COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF PROPOSED CHANGES TO ITS QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES TARIFFS	))))))	**Case No. 2023-00102**

Response to the Commission Staff's First Request for Information

dated April 12, 2023

FILED: April 28, 2023

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF PROPOSED CHANGES TO ITS QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES TARIFFS

CASE NO. 2023-00102

VERIFICATION

I, Ronald R. Repsher, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Ronald R. Repsher

COMMONWEALTH OF KENTUCKY)
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Ronald R. Repsher on this the 27th day of April, 2023.

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP43028

My Commission Expires 2/22/26

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2023-00102

VERIFICATION

I, John Wolfram, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

John Wolfram

COMMONWEALTH OF KENTUCKY)
COUNTY OF JEFFERSON)

SUBSCRIBED AND SWORN TO before me by John Wolfram on this the 26th day of April, 2023.

COREY SCOTT JONES
Notary Public - State at Large
Kentucky
My Commission Expires Apr. 08, 2026
Notary ID KYNP48750

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP48750

My Commission Expires 04/08/2026

COREY SCOTT JONES
COMM. EXP. 04/08/2026
NOTARY
PUBLIC
ID # KYNP48750
STATE AT LARGE, KENTUCKY

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2023-00102

Response to the Commission Staff's
First Request for Information
dated April 12, 2023

April 28, 2023

Item 1) ***Refer to the proposed tariff, Sheet No. 39.***

a. Explain whether there are Qualifying Facility (QF) customers who have generation in excess of 5 MW that under the current tariff BREC is obligated to purchase, but will not be required to purchase under the proposed tariff.

b. Explain whether BREC is still purchasing excess power from a QF. Include how it is priced and whether any of that capacity is being counted toward its Midcontinent Independent System Operator (MISO) capacity/reserve margin obligations.

c. Explain how customers taking service under the Cogeneration/Small Power Production Purchase – Over 100 KW (QFP Tariff) and Cogeneration/Small Power Production Sales – Over 100 KW (QFS Tariff) will each receive the same services under the proposed tariff.

Response)

a. Big Rivers has two QF members under the current tariff. Both QF Members are under 5 MW of generation. These two QF members will still take service under the proposed tariff.

b. The two existing QF Members do provide excess generation back to the Big Rivers' grid. Big Rivers purchases this excess generation at the rates under its existing QFP tariff. Big Rivers does not include any capacity from the existing two QF Members in its capacity obligations with MISO.

c. There are currently two retail customers on the Big Rivers system with QFs that qualify under Big Rivers' existing QFP and QFS tariffs: Southern Star Central Gas Pipeline, Inc. ("Southern Star") and the Commonwealth of Kentucky (for a Kentucky National Guard facility) ("KYNG"). Both of these customers are served under special contracts that refer back to the existing QFP and QFS tariffs.

Neither of the special contracts will change as a result of the proposed QF tariff, and so, none of the service provided to the QF customer will change. With regard to purchases from the QF, Big Rivers will continue to purchase all energy and capacity from Southern Star's QF in excess of its needs, and Big Rivers will continue to purchase all energy[1] from KYNG's QF in excess of its needs. The only difference will be the rates Big Rivers' pays. The rates for energy and capacity under the proposed QF tariff will generally be higher than current rates. *See* Big Rivers' response to Item No. 7 of the Commission Staff's First Request for Information.

With regard to sales to the QF Members, the QF tariff provides, "That portion of the QF Member's load requirements not met by the QF shall be provided to the Member Cooperative under the terms and conditions of one or more of Big Rivers' standard rates applicable to the load requirements and type of service of the QF Members." Thus, under the proposed QF tariff, Big Rivers will continue to provide the wholesale power required to meet the needs of QF Members in excess of their own generation. This is consistent

[1] KYNG did not want to sell the capacity from its QF to Big Rivers.

with how Big Rivers provides the wholesale power to meet the needs of retail net metering customers in excess of those customers' generation.

Witness) Ronald R. Repsher

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2023-00102

Response to the Commission Staff's
First Request for Information
dated April 12, 2023

April 28, 2023

Item 2) ***The results of BREC's latest integrated resource plan (IRP) indicated BREC intends to pursue the capacity addition of a natural gas combined cycle (NGCC) unit.[2] Provide an update on how BREC will acquire Natural Gas Combined Cycle generation capacity.***

Response) Big Rivers is currently engaged in the final stages of a study effort to determine the best options to meet future capacity needs. That study includes the option of adding National Gas Combined Cycle generation capacity. Until the current analysis is completed and any required regulatory approvals are in place, no firm actions are being undertaken.

Witness) Ronald R. Repsher

2 Case No. 2021-00299, *Electronic 2020 Integrated Resource Plan of Big Rivers Electric Corporation* (filed Sept. 21, 2020), Application at 171–174 and 176.

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF PROPOSED CHANGES TO ITS QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES TARIFFS
CASE NO. 2023-00102

Response to the Commission Staff's First Request for Information dated April 12, 2023

April 28, 2023

Item 3) ***Refer to the current QFS tariff. Also refer to the proposed QF tariff. Explain how the services provided in the QFS tariff will be provided in the proposed QF tariff. If the same services are not provided in the proposed QF tariff, explain how the services will be provided to the QF customer and the rates.***

Response) Please see Big Rivers' response to Item 1(c) of the Commission Staff's First Request for Information.

Witness) Ronald R. Repsher

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF PROPOSED CHANGES TO ITS QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES TARIFFS
CASE NO. 2023-00102

Response to the Commission Staff's
First Request for Information
dated April 12, 2023

April 28, 2023

Item 4) ***Refer to the proposed tariff, Sheet No. 40 and the Direct Testimony of John Wolfram (Wolfram Testimony), page 4, lines 9–15.***

a. Regarding the monthly credits or payments for energy delivered to BREC, explain why the locational marginal price (LMP) at the time of delivery is the appropriate avoided cost.

b. Provide BREC's avoided cost of generation for each generating unit and the lowest, highest, and average LMP for the 12 months ended March 31, 2023.

