the most recent monthly and seasonal cases and perform the SFT. The allocation of the IFTR requests will then be inserted into the cases as “Obligation” to prepare monthly “pre-network upgrade IFTR” cases by saturating the existing unused Transmission capacity prior to the upgrade. The Network Upgrades of the Market Participant under study will then be inserted into the “pre-network upgrade IFTR” cases, along with the IFTR requests, to prepare “post-network upgrade IFTR” cases, and the SFT will be performed on these cases. The resulting allocation of the IFTR requests from the “post-network upgrade IFTR” cases will be the IFTRs awarded to the Market Participant.

The IFTRs associated with the Network Upgrade issued by MISO will be eligible for sale into the monthly auction following the month in the current Annual ARR Allocation period in which that Network Upgrade becomes physically operational in the Transmission System.

A Network Upgrade collectively funded by multiple Market Participants will be studied as a single IFTR study. Please see section 4.9.5 regarding how the allocation of the IFTR will be done among the Market Participants upon the completion of the study.

4.9.4.1 IFTR Study Model

The IFTR Study model will be based on the most recent monthly and seasonal cases. If a Market Participant funded Network Upgrade is contingent on a Transmission Owner upgrade, the Transmission Owner's upgrade will be modeled in both the "pre-network upgrade" and "post-network upgrade" cases.

4.9.5 Allocation among Multiple Market Participants

Market Participants collectively funding a Network Upgrade are encouraged to agree in writing among themselves, and to submit the details of such agreement along with the IFTR request pursuant to Section 4.9.1, including how such IFTRs are to be allocated following completion of the Network Upgrade IFTR study. Where such agreement does not exist, IFTRs will be prorated consistent with each Market Participant's financial contribution to the Network Upgrade (including construction, research, and development costs).

4.10 FTR Auction

MISO conducts FTR Auctions on an annual and monthly basis.

4.10.1 FTR Bids

FTR Bidders are responsible for submitting an FTR Bid that includes the following information:

1. Type of FTR (i.e., Obligation only);
2. FTR Receipt Point and FTR Delivery Point, provided that the FTR cannot be defined as having an FTR Receipt Point and an FTR Delivery Point within the same Bus;
3. Maximum MW quantity desired;
4. Maximum acceptable price, in $/MW;
    i. Positive or negative price for Obligations
    ii. Cannot exceed +/- $150,000/MW
5. Time-of-use (Peak or Off-peak); and
6. Period (season or month)

An FTR Bid for a specified MW quantity of FTRs constitutes an FTR Bid to purchase a quantity of FTRs equal to or less than the specified quantity. An FTR Bid may not specify a minimum quantity of MW that the FTR Bidder wishes to purchase.

All FTR Bids and the actions of FTR Bidders are subject to the provisions of Module D, Market Monitoring and Mitigation Measures, of the Tariff.

If an FTR Bid that defines the FTR source and sink within the same Bus has been submitted in the FTR Auction, the bid will be rejected prior to the moment that the FTR auction execution has commenced. Market Participants who have submitted same Bus FTR bids will be notified and the Transmission Provider could request that future submission of such bids be stopped. In the event where FTR bids on same Bus paths have not been identified prior to Auction clearing and resulting in erroneously clearing of same Bus FTRs, MISO will resettle these FTRs as allowed by Tariff anytime during the planning year where these FTRs are applicable. If applicable, MISO would resettle by reversing any charges and credits related to the erroneously cleared FTRs on same Bus paths.

4.10.1.1 FTR Bid Curve (MW/Price Pairs)

FTR Bidders can submit up to ten MW/Price pairs. The MW values are accepted to the 10th of a MW. The MW/Price pairs must be monotonically non-increasing, and MW must be monotonically

non-decreasing (e.g., 0 MW @ $2.00, 40 MW @ $2.00, 50 MW @ $2.00 are accepted; 0 MW @ $2.00, 40 MW @ $2.00 and 50 MW at $2.50 is not accepted due to the increasing price values; and 0 MW @ $2.00, 40 MW @ $2.00, 30 MW @ $2.00 is not accepted due to the decreasing MW value). The MW of the first MW/Price pair always begin with zero (0) MW and the MW of the last MW/Price pair specifies the maximum MW requested by the FTR Bidder.

The MW/Price pairs are not cumulative, meaning if a FTR Bidder submits an MW/Price pair of 0 MW @ $10.00, 10 MW @ $10.00, 20 MW @ $5.00 and the FTR Auction clears at $4.00, 20 MW is cleared and not 30 MW.

4.10.2 FTR Offers

FTR Offerors are responsible for submitting an FTR Offer that includes the following information:

1. ID number of FTR offered;
2. Maximum MW quantity offered;
3. Minimum acceptable price (also called the reserve price) in $/MW;
    i. Positive or negative price for Obligations
    ii. Cannot exceed +/- $150,000/MW
4. Type of FTR (Obligation only);
5. Maximum MW quantity offered;
6. Time-of-use (Peak or Off-peak); and
7. Period (season or month)

An FTR Offer for a specified MW quantity of FTRs must constitute an Offer to sell a quantity of FTRs equal to or less than the specified quantity. An FTR Offer may not specify a minimum quantity offered but may specify a reserve price, below which the FTR Holder does not wish to sell the FTR.

If an FTR's sink and source were not within the same Bus when it was awarded in a previous FTR Auction, but the FTR's source and sink were subsequently defined by MISO as within the same Bus due to CPNode remapping performed during an ensuing quarterly Commercial Model change, the Market Participant holding such an FTR will be allowed to offer it into a future FTR Auction.

All FTR Offers and the actions of FTR Holders submitting such Offers are subject to the provisions of Module D, Market Monitoring and Mitigation Measures, of the Tariff.

4.10.2.1 FTR Offer Curve (MW/Price Pairs)

FTR Offerors can submit up to ten MW/Price pairs. The MW values are accepted to the 10th of a MW. The MW/Price pairs must be monotonically non-decreasing and MW must be monotonically non-decreasing (e.g., 0 MW @ $2.00, 40 MW @ $2.00, 50 MW @ $2.50 is accepted; 0 MW @ $2.00, 40 MW @ $3.00, 50 MW @ $1.50 is not accepted due to decreasing Price value; and 0 MW @ $2.00, 40 MW @ $2.00, 30 MW @ $2.00 is not accepted due to the decreasing MW value). The MW of the first MW/Price pair always begin with zero (0) MW and the MW of the last MW/Price pair specifies the maximum MW offered by the FTR Offeror.

The MW/Price pairs are not cumulative, meaning if a FTR Offeror submits an MW/Price pair of 0 MW @ $10.00, 10 MW @ $10.00, 20 MW @ $12.00 and the FTR Auction clears at $15.00, 20 MW is cleared and not 30 MW.

4.10.3 Evaluation of Creditworthiness of Bidders, Offerors, and Self-Schedulers

MISO ensures that each party submitting an FTR Bid is a Market Participant qualified to submit such a Bid consistent with the creditworthiness provisions maintained by MISO. As a result of this evaluation of creditworthiness, before the auction MISO states a limit on the value of the FTRs that the Market Participant may bid in the auction. The aggregate value of the FTR Bids minus the value of FTR Obligation Offers with a negative Offer price submitted by any Market Participant submitting FTR Bids and Offers into the FTR Auction must not exceed that Market Participant's ability to pay or the maximum value of FTR Bids that it is permitted to place, as determined by MISO (based on an analysis of the FTR Bidder's creditworthiness). The self-scheduling of ARRs will have no impact on the evaluation of a Market Participant's creditworthiness. Further details are available in the Attachment L of the Tariff (Credit Policy).

Each FTR Bidder and ARR Self-Scheduler must pay the FTR Market Clearing Price for each FTR it is awarded in the auction. Each FTR Offeror is paid the FTR Market Clearing Price for each FTR it sells in the auction.

4.10.4 Information Made Available to FTR Bidders, FTR Offerors, and ARR Self-Schedulers

To aid Market Participants in their participation in the auction, MISO makes the following information available before each FTR Auction:

a. Optimization process data used as the starting point for the auction, including all assumptions:

i. Assumptions made by MISO relating to transmission maintenance outage schedules
ii. All limits associated with transmission facilities, contingencies, thermal, voltage and stability that are monitored as constraints in the optimization process

b. Marginal Congestion Component of Day-Ahead Ex Post LMPs for each CPNode, if available
c. Previous round auction results (in the presence of multi-round auctions)
d. Results of prior FTR Auctions, subject to the restrictions of Section 4.10.6 of this BPM
e. A list of FTR paths (FTR Sources and FTR Sinks that are defined at the same Bus) that Market Participants are not allowed to bid. The latest FTR Commercial and Network Models will be used to determine the list of FTR paths are at the same Bus and such FTRs shall be posted once a quarter.

4.10.5 Other MISO Responsibilities

MISO has an auditable information system to facilitate analysis and acceptance or rejection of FTR Bids/Offers and ARR Self-Schedules, to provide a record of all FTR Bids/Offers and ARR Self-Schedules, and to provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, award and recording of FTR Bids/Offers and ARR Self-Schedules.

MISO Market Portal will be used to communicate auction-related information to all auction participants. MISO receives FTR Bids/Offers and ARR Self-Schedules from any entity that meets the eligibility criteria and that complies with the auction bidding rules previously established by MISO. MISO utilizes an optimization process program to determine the set of winning FTR Bids/Offers and ARR Self-Schedules for each auction and calculates the FTR Market Clearing Price of all FTRs at the conclusion of the auction, in the manner described in this BPM.

4.10.6 Continuing Confidentiality of FTR Bids and FTR Offers

MISO will not reveal the FTR Bids and FTR Offers submitted by any FTR Bidder and Offeror in an FTR Auction until ninety (90) days after the auction. When these FTR Bid and Offer data are posted, the identity of the FTR Bidders and FTR Offerors will not be publicly revealed, but will be posted in such a way as to allow each individual entity's Bids and Offers to be tracked over time.

4.10.7 Determination of FTR Market Clearing Price

All Comparable FTRs sold in an FTR Auction are sold at the same FTR Market Clearing Price, expressed in $/MW.

a. For an FTR Obligation, the FTR Market Clearing Price is calculated from the shadow prices of the transmission constraints in the FTR Auction Linear Programming (LP) problem. The shadow price of a transmission constraint is the rate of change in the objective function value for an infinitesimal increment or decrement in the capacity of the constraint. The market clearing price for the FTR Obligation is the sum over all transmission constraints of the product of the Power Transfer Distribution Factor (PTDF) (or Outage Transfer Distribution Factor (OTDF)) of the Obligation on the constraint times the shadow price of the constraint limit in the direction of the corresponding PTDF (or OTDF) over all transmission constraints.
b. For an FTR Option,[43] the FTR Market Clearing Price is calculated from the shadow prices of the transmission constraints in the FTR Auction LP problem. The shadow price of a transmission constraint is the rate of change in the objective function value for an infinitesimal increment or decrement in the capacity of the constraint. The market clearing price for the FTR Option is the sum over all transmission constraints of the positive values of the product of the Power Transfer Distribution Factor (PTDF) (or Outage Transfer Distribution Factor (OTDF)) of the Option on the constraint times the shadow price of the constraint limit in the direction of the corresponding PTDF (or OTDF) over all transmission constraints.

Appendix D of this BPM presents an FTR Auction example.

4.10.8 Annual FTR Auctions

MISO conducts three-round Annual FTR Auctions to:

a. Allow MISO to sell FTRs for the residual FTR capability of the Market Footprint;
b. Allow the conversion of ARRs allocated in the annual allocation to FTRs through a process known as self-scheduling; and
c. Facilitate the buying, selling, and reconfiguration of existing FTRs between Market Participants.

[43] FTR Options are currently not yet available to Market Participants in MISO.

MISO conducts FTR Auctions in a manner consistent with the Tariff and the standards and procedures set forth in the BPMs.

4.10.8.1 Nature and Timing of Annual FTR Auctions

a. The Annual FTR Auction is conducted immediately following the Annual ARR Allocation and consists of eight independent auctions: for the Peak and the Off-Peak for four seasons.
b. The four seasons are:
    i. ***Winter:*** December, January, and February
    ii. ***Spring:*** March, April, and May
    iii. ***Summer:*** June, July, and August
    iv. ***Fall:*** September, October, and November
c. Peak is defined from 0700 hours EST to 2200 hours EST (hour 7 and hour 22, inclusive) from Monday through Friday excepting New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day, or if the holiday occurs on a Sunday, the Monday immediately following the holiday.
d. Off-Peak are all periods of time not classified as Peak.
e. All FTRs offered for sale through the annual FTR Auctions have a term of one Season for either the Peak or Off-Peak.
f. All Offers by FTR Holders to sell FTRs, all Bids to purchase FTRs, and all requests to self-schedule ARRs must be submitted to MISO during the annual bidding period. When multi-round auctions are implemented, all ARR self-schedules must be submitted during the first-round bidding period.
g. MISO posts the results of the annual FTR Auction after verifying the characteristics of the binding constraints resulting from the auction clearing calculations. The posted annual FTR Auction results shall include the name of the FTR Bidder/FTR Offeror; the megawatt quantity; whether the awarded FTR is an Obligation or an Option; the FTR period (Peak/Off-Peak); whether the FTR is a Buy or Sell; the round of the FTR Auction where each FTR was awarded; the term; the receipt and delivery points for the awarded FTR; and the FTR Market Clearing Price for each awarded FTR.
h. Each Market Participant cannot exceed a combined total of 6,000 bids and/or offers for each period in a seasonal auction (peak and off-peak combined).

4.10.8.2 Determination of the Available Transmission Capacity

ARRs that are allocated from the Annual ARR Allocation will not be considered as base loading in annual FTR Auction. Only loop flows and FTRs awarded in previous rounds will be considered as the base loading to calculate available transmission capacity.

Available transmission capacity will be equally distributed to all remaining rounds.

- Round 1: One third of available transmission capacity will be utilized.
- Round 2: Half of available transmission capacity will be utilized.
- Round 3: All remaining transmission capacity will be utilized.

Exhibit 4-2 illustrates the rating of one monitored transmission line that will be enforced in each round of multi-round annual FTR Auction. In this example, loop flows contribute 30 MW of base loading to the monitored transmission line, which leaves 120 MW of available transmission capacity for the annual FTR Auction. Therefore, the enforced rating for Round 1 is 70 MW, including 40 MW of available transmission capacity. In Round 2, loop flows and previous awarded FTRs contribute 60 MW to the monitored transmission line, which leaves 90 MW of available transmission capacity for Round 2 and Round 3. Therefore, the enforced rating for Round 2 is 105 MW, including 45 MW of available transmission capacity. In Round 3, the enforced rating is the line rating since all the remaining transmission capacity will be utilized.

Exhibit 4-2: Available Transmission Capacity in multi-round Annual FTR Auction

Round	Line Rating (MW)	Rating Enforced (MW)	Final Flow (MW)
1	150	70	60
2	150	105	105
3	150	150	140

4.10.8.3 ARR Self-Schedules

ARRs meeting the following conditions will be eligible for conversion into FTR rights through a process known as self-scheduling.

a. Only feasible ARRs allocated in Stage 1 of the Annual ARR Allocation, including Stage 1A ARRs, restoration/counterflow ARRs as well as Stage 1B ARRs, will be eligible for self-scheduling. Infeasible ARRs and Stage 2 ARRs are not eligible for self-scheduling.

b. Long term firm PTP Transmission Service that has renewal rights does not have to be exercised prior to the cutoff date to be eligible for self-scheduling in the annual FTR Auction. The Market Participant will be eligible to self-schedule and receive FTRs in the FTR Auction process as if the rollover right had been exercised prior to the cutoff date, provided the rollover right has been registered during the Annual ARR Registration process. If the Market Participant does not exercise rollover rights pertaining to the Transmission Service on MISO OASIS, MISO will terminate such allocated ARRs when the Transmission Service terminates. However, the assignment of self-scheduled FTRs is automatic and mandatory, does not depend upon service renewal, and is not at the option of the Market Participants. If the rollover right is not exercised, the corresponding self-scheduled rollover FTRs will not be terminated.

ARR self-schedulers are responsible for submitting an ARR Self-Schedule that includes the following information:

i. ID number of ARR being self-scheduled;
ii. Type of ARR (Obligation only);
iii. Maximum MW quantity desired;

MISO will check to ensure that a Market Participant self-scheduling an ARR in the auction holds the ARRs being self-scheduled. An ARR Self-Schedule for a specified MW quantity of FTRs constitutes a desire to purchase a MW quantity of FTRs equal to the specified quantity. An ARR Self-Schedule cannot specify a minimum quantity of MW that the ARR self-scheduler wishes to purchase. All ARR Self-Schedules will be price takers. The awarding of ARR Self-Schedules holds priority over the awarding of all FTR Bids/Offers.

The MW eligibility of self-scheduled ARR in each round is determined as follows:

- Round 1: One third of self-scheduled ARR MW will be eligible for conversion into FTRs.
- Round 2: Half of remaining self-scheduled ARRs not converted will be eligible for conversion into FTRs.
- Round 3: All remaining self-scheduled ARRs not converted will be eligible for conversion into FTRs.

All FTRs resulting from the self-scheduling of ARRs and the actions of ARR self-schedulers are subject to the provisions of Module D, Market Monitoring and Mitigation Measures, of the Tariff.

4.10.8.4 Selection of Winning Bids and Offers

MISO treats each season and FTR Period (Peak and Off-Peak) as a separate auction. Consequently, the annual auction consists of eight independent auctions (4 seasons times 2 FTR Periods). MISO uses an LP model for each FTR Auction, that considers all FTR Bids and FTR Offers submitted, and selects a combination of FTR Bids and FTR Offers (winning FTR Bids and winning FTR Offers, respectively) that:

- Makes the solution simultaneously feasible in light of the transfer capability of the Market Footprint over the period in the subject season; and
- Maximizes the objective function, which is equal to the total economic value (as expressed in the FTR Bids) of the winning FTR Bids, less the total economic cost (as expressed in the FTR Offers) of the winning FTR Offers.

To maximize the economic value of the winning FTR Bids, less the cost of the winning FTR Offers, the LP model automatically reconfigures the FTRs offered for sale in FTR Auctions by FTR Holders. If there are two or more winning FTR Bids that are identical in all material respects except for the quantity of MW sought, then each such winning FTR Bid reflects its *pro rata* share of the quantity of MW awarded.

4.10.8.5 Treatment of Infeasibility in Annual FTR Auction

Since Market Participants are not obligated to self-schedule all the ARRs they received in the annual allocation, it is possible that the set of ARRs self-scheduled by Market Participants in the auction will not satisfy the SFT. That is, the power flow and contingency analysis conducted using the set of self-scheduled ARRs could result in overloaded facilities. It is possible that the FTR Bids/Offers may resolve this infeasibility by providing the required counterflow on the facilities overloaded by the self-scheduled ARRs. If the FTR Bids/Offers do not resolve the infeasibility, then the self-scheduled ARRs will be curtailed to maintain feasibility.

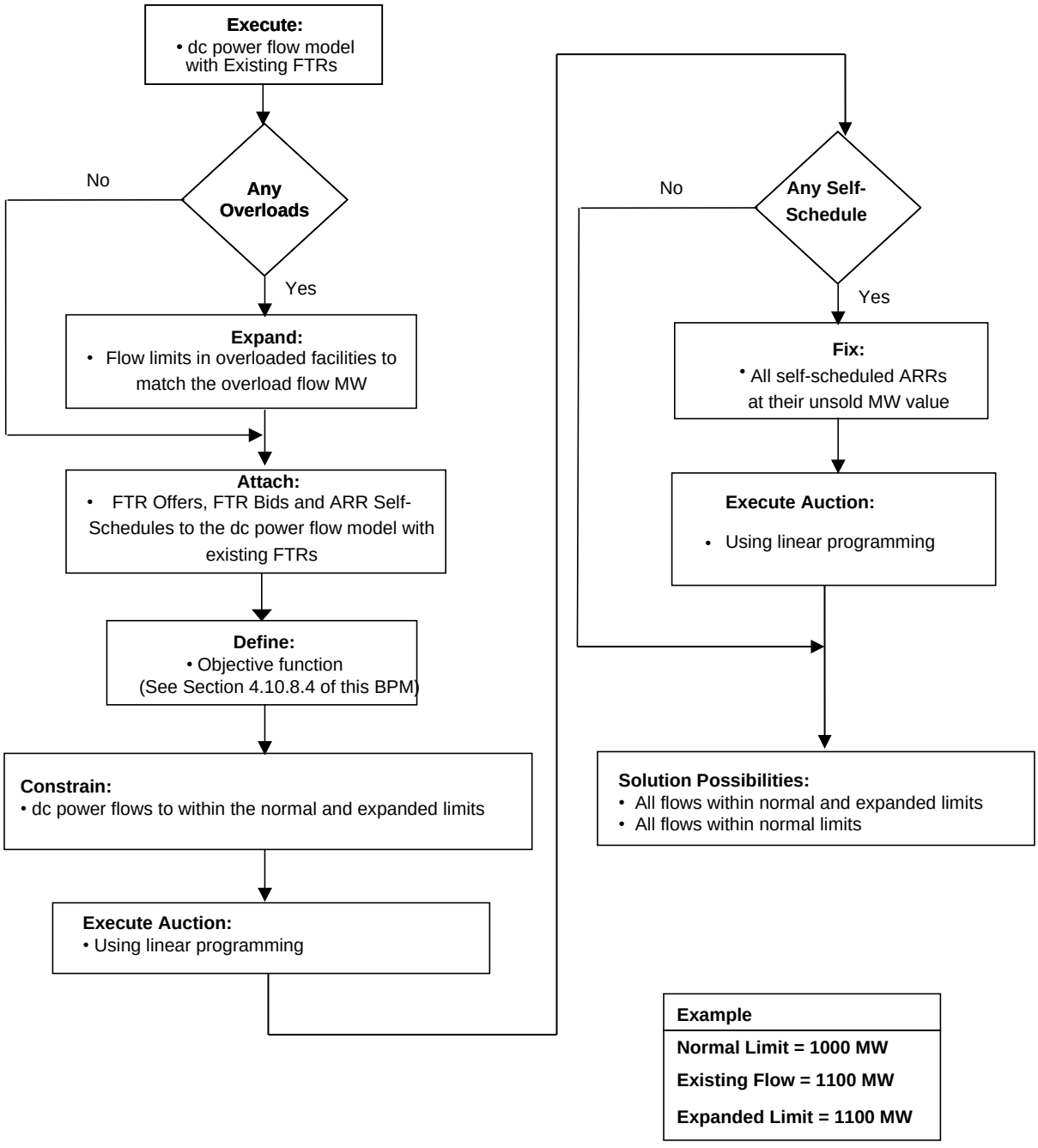
When multi-round auctions are implemented, it is possible that the existing set of FTRs awarded to Market Participants in previous rounds may not satisfy the SFT. This could potentially be caused by adjustments to the Network Model between the rounds, which are expected to happen in rare and emergency situations. In such situations, the power flow and contingency analysis conducted using the existing set of FTRs could result in overloaded facilities. If this occurs, MISO will still conduct the auction, with the limits of the overloaded facilities expanded to their

overloaded flow values. The auction will not make any constraint violation worse or cause new violations. The auction process may (but is not forced to) reduce or eliminate the original overloads. Exhibit 4-4 illustrates the process.

All parties with FTRs from the previous rounds that were not sold, and those purchasing FTRs in the current round of the annual FTR Auction, maintain the FTRs held or received. MISO collects sufficient revenue from parties purchasing FTRs and self-scheduling ARRs in the auction to pay parties selling FTRs.

The expansion of the transmission limits for purposes of FTR Auctions could result in revenue inadequacy between the congestion payments collected in the Day-Ahead Energy and Operating Reserve Market and the congestion revenue paid to FTR Holders. Such potential revenue inadequacy is handled using the methods for settling with FTR Holders described in the *BPM for Market Settlements (BPM-005)*. Expanding the transmission limits in the FTR Auction does not imply that any facilities will be physically overloaded.

Exhibit 4-3: FTR Annual Auction Feasibility



4.10.9 Multi-Period Monthly FTR Auction

MISO conducts multi-period monthly FTR Auctions to:

- Sell the residual FTR Capability of the Market Footprint
- Facilitate Market Participant the buying and selling of existing FTRs.

4.10.9.1 Nature and Timing of Multi-Period Monthly FTR Auctions

The multi-period monthly FTR Auction consists of a single market being offered with one or multiple seasons/months, called as periods, and each period having a Peak and Off-Peak (Exhibit 4-6). All FTRs sold in multi-period monthly FTR Auction term of one of the periods and are associated with either the Peak or the Off-Peak.

a. All Offers by FTR Holders to sell FTRs and all Bids to purchase FTRs must be submitted to MISO during the monthly bidding period.
b. MISO posts the results of the multi-period monthly FTR Auction on the internet webpage after verifying the characteristics of the binding constraints resulting from the auction clearing calculations. The posted multi-period monthly FTR Auction results shall include the name of the FTR Bidder/FTR Offeror; the megawatt quantity; whether the awarded FTR is an Obligation or an Option; the FTR period (Peak/Off-Peak); whether the FTR is a Buy or Sell; the round of the FTR Auction where each FTR was awarded; the term, the receipt and delivery points for awarded FTR; and the FTR Market Clearing Price for each awarded FTR.
c. Each Market Participant cannot exceed a combined total of 6,000 bids/ offers for each period in a monthly FTR Auction (Peak and Off-Peak combined).

Auction results will be made available before the start of the subsequent month as per Exhibit 4-6.

4.10.9.2 Selection of Winning Bids and Offers

MISO uses an LP model for each FTR Auction, that considers all FTR Bids and FTR Offers submitted, and selects a combination of FTR Bids and FTR Offers (winning FTR Bids and winning FTR Offers, respectively) that:

- Makes the solution simultaneously feasible given the transfer capability of the Market Footprint over the subject period; and
- Maximizes the objective function, which is equal to the total economic value (as expressed in the FTR Bids) of the winning FTR Bids, less the total economic cost (as expressed in the FTR Offers) of the winning FTR Offers.

To maximize the economic value of the winning FTR Bids, less the cost of the winning FTR Offers, the LP model automatically reconfigures the FTRs offered for sale in FTR Auctions by FTR Holders. If there are two or more winning FTR Bids that are identical in all material respects except for the quantity of MW sought, then each such winning FTR Bid reflects its pro rata share of the quantity of MW awarded.

4.10.9.3 Treatment of Infeasibility in FTR Multi-Period Monthly Auction

It is possible that the existing set of FTRs held by Market Participants prior to the auction may not satisfy the SFT. That is, the power flow and contingency analyses conducted using the existing set of FTRs could result in overloaded facilities. If this occurs, MISO still conducts that auction, possibly with the limits of the overloaded facilities expanded to their overloaded flow values. The auction process may (but is not forced to) reduce or eliminate the original overloads. Exhibit 4-5 illustrates the process.

All parties already holding FTRs prior to the auction, and those purchasing FTRs in the auction, will maintain the FTRs held or received. MISO collects sufficient revenue from parties purchasing FTRs in the auction to pay parties selling FTRs.

The expansion of the transmission limits for purposes of FTR Auctions could result in revenue inadequacy between the congestion payments collected in the Day-Ahead Energy and Operating Reserve Market and congestion revenue paid to FTR Holders. Such potential revenue inadequacy is handled using the methods for settling with FTR Holders described in the *BPM for Market Settlements*. Expanding the transmission limits in the FTR Auction does not imply that any facilities will be physically overloaded.

Exhibit 4-4: FTR Multi-Period Monthly Auction Feasibility

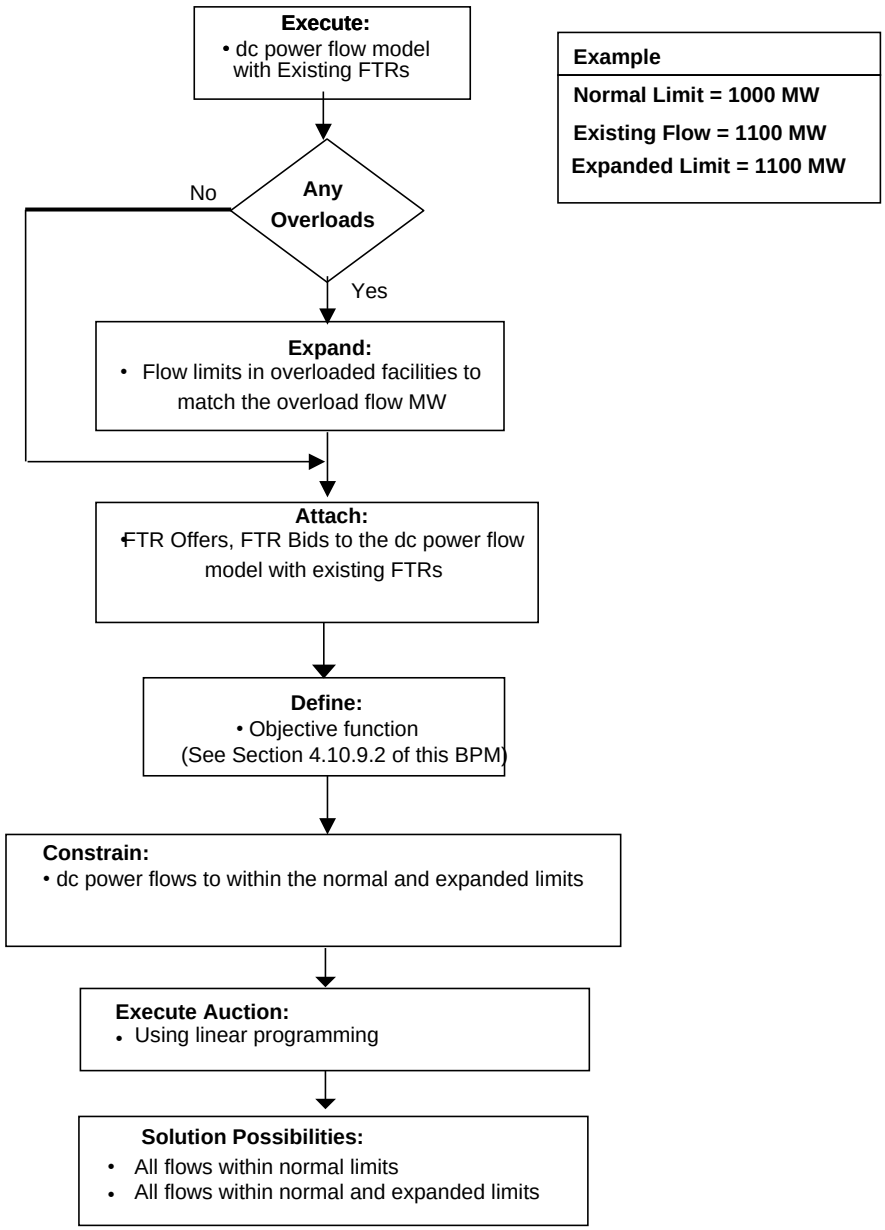


Exhibit 4-6: FTR Multi-Period Monthly Auction Schedule

MPMA Auction Schedule (Peak and Off-Peak)							
Season	**Auction In**	**Auction For**					**No. of Periods**
Spring	**May**	June					1
Summer	**June**	July	August	**Fall (SON)**	**Winter (DJF)**	**Spring (MAM)**	5
	July	August	September	October	November		4
	August	September	October	November			3
Fall	**September**	October	November	**Winter (DJF)**	**Spring (MAM)**		4
	October	November	December	January	February		4
	November	December	January	February			3
Winter	**December**	January	February	**Spring (MAM)**			3
	January	February	March	April	May		4
	February	March	April	May			3
Spring	**March**	April	May				2
	April	May					1

Notes:
Fall (SON) = September, October, November
Winter (DJF) = December, January, February
Spring (MAM) = March, April, May

4.10.10 Auction Bidding Window

MISO will accept FTR Bids/Offers from the Market Participants during a pre-defined bidding period that is communicated to Market Participants and posted on the MISO website. Extensions to the auction bidding window will only be considered for technical difficulties of the MISO infrastructure impacting Market Participants' ability to submit their Bids/Offers

5 Secondary FTR Market

Market Participants can trade FTRs on MISO-administered secondary market. Such trade must be performed on an outstanding FTR. The trade involves change in the partial (MW, duration or both) or full ownership of an FTR from an FTR Holder to the acquiring Market Participant. Such reconfiguration may be accomplished in the annual and monthly FTR Auction. There is no clearing mechanism in the secondary market that would provide settlement prices. The trade is bilateral in nature. Market Participants determine the settlement price outside of MISO processes.