Response)

a. Big Rivers participates in the MISO energy market, in which Big Rivers purchases all of the energy it needs to meet load obligations and sells all of its generation into the market. Typically, the load cost and generation prices are essentially the same which allows the generators to be a hedge for the Member load pricing. Because the load and generation cost are essentially the same, when Big Rivers' generation covers its load, the actual cost to the Members is the variable cost of the Big Rivers generators. This process is the same regardless of QF. The energy purchased from the QF will be purchased at the LMP at the time of delivery because it reduces the amount of energy Big Rivers would otherwise purchase from MISO at the same LMP price, thus creating a net zero cost to Big Rivers and its Members. More importantly, the LMP reflects the true value of the QF generator, and thus complies with the legal requirements set forth in 807 KAR 5:054 Section 7.

b. For the period of April 2022 to May 2023, the fuel cost for each owned generating unit, which can serve as a proxy for the avoided cost, is as follows:

- Green 1: $67.86/MWh
- Green 2: $71.89/MWh
- Reid CT: $83.69/MWh
- Wilson: $28.33/MWh

The BREC.BREC LMPs which represent the majority of Big Rivers' load in MISO are as follows:

- Average LMP:
  - Day Ahead LMP = $66.74
  - Real Time LMP = $67.31
- Lowest LMP:
  - Day Ahead LMP = $16.27
  - Real Time LMP = -$4.54
- Highest LMP:
  - Day Ahead LMP = $635.25
  - Real Time LMP = $2,461.25

Witness) Ronald R. Repsher

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2023-00102

Response to the Commission Staff's
First Request for Information
dated April 12, 2023

April 28, 2023

Item 5) ***Refer to the proposed tariff, Sheet No. 41, paragraph 8 and the Wolfram Testimony, page 5, lines 15–16.***

a. ***Explain whether there are any non-dispatchable QFs on BREC's system.***

b. ***Explain whether BREC takes into account any QF customer's generation capacity toward its MISO capacity/reserve margin obligations and, if so, identify the generation resource and the amount of capacity credited toward BREC's obligation.***

c. ***Provide BREC's most recent load forecast, existing generation resources by type, and any resource additions or retirements by resource type that supports the reserve margin required by MISO. Include in the response all intermittent, demand side management and energy efficiency programs.***

d. ***Explain whether BREC attributes capacity credits to solar power purchase agreements (PPAs) or any other non-dispatchable resource***

toward its reserve margin capacity requirements at any time during the year.

e. Given that in order to produce energy there must be some level of capacity, explain why non-dispatchable qualifying facilities should not be credited with some level of capacity, and hence, a capacity payment for the time when the QF is producing energy and selling to BREC.

Response)

a. Big Rivers currently has two QF Members who take service under the existing tariff and would take service under the proposed tariff. The special contracts, which govern the service provided by Big Rivers to existing QF Members, both state in relevant party:

> "Except as provided in this Agreement, Seller will sell, and Big Rivers will purchase, all energy and capacity from Seller's Qualifying Facility in excess of Seller's own needs, at the Delivery Point, on a non-dispatchable basis."

Upon taking service under the new tariff, confirmation of the non-dispatchable status will be confirmed with each existing QF Member.

b. Big Rivers does not take into account any existing QF customer's generation capacity toward its MISO capacity/reserve margin obligations.

For a QF's resource to be counted toward the Big Rivers reserve margin capacity requirement, Big Rivers needs to register those resources with MISO, which includes numerous obligations and the underlying risk of such obligations. QF Members have to make the business decision whether to undertake those obligations and its resulting risk. To the extent a QF Member is willing to undertake these obligations, Big Rivers will then register the resource.

c. Please see the attached Excel spreadsheet, showing Big Rivers' current load forecast and generation sources (i.e., nameplate generation capacity).

d. Big Rivers does not currently have any solar facilities or other types of non-dispatchable facilities to which it attributes capacity credits.

e. There is a fundamental difference between capacity and nameplate capability. Capacity in the utility sense can be planned on to generate energy during peak load conditions or other times of need. This is most often characterized as, but certainly not exclusive to, a fully dispatchable "steel in the ground" resource that can produce energy when needed.

Nameplate capability does not translate to capacity. Nameplate capability refers to the amount of energy that can be produced at peak or optimal operation of the facility. Nameplate capability does not guarantee, or even strongly indicate, that the nameplate value can be produced during peak load conditions or other times of need. Capacity on the other hand, represents a dependability that the energy is available when needed, whether during peak times or other times of need.

It is important to note that the term "capacity" is often used interchangeably to describe both descriptions listed above when communicating generally.

Big Rivers is not alone in this view as MISO holds a similar view. MISO does not give capacity accreditation equal to nameplate capability. Accreditation is based upon historical performance of a unit and its dependability during times of need. This is consistent across dispatchable and non-dispatchable resources.

Because capacity is rooted in dependability to produce future energy when needed, capacity is transacted in advance of the energy production. Examples are bilateral trades for a not-yet-occurred time period, or the seasonal and annual constructs of RTO's such as MISO. Capacity is not an hourly transaction. So while a resource may be able to produce energy in a given hour or time period due to its nameplate capability, that alone doesn't equate to capacity. It doesn't allow Big Rivers to avoid capacity costs, particularly from MISO. Non-dispatchable resources that are not counted toward the Big Rivers reserve margin capacity requirement under the MISO capacity market construct do not permit Big Rivers to avoid any capacity costs in MISO, so they should not receive avoided capacity cost credits.

Witness) Ronald R. Repsher

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2023-00102

Response to the Commission Staff's
First Request for Information
dated April 12, 2023

April 28, 2023

Item 6) ***Refer to the proposed tariff, Sheet No. 42, Additional Charges.***

a. Explain which MISO ancillary service charges BREC might incur to maintain reliability for a QF's failure to generate.

b. Define MISO Revenue Sufficient Guarantee (RSG) charges.

c. Explain why the MISO RSG and ancillary service charges would be charged to BREC for a QF's failure to generate.

Response)

a. This section of the proposed tariff is intended to address any potential other charges from MISO associated with a QF's failure to generate. Big Rivers is not aware of which specific "ancillary" charges might apply but aims to ensure that the QF (and not Big Rivers' other members) bear any of those costs, consistent with cost causation. (Here "ancillary" is meant in a general sense and is not limited to "Ancillary Service" charges as set forth by FERC in Order Nos. 888 and 889 for use in Open Access Transmission Tariffs.)

b. For an overview of Revenue Sufficiency Guarantee and MISO's related settlement procedures, see the attached "Frequently Asked Questions- Real-Time Revenue Sufficiency Guarantee." The attached MISO Business Procedure Manual, BPM-005, beginning at pages 64 and 65 provides a more specific explanation. At a very high level, MISO uses the RSG as the median to ensure that all generators following MISO's appropriate instruction are made financially whole. MISO issues charges to applicable generators and load serving entities that in some form caused the additional generation cost that is required to be collected in order to honor the Revenue Sufficiency Guarantee. These are often called in RSG charges.

c. If a QF Member's resource is dispatchable and the QF Member has elected to provide firm capacity and energy, Big Rivers will register that resource with MISO in order to receive capacity credit. Big Rivers will also include the expected output of the generation as provided by the QF Member, and its effect on net load, into the overall Big Rivers' load demand bids submitted to MISO. Any deviation of load and generation from market clearings result in various charges from MISO such as RSG and other ancillary charges being applied to Big Rivers. Big Rivers will pass through to the QF Member any charges that were caused by the QF Member's failure to generate.