The acquiring Market Participant may take ownership of an outstanding FTR for quantity and/or date that is less than or equal to the original FTR, but not greater. Such requests are granted only for transfers of ownership to Market Participants and only after all applicable credit requirements have been satisfied. FTRs cannot be reconfigured with respect to FTR Receipt Points and FTR Delivery Points in the secondary market, or to register or change ownership of a private bilateral trade with MISO. Such reconfiguration and/ or registration may be accomplished in the annual and monthly FTR Auction. Refer to Attachment L of the Tariff.

A given original FTR may be split into two or more FTRs with MW quantities and/or effective time periods that vary from that in the original FTR. All other terms of the reconfigured FTRs – including but not limited to FTR Receipt Point and FTR Delivery Point – may not be different from such terms of the original FTR. In all cases, the aggregate of the reconfigured FTRs must be comparable in all respects to the original FTR. The FTR quantity specified in any reconfigured FTRs must not be less than 1 MW. The FTR dates specified in any reconfigured FTR must not span a period less than one day.

Market Participants will have the option to transfer the transaction charges[44] related to the traded FTRs to the acquiring Market Participant. This option is only available when:

a. Market Participant choose this option during the FTR transfer
b. The transfer is for the whole remaining FTR term and the term is a season or in increment of whole month

[44] The transaction charges include the monthly net charge or credit from FTRs purchased and/or sold in the monthly FTR Auction expressed in Dollars and monthly net charge or credit for FTRs purchased, sold or self-scheduled from ARRs in the Annual FTR Auction expressed in Dollars.

c. The FTR has not been reconfigured (i.e., split into two or more FTRs with MW quantities and/or effective time periods that vary from that in the original FTR)
d. Both Market Participants agrees to the transaction charge transfer.

Market Participants requesting such transaction charge transfer must submit a Service Request to MISO's Client Services and Readiness team, at least ten (10) BDs prior to the start of the month in which the FTRs are to be transferred. The Service Request, at minimum, must contain following details:

a. Buyer's Asset Owner Name
b. Seller's Asset Owner Name
c. Copies of approval emails from Buyer and Seller
d. Secondary FTR market details:
    i. Date of transfer
    ii. List of FTR Identifiers in Microsoft Excel or CSV format

5.1 MISO FTR Bulletin Board

The Secondary Market is an FTR bulletin board that is accessible via the Market Portal and can be used to register changes of FTR Holders of record with MISO. This bulletin board is available daily to Market Participants for the posting of FTR trades. The FTR bulletin board is purged each midnight EST by MISO.

6 `Settlement of ARRs and Annual FTR Auction transactions

6.1 Distribution of ARR Auction Revenues

The total target settlement of all feasible ARRs allocated in the Annual ARR Allocation is calculated each month for each Asset Owner. The total target may be discounted if the total auction revenue available from the annual auction associated with the given month is less than the monthly target feasible ARR values. The same discount factor will be applied to all Asset Owners for the settlement of the ARR revenues. The settlement is performed on the first Operating Day in a calendar month. The ARR re-distribution due to Load shift for the prior month will also be included in this settlement.

Amounts remaining from the Annual FTR Auction after all feasible Stage 1 ARRs have been funded are distributed to ARR holders pro rata based on the difference between the nomination cap and the total MW of ARRs owned (including the infeasible ARRs). This calculation is performed and trued-up on every settlement of the first Operating Day in a calendar month.

Additional details containing the calculations can be found in the Market Settlement BPM.

6.2 ARR Settlement

ARRs are settled based on the auction clearing prices from the annual FTR Auction. An ARR Obligation will provide the ARR Holder with credits when the value of the ARR Obligation is positive and will impose charges when the value of the ARR is negative. The value of the ARR Obligation is positive when the auction clearing price at the ARR Receipt Point (ARR Source) is greater than the clearing price at the ARR Delivery Point (ARR Sink). Conversely, an ARR Obligation will impose charges on its ARR Holder when the clearing price of the ARR Receipt Point is less than the clearing price of the ARR Delivery Point.

The portion of an ARR that is successfully converted to FTRs in each round is settled based on the round clearing price of its path from the annual FTR Auction for the corresponding season and FTR Period, whereas the portion of an ARR that is not converted to FTRs is settled based on the un-weighted average of round clearing prices of its path from the annual FTR Auction for the corresponding season and FTR Period. This is to ensure that ARR payments from the MW amount that are successfully self-scheduled to FTRs will be equal to transaction charges from self-scheduling.

Therefore, the clearing price of an ARR should be calculated based on the following four components,

1. Clearing price (P_1) and MW (X_1) converted in round 1
2. Clearing price (P_2) and MW (X_2) converted in round 2
3. Clearing price (P_3) and MW (X_3) converted in round 3
4. Equal average of all three round clearing prices and ARR MW not converted ($X - X_1 - X_2 - X_3$) after annual auction, where X is the ARR MW amount.

with the following equation,

$$P = \frac{\sum_i P_i X_i + (X - \sum_i X_i)\sum_j P_j / 3}{X}$$

where

P denotes the ARR clearing price to be determined,
P_i is the FTR Auction clearing price in Round *i,*
X_i is the MW amount that is successfully converted to FTRs in Round *i,*
X is the ARR MW amount.

If there is no conversion or curtailment, price will simply be the unweighted average price of all three round clearing prices, shown as follows,

$$P = \sum_j P_j / 3$$

Exhibit 6-1 illustrates how the clearing price of an ARR is calculated when it is partially converted into FTRs, and the amount of MW converted is different among rounds. The clearing price for the ARR is ($120,000+90*$2,000)/150 =$2000.

Exhibit 6-1: ARR Clearing Price Calculation

Round	ARR (MW)	ARR Converted (MW)	Clearing Price ($/MW)	Converted MW*Clearing Price ($)
1	150	20	$1,000	$20,000
2	150	20	$2,000	$40,000
3	150	20	$3,000	$60,000
Total				$120,000

ARR (MW)	ARR Unconverted (MW)	Equal Weighted Average of Clearing Prices ($/MW)	Unconverted MW*Clearing Price ($)
150	90	$2,000[45]	$180,000

The infeasible ARRs are funded via uplift. The uplift for each Market Participant is calculated as the ratio of its total LTTR MW by the total LTTR MW for all Market Participants. This proportion of the LTTR fund is collected from each Market Participant and disbursed back to all Market Participants having infeasible ARRs. LTTRs are defined by all ARRs allocated in Stage 1A, which includes the restoration, counterflow and Stage 1A infeasible ARRs. An infeasible ARR is path dependent and its value is computed using the clearing prices from the annual FTR Auction. The infeasible ARRs are not discounted as in the case of feasible ARRs described above. This calculation is performed and trued-up on every settlement of the first Operating Day in a calendar month.

[45] This is the equal average price of all three round clearing prices.

6.3 Settlement of FTR transactions from the Annual Auction

The transaction charges related to FTRs that are self-scheduled or awarded in the annual FTR Auction are settled once each month during the term of an FTR. The settlement is performed and trued-up on the first Operating Day in a calendar month.

Additional details regarding the settlement of FTRs and FTR transactions can be found in the BPM for Market Settlements.

6.4 Settlement of MVP ARR

MVP ARRs will be valued based on the auction clearing prices from the annual FTR Auction. The annual FTR auction clearing price is based on the average of three annual FTR Auction round clearing prices. The MVP ARRs will only be valued when the auction clearing price at the ARR Receipt Point is greater than the auction clearing price at the ARR Delivery Point. Therefore, MVP ARRs are like Options, as their value will always be positive.

The revenue generated by MISO held ARRs discounts the Schedule 26-A Usage Rate pursuant to Schedule 26-A Multi-Value Project Cost Recovery section of Transmission Settlement Business Practice Manual (BPM-012).

7 Appendix A

7.1 Simultaneous Feasibility Test

The Simultaneous Feasibility Test (SFT) is a market feasibility test, run by MISO, which checks for revenue adequacy by ensuring that MISO's Transmission System can support the subscribed set of ARRs/FTRs during normal system conditions, including defined contingencies.

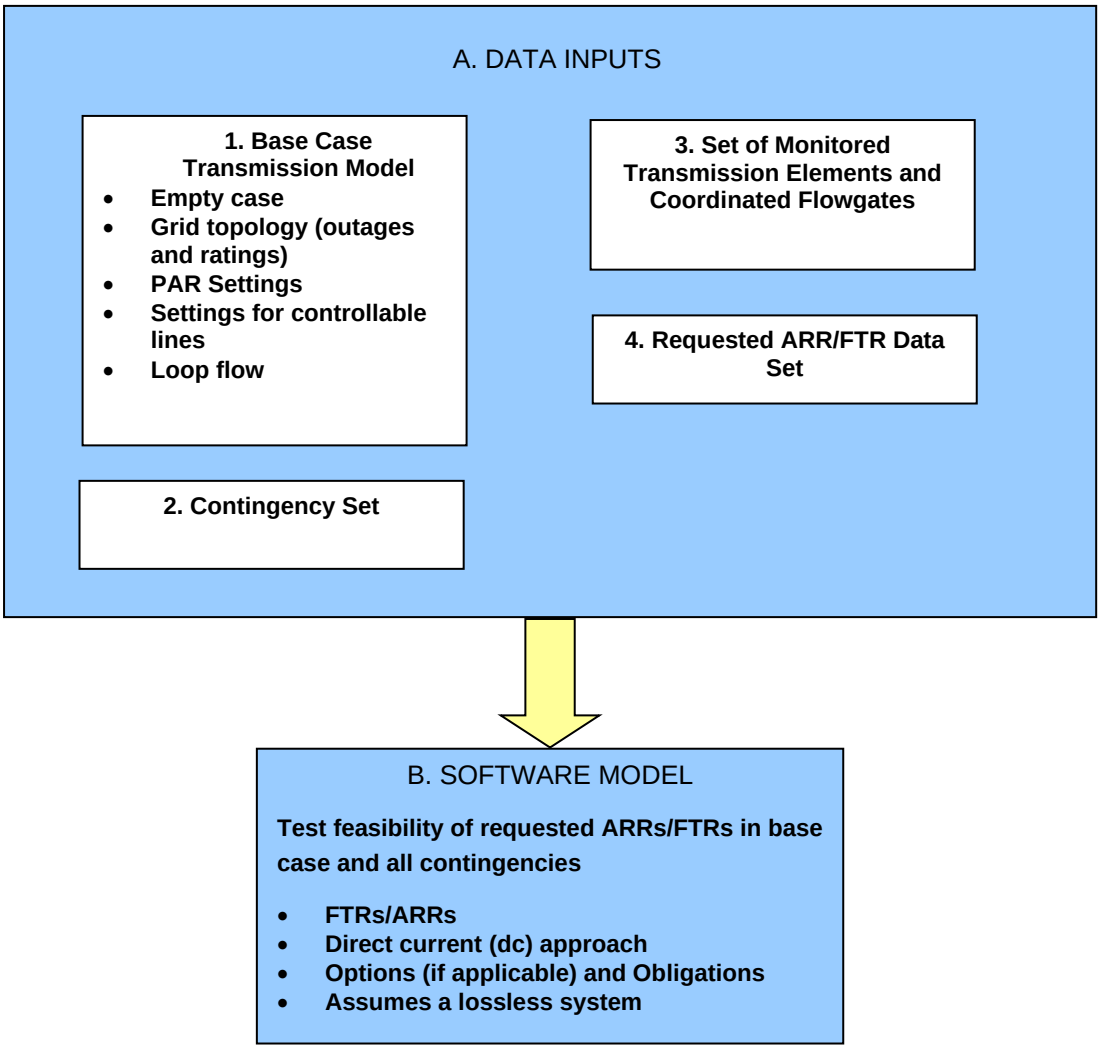
MISO performs a SFT any time that it awards a new or reconfigured ARR or FTR. In particular, MISO assesses the simultaneous feasibility of the allocation of ARRs and of FTRs sold through FTR Auctions. The same software model and process is used to perform the SFT, for whatever reason it is run.

Exhibit 7-1 illustrates the primary components of the SFT. It consists of four major data inputs:

1. A base case transmission model,
2. A set of defined contingencies,
3. A set of monitored transmission elements, and
4. A requested ARR/FTR data set as well as the selected software model.

Each component of the SFT is discussed below.

Exhibit 7-1: Simultaneous Feasibility Test



7.2 Box A: Data Inputs

Data inputs are tailored to the specific period covered by the SFT. MISO determines data inputs, such as loop flow assumptions and grid topology that are appropriate for the particular year, season, month, etc., covered by the test.

In specifying the data inputs to the SFT for the ARR/FTR analysis, the objective is to choose settings that are consistent with the accepted average state of MISO Transmission System for the period that the ARRs/FTRs are scheduled. Revenue adequacy of FTRs (i.e., whether or not

MISO collects sufficient Transmission Congestion Charges to pay the Transmission Congestion Credit Target Allocation owed to holders of FTRs) depends on differences between the base case transmission model, contingency specifications, and set of monitored transmission elements used for the SFT and those used for scheduling the Day-Ahead Energy and Operating Reserve Market; the fewer differences, the more likely MISO will be revenue adequate. Revenue adequacy of ARRs (i.e., whether revenue collected in the FTR Auction will be sufficient to pay ARR Holders based on FTR Auction path prices) depends on differences between the modeling elements used for the ARR Allocation SFT and the FTR Auction SFT.

7.2.1 Box 1: Base Case Transmission Model

The base case transmission model is an empty model, consisting only of a transmission configuration and loop flow due to generation and Load in external LBAAs.

The base case transmission model includes data and assumptions concerning:

- Grid topology (including transmission outage schedules);
- Phase angle regulator (PAR) settings;
- Schedules for controllable lines;
- Breaker settings; and
- Loop flow.

Uncompensated loop flow through the Market Footprint from external LBAAs is included in the base case transmission model. Uncompensated loop flow is loop flow that does not pay a Transmission Congestion Charge to MISO. The limits on Coordinated Flowgates are consistent with the seams agreements between MISO and Stage I transmission systems.

MISO requests data and coordinates to the extent possible with transmission service providers external to the Market Footprint to develop the best Generator, Load, and transaction data possible for modeling purposes where seams agreements are not in effect. This information is loaded into the model and results in flows over the Market Footprint that are representative of the impacts of external operation on MISO. To the extent that such contract information is not provided to MISO, MISO develops estimates of loop flow using the best available data.

The base case transmission model, including loop flow modeling assumptions, is available on MISO's Extranet for review by Market Participants.

7.2.2 Box 2: Contingency Set

Box 2 consists of the set of all contingencies that need to be considered to preserve the security of MISO's Transmission System (i.e., Market Footprint) during the relevant period. The set of contingencies includes, at a minimum, single contingencies that MISO real-time operators protect against.

The set of contingencies included in the SFT are consistent with the contingencies included in the software for scheduling the Day-Ahead Energy and Operating Reserve Market.

7.2.3 Box 3: Set of Monitored Transmission Elements

The third input to the SFT is the set of monitored transmission elements or constraints and associated rating limits for the Market Footprint. This includes equipment that is monitored for limit violations. Since MISO uses a direct current (DC) model for the SFT, the set of monitored elements include Flowgate proxy representations of relevant voltage and stability limits. Thermal operating limits for transmission lines and Flowgate limits for groups of lines are expressed in megawatts, corresponding to the use of a dc power flow model.

The set of monitored transmission elements and rating limits included in the SFT are consistent with those included in the software for scheduling the Day-Ahead Energy and Operating Reserve Market for the relevant period, with consideration for future system conditions.

7.2.4 Box 4: Requested ARR/FTR Data Set

The last major input to the SFT is the requested ARR/FTRs data set to be tested for feasibility. Each requested FTR is designated as either an FTR Option[46] or FTR Obligation. ARRs are always modeled as obligations.

The requested ARR/FTR data set includes all new requested ARRs/FTRs for the study period, as well as any existing ARRs/FTRs that remain valid during the period.

- For the allocation of ARRs, the requested ARR data set is the set of CARRs, determined for the existing entitlements to MISO's Transmission System.

[46] The SFT process described in this Appendix A will support FTR Options when they become available to Market Participants.

- In the case of FTR Auctions, the requested FTR data set is the set of FTR Bids and Offers under consideration at a given stage in the optimization process.

7.2.5 Box B: Software Model

The software model uses a dc power flow to perform the SFT based on the specified data inputs for the period being analyzed.

The software model simultaneously assesses the feasibility of all ARRs/FTRs in the requested ARR/FTR data set. All requests are represented in the model at the same time; the model does not sequentially evaluate requests corresponding to different types of Transmission Service or Transmission Service of different terms. While the assessment is simultaneous, the modeling approach for FTRs varies depending on the type of FTR, since Options and Obligations have different characteristics. The different types of FTRs impact the power flow in different ways and are represented in different ways in the SFT.

- Requested FTR Obligations and ARRs are loaded in the model in the form of megawatt injections at the Receipt Points paired with withdrawals at the Delivery Points. These injections and withdrawals are loaded into a transmission model that is empty, except for a background representation of loop flow from External LBAAs.
- Requested FTR Options are addressed by monitoring each transmission constraint to ensure that it is not violated under the worst-case combination of exercised FTR Options. Counter-flow created by an FTR Option is ignored.

Consistent with MISO operating and planning criteria, the SFT evaluates the ability of all system facilities to remain within normal ratings during normal, extended-period operation given the data input for the requested ARRs/FTRs. MISO's Transmission System must also be able to sustain any single contingency event with all Transmission System facilities operating consistently with MISO operating and planning criteria.

The software model determines whether the power flow from the set of requested ARRs or FTR Obligations and FTR Options violates any monitored element in the base case power flow. The model also tests whether the set of requests is feasible in each of the defined contingencies. To do this, it tests whether the power flows associated with the nominated ARRs/FTRs would violate the adjusted rating limit for any monitored constraint under any defined contingency.

In an FTR Auction, the optimization process ensures that the final set of FTR Bids and Offers accepted satisfies the SFT. In an ARR allocation, MISO checks whether the set of CARRs

satisfies the SFT. If reductions must be made to the CARRs to achieve simultaneous feasibility, MISO applies the “weighted least squares” approach to determine the required ARR MW reductions. Appendix B of this BPM illustrates the process. The final allocated or cleared amount is specified to the nearest 0.1 MW.

8 Appendix B

8.1 ARR/FTR Example #1 – ARR MW Reduction for Simultaneous Feasibility

This example illustrates the Weighted-Least-Squares (WLS) ARR MW reduction methodology to achieve simultaneous feasibility in ARR allocation processes.

When the application of a set of CARRs would result in one or more transmission network overloads, the CARRs are reduced to attain feasibility. Since there are many possible ways of reducing the CARRs, it is necessary to either place a value on the remaining ARR MW or alternatively place a penalty on CARR MW reduction.

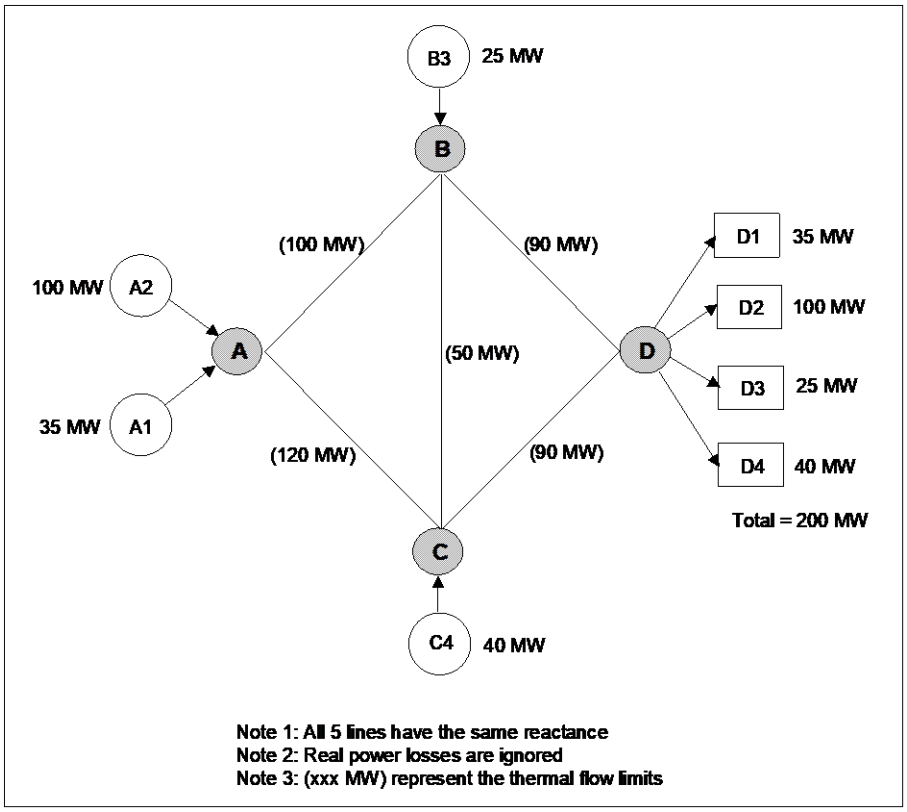
The approach currently chosen by MISO is to place a quadratic cost penalty on a CARR's MW reduction. This approach distributes the CARR MW reductions in a rational manner that not only considers the sizes of the original CARRs but also their effectiveness in achieving feasibility.

8.1.1 Base Case CARR and Network Conditions

Exhibit 8-1 presents an example consisting of 4 original CARRs applied to a network of 4 Buses and 5 transmission lines. The original CARRs are listed as follows for a total Load of 200 MW:

CARR Source	CARR Sink	CARR MW
A1	D1	35
A2	D2	100
B3	D3	25
C4	D4	40

Exhibit 8-1: Original Assignment of CARRs



8.1.2 Application of Original CARRs and Resulting Flow Limit Violations

To check the feasibility of the original set of CARRs, the original CARR sources and sinks are applied to the Network Model. The injection and withdrawal of the CARR MW at the source CPNode and the CARR sink CPNode, respectively, affects the flows on the Network Model. The source CPNode is typically a Generator with one-to-one mapping to an EPNode. The sink CPNode, on the other hand, is an ARR Zone constituting multiple EPNodes. The distribution of the CARR MW to the individual EPNodes of an ARR Zone can be illustrated with the following example.

Say, Market Participant has an FTR from A to B for 100 MW. B can be an ARR Zone or a Load Zone, it does not really matter. The 100 MW will sink into B in the same manner for a Load Zone or an ARR Zone. Also, assume the following:

B is made of two EPNodes with Participation Factors (PF) of 80 MW and 50 MW respectively.

Market Participant has 0.8 percent of node on EPNode1 and 1 percent of node on EPNode2.

The 100 MW will be distributed into the two EPNodes in the following manner:

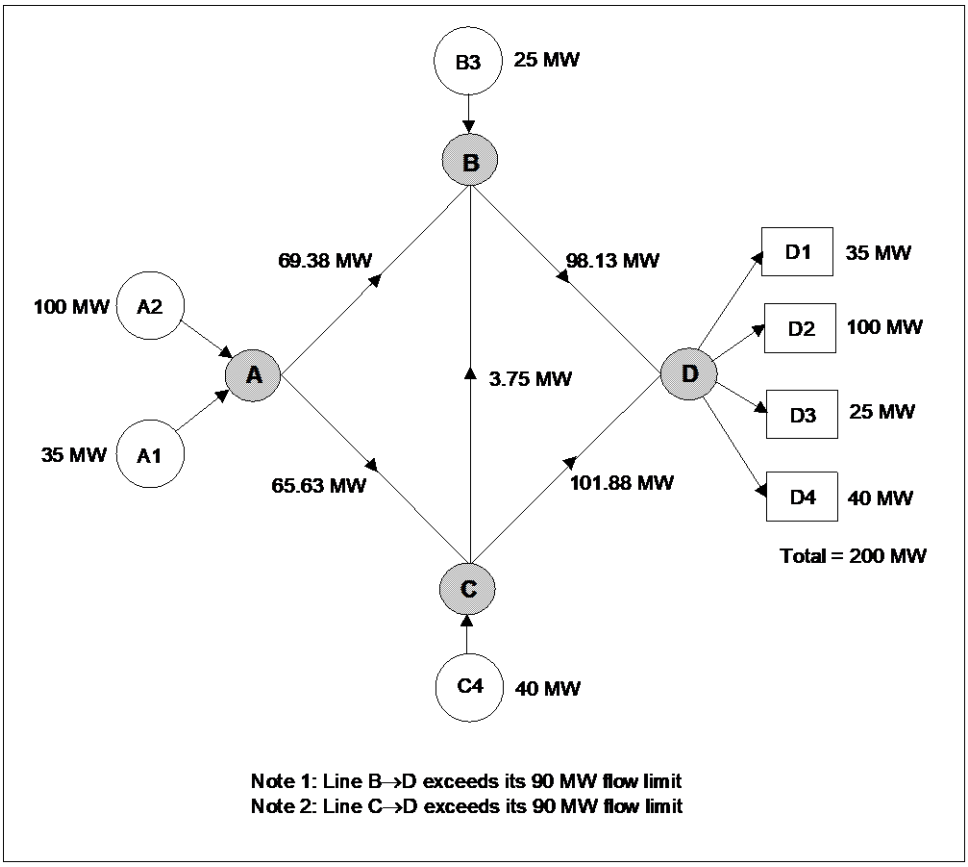
Effective PF of EPNode1 for Market Participant = 80 x 0.8 = 64; Effective PF of EPNode2 for Market Participant = 50 x 1.0 = 50

Normalized effective PF EPNode1 = 64/ (64+50) = 0.56; Normalized effective PF EPNode2 = 50/ (64+50) = 0.44

100 MW FTR sink into EPNode1 = 0.56 x 100 = 56; 100 MW FTR sink into EPNode2 = 0.44 x 100 = 44

In this example below, the flows on lines B→D and C→D exceed their respective 90 MW limits as shown by **Error! Reference source not found.**. The network solution in this example is obtained by executing a dc power flow.

Exhibit 8-2: Unrestricted Flow with Original CARRs



8.1.3 Weighted-Least-Squares MW Reduction

One ARR MW reduction method is called the WLS approach.

The problem is how to reduce the original CARRs in an “equitable” way so that the network does not become overloaded with all the CARRs simultaneously converted to actual MW schedules.

The WLS approach essentially places a “cost” penalty on CARR MW reduction. In other words, the greater the reduction, the greater the cost penalty will be. The penalty increases as the square of the MW reduction and is weighted to place a greater penalty on MW reductions that are associated with smaller ARRs. Exhibit 8-3 presents the cost penalties that are associated with the CARRs in this example.

Exhibit 8-3: Weighted-Least-Squares Reduction Penalty

ARR MW Reduction	A1 to D1 35 MW	A2 to D2 100 MW	B3 to D3 25 MW	C4 to D4 40 MW
0	0.00	0.00	0.00	0.00
1	0.03	0.01	0.04	0.03
2	0.11	0.04	0.16	0.10
3	0.26	0.09	0.36	0.23
4	0.46	0.16	0.64	0.40
5	0.71	0.25	1.00	0.63
6	1.03	0.36	1.44	0.90
7	1.40	0.49	1.96	1.23
8	1.83	0.64	2.56	1.60
9	2.31	0.81	3.24	2.03
10	2.86	1.00	4.00	2.50
11	3.46	1.21	4.84	3.03
12	4.11	1.44	5.76	3.60
13	4.83	1.69	6.76	4.23
14	5.60	1.96	7.84	4.90
15	6.43	2.25	9.00	5.63
Reduction Penalty = (ARR MW Reduction)^2/(Original ARR MW)				

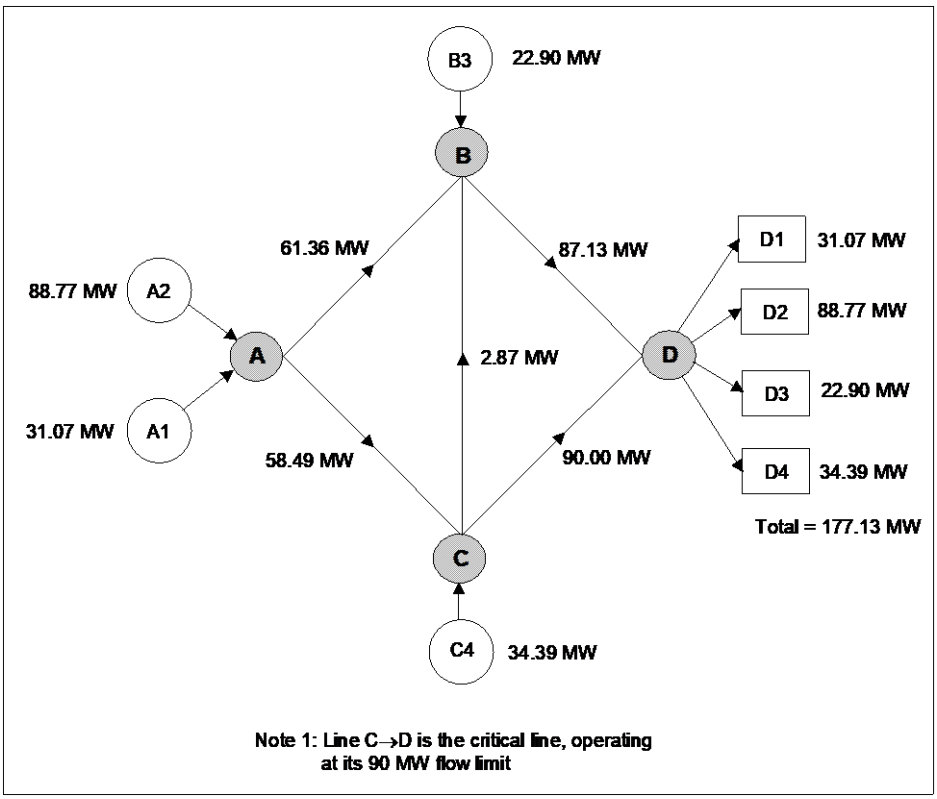
From the table we can observe the following:

- The penalty for the same MW reduction on the B3→D3 (25 MW ARR) is 4 times the penalty on the A2→D2 (100 MW ARR).
- In general, the penalty ratio (for the same MW reduction) is equal to the inverse ratio of the original ARR MWs.

8.1.4 Feasibility

Exhibit 8- gives the solution to the ARR MW reduction problem, applying the WLS approach.

Exhibit 8-4: CARR MW Reduction to Achieve Feasibility



The WLS method reduces ARRs by the same percentage only when the ARRs have identical source/sink Buses.

In this example, the MW reductions and percentage reductions are:

- ARR A1→D1 was reduced by 3.93 MW or (3.93 ∗ 100/35 = 11.23%)
- ARR A2→D2 was reduced by 11.23 MW or (11.23 ∗ 100/100 = 11.23%)
- ARR B3→D3 was reduced by 2.10 MW or (2.10 ∗ 100/25 = 8.42%)
- ARR C4→D4 was reduced by 5.61 MW or (5.61 ∗ 100/40 = 14.03%)

Note that the total feasible Load of 177.13 MW is very close to the maximum Load of 180 MW, which could be supplied by the two 90 MW lines with a different allocation of ARR MW reductions.

9 Appendix C

9.1 ARR/FTR Example #2 – ARR Restoration via Counterflow candidates

This example illustrates the restoration of the restoration candidates (i.e., curtailed Stage 1A CARRs, and curtailed candidate LTTRs) using counterflow candidates (i.e., counterflow and HUFU ARR entitlements, and LTTR termination requests). The restoration process involves an SFT that maximizes the restoration, and maximizes the termination of the LTTRs for which LTTR termination requests were made during Stage 1A. The restoration process is conducted after Stage 1A is concluded and before the Stage 1B nominations are accepted. The procedure is summarized as follows:

a. Establish the Network Model and attach the existing ARRs. Calculate the initial flow conditions based on the existing ARRs. This base case condition must be feasible to proceed with the development of Counterflow ARR Entitlements.
b. Identify the location and maximum MW for all the Counterflow ARR Entitlements.
c. Attach the available Counterflow ARR Entitlements to the Network Model.
d. Attach the desired restoration candidates to the Network Model.
e. Execute the optimization process with the objective of minimizing:
    i. Weighted sum of squares of the amount of restoration CARR MW that is **not** granted (i.e., the MW amount of the candidate LTTRs and year 1 Stage 1A CARRs that were curtailed in Stage 1A and were eligible for restoration but could not be restored based on the inclusion of counterflow CARR MW). The restoration CARR MW granted is termed restoration ARR MW. The weights in the weighted sum of squares will be equal to the inverse of the restoration CARR MW (restoration CARRs MW are the restoration candidates as described in Section 3.11.5.2).
    ii. Plus a weight α times
    iii. The weighted sum of squares of the counterflow ARR MW (counterflow ARR MW in the discussion below collectively mean Counterflow ARRs (allocated portion of Counterflow ARR Entitlement) and the unaccepted MW of the LTTR termination requests). The weights in the weighted sum of squares will be equal to the inverse of the counterflow CARR MW (counterflow CARRs MW are the counterflow candidates as described in Section 3.11.5.2).