Witness) Ronald R. Repsher

Manual No. 005

Business Practices Manual

Market Settlements

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Disclaimer

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Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-005-r22	Updated sections 2.4.2 and 2.6.3.3 to include SATOA and ESR. Added new section 2.7.6 for SATOA	C. Delk	JUN-06-2022
BPM-005-r21	Updated Section 2.6.1.3 to include DA_ASM_STR charge type and description. Updated Section 2.6.3.3 to include RT_ASM_STR, RT_ASM_STR_DIST, and RT_ASM_STRDFC charge types and descriptions.	C. Delk A. DeRose	DEC-07-2021
BPM-005-r20	Annual Review Completed Updated Section 5 Market Disputes to reflect changes for the transition from Siebel to Dynamics. Added Section 2.20.5 De Minimis Threshold.	E. Fjellman S. Thompson	APR-20-2021
BPM-005-r19	Annual review completed. Updated Section 1.2 Purpose of This BPM to cover operating days beginning with the start of 5-Min Settlements and including the resettlement time limitation set forth in FERC Docket Nos. ER18-1648-000, etc. Updated Charge Type Section 2.6.1.3 to include Day-Ahead Ramp Capability Amount.	E. Fjellman	FEB-08-2020
BPM-005-r18	Updated FTR sections 2.9.3 to perform yearly FTR allocation process on all standard settlements of December 31. Updated Market close time to 10:30 EST in section 2.6.1 Updated dispute timeline to 120 Calendar Days in sections 5.1.1, 5.2.6, and 5.5.1. Capitalized all references to Calendar Day(s) and one reference to “operating day.” Removed section 2.13.4 and all references to Day 1 Net Inadvertent Payback.	C. Delk	DEC-31-2018
BPM-005-r17	Annual review completed. No additional updates necessary.	E. Fjellman	JUN-09-2018
BPM-005-r16	Includes Internal Commercially Pseudo-Tied Load EP Node meter data submission information in compliance with FERC Order Docket No. ER12-678-008. Effective Date is per order, SEP-1-2012 Annual review completed.	M. Dawson E. Fjellman	JUN-30-2017
BPM-005-r15	Annual review completed. No additional updates necessary.	E. Fjellman	JUN-30-2016
BPM-005-r14	Annual review completed. No additional updates necessary.	E. Fjellman	JUN-30-2015

BPM-005-r13	Annual Review completed. Update the description for FTR_ARR_INF_UPL to describe Southern Region transition period splitting of uplift by region.	L. Hall S. Mansouri	JUN-12-2014
BPM-005-r12	Additional LRS methodology added to RT_MISC Charge Type	M. Dawson	MAR-01-2014
BPM-005-r11	Annual review completed. Removed MISO Billing Meter Standards from References section	B. Selear	JUN-12-2013
BPM-005-r10	Annual review completed. Updated section 2.10.5 to add meter data validating for Demand Response Resources using the Demand Response Tool Updated section 2.10.6 to update meter data expectations for Demand Response Resources using the Demand Response Tool Removal of Host Load Zones in Sections 2.10.5 and 2.10.6	R. Terry	JUN-12-2012
BPM-005-r9	Corrected formatting in section 5.2.2 (no content changes)	B. Selear	OCT-01-2011
BPM-005-r8	• Updated the following sections for financially binding S7 settlements: ▪ 2.1.3 ▪ 2.6.4.3 ▪ 3 • Corrected exhibit numbers throughout section 2 • MISO rebranding changes for statement header examples in section 2	J. Zimmer B. Selear	OCT-01-2011
BPM-005-r7	• MISO Rebranding changes throughout • Inserted Market Settlements Timeline exhibit in section 2.1.3 • Updated section 2.3.4 to reflect change from SAS 70 to SSAE 16 compliance standards • Updated section 2.4.2 to include descriptions for DIRs and SERs	B. Selear	APR-01-2011
BPM-005-r6	Updated RT_ASM_CRDFC description in Section 2.6.3.3	M. Dawson	APR-01-2011
BPM-005-r5	Updated 2.23.4 with clarification to the Roles and Responsibilities of the MDMA	R. Stevens	SEP-01-2010
BPM-005-r4	Changed document title to match BPM manual number Removed Issue Date column Restored Revision History rows back to document origination. Updated Charge Type reference in Section 2.21. Changed number of dispatch intervals for EDEDC eligibility from 3 to 4 (effective	B. Selear P. Wang K. Crespo C. Delk	MAR-01-2010

	3/1/2010) Updated timeline for meter data submission in section 2.10.6 (effective 4/1/2010)		
MS-BPM-001-r3	Updated the following sections for the Automation of the Meter Data Validation: • 2.10 (Metering Settlement Overview) • 2.10.5 (Meter Data Validation) • 2.10.6 (Meter Data Submission and Processing) • 2.14.5.2 (Residual Load Account Settlement Statement Format) • 2.20.3 (Nonstandard Settlement Data Submission)	D. Croy	SEP-01-2009
MS-BPM-001-r2	Revised to reflect the September 14, 2007, subsequent September 19 Errata filing and March 26, 2008 30-Day Compliance Filing of the Open Access Transmission and Energy Markets Tariff for the MISO, Inc. (EMT) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement. Established separate Controlled Documents for files formerly known as Attachments A, B & C.	C. Delk	JAN-06-2009

Restored Revision History Since Format Change

Document Number	Reason for Issue	Revised by:	Effective Date
MS-BPM-001	Updated Section 2.10.6 regarding timing of meter data submission	Chris Delk	NOV-1-2008
MS-BPM-001	Updated section 2.7.1.10 to remove language regarding automatic setting of UD exemption flag. Updated section 2.9.8 and 2.9.9 to reflect correct ARR charge type names and description of Retail Load Shift.	Chris Delk	NOV-1-2008
MS-BPM-001	Updated section 2.6.2.3 to correct charge type names	Chris Delk	MAR-01-2008

MS-BPM-001	Updated section 2.9.8 and 2.9.9 to reflect ARR charge types settling on the first day of the month		MAR-01-2008
MS-BPM-001	Format Change	D. Croy	MAR-01-2008