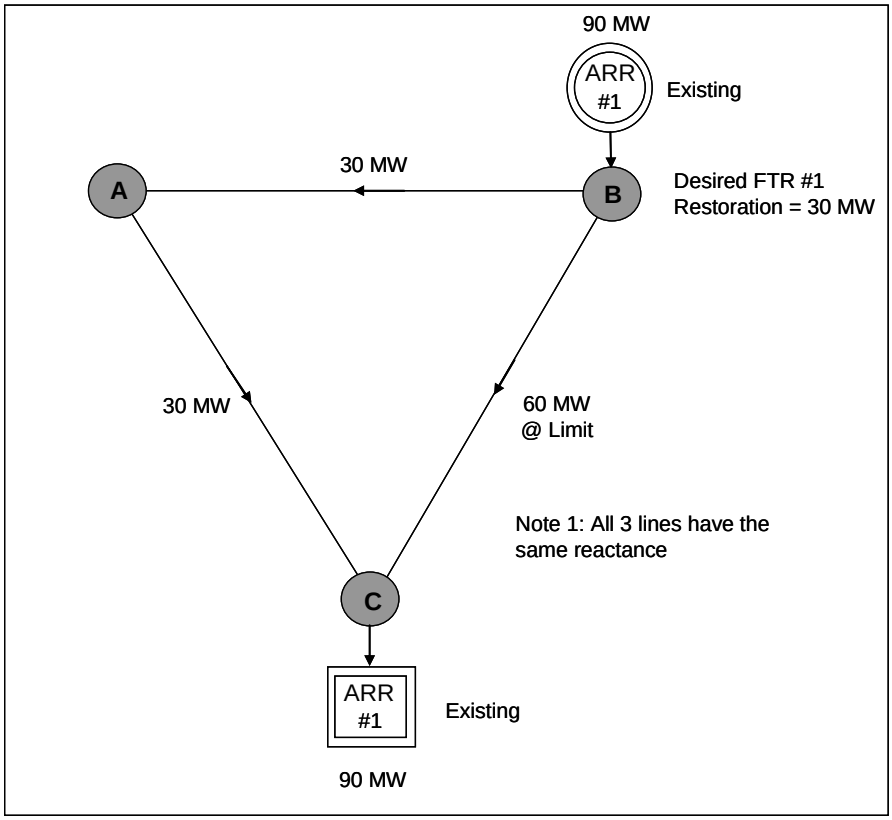
The variables are the counterflow ARR MW and the restoration ARR MW. In this way, MISO will try to maximize a measure of the amount restored. The weight α is selected to control the amount of counterflow ARRs that are added in order to increase the number of restored ARRs.

9.1.1 Base case feasibility Conditions

A three-Bus example was constructed as shown in Exhibit 9-1. The initial conditions are as follows:

- ***dc style network*** – reactances only and ignoring transmission losses
  - Line A → B: 1.0 ohm with a 100 MW limit
  - Line A → C: 1.0 ohm with a 100 MW limit
  - Line B → C: 1.0 ohm with a 60 MW limit
- A single obligation ARR Holder #1:
  - Existing ARR = 90 MW from B → C
  - Desired restoration ARR = 30 MW from B → C

Exhibit 9-1: Feasible Base Case Conditions



This three-Node example with equal line reactances was chosen so that reader can easily follow and verify all calculated results.

The initial flows on the lines are derived from the dc power flow solution and are within or at their MW limits. Existing ARR #1 is modeled as a 90 MW injection at Node B and a 90 MW withdrawal at Node C. The desired restoration is shown but has no impact on the base case flows. The flow on line from B $\rightarrow$ C is at its limit of 60 MW.

Note that 2/3 of the ARR flows on the “short” path and 1/3 of the ARR flows on the “long” path.

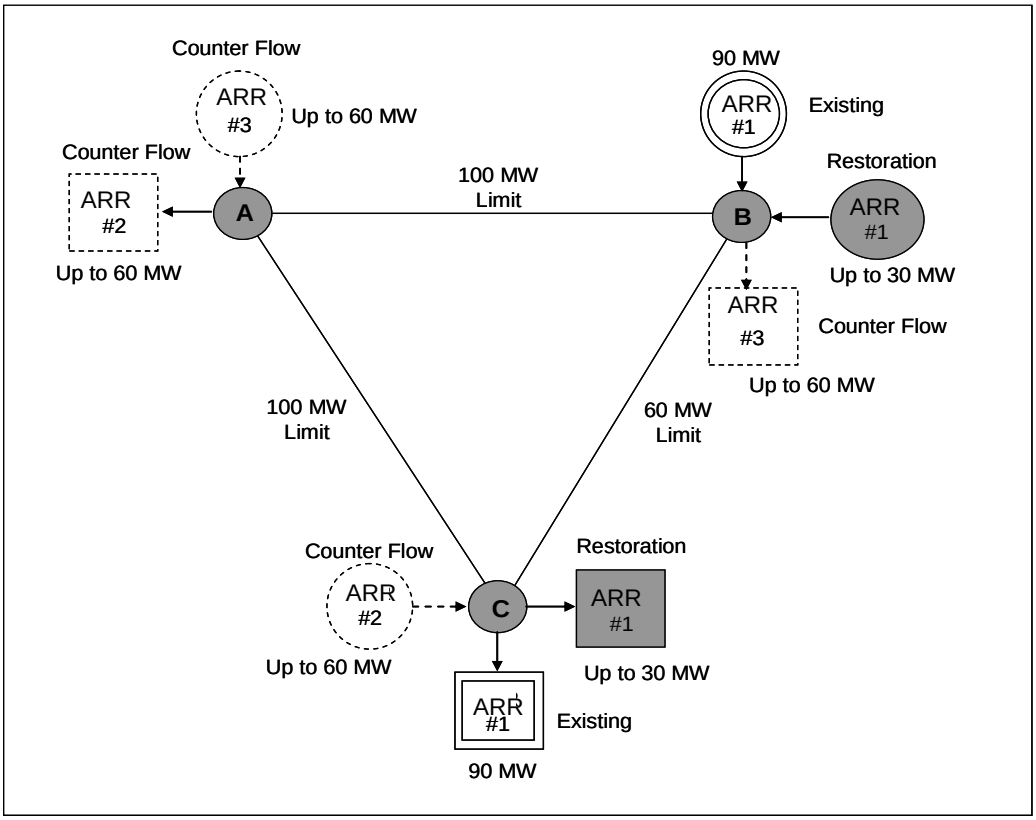
9.1.2 Counterflow CARRs

For illustration, we assume that there are two counterflow CARRs available to us for ARR MW restoration. These are:

- Counterflow CARR #2: 60 MW maximum from C → A
- Counterflow CARR #3: 60 MW maximum from A → B

Exhibit 9-2 shows the combined network and ARR model to be used for the Optimization process.

Exhibit 9-2: Optimization Model



9.1.3 Optimization Solution

The objective of the optimization is to minimize:

$$\psi = \sum_{n} \frac{\left(\text{Restoration CARR MW - Restoration ARR MW}\right)_n^2}{\text{Restoration CARR MW}_\text{n}} + \alpha \sum_{m} \frac{\left(\text{Counterflow ARR MW }\right)_m^2}{\text{Counterflow CARR MW}_\text{m}}$$

by adjusting the counterflow CARRs and restoration CARRs (within their limits), while not exceeding the flow limits of the dc Network Model.

In the above objective function:

Restoration ARR MW = Restoration MW variable, up to its maximum amount (i.e.,. restoration CARR MW)

Restoration CARR MW = The MW amount of the candidate LTTRs and year 1 Stage 1A CARRs that were curtailed in Stage 1A, and that are eligible for restoration

n = Restoration ARR index

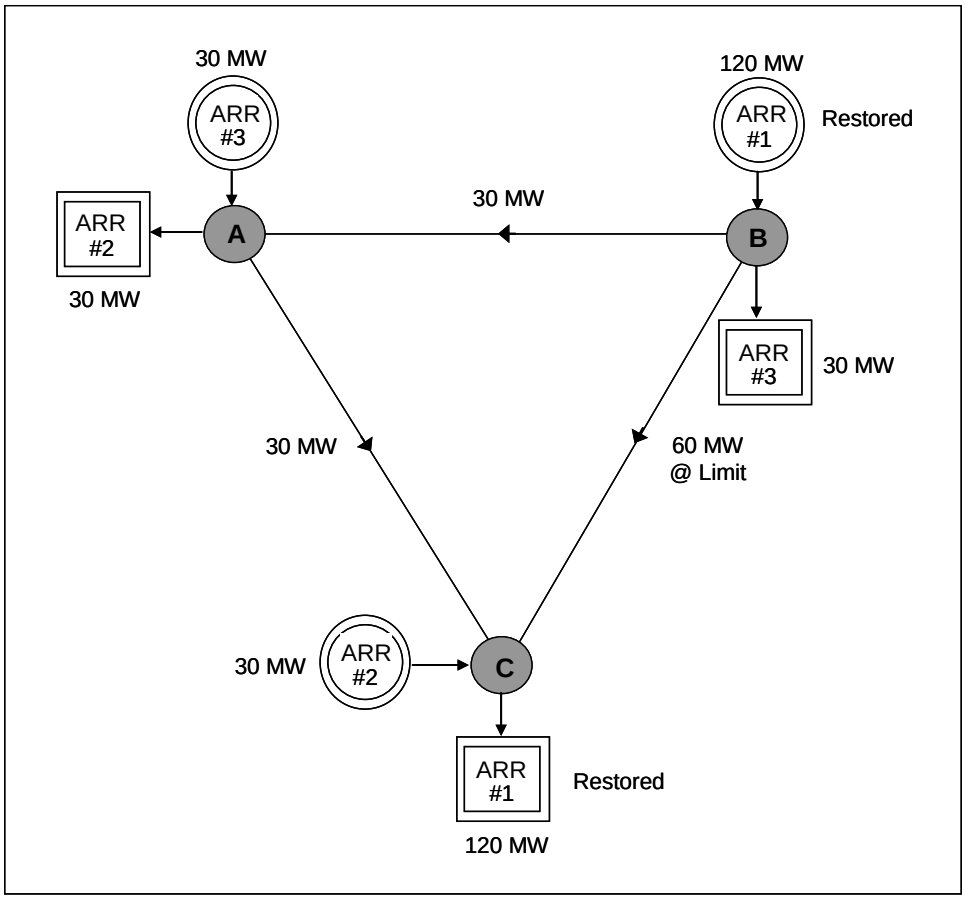
Counterflow ARR MW = Counterflow MW variable, up to its maximum amount (i.e.,. counterflow CARR MW)

Counterflow CARR MW = Counterflow ARR Entitlements and LTTR Termination Requests (i.e. counterflow candidates)

m = Counterflow ARR index

Exhibit 9-3 shows the solution to the optimization for $\alpha = 0.001$:

Exhibit 9-3: Optimization Solution



The final ARR situation is:

ARR #1 = 120 MW from B → C (90 MW prior to restoration plus 30 MW restored)

ARR #2 = 30 MW from C → A

ARR #3 = 30 MW from A → B

10 Appendix D

10.1 ARR/FTR Example #3 – FTR Auction

This example illustrates the auction process for buying and selling FTR obligations and covers the following:

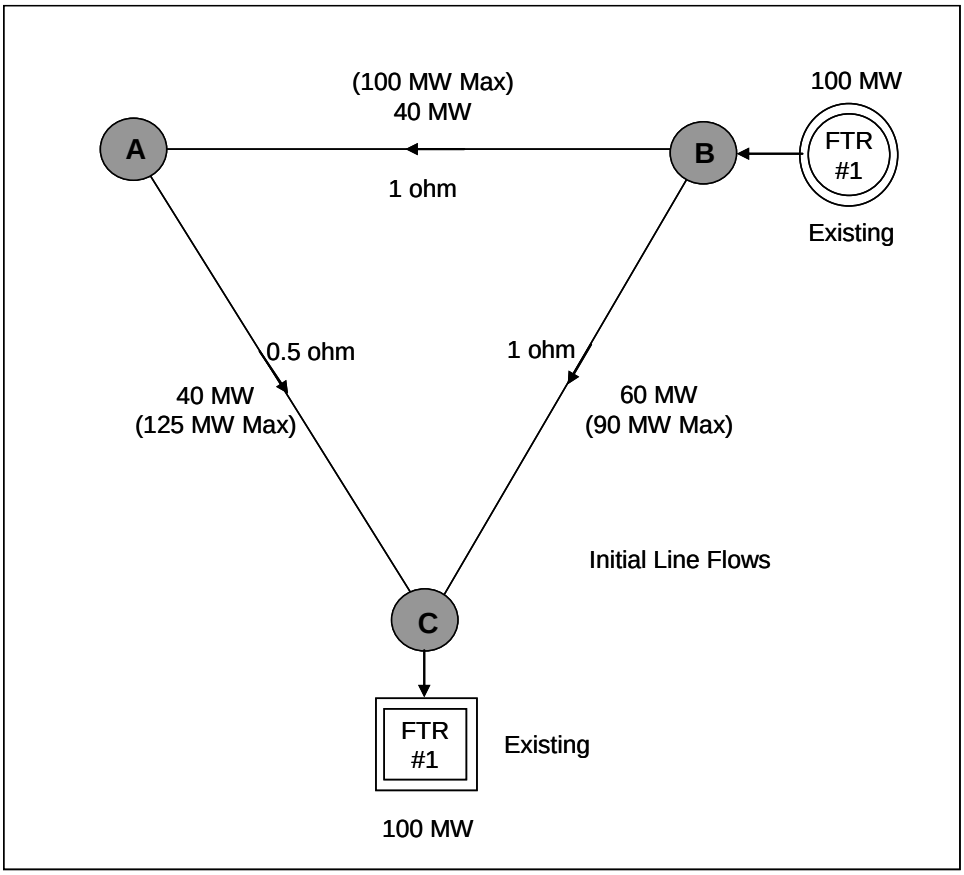
- Network Model;
- Network flows resulting from existing FTRs;
- Modeling of Offers and Bids;
- Unconstrained network flows resulting from the maximum Offers and Bids;
- Linear Programming (LP) set-up;
- LP solution and resulting network flows;
- FTR Auction clearing prices
- FTR Auction settlement; and
- New FTR allocation.

10.1.1 Pre-Auction Base Case Conditions

A three-Bus example was constructed as shown below. The initial conditions are as follows:

- DC style network – reactance only and ignoring transmission losses:
  - Line A → B: 1.0 Ohm with a 100 MW limit
  - Line A → C: 0.5 Ohm with a 125 MW limit
  - Line B → C: 1.0 Ohm with a 90 MW limit
- A single obligation FTR Holder #1: 100 MW from B → C

Exhibit 10-1: Pre-Auction FTR Model



The initial flows on the lines are derived from the dc power flow solution and, in this example, are well within their MW limits. FTR #1 is modeled as a 100 MW injection at Node B and a 100 MW withdrawal at Node C.

If any initial flow violates its limit, we need to first expand its limit to match the initial flow before proceeding to the next step.

10.1.2 FTR Auction Modeling

The auction process begins by extending the base case Network Model to include FTR Offers and Bids. The following Offer and Bids were submitted for this example:

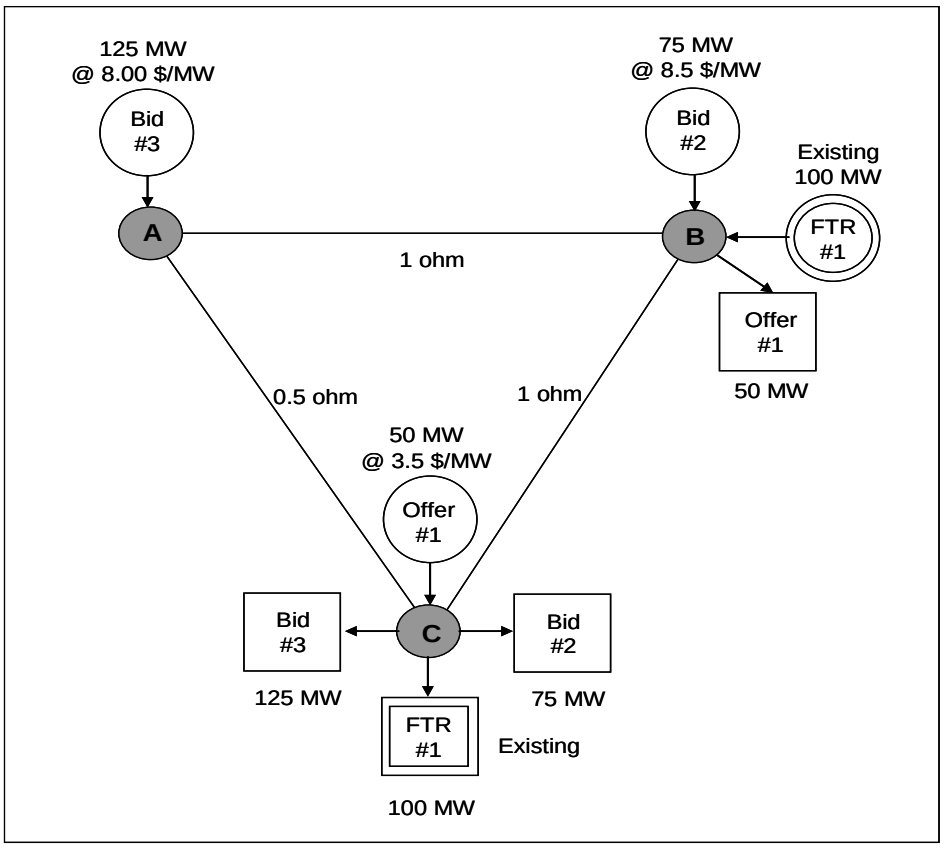
1. FTR Holder #1 offered 50 MW of its FTR at 3.5 $/MW from B → C. The Offer price is the minimum that entity #1 is willing to accept. To be eligible, an Offer must be associated with an existing FTR.
2. Bidder #2 Bid 75 MW at 8.5 $/MW from B → C. The Bid price is the maximum that entity #2 is willing to pay.
3. Bidder # 3 Bid 125 MW at 8.0 $/MW from A → C. The Bid price is the maximum that entity #3 is willing to pay.

The auction model is constructed as a combination of three types of elements:

1. Initial FTRs are modeled as injections and withdrawals from Receipt Point to Delivery Point, respectively.
2. Offers are modeled as withdrawals and injections from the FTR's Receipt Point to Delivery Point, respectively. In other words, Offers are "subtracted" from their corresponding FTRs.
3. Bids are modeled as injections and withdrawals from Receipt Point to Delivery Point, respectively. Bids are modeled in the same manner as FTRs.

Exhibit 10-2 shows the application of the existing FTR, Offer, and Bids to the Network Model.

Exhibit 10-2: Offer/Bid Auction Model



Next, we describe how to arrive at the “constrained” FTR Auction solution.

10.1.3 FTR Auction Solution Procedure

Setting up the FTR Auction model is the first step in the overall procedure. The objective is to derive offer MW values and bid MW values that:

- Honor the network flow constraints while not exceeding the Offer/Bid MW and price parameters; and
- Maximize a mathematical objective function.

The solution methodology that has gained wide acceptance in the industry and that is used by MISO is that of LP. The FTR Auction problem is described mathematically for the LP solution engine, as follows:

- ***LP variables*** – Offer MW and Bid MW, which can range from zero to their maximum Offer/Bid MW values, positive variable.
- ***LP network constraints*** – Linearized network flow equations in terms of initial conditions and sensitivity coefficients (flow MW versus Offer/Bid MW) applied to the LP variables. Alternatives such as incorporating the dc power flow model (instead of sensitivity coefficients) also work.
- ***Objective function*** – The objective function that is maximized is defined as follows, where "Sum" is for all Bids and Offers:

Objective Function = Sum (Bid Price ∗ LP Bid MW) – Sum (Offer Price ∗ LP Offer MW)

Exhibit 10-3 presents the sensitivity coefficients (also called shift factors) for this example.

Exhibit 10-3: Line Flow Shift Factors versus Offers/Bids

	Line Flow A → B	**Line Flow A → C**	**Line Flow B → C**
Offer # 1 C → B	+ 0.40	– 0.40	– 0.60
Bid # 2 B → C	– 0.40	+ 0.40	+ 0.60
Bid # 3 A → C	+ 0.20	+ 0.80	+ 0.20

Exhibit 10-4 shows the LP setup for this example, without an explicit representation of the power flow model.

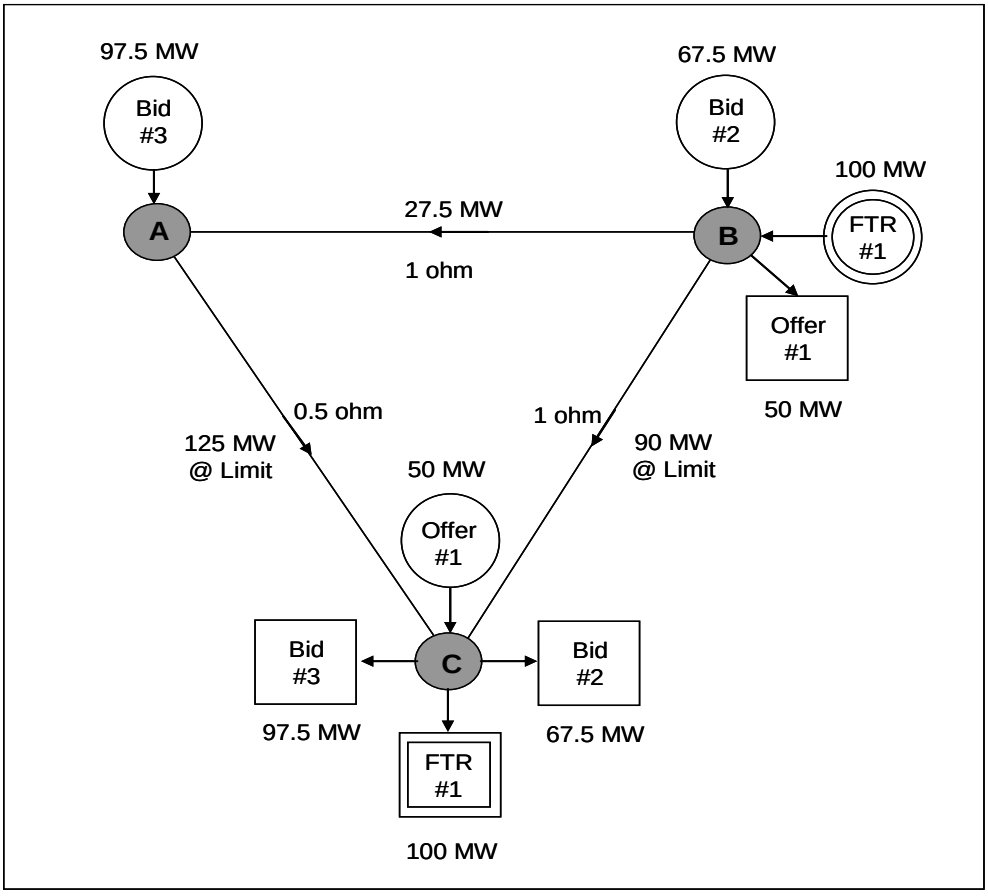
Exhibit 10-4: Linear Program Setup

LP Variables	Offer #1	Bid #2	Bid #3
	0 ∗ LP1 ∗ 50	0 ∗ LP2 ∗ 75	0 ∗ LP3 ∗ 125

LP Network Constraints	Line A → B	– 100 ∗ – 40 + 0.40 LP1 – 0.40 LP2 + 0.20 LP3 ∗ 100
	Line A → C	– 125 ∗ 40 – 0.40 LP1 + 0.40 LP2 + 0.80 LP3 ∗ 125
	Line B → C	– 90 ∗ 60 – 0.60 LP1 + 0.60 LP2 + 0.20 LP3 ∗ 90
Objective Function	– 3.5 LP1 + 8.5 LP2 + 8.0 LP3	

Exhibit 10-5 shows the LP solution for the Offer and Bids and the corresponding flows in the network. Lines A → C and B → C are at their respective limits.

Exhibit 10-5: Offer/Bid FTR Auction Model – Solution



The last step in the FTR Auction process is to establish the FTR clearing prices, settlement, and the resulting FTR allocations.

10.1.4 FTR Auction Clearing Prices and Settlement

The auction clearing prices can be derived in several ways as described in Section 4.10.7 of this BPM. For illustration we have calculated the auction clearing prices by incrementing each Offer/Bid (independently) by a small amount (1 MW), executing the LP, and recording the corresponding objective function value.

Exhibit 10-6 summarizes the results of the LP runs.

Exhibit 10-6: FTR Auction Clearing Prices

	Objective Function	Auction Clearing Price
LP Solution	$1178.75	
Offer # 1 LP1 – 1 MW	$1170.25	(1178.75 – 1170.25)/1 = 8.50 $/MW
Bid # 2 LP2 + 1 MW	$1170.25	(1178.75 – 1170.25)/1 = 8.50 $/MW
Bid # 3 LP3 + 1 MW	$1170.75	(1178.75 – 1170.75)/1 = 8.00 $/MW

After we obtain the auction clearing prices, we can calculate the auction settlement as shown by Exhibit 10-7.

Exhibit 10-7: FTR Auction Settlement

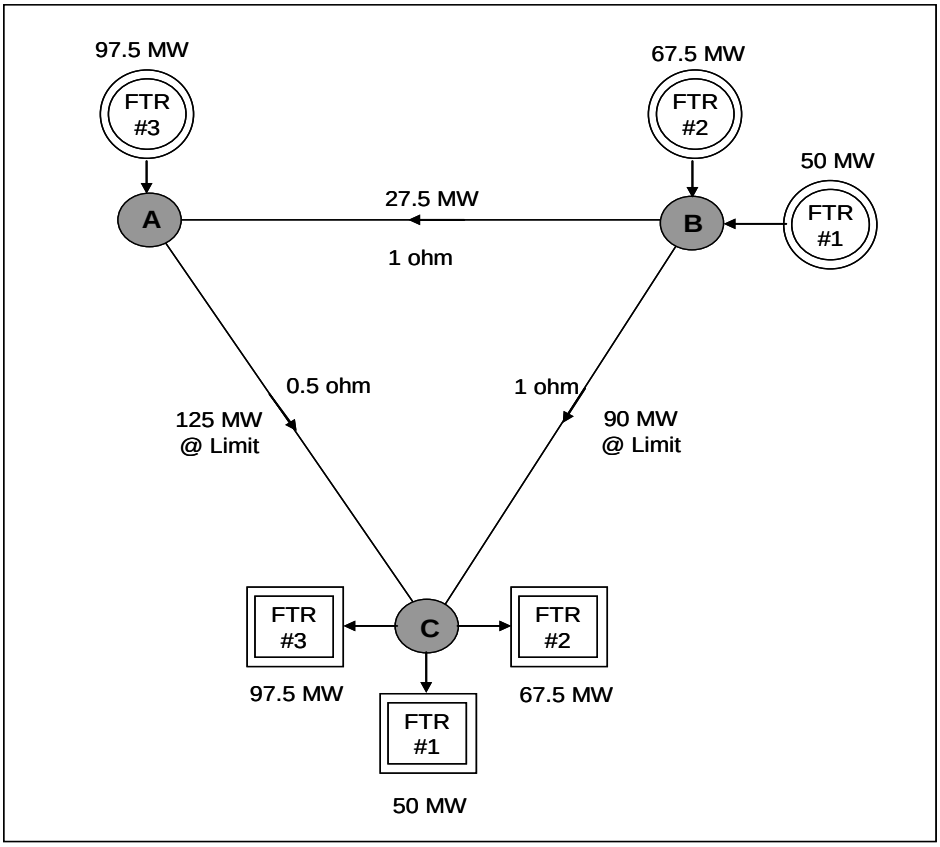
	LP Variable	Auction Settlement
Offer # 1 C → B	50.0 MW	8.5 ∗ 50.0 = $425.00 Credit
Bid # 2 B → C	67.5 MW	8.5 ∗ 67.5 = $573.75 Charge

Bid # 3 **A → C**	97.5 MW	8.0 * 97.5 = $780.00 Charge
Auction Net		$928.75 Excess

The *BPM for Market Settlements* describes the disposition of the excess revenues obtained from the FTR Auctions.

Exhibit 10-8 shows the results of the FTR Auction in terms of the new FTRs that are awarded to FTR Holders #1, #2, and #3.

Exhibit 10-8: Post-Auction FTR Model



Note that the FTR Auction in this example resulted in the creation of three new FTRs that replaced the original single FTR. This happened because there was “unused” network capacity in the Base Case.

11 Appendix E

11.1 Example demonstrating the creation of Network ARR Entitlements

11.1.1 ARR Registration – Phase 3

The following example illustrates the computation of ARR entitlements (AEs) associated to Network Load service. AEs are seasonal. This example shows calculations only for one season. The same steps would be followed to compute entitlements for the remaining three seasons.

In this example, there are two ARR Zones, both with Load served by two entities: AO1 and AO2. Exhibit 11-1 shows the Summer Transmission Entitlements associated to these ARR Zones.

Exhibit 11-1: Network TE data for NITS AE calculation

ARR zone	AO	Network Load	Season
AZ1	AO1	50	Summer
AZ2	AO 1	100	Summer
AZ1	AO 2	200	Summer
AZ2	AO 2	100	Summer

Three Generation Resources are associated with the Load in AZ1 and AZ2. Exhibit 11-2 shows the Capacity remaining off each of these Generation Resources after the definition of GFA and PTP entitlements.

Exhibit 11-3 shows Reserved Source Point (RSP) information associated with AZ1 and AZ2.

Exhibit 11-2: Sample generation CPNode data (after GFA and PTP definition)

Resource	Capacity	Season	Capacity used in GFA/PTP definition	Remaining capacity for Network entitlements
GEN1	150	Summer	50	100
GEN2	300	Summer	100	200
GEN3	275	Summer	75	200

Exhibit 11-3: Generation to ARR Zone relation

Resource	ARR Zone	Season	Resource %	BRSS
GEN1	AZ1	Summer	50	N
GEN2	AZ1	Summer	70	Y
GEN1	AZ2	Summer	50	Y
GEN2	AZ2	Summer	30	Y
GEN3	AZ2	Summer	100	N

AEs are calculated by splitting the share of each Resource associated with an ARR Zone among the entities serving Load in that ARR Zone. The data gathered during year 1 of the Annual ARR Registration will make up the initial set of RSPs (RSPs and their MW quantity) and ARR Zones to create the AEs for the year 1 and future Annual ARR Allocation periods. From thereon, RSPs will only change subject to the procedures for replacement, new or retirement of RSPs. The split is in accordance with the Load Ratio Share.

ARR entitlement AE01 for Asset Owner AO1, from GEN1 to AZ1 is calculated as the product:

$$\underbrace{100\ \text{MW}}_{\text{Available capacity at GEN1 after GFA and PTP AE definition}} \times \underbrace{0.5}_{\text{Portion of the capacity of GEN1 allocated to AZ1}} \times \underbrace{0.2}_{\text{AO1's share of NITS peak at AZ1}} = 10\ \text{MW}$$

All remaining entitlements will be calculated in a similar way. The resulting set of AEs is shown in
.

Exhibit 11-4.

Exhibit 11-4: Resulting ARR entitlements

ARR entitlement	Source	Sink	AO	Available Generation	ARR zone share of generation	AO share of peak load	MW	BRSS flag
AE01	GEN1	AZ1	AO1	100	0.5	0.2	10	N
AE02	GEN1	AZ2	AO1	100	0.5	0.5	25	Y
AE03	GEN2	AZ1	AO1	200	0.7	0.2	28	Y
AE04	GEN2	AZ2	AO1	200	0.3	0.5	30	Y
AE05	GEN3	AZ2	AO1	200	1	0.5	100	N
AE06	GEN1	AZ1	AO2	100	0.5	0.8	40	N
AE07	GEN1	AZ2	AO2	100	0.5	0.5	25	Y
AE08	GEN2	AZ1	AO2	200	0.7	0.8	112	Y
AE09	GEN2	AZ2	AO2	200	0.3	0.5	30	Y
AE10	GEN3	AZ2	AO2	200	1	0.5	100	N

The BRSS flag, which is determined based on the RSP data, indicates whether an AE is eligible for Stage 1A nomination. AEs with BRSS flag “Y” are eligible for Stage 1A nomination.