Restored Revision History Prior to Format Change

Version	Date	Description
13	03-01-2008	Updated Section 2.6.2 to include ARRs Added Section 2.9.8 for ARR Settlement overview Added Section 2.9.9 for Retail Load Shift overview Updated Attachment A - • Added Section C.9 – FTR_ARR_FTR_TXN • Added Section C.10 – FTR_ARR_ARR_TXN • Added Section C.11 – FTR_ARR_INF_UPL • Added Section C.12 – FTR_ARR_STG2_DIST Updated the following sections regarding Asset to Asset Owner relationship changes invalidating finSched contracts and schedules • 2.8.2 – Financial Bilateral Transaction Settlement • B.1 – Day Ahead Asset Energy Amount (DA_ASSET_EN) • B.6 – Day Ahead Non-Asset Energy Amount (DA_NASSET_EN)
12	09-17-2007	Updated Attachment A – modified the following: ▪ Section C - Added content to handle the modifications to the FTR monthly funding process.
11	07-16-2007	Updates regarding the dispute timeline modification as approved by the Federal Energy Regulatory Commission. Sections 5.1.1, 5.2.6 & 5.5.1 were updated.
10	01-26-2007	Format changes as a result of a comprehensive effort to update, correct and reformat all of the Business Practices Manuals.
9	03-16-2006	Main Body – The following changes were made: ▪ Section 2 Market Settlements Overview – This Section was revised to reflect Tariff Schedule 24. ○ Section 2.6.1.3: Day-Ahead Energy Market Charge Types – New Charge Type (DA_SCHD_24_ALC) was added to the list. ○ Section 2.6.3.3: Real-Time Energy Market Charge Types – New Charge Types (RT_SCHD_24_ALC and RT_SCHD_24_DIST) were added to the list. ○ Section 2.12: Schedule 24 Overview – New Section. ▪ Section 5 Market Disputes – This Section was revised as a result of MISO Legal Department’s proposed FERC filing to consolidate MISO’s dispute resolution process by referencing such dispute resolution process as set forth in Appendix D of MISO Agreement and § 12 of the Energy Markets Tariff. More specifically, this Section was revised as follows: ○ Section 5.1: Categories of Disputes – The first paragraph was modified to state MISO’s Market Quality Department has responsibility to

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Version	Date	Description
		review, evaluate, research, and resolve "certain" disputes (in lieu of "all" disputes). – With respect to the section concerning "issues which are not considered disputes," language was added to reference the ADR process with Appendix D (Dispute Resolution) of MISO Agreement. In addition, Paragraph 3) of this section was deleted in its entirety and Paragraph 4) was renumbered as a result thereof. ○ Section 5.1.1: Dispute Timeline – This paragraph was updated to clarify the current Settlement Dispute submission deadline. ○ Section 5.2.6: Dispute Resolution – The text for the "Rejected" dispute status was updated to reflect dispute submission deadline. ○ Section 5.2.8: Appeal Process – Paragraph 1) was revised to reference MISO's ADR processes with §12 of the Energy Markets Tariff and Appendix D of MISO Agreement. In addition, Paragraph 2) was deleted in its entirety. ○ Section 5.5.1: Market Participant's Responsibilities – This paragraph was updated to reflect the current Settlement Dispute submission deadline. ▪ Attachment A – The following changes were made: ○ Created the following Sections related to Schedule 24 Charge Types: – Section B.5 – Day-Ahead Schedule 24 Allocation Charge Type. – Section D.8 – Real-Time Schedule 24 Allocation Charge Type. – Section D.9 – Real-Time Schedule 24 Distribution Charge Type. ○ Section B.11 – DA RSG Distribution Amount – Modified section to include impacts from FERC Order regarding GFA Carve-Outs being excluded from RSG Distribution Volume. ○ Section D.14 – RT RSG Distribution Amount – Modified section to include impacts from FERC Order regarding GFA Carve-Outs being excluded from RSG Distribution Volume
8	12-22-2005	Main Body – The following changes were made: ▪ Section 2.7.1.10: Uninstructed Deviation Settlement ○ Added description of automatic UD exemption. ▪ Section 2.7.1.11: Emergency Manual Dispatch Settlement ○ Added new section. Describes the reimbursement conditions for Generation Resources under emergency conditions. ▪ Section 2.15.2: Marginal Losses Distribution Overview, Charge Type Calculation Methodology

Version	Date	Description
		○ Clarified that the Real-Time Over-Collected Losses to include the 'Incremental Real-Time Over-Collected Losses RT OCL'. ○ Modified calculation for Marginal Loss Surplus by adding the last bullet point. ▪ Section 2.15.3.2: Incremental Real-Time Over-Collected Losses Revenue Summary ○ Removed description of old DART MEC*tau method ○ Added text and formulae to reflect the 'Points of Injection/ Withdrawal' Method currently used in settlements. ▪ Section 2.15.3.3: Over-Collected Losses Revenue Methodology ○ Deleted the section and therefore 'proof of the DART MEC * tau method. ▪ Section 4.1: Payment of Net Invoice Charges ○ Updated financial institution and ABA number for wire transactions. ▪ Minor edits throughout the document. Attachment A – The following changes were made: ▪ Where relevant, Changed Cost to Offer ▪ Section C.1: Financial Transmission Rights Hourly Allocation Amount ○ Modified the Hourly revenue allocation process (FTR_HR_ALC) by deleting the Hourly Day-Ahead Revenue Inadequacy Excess Funds from Group B and Hourly Day-Ahead Revenue Inadequacy Shortfall from Group C. ▪ Section C.1.2.1: Intermediate Calculations for FTR Hourly Congestion Fund Portion of FTR_HR_ALC ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Windfall MISO_DA_RI_XS ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Shortfall MISO_DA_RI_SF ○ Deleted Total MISO Day-Ahead Hourly Congestion Fund Available to Fund Day-Ahead Revenue Inadequacy MISO_DA_HR_CG_FOR_RI ○ Modified the equation for Total MISO Day-Ahead Hourly Congestion Fund Available to Fund Day-Ahead JOA Account Payable - MISO_DA_HR_CG_FOR_JOA ○ Modified the equation for Total MISO Day-Ahead Hourly Congestion Fund Available to Fund Hourly FTR Revenue Allocation - MISO_DA_HR_CG_FOR_FTR ▪ Section C.3: Financial Transmission Rights Monthly Allocation Amount ○ Modified the description of the Monthly revenue allocation process (FTR_MN_ALC) ▪ Section C.3.2.2; Intermediate Calculations for FTR Monthly Funding Allocation Portion of FTR_MN_ALC