12 Appendix F

12.1 Re-Assignment of ARR Entitlements prior to Annual ARR Registration

The following example illustrates the computation of ARR Entitlements for an ARR Zone after year 1. In this example, there is one ARR Zone (AZ1), with Load served by five entities: A, B, C, D and E. Exhibit 12-1 shows the year 1 NITS Peak Load Forecast (Y1 NPLF) associated with this ARR Zone for each Market Participant as calculated for the year 1 Annual ARR Allocation. Refer to Section 3.24 for the calculation of the NPLF.

Exhibit 12-1: Load Forecast of AZ1 in Year 1

Market Participant	Y1 NPLF
A	150 MW (15 %)
B	500 MW (50 %)
C	200 MW (20 %)
D	100 MW (10 %)
E	50 MW (5 %)

The PRSS of this ARR Zone is made up of one Generation Resource, shown in

Exhibit 12-2. This Generation Resource also qualifies under the BRSS criteria.

Exhibit 12-2: PRSS of AZ1 in the Year 1 ARR Registration

Generator	RSP capacity
G1	100 MW

Exhibit 12-3 shows the year 1 ARR Entitlements for each Market Participant in ARR Zone AZ1 per the Network ARR Entitlements calculation in Appendix E. The ARR Entitlements are seasonal. This example shows calculations only for one season. The same steps would be followed to compute the ARR Entitlements for the remaining three seasons. Exhibit 12-3 also shows the allocated LTTR MW amounts that were nominated and allocated in Stage 1A of year 1 Annual ARR Allocation.

Exhibit 12-3: Year 1 ARR Entitlements and allocated ARRs

Owner	NITS nomination cap	Source	Sink	ARR Entitlement MW	Year 1 allocated LTTR MW
A	150 MW	G1	AZ1	15	15
B	500 MW	G1	AZ1	50	45
C	200 MW	G1	AZ1	20	11
D	100 MW	G1	AZ1	10	10
E	50 MW	G1	AZ1	5	2

Y1 NPLF is the Load shifts between Market Participants in AZ1 as identified in Exhibit 12-1. The Y1 adjusted NPLF (ADJ NPLF) will be Load shift data reported per the requirements laid out in Section 3.26 of this BPM (this is the Load shift data for the current Annual ARR Allocation period). Note that the sum of the Y1 ADJ NPLF is equal to the total of the Y1 NPLF for all Market Participants in AZ1, which was 1000 MWs. Y2 NPLF will be calculated using the Module E NPF as described in Section 3.24.

The loss and gain percentage calculations displayed in

Exhibit 12-4 are calculated as below:

$$\text{Gain \%} = (\text{MW Gained} / \Sigma\text{MW Gained}) \times 100$$

- Gain %: Gain percentage calculated for each LSE that gains Load
- MW Gained: Y1 ADJ NPLF – Y1 NPLF
- ΣMW Gained: Sum of MW gained across all LSEs that gained Load

Exhibit 12-4: Load Shift Calculation

Market Participant	Y1_NPLF	Y1_ADJ_NPLF	MW Lost	Loss %	MW Gained	Gain %	Y2 NPLF	Year 1 allocated LTTR MW
A	150	125	25	17%	-		135	15
B	500	450	50	10%	-		450	45
C	200	200	-		-		200	11
D	100	101	-		1	1%	150	10
E	50	124	-		74	99%	75	2
Total	1000	1000	75		75		1010	83

Every year, in the preparation of the next Annual ARR Registration and Allocation, ARR Entitlements and LTTRs are adjusted for the scenarios described in Section 3.10.6. The ARR Entitlements and LTTRs will shift as shown in Exhibit 12-5. For each Market Participant, the calculations are as below:

Lost ARR Entitlement MW = (Y1 ARR Entitlement * Loss %)

Lost LTTR MW = Y1 LTTR – (Y1 LTTR * Loss %)

Y2 ARR Entitlement (for Market Participants that lost Load) = Y1 ARR Entitlement - Lost ARR Entitlement MW

Y2 LTTR (for Market Participants that lost Load) = Y1 LTTR - Lost LTTR MW

Y2 ARR Entitlement (for Market Participants that gained Load) = Y1 ARR Entitlement + Σ Lost ARR Entitlement MW across all Market Participants * Gain %

Y2 LTTR (for Market Participants that gained Load) = Y1 LTTR + Σ Lost LTTR MW * Gain %

Y2 ARR Entitlement (for Market Participants that neither gained nor lost Load) = Y1 ARR Entitlement

Y2 LTTR (for Market Participants that neither gained nor lost Load) = Y1 LTTR

Exhibit 12-5: ARR reassignment in AZ1 for Year 2 ARR Registration

Market Participant	Y1 ARR Entitlement (from RSP G1)	Lost ARR Entitlement MW LOAD_SHIFT_BUCKET	Y2 ARR Entitlement (from RSP G1)	Y1 allocated LTTR MW (from RSP G1)	Lost Year 1 allocated LTTR MW LOAD_SHIFT_BUCKET	Y2 eligible LTTR MW (from RSP G1)
A	15	2.5	12.5	15	2.5	12.5
B	50	5	45	45	4.5	40.5
C	20	0	20	11	0	11.0
D	10	0	10.1	10	0	10.1
E	5	0	12.4	2	0	8.9
Total	100	7.5	100	83	7	83

Exhibit 12-5 depicts the calculation of the year 2 AEs and LTTRs using the year 1 NPLF.

Exhibit 12-6: Y1 and Y2 NPLF

Market Participant	Y1 NPLF	Y2 NPLF[47]
A	150 MW (15 %)	135 MW (13 %)
B	500 MW (50 %)	450 MW (45 %)
C	200 MW (20 %)	200 MW (20 %)
D	100 MW (10 %)	150 MW (15 %)
E	50 MW (5 %)	75 MW (7 %)
Total	1000 MW	1010 MW

[47] Y2 NPLF will be calculated using the ModE NPF as described in Section 3.24

The following two exhibits (Exhibit 12-7 and Exhibit 12-8) demonstrate the creation of ARR Entitlements for an RSP addition to this ARR Zone. Assume that 10 MW from G2 were added into the PRSS of AZ1 pursuant to Section 3.21.2. The resulting set of Resources is shown in Exhibit 12-7. The new Resource G2 will be distributed among the Market Participants in AZ1 per the calculations in Appendix E using the Y1 NPLF.

Exhibit 12-7: PRSS of AZ1 in the Year 2 ARR Registration

Generator	RSP capacity
G1	100 MW
G2	10 MW

Exhibit 12-8 summarizes the entitlements associated with Network Load service in ARR Zone AZ1 for the year 2 Annual ARR Allocation.

Exhibit 12-8: Year 2 ARR Entitlements and LTTRs

Owner	NITS nomination cap	Source	Sink	Entitlement MW	Year 2 eligible LTTR MW
A	135 MW	G1	AZ1	12.5	12.5
		G2	AZ1	1.5	
B	450 MW	G1	AZ1	45	40.5
		G2	AZ1	5.0	
C	200 MW	G1	AZ1	20	11
		G2	AZ1	2	
D	150 MW	G1	AZ1	10.1	10.1
		G2	AZ1	1.0	
E	75 MW	G1	AZ1	12.4	8.9
		G2	AZ1	0.5	

13 Appendix G

13.1 Example of Stage 2 Allocation

Exhibit 13-1 demonstrates the Stage 2 calculation. Assume the following nomination and allocation results for the 4 Market Participants from the Annual ARR Allocation:

Exhibit 13-1: Stage 2 calculation

A	B	C	D	E	F	G	H	I	J
MP	NITS +GFA A Cap	PTP Cap	ARR Nomination for NITS and GFA Option A	Stage 1 ARR Allocation for NITS and GFA Option A	ARR Nomination for PTP	Stage 1 ARR Allocation for PTP	Unallocated portion of NITS Cap	Unallocated portion of PTP Cap	Share of the Stage 2 Revenue (H+I)/(Sum(H)+ Sum(I))
MP1	50	10	25.0	20.0	10	8	30	2	(30+2)/ (75+6) = .395 (39.5%)
MP2	30	2	15.0	10.0	2	2	20	0	(20+0)/ (75+6) =.247 (24.7%)
MP3	30		20.0	15.0			15		(15+0)/ (75+6) = .185 (18.5%)
MP4	10	5	0.0	0.0	5	1	10	4	(10+4)/ (75+6) =.173(17.3%)
Total	120	17	60.0	45.0		11	75	6	1

Let's assume that the total revenue from the Annual FTR Auction was $1000.00. MP1, MP2 and MP3 will be paid first based on their ARR value from the auction clearing price. Assume that the total payment for their Stage 1 ARRs equals $600.00.

The remaining $400.00 will be paid to the 4 Market Participants based on the Stage 2 share as shown in the last column of Exhibit 13-1.

No payment will be made if the revenue from the auction equals, or is less than, the Stage 1 requirement.

Option B and Carved-Out GFAs are not included in the Stage 2 calculation.

14 Appendix H

14.1 Restoration, Counterflow and LTTR Termination Eligibility

This section describes the restoration, counterflow and LTTR termination candidates and how those play into the allocation process. This example begins with the second year. The second year is year 1 for a few Market Participants and year 2 for the others in the example below. It is assumed that the year 1 Market Participants joined due to the integration of a new Transmission Owner. In year 2, the current set of curtailed Stage 1A LTTRs and year 1 Stage 1A CARRs are eligible for restoration. The current set of LTTRs is also eligible for termination. The restoration occurs during the restoration stage, whereas the request for terminating the LTTRs occurs during the Stage 1A nomination process. Any unnominated year 1 Stage 1A HUFU and ARR Entitlements are considered counterflow ARR entitlements and can be potentially allocated counterflow HUFU and ARRs at the conclusion of the restoration stage.

The following example demonstrates the year 2 process. Exhibit 14-1 establishes the Market Participants, their AEs, and year of participation.

Exhibit 14-1: Set of ARR Entitlements

AE	Market Participant	AE Volume	Year of participation	Year 1 LTTR
1	MP1	100	Year 2	90
2	MP2	50	Year 1	0
3	MP3	100	Year 1	0
4	MP4	100	Year 2	10
5	MP2	25	Year 1	0

Exhibit 14-2: Year 2 Stage 1A candidates and allocation

1	2	3	4	5	6	7
MP	AE	AE Volume	Candidate LTTR[48]	LTTR Termination Request	Incremental / New Stage 1A nomination [49]	Stage 1A allocation
MP1	1	100	90[50] + 0[51]	0		60
MP2	2	50		0	30	20
MP3	3	100				
MP4	4	100	10	10	0	
MP2	5	25			25	15

a. Curtailed Candidate LTTRs and curtailed Year 1 Stage 1A CARRs are "re-nominated" as restoration candidates (Restoration CARRs)
b. LTTR Termination Requests and Counterflow and HUFU ARR Entitlements (unnominated portion of the Year 1 AEs) are used as counterflow candidates (Counterflow CARRs).

[48] LTTR and Counterflow HUFU and ARR allocated in the current allocation period (Year 1), which becomes the candidate LTTR for the next allocation period (Year 2). This MW is auto-nominated by the system in Year 2. Market Participant must request for termination during Stage 1A nomination of Year 2 if it intends not to nominate any portion of this candidate LTTR.

[49] MP2 and MP3's Year 1 nomination is reflected in this column.

[50] Year 1 LTTR MW based upon Market Participant nomination.

[51] Year 1 Counterflow HUFU and ARR.

Exhibit 14-3: Year 2 Restoration and Counterflow candidates and allocation

1	2	3	4	5	6	7	8	9
AE	AE Volume	Candidate LTTR[52]/ Stage 1A CARR[53]	Stage 1A allocation [54]	Restoration CARR (3–4)	Counterflow CARR [55]	Restored	Accepted LTTR Termination Request	Counterflow ARR
1	100	90	60	30	0	20	0	
2	50	30	20	10	20	10	0	20
3	100	0	0	0	100	0		40
4	100	10	0	0	10	0	8	
5	25	25	15	10	0	0		

Year 2 results can be summarized as follows.

Exhibit 14-4: Year 2 Stage 1A + Restoration Results

1	2	3	4	5	6	7
AE	AE Volume	Total LTTR[56] (4+5+6+7)	Stage 1A LTTR	Restored LTTR	Unaccepted LTTR Termination Request or Counterflow ARR	Stage 1A Infeasible LTTR
1	100	90	60	20	0	10
2	50	50	20	10	20	0
3	100	40	0	0	40	0
4	100	2	0	0	2	0
5	25	15	15	0		0

[52] Column 4 in Exhibit 14-2.
[53] Column 6 in Exhibit 14-2.
[54] Column 7 in Exhibit 14-2.
[55] LTTR Termination Request or Counterflow HUFU and ARR Entitlement.
[56] This LTTR MW becomes candidate LTTR for future periods.

Summary:

- Second year is the year 2 for MP1. In year 1, MP1 nominated 100 MW from AE 1 and was allocated 90 MW in Stage 1A. The year 1 90 MW allocation qualified as LTTR for future years. In year 2, MP1 did not make any LTTR termination request, i.e., 90 MW from AE 1 was nominated by the system into Stage 1A and was allocated to 60 MW. The unallocated amount (30 MW) was restored to 20 MW and the remaining 10 MW was allocated as Stage 1A infeasible ARR. Total LTTR for year 3 = 90 MW.

- Second year is the year 1 for MP2. In year 1, MP2 nominated 30 MW from AE 2 in Stage 1A and was allocated 20 MW. The remaining 10 MW was eligible for restoration and was restored to full. The unnominated 20 MW (50-30) qualified as counterflow ARR Entitlement. The system needed the counterflow from this AE and allocated 20 MW of counterflow ARRs. Total LTTR for year 2 = 50 MW.

- Second year is year 1 for MP3. In year 1, MP3 did not nominate any of its 100 MW from AE 3. All the 100 MW of AE 3 qualified as counterflow ARR Entitlement. The system needed the counterflow from this AE and allocated 40 MW as counterflow ARRs. Total LTTR for year 2 = 40 MW.

- Second year is year 2 for MP4. In year 1, MP4 did not nominate any of its AE 4 (100 MW) and was allocated 10 MW of counterflow ARRs. In year 2, MP4 requested termination of the 10, of which 8 MW was accepted. Total LTTR for Year 3 = 2 MW.

- Second year is year 1 for MP2. In year 1, MP2 nominated all of its 25 MW of AE 5and was allocated 15 MW in Stage 1A. The remaining 10 MW qualified for restoration and none could be restored. Total LTTR for year 2 = 15 MW.

15 Appendix I

15.1 Examples of ARR Revenue Re-assignment to Reflect Load Switching

The following few examples demonstrate MISO's review of the adjusted NPLF data and the funding obligation.

15.1.1 Market Participant Annual NPLF

Consider the ARR Zone ABC.AZ. The table below shows the annual NPLF for each Market Participant within the ARR Zone and the ARR Zone annual NPLF (1000 MWs).

Exhibit 15-1: Market Participant Annual NPLF

ARR Zone: ABC.AZ	Annual Allocation	Stage 1 ARR	Stage 2
Market Participant	Annual NPLF	Allocation	Allocation
MP1	150	100	50
MP2	200	150	50
MP3	500	300	200
MP4	100	60	40
MP5	50	30	20
Total	1000	640	360

Assume that no Load shift data was reported for the month of June. There will be no ARR revenue re-distribution reflected on the S55 statement for the June 1st Operating Day (OD). Please note that the ARR revenues for each month would be settled on the S7 statement for the first OD of that month. The revenue re-distribution due to Load shift, if submitted, will occur on the S55 statement.

15.1.2 Load Shift Data for the Month of July

Now, consider that Load shifts occur in the month of July in the ARR Zone and the following data was reported by the designated entity to MISO by August 10th:

Exhibit 15-2: Load Shift Data for the Month of July

ARR Zone: ABC.AZ	July-08	Comparison of annual vs. adjusted NPLF
Market Participant	**Adjusted NPLF**	
MP1	125	25 MW decrease
MP2	200	No change
MP3	450	50 MW decrease
MP4	150	50 MW increase
MP5	75	25 MW increase
Total	1000	Net change is 0

The sum of the Market Participants' adjusted NPLF for the month of July matches the ARR Zone annual NPLF. The FTR Team will forward this Load shift data to the Settlement group for the ARR revenue re-distribution to take effect on the S55 statement.

15.1.3 July ARR Calculations

The ARR revenue for the month of July will be re-distributed in the following manner based on the Stage 1 and 2 allocations, as shown in Exhibit 15-3:

Exhibit 15-3: July ARR Calculations

	Total Loss			Net Effect					
Supplier	Load Shift MWs	ARR Loss %	Stage 1 ARR Loss MWs	ARR Gain %	Stage 1 ARR Gained MWs	New Load	New Stage 1 Allocation	New Stage 2 Allocation	Stage 2 Gain/Loss
MP1	-25.0	-17%	17.0	0%	0.0	125.0	83.0	42.0	-8.0
MP2	0.0	0%	0.0	0%	0.0	200.0	150.0	50.0	0.0
MP3	-50.0	-10%	30.0	0%	0.0	450.0	270.0	180.0	-20.0
MP4	50.0	0%	0.0	67%	31.5	150.0	91.5	58.5	18.5
MP5	25.0	0%	0.0	33%	15.5	75.0	45.5	29.5	9.5
	0.0		47.0		47.0	1000	640	360	0

Exhibit 15-3 illustrates the 75 MWs gained by MP4 (31.5 MWs in Stage 1 and 18.5 MWs in Stage 2) and MP5 (15.5 MWs in Stage 1 and 9.5 MWs in Stage 2). Also, Exhibit 15-3 displays the 75 MWs lost by MP1 (17 MWs in Stage 1 and 8 MWs in Stage 2) and MP3 (30 MWs in Stage 1 and 20 MWs in Stage 2).

15.1.4 Load Shift Data for the Month of August

Now consider the following situation. MISO receives the following data submission for the month of August (by September 10th):

Exhibit 15-4: Load Shift Data for the Month of August

ARR Zone: ABC.AZ	Aug-08	Comparison of annual vs. adjusted NPLF
Market Participant	Adjusted NPLF	
MP1	150	No change
MP2	150	50 MW decrease
MP3	500	No change
MP4	150	50 MW increase
MP5	75	25 MW increase
Total	1025	Net change is +25

In this case, MISO will reject the August data submission and retain the Load Ratio Shares from July when calculating the ARR revenue re-distribution for August. This is because the sum total of the Market Participants' adjusted NPLF in August did not match the ARR Zone annual NPLF.

15.1.5 Examples of ARR Dollars Moving Due to Retail Load Shift

ARRs Lost Pro-Rata across Each ARR the Market Participant Owns

MP1 has 3 ARRs in his portfolio as follows:

ARR ID	MW	Price	Total
ARR 1	50	20	1000
ARR 2	30	10	300
ARR 3	20	5	100
	100		1400

MP1 lost 17% of his ARR MWs (17 of 100) resulting in the following adjustments

ARR ID	MW	Price	Total
ARR 1 – adj	-8.5	20	-170
ARR 2 – adj	-5.1	10	-51
ARR 3 – adj	-3.4	5	-17
	-17		-238

MP3 has 2 ARRs in his portfolio as follows:

ARR ID	MW	Price	Total
ARR 4	200	20	4000
ARR 5	100	10	1000
	300		5000

ARR ID	MW	Total
ARR 4 – adj	-20	-400
ARR 5 – adj	-10	-100
	-30	-500

Total dollar value of ARRs lost	-738
Total ARR MWs lost	-47
Avg price/MW of ARRs lost	15.70

ARRs Gained Pro-Rata across Each ARR the Market Participant Owns

MP4 has 3 ARRs in his portfolio as follows:

ARR ID	MW	Price	Total
ARR 6	30	25	750
ARR 7	10	-10	-100
ARR 8	10	5	50
	50		700

MP4 gained 67% of the ARRs lost (31.5 of 47) resulting in the following adjustments

ARR ID	MW	Price	Total
ARR 6 – adj	18.9	15.7	296.73
ARR 7 – adj	6.3	15.7	98.91
ARR 8 – adj	6.3	15.7	98.91
	31.5		494.55

MP5 has 2 ARRs in his portfolio as follows:

ARR ID	MW	Price	Total
ARR 9	20	15	300
ARR 10	5	10	50
	25		350

MP5 gained 33% of the ARRs lost (15.5 of 47) resulting in the following adjustments

ARR ID	MW	Price	Total
ARR 9 – adj	12.4	15.7	194.68
ARR 10 – adj	3.1	15.7	48.67
	15.5		243.35

Total dollar value of ARRs gained	738
Total ARR MWs gained	47

It should also be noted that Market Participants will not see an adjustment for each ARR due to retail Load shift on their settlement statements. There will be a single line item that will address all the Market Participants' ARRs. Please see the Market Settlements BPM for further detail.

16 Appendix J

16.1 Examples of RSP Termination – Requests and Effective Periods

Following are the assumptions for setting up the example:

MP1's PPA1 qualified as RSP1 for 50 MW and was included in Category 1 ARR Zone AZ1

MP2 is the owner of the Generation Resource (GR1) for the underlying PPA1. MP2 is qualified GR1 for 450 MW as RSP2 into AZ1

MP3 is present in the AZ1 and had no PPA from GR1

RSP1 and 2 split in Load Ratio Share between MP1, 2 and 3 in 15%, 80% and 5% respectively

MP1 and 3 did not nominate in 2008 Annual ARR Allocation and were assigned counterflow ARRs from RSP1 and RSP2

- Counterflow ARRs for MP1 - LTTR11 and LTTR12
- Counterflow ARRs for MP3 – LTTR31 and LTTR32

MP2 nominated from RSP1 and RSP2 in 2008 and was allocated LTTRs

- LTTRs for MP2 - LTTR21 and LTTR22

Note: The RSP1 and RSP2 sourcing at GR1 identified, as two separate RSPs for the same ARR Zone is not a common occurrence in practice.

- Example 1
  - PPA1 expired on Dec 31, 2009
  - MP1 may request for termination of RSP1 for the 2010 allocation
  - MP1 demonstrates the expiry of PPA1 prior to 2010 registration
  - MISO will terminate RSP1 and LTTR11, LTTR21, LTTR31 for MP1, 2 and 3 respectively from Summer 2010 onwards

MP	MP1	MP2	MP3	Total
~~RSP1 share~~	~~7.5~~	~~40~~	~~2.5~~	~~50~~
RSP2 share	67.5	360	22.5	450

- Example 2
  - PPA1 expired on Dec 31, 2010
  - MP1 may request termination of RSP1 for the 2010 allocation
  - MP1 demonstrates the expiry of PPA1 prior to the 2010 registration
  - MISO will terminate RSP1 and LTTR11, LTTR21, LTTR31 for MP1, 2 and 3, respectively from Spring 2010 onwards

MP	MP1	MP2	MP3	Total
~~RSP1 share~~	~~7.5~~	~~40~~	~~2.5~~	~~50~~
RSP2 share	67.5	360	22.5	450

- Example 3
  - PPA1 expired on March 31, 2012
  - MP1 may request termination of RSP1 for the 2013 allocation
  - MP1 demonstrates the expiry of PPA1 prior to the 2013 registration
  - MISO will terminate RSP1 and LTTR11, LTTR21, LTTR31 for MP1, 2 and 3, respectively from Summer 2013 onwards

MP	MP1	MP2	MP3	Total
~~RSP1 share~~	~~7.5~~	~~40~~	~~2.5~~	~~50~~
RSP2 share	67.5	360	22.5	450

- Example 4
  - PPA1 expired on December 31, 2018
  - MP1 may request termination of RSP1 for the 2018 allocation
  - MP1 may submit the 5 year termination notice as early as in 2013
  - MP1 demonstrates the expiry of PPA1 prior to the 2018 registration
  - MISO will terminate RSP1 and LTTR11, LTTR21, LTTR31 for MP1, 2 and 3, respectively from Spring 2018 onwards

MP	MP1	MP2	MP3	Total
~~RSP1 share~~	~~7.5~~	~~40~~	~~2.5~~	~~50~~
RSP2 share	67.5	360	22.5	450

17 Appendix K

17.1 Example of RSP Addition/Replacement Request Study

Request Number	Effective Season	Sink	Old Resource	New Resource	Add/ Replace	MW	Minimum Acceptable MW Ratio for Replacement	PRSS Option?	Previously PRSS?
1	Summer	ARRZONE1.AZ		N_CPNODE1	A	15		Y	
2	Summer	ARRZONE1.AZ		N_CPNODE2	A	10			
3	Summer	ARRZONE1.AZ	O_CPNODE1	N_CPNODE3	R	40	60%	Y	
4	Summer	ARRZONE1.AZ	O_CPNODE1	N_CPNODE4	R	20	45%		
5	Summer	ARRZONE1.AZ	O_CPNODE2	N_CPNODE5	R	5	45%		

Following are the assumptions for setting up the example:

1. The above table shows the requests of one MP to add/ replace RSP into BRSS
2. ARRZONE1.AZ Baseload Usage (50% NPLF) is 100 MW; Peakload Usage (a.k.a. NPLF) is 200 MW
3. Existing BRSS in ARRZONE1.AZ total 95 MW
4. Existing PRSS in ARRZONE1.AZ total 190 MW
5. Generation Resource in N_CPNODE4 becomes commercially operational in Jan. 2012
6. The MP has entitlement sourcing from O_CPNODE2 but another MP has the ownership in it and brought it into the ARRZONE1.AZ

Following are the evaluations and validations performed prior to SFT:

1. From assumptions 1, 2 and 3, we know that there are 20 MW of capacity available in ARRZONE1.AZ to add new BRSS RSP and 40 MW of capacity available to add new PRSS RSP.
2. 10 MW in Request 2 will be truncated to 5 MW because Request 1 used 15 MW of 20 MW available.
3. According to assumption 5, MISO will reject Request 4 because Resource in N_CPNODE4 is not commercially operational for the summer study period.

4. According to assumption 6, MISO will reject Request 5 because the MP who requested the RSP replacement is not the same qualified MP whose ownership or contractual relationship with the old RSP was the basis for the original inclusion of the RSP in BRSS.

The following requested MWs will be studied through SFT:

Request Number	Effective Season	Sink	Old Resource	New Resource	Add/ Replace	MW	Minimum Acceptable MW Ratio for Replacement	PRSS Option?	Previously PRSS?
1	Summer	ARRZONE1.AZ		N_CPNODE1	A	15		Y	
2	Summer	ARRZONE1.AZ		N_CPNODE2	A	5			
3	Summer	ARRZONE1.AZ	O_CPNODE1	N_CPNODE3	R	40	60%	Y	

Further assumptions for the SFT results:

1. MISO will conduct SFT for the three requests sequentially. The result from the earlier request will be considered “pre-confirmed” by MP and become the baseloading in the model for the next request.
2. Assume SFT results 5 MW feasible for Request 1, then 5 MW become BRSS RSP and the remaining 10 MW will be included in PRSS automatically, per MP request (MP checked the box).
3. Assume SFT results Request 2 fully feasible, then all 5 MW become BRSS RSP
4. Assume SFT results Request 3 not feasible, then the old resource O_CPNODE1 remains and the new resource N_CPNODE3 will be included in PRSS automatically, capped at NPLF (200 MW) and per MP request.
5. Therefore, 40 (PRSS headroom) – 15 (Request 1) – 5 (Request 2) = 20 MW capacity is available for PRSS RSP to be included in the ARRZONE1.AZ.
6. Request 3 will have only 20 MW (not 40 MW) RSP into PRSS

Final Results:

Request Number	Effective Season	Sink	Old Resource	New Resource	Add/ Replace	Request MW	Study MW	Award MW in BRSS	Award MW in PRSS
1	Summer	ARRZONE1.AZ		N_CPNODE1	A	15	15	5	10
2	Summer	ARRZONE1.AZ		N_CPNODE2	A	10	5	5	0
3	Summer	ARRZONE1.AZ	O_CPNODE1	N_CPNODE3	R	40	40	0	20
4	Summer	ARRZONE1.AZ	O_CPNODE1	N_CPNODE4	R	20	0	0	0
5	Summer	ARRZONE1.AZ	O_CPNODE2	N_CPNODE5	R	5	0	0	0

18 Appendix L

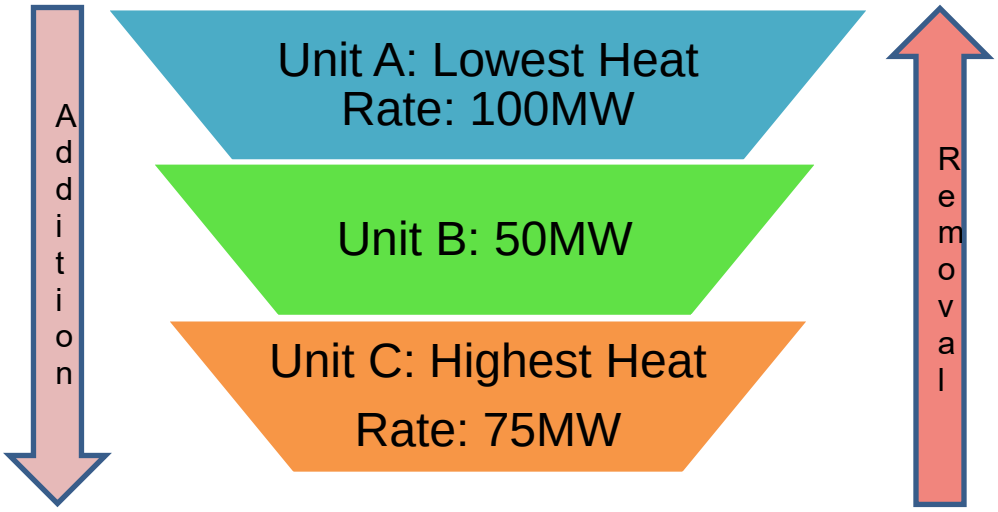
Heat Rate Stack is the second BRSS Entitlement Gap filler. (Section 3.9.2.5 of this BPM). The example in this appendix assumes that the Market Participant has completed the Term Reduction BRSS Entitlement Gap filling process and a BRSS Entitlement Gap remains.

MISO receives a request from the Market Participant to fill in the gap. To utilize this rule the Market Participant must have RSPs in the PRSS. MISO can use publicly available heat rate data, if such data is otherwise unavailable from the Market Participant. MISO will stack the non-BRSS entitlements into a BRSS stack in order of the lowest heat rate to the highest heat rate.

Exhibit 18-1 assumes that the Market Participant has three non-BRSS units of different generating capacity that have been sorted from the lowest to highest heat rate and 150 MW of BRSS Entitlement Gap. Unit A, which has a capacity of 100MW, will be selected first. The BRSS Entitlement gap is now reduced from 150 MW to 50 MW due to Unit A being selected. Unit B has a capacity of 50MW and is selected next which fills in the BRSS Entitlement gap. Unit C, which has the highest heat rate, is not needed in this example.

If the Market Participant would like to reject any of these entitlements, the entitlement from Unit B would have to be rejected before Unit A. The rejection process always starts with the unit with the highest heat rate that has been utilized to fill in the BRSS Entitlement gap.

Exhibit 18-1: Administration of Heat Rate Stack Rule



19 Appendix M

The Minimum Acceptance Ratio (Section 3.21.2 of this BPM) refers to the minimum level of ARR Entitlements, resulting from a contemplated RSP replacement, that the relevant Market Participant would accept before considering the RSP replacement. This minimum replacement level, expressed as a ratio, is the ratio of the replacement ARR Entitlements (R) divided by the existing replaced ARR Entitlements (E) determined by the Simultaneous Feasibility Test (SFT).

If the calculated ratio of the replacement entitlements over the existing replaced entitlements is less than what the Market Participant is willing to accept, then the request will be denied. Conversely, if the calculated ratio of the replacement entitlements over the existing replaced entitlements is equal to or more than what the Market Participant (MP) is willing to accept, then the request will be granted.

An example is listed below:

MAR = Minimum Acceptance Ratio submitted by MP

R = Replacement MWs established from the SFT

E = Existing Replaced MWs established from the SFT

Example 1

MAR = 25%

R = 35

E = 50

$\frac{35}{50}$ = **70%**

This request will be **Granted.**

Example 2

MAR = 25%

R = 10

E = 50

$\frac{10}{50}$ = **20%**

This request will be **Denied.**

The requesting Market Participant must submit the Minimum Acceptance Ratio for the replacement request during Round 2 (BRSS Addition or Replacement), or Round 3 (PRSS Addition or Replacement). The Minimum Acceptance Ratio must be entered if the action of the RSP request is “Replace” and it must be numeric between 0.01 and 100.00 (in percentage).