Version	Date	Description
		○ Deleted Intermediate Calculations for Determining Real-Time Excess Congestion Fund for FTR_MN_ALC ▪ Section D.11.2: Revenue Inadequacy Uplift ○ Modified the Revenue Inadequacy Uplift description. ▪ Section D.11.2.2: Intermediate Calculations for the Day-Ahead Portion of MISO Revenue Inadequacy Uplift ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Windfall - MISO_DA_RI_XS ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Shortfall - MISO_DA_RI_SF ▪ Section D.11.2.4: Intermediate Calculations for the Real-Time Portion of MISO Revenue Inadequacy Uplift ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Windfall - MISO_DA_RI_XS ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Shortfall - MISO_DA_RI_SF ▪ Section D.11.2.5: Intermediate Calculations for Determining MISO Revenue Inadequacy Uplift ○ Deleted the words “Uplift Portion” from the title ○ Deleted Total MISO Day-Ahead Hourly Congestion Fund Available to Fund Day-Ahead Revenue Inadequacy MISO_DA_HR_CG_FOR_RI ○ Deleted Total MISO Real-Time Hourly Congestion Fund Available to Fund Real-Time Revenue Inadequacy MISO_RT_HR_CG_FOR_RI ○ Deleted Total MISO Day-Ahead Hourly Revenue Inadequacy Uplift MISO_DA_RI_UPLIFT ○ Deleted Total MISO Real-Time Hourly Revenue Inadequacy Uplift MISO_RT_RI_UPLIFT ○ Added Total MISO Real-Time Hourly Joint Operating Agreement (JOA) Charges MISO_RT_JOA ○ Added Net MISO Real-Time Hourly Joint Operating Agreement Account Receivable MISO_RT_JOA_AR ○ Added Hourly MISO Loss Surplus Amount MISO_LOSS_SURPLUS ○ Added Total Hourly Asset Marginal Loss Component for all MISO MISO_LOSS_MLC ○ Added Total MISO Hourly Loss Distribution Uplift MISO_LOSS_DIST_UPLIFT ○ Added Calculation for MISO_RT_JOA_AP Net MISO Real-Time Hourly Joint Operating Agreement Account Payable ○ Added calculation for MISO_RT_HR_CG_FOR_JOA Total MISO Real-Time Hourly Congestion Fund Available to Fund Real-Time JOA Account Payable ○ Modified MISO_RT_HR_CG_FND Total MISO Real-Time Hourly Congestion Fund after JOA offset ○ Modified Total MISO Hourly Revenue Inadequacy Uplift RI_UPLIFT

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

<table>
<tr><th>Version</th><th>Date</th><th>Description</th></tr>
<tr><td></td><td></td><td>Section D.11.3.4: Intermediate Calculations for Determining Real-Time Portion of MISO JOA Uplift
Modified the calculation for Hourly MISO Real-Time JOA Accounts Payable MISO_RT_JOA_AP
Modified the calculation for Hourly MISO Real-Time JOA Accounts Receivable MISO_RT_JOA_AR
Modified the calculation for Hourly MISO Real-Time JOA MISO_RT_JOA
Section D.12.1: Calculation Inputs for RT_RSG_DIST1
Modified the description of RT_RSG_ELIGIBILITY
Section D.13.1: Calculation Inputs for RT_RSG_MWP
Modified production cost definition
Minor edits throughout the document
Added a new Attachment B: FERC EQR Reporting</td></tr>
<tr><td>7</td><td>06-08-2005</td><td>Section 2:
Section 2.12.4; minor editing
Section 2.12.1; minor edits
Inserted Section 2.13.4 Balancing Authority Residual Load Account Statements
Section 2.16; Provided additional information on Option B Grandfathered Agreements concerning generation supply volume and load obligation volume
Sections 2.17.2 and 2.17.3; Combined sections
Attachment A
Section A.3.1; Additional Charge Type determinants defined
Section B.1; Added description of Grandfathered Agreement Option B Expanded Congestion Cost Hedge (GFAOB ECCH) Financial Bilateral Transactions plus other related minor additions throughout the section
Section B.1.1; Added definitions for Day-Ahead Net Virtual Schedule Volume at a CPNode and Day-Ahead Asset Withdrawal Volume for Validating Option B Grandfathered Agreements
Section B.1.1; Modified definition of Day-Ahead Option B Grandfathered Agreement Financial Bilateral Transaction Intermediate Validated Volume
Section B.11.1; Modified several definitions to explain when values are displayed on statements
Section B.2; Added description of GFAOB ECCH Financial Bilateral Transactions plus other related modifications throughout the section
Section B.3; Added description of GFAOB ECCH Financial Bilateral Transactions plus other related modifications throughout the section
Section B.4; Modified several subsections related to GFAOB ECCH Financial Bilateral Transactions
Section B.5; Added description of GFAOB ECCH Financial Bilateral Transactions plus other related modifications throughout the section</td></tr>
</table>

Version	Date	Description
		▪ Section B.8; Modified several subsections related to GFAOB ECCH Financial Bilateral Transactions ▪ Section B.9.2; Modified definition of DA_FIN_GFAOB_BUY_LS and DA_FIN_GFAOB_SELL_LS ▪ Section B.11.1; Modified definition of DA_RSG_ELIGIBILITY ▪ Section B.11.2; Deleted definition of DA_RSG_ASSET_CR ▪ Section B.11.2; Added definition of DA_ASOF_MWP and DA_IMM_MWP ▪ Section B.11.2; Modified definition of DA_RSG_ASSET_CR_HR ▪ Section C.1; minor modifications related to GFAOB ECCH Financial Bilateral Transactions ▪ Section C.2; minor modifications related to GFAOB ECCH Financial Bilateral Transactions ▪ Section D.1.2; Modified definition of RT_ADJ_MTR ▪ Section D.11.4, minor modifications related to GFAOB ECCH Financial Bilateral Transactions ▪ Section D.11.6.4; Modified definition and equation for Total Real-Time Physical Export Volume for an Asset Owner ▪ Section D.12; Modified description of Real-Time RSG First Pass Distribution volume ▪ Section D.12.1; Modified definition of RT_RSG_ELIGIBILITY ▪ Section D.12.1; Added definition of UD_XMPT ▪ Section D.12.2; Modified definition of RT_ADJ_MTR ▪ Section D.12.2; Modified equations for Real-Time Load Schedule Imbalance Volume, RT_UNDER_GEN, RT_OVER_GEN, RT_DERATE_VOL and RT_MR_VOL ▪ Section D13.1; modified several definitions to explain when values are displayed on statements ▪ Section D.13.2; Modified definitions of RT_ADJ_MTR, RT_ASOF_MWP and RT_IMM_MWP ▪ Section D13.2; Modified equations for RT_MWP_CR_TOTAL, RT_MWP_MIT_CR_TOTAL and RT_RSG_ASSET_CR_HR ▪ Section D.14.2; Modified definition of RT_ADJ_MTR Deleted Attachment B: Meter Data Management Agent's (MDMA's): Roles and Responsibilities Data and Submission Standards – Please see the BPM Roles and Responsibilities Section below
6	03-15-2005	Section 2: ▪ Section 2.12; Changed "Net Actual Interchange" to "Net Scheduled Interchange" and modified table in 2.12.4 "Day One Net Inadvertent Payback Example" ▪ Section 2.13; Deleted "Grandfathered Agreement Congestion Rebate Distribution" and performed minor editing ▪ Section 2.16; Changed "Grandfathered Agreement Congestion Rebate Distribution" to "Revenue Neutrality Uplift" and made minor edits ▪ Section 2.18; minor editing Section 3: ▪ Modified Section 3.1 to reflect current invoice practices

Version	Date	Description
		Section 4: ▪ Added Section 4.2.1: Electronic Remittance Advice Email and Document Section 5: ▪ Expanded the process detail for submitting a dispute Attachment A: ▪ Section B.3; Added definition of Carve-Out Grandfathered Agreement Transaction delivery point ▪ Section B.9; Modified description of Option B Grandfathered Agreement portioned refunds ▪ Section C.4; Edited wording to clarify original Asset Owner and new Asset Owner relating to FTR transactions ▪ Section D.2.2.2; minor editing ▪ Section D.12.2; Edited the formula and definition of RT_LOAD_IMB
5	02-15-2005	General: ▪ Spelling and Grammar corrections Section 2: ▪ Added Section 2.12.4 Day-One Net Inadvertent Payback ▪ Deleted Section 2.23 and combined with Section 2.21 Settlement Revenue Neutrality Section 3: ▪ Modified Invoices to reflect current practices Section 4: ▪ Modified Section 4.2 Payment of Net Invoice Revenue Attachment A: ▪ Minor editing
4	01-14-2005	Revisions were made in the following sections: ▪ Section 2: ○ Included the Network Model from the *BPM for Network and Commercial Models* ○ Clarification of Settlement Statement Information ○ Added information on Carve-Out Grandfathered Agreement Settlements ○ Updated Meter Data Process flow ○ Added Joint Operating Agreement Settlement information ○ Added Revenue Neutrality Settlement information ○ Added FTR Auction Rights Settlement information ○ Added Loss Distribution Settlement information ▪ Section 4: ○ Updated information on Payments, Notice and Suspensions ▪ Attachment A: ○ Modified calculations to reflect changes in Section 2
3	12-28-2004	Updated Section 5. Attachment A revised to address new FERC requirements.
2	09-10-2004	Revised based on Market Practices Task Force (MPTF) and Market Settlements Assessment Task Force comments. Added minor clarifications including adding Counter Flow FTR settlement.

Version	Date	Description
1	07-15-2004	Updated new charge types, rewrote and reorganized the document to provide additional detail and understanding.
0	09-15-2003	Initial Draft

TABLE OF CONTENTS

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

List of Exhibits:

1. Introduction

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

1.1 Purpose of 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, provision of transmission reliability services, and compliance with the MISO settlements, billing, and accounting requirements. A complete list of MISO BPMs is available for reference through MISO's website. All definitions in this document are as provided in the MISO Tariff, the NERC Glossary of Terms Used in Reliability Standards, or are as defined by this document.

1.2 Purpose of this Business Practices Manual

This *BPM for Market Settlements* is specific to Market Settlements, Market Participant (MP) invoicing, and Market Disputes. These calculations and descriptions apply to the Operating Days after November 1, 2018, and those otherwise covered by Tariff revisions accepted in FERC Docket Nos. ER18-1648-000, etc. that established time limitations effective on that date.

MISO prepares and maintains the *BPM for Market Settlements* as it relates to the operation of the Market Settlements process. This BPM conforms and complies with MISO's Tariff, North American Electric Reliability Corporation (NERC), also known as the Electric Reliability Organization (ERO), operating policies, and the applicable Regional Entity or Regional Reliability Organization (RRO) reliability principles, guidelines, and standards and is designed to facilitate administration of efficient Energy and Operating Reserve Markets.

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

- What are the business processes for Market Settlements?
- What are the business rules of each Market Settlement process?
- What are the responsibilities of MPs?
- What are the roles and responsibilities of MISO for Market Settlements?
- How do the MPs and MISO interact?

This BPM provides sufficient detail to aid in MPs' understanding of Market Settlements and assist in building their own business processes to participate in MISO Energy and Operating Reserve Market Settlements.

1.3 References

The references to other documents that provide other reference information related to this BPM are as follows:

- BPM-004 Financial Transmission Rights and Auction Revenue Rights (MO-BPM-003)
- BPM-010 Network and Commercial Models (MP-BPM-001)
- Commercial Operation System: XML Interface Reference (located on MISO Extranet)
- MS-OP-029 Market Settlements Calculation Guide
- MS-OP-030 MISO Guide to FERC Electric Quarterly Reporting
- MS-OP-031 Post Operating Processor Calculation Guide
- Tariff of MISO

2. Market Settlements Overview

Settlement is the process by which MISO determines what charges and credits MPs have incurred. MISO operates two distinct settlement processes:

Transmission Settlements **–** The Transmission Settlements process financially settles MPs' use of MISO's Transmission System and mandated, non-competitive Ancillary Services such as scheduling and voltage support. MP charges for transmission and Ancillary Services are calculated based on the Tariff that has been approved by the Federal Energy Regulatory Commission (FERC). The collected funds are distributed to the Transmission Owners and the providers of the mandated Ancillary Services. For more detailed information on MISO's Transmission Settlement process, please see the *BPM for Transmission Settlements*.

Market Settlements **–** The Market Settlements process financially settles competitive transactional activities by and between MPs within MISO's managed Transmission System (i.e., market operations footprint). MP charges and credits resulting from the Day-Ahead, Financial Transmission Rights (FTRs), and Real-Time Energy and Operating Reserve Markets are calculated based on the Tariff.

This manual is exclusively for MISO Market Settlements process.

2.1 Market Types and Settlements

2.1.1 Financial Transmission Right, Day-Ahead and Real-Time Energy and Operating Reserve Markets

MISO operates three competitive markets and acts as a financial clearinghouse for MP electric Energy supply, electric energy Load, and FTRs. The three competitive markets are referred to as:

- FTR Market;
- Day-Ahead Energy and Operating Reserve Market; and
- Real-Time Energy and Operating Reserve Market.

The purpose of these markets is to facilitate competition between MPs, dispatch the least cost available Generation Resources, optimize the use the Transmission System, and provide MPs with the ability to hedge future Energy and congestion costs. In providing these Energy and Operating Reserve Market mechanisms, FERC permits MISO to recover the costs of providing these services from MPs as part of Market Settlements.

2.1.2 Settling and Invoicing the Financial Transmission Right, Day-Ahead and Real-Time Energy and Operating Reserve Markets

Market Settlements is a process that assigns financial charges and credits to MPs and their assigned Asset Owners (AOs) based upon their participation in the FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Markets.

FTR Market Settlements – The FTR Market is settled using the Day-Ahead Energy and Operating Reserve Market cleared Locational Marginal Price (LMP) ($/MWh). Holders of FTR Obligations (and Options, if already made available by MISO) receive a credit if congestion is present in the direction of the FTRs. An FTR Obligation holder is charged congestion costs if congestion is present in the opposite direction. A holder of FTR Options (if such options are already made available) is not charged congestion costs.

Day-Ahead Energy and Operating Reserve Market Settlements – In the settlement of the Day-Ahead Energy and Operating Reserve Market, each MP that purchased energy is charged the Day-Ahead LMP applicable at the relevant Commercial Pricing Node (CPNode) for the quantity (in MWh) of energy scheduled and/or cleared. Day-Ahead Financial Schedules are settled using the Marginal Loss Component (MLC) and the Marginal Congestion Component (MCC) of the LMP of the transaction Source/Sink/Delivery Points. Day-Ahead asset schedules for Energy and Interchange Schedules are settled using Day-Ahead LMP at the relevant CPNode for the hourly quantity of energy sold. Day-Ahead asset schedules for Operating Reserve are settled using the applicable Day-Ahead Market Clearing Price (MCP) at the relevant CPNode for the hourly quantity of Operating Reserve sold.

Real-Time Energy and Operating Reserve Market Settlements – In the settlement of the Real-Time Energy and Operating Reserve Market, each MP is settled for Energy based upon the incremental difference between its real-time energy transactions and its day-ahead scheduled energy transactions multiplied by the applicable Real-Time LMP. For Operating Reserve, each MP is settled based upon the incremental difference between its Real-Time cleared Operating Reserve and its day-ahead scheduled Operating Reserve multiplied by the applicable Real-Time MCP. Additional charges related to system reliability, asset performance, Operating Reserve and the distribution of system losses are also settled in the Real-Time Energy and Operating Reserve Market.

Charges owed by participants to MISO are displayed as positive numbers. Credits owed by MISO to participants are displayed as negative numbers.

Input data for Market Settlements is acquired and validated from MPs, market-clearing operations, and Balancing Authority (BA) interchanges. Charges and credits are calculated and assessed to MPs based upon the Tariff.

The Market Settlements process produces FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Market Settlement Statements at the AO level along with settlement summary statements at the AO and MP levels. Although Settlement Statements are produced at the AO level, Settlement Statements are only provided to MPs. Settlement Statements are provided for MP review and MP invoicing.

FTR, Day-Ahead Energy, and Real-Time Energy and Operating Reserve Market Settlement Statements are specific to an Operating Day (OD) and display each charge type along with the underlying billing determinants used in the associated charge type calculations. Settlement summary statements are specific for the day the Settlement Statements are scheduled to be generated and display the summary of all charges from individual FTR, Day-Ahead Energy, and Real-Time Energy and Operating Reserve Market Settlement Statements generated that day. Summary Settlement Statements allow MPs to review the charges and credits that are invoiced to them on upcoming invoice statements.

Invoice statements are MISO's bill to the MP and do not provide the charge type determinant details that are available on Settlement Statements. An invoice can be either a charge or a credit.

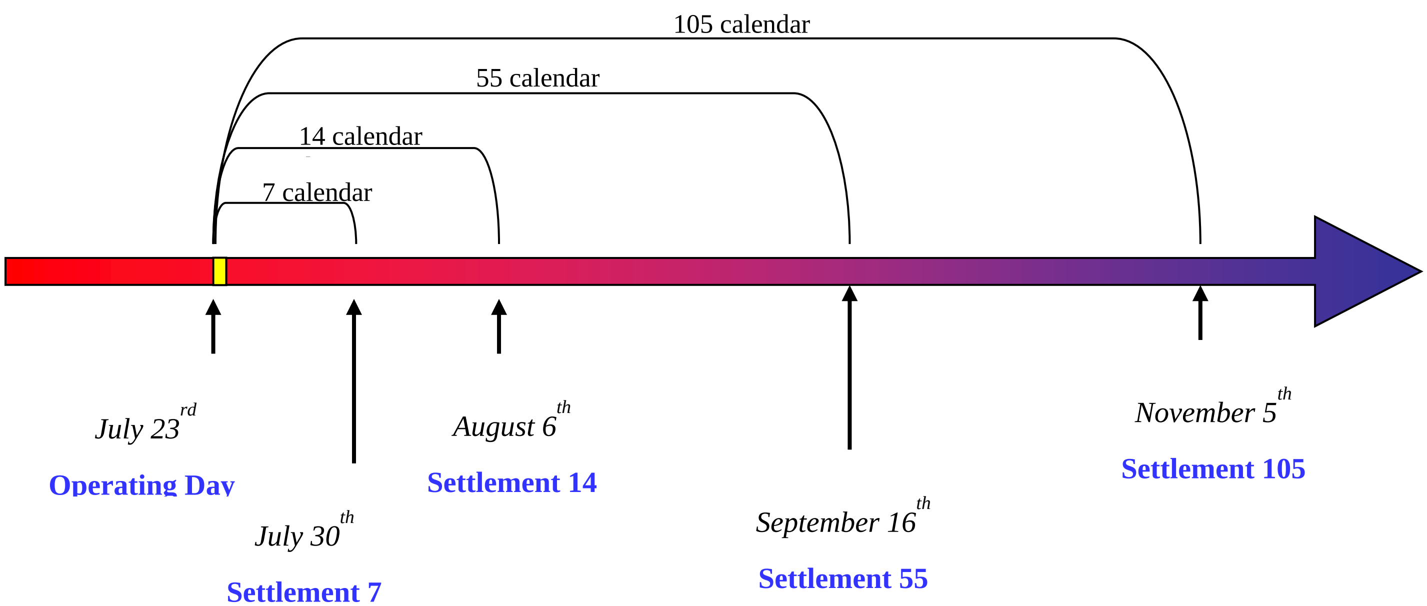
2.1.3 Market Settlement Timeline

The FTR, Day-Ahead, and Real-Time Energy and Operating Reserve Markets for each OD are settled a minimum of four times and may be settled additional times as deemed necessary by MISO. MISO has established a standard settlement calendar timeline for settling ODs. An OD is initially settled 7 Calendar Days (S7) after the OD and then again at 14 days (S14), 55 days (S55), and 105 days (S105) after the OD. After October 1, 2011, MPs will be invoiced for the OD's charges and credits based upon the S7 settlement, rather than the S14 settlement. When an OD is settled, the most recent data that has been provided to settlements is used in the calculations. Generally, only the data difference between each settlement is revised or submitted meter data. The initial settlement is performed seven days after the OD to provide participants with preliminary settlement results. MPs are expected to verify the accuracy of the settlement input data and identify discrepancies prior to the second scheduled settlement that occurs 14 days after the OD. The second settlement, S14, fully recalculates the OD and displays the incremental charge type differences between the second (S14) and the first settlement (S7).

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

The settlements at 55 and 105 days after the OD are to accommodate updates to meter data submitted by MPs. The 55-day settlement (S55) fully recalculates the OD's charges and credits and displays the incremental financial changes from the prior settlements. The fourth settlement is scheduled at 105 days (S105) after the OD and is the last normally scheduled settlement. MPs must have all their final meter data into MISO prior to this settlement. The S105 settlement fully recalculates all charges and credits and displays any incremental financial change from the prior settlements.

Exhibit 2-1: Market Settlements Timeline



Extraordinary events can occur that make it necessary for MISO to settle an OD additional times outside the standard settlement calendar timeline. When these types of events occur that necessitate a nonstandard settlement, MISO informs MPs and settles the OD similarly to a normally scheduled settlement.

2.2 Confidentiality

MISO strictly adheres to all applicable Confidential Information policies, and does not disclose Confidential Information to third parties, except in accordance with these policies and as required by the Tariff and other BPMs.

MISO collects and uses Confidential Information only in connection with its authority under the Tariff and the retention of such information is in accordance with MISO's data retention policies.

2.2.1 Confidential Information

MISO safeguards all Confidential Information. The *BPM for List of Business Practices Manuals and Definitions* defines Confidential Information as:

> "Any proprietary or commercially or competitively sensitive information, trade secret or information regarding a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Transmission Customer, Market Participant, or other user, which is designated as confidential by the entity supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by the Transmission Provider and is not disclosed except under the terms of a Confidential Information policy."

2.2.2 Composite Information

MISO provides composite data as part of administering the Energy and Operating Reserve Markets. The composite data may be developed based on such confidential documents, data, or information if the composite does not disclose any individual MP's confidential data or information.

2.2.3 Disclosure to Agents

MISO may provide Confidential Information to its agents, representatives, or contractors to the extent that any such person or entity is bound by an obligation to maintain such confidentiality.

2.2.4 Disclosure to Third Parties

MISO may disclose Confidential Information to the FERC or other Third Parties as required by law and as specified in the Tariff.

2.3 Market Settlements Governance

MISO Market Settlements is governed by the Tariff. MISO utilizes BPMs as well as Procedures to clarify the implementation of the Tariff and provide guidance to MPs.

2.3.1 Open Access Transmission, Energy and Operating Reserve Markets Tariff

The Tariff as filed and amended with the FERC governs all Energy and Operating Reserve Markets Operations and Administration. MISO Market Settlements department establishes Business Practices and Procedures to ensure that all settlement processes, charge calculations, dispute procedures, mitigation measures, and any other Market Settlement requirements specified in the Tariff are implemented. Controls are established and reviews (SSAE16 Type 2) conducted to ensure compliance with all Market Settlements Tariff specifications.

2.3.2 Business Practices Manual

MISO Market Settlements department publishes and maintains this *BPM for Market Settlements* to promulgate background information, guidelines, business rules and processes established by MISO for the administration of Market Settlements for the different MISO markets, and compliance with MISO settlements, billing, and accounting requirements.

2.3.3 Procedures

MISO Market Settlements develops, implements, and maintains Procedures for administering Market Settlements and invoicing business processes.

2.3.4 SSAE 16 Compliant

In July 2002, the United States Congress passed the Sarbanes-Oxley Act ("the Act") into law. The Act was primarily designed to restore investor confidence following well-publicized bankruptcies that brought chief executives, audit committees, and the independent auditors under heavy scrutiny. The Act is applicable to all publicly registered companies under the jurisdiction of the Securities and Exchange Commission (SEC). The Act requires management's quarterly certification of their company's financial results (Section 302) and management's annual assertion that internal controls over financial reporting are effective (Section 404). In the case of Section 404, the independent auditor of the organization is required to opine on management's assertion over internal control in addition to the auditor's opinion on the fair presentation of the organization's financial statements. Section 404 draws attention to the significant processes that feed and comprise the financial reporting for an organization. In order for management to make its annual assertion on the effectiveness of its internal control, management is required to document and evaluate all controls that are deemed significant to the financial reporting process.

Management either needs to conduct an evaluation of the organization's controls, or management may obtain a favorable Statement on Standards for Attestation Engagements (SSAE) No. 16 Service Auditor's Report opinion.

SSAE 16 is an attestation standard put forth by the Auditing Standards Board (ASB) of the American Institute of Certified Public Accountants (AICPA) that addresses engagements undertaken by a service auditor for reporting on controls at organizations (i.e., service organizations) that provide services to user entities, for which a service organization's controls are likely to be relevant to a user entities internal control over financial reporting.

In a Service Auditor's Type 2 Report, the service auditor expresses an opinion on (1) whether the service organization's description of its controls presents fairly, in all material respects, the relevant aspects of the service organization's controls that had been placed in operation as of a specific date, and (2) whether the controls were suitably designed to achieve specified control objectives, and (3) whether the controls that were tested were operating with sufficient effectiveness to provide reasonable, but not absolute, assurance that the control objectives were achieved during the period specified.

MISO is committed to achieving and maintaining a favorable SSAE 16 Service Auditor's Report Type 2 opinion.

MISO Market Settlement department has established SSAE 16 Control Objectives and Activities to support achieving and maintaining a favorable SSAE 16 Service Auditor's Report Type 2 opinion.

2.4 MISO Network and Commercial Models

There are two significant models referenced in this document and used by MISO for Market Settlements:

Physical Network Model **–** The Physical Network Model is a representation of the actual Transmission System, including all generation and Load connection points. This model is used to analyze the anticipated impact of physical energy flow across the Transmission System. Whenever the Transmission System integrity (also referred to as security) is at risk, MISO personnel direct a combination of market based mitigation actions and operating practices to preserve the Transmission System.

Commercial Model – The Commercial Model differs from the Physical Network Model in that it describes the financial market relationships of the MPs, AOs, and the commercial relationships with the elements of the Physical Network Model.

2.4.1 MISO Network Model

The Network Model supports the Real-Time and study network analysis functions used to determine the power system reliability and certain market operations functions that are used to securely commit and dispatch generation and assess the availability of FTRs. The Network Model is populated with data provided by authorized Transmission Owners and MPs. The Network Model is part of the set of Energy Management System (EMS) databases. The Network Model provides a mathematical representation of the electric power system.

The State Estimator (SE), using the Network Model, is a steady state power system analysis function that calculates the complex voltages at all network buses using the power flow equations and redundant real-time measurements. The voltages are then used to calculate real and reactive power flows even though measurements are not available at all locations.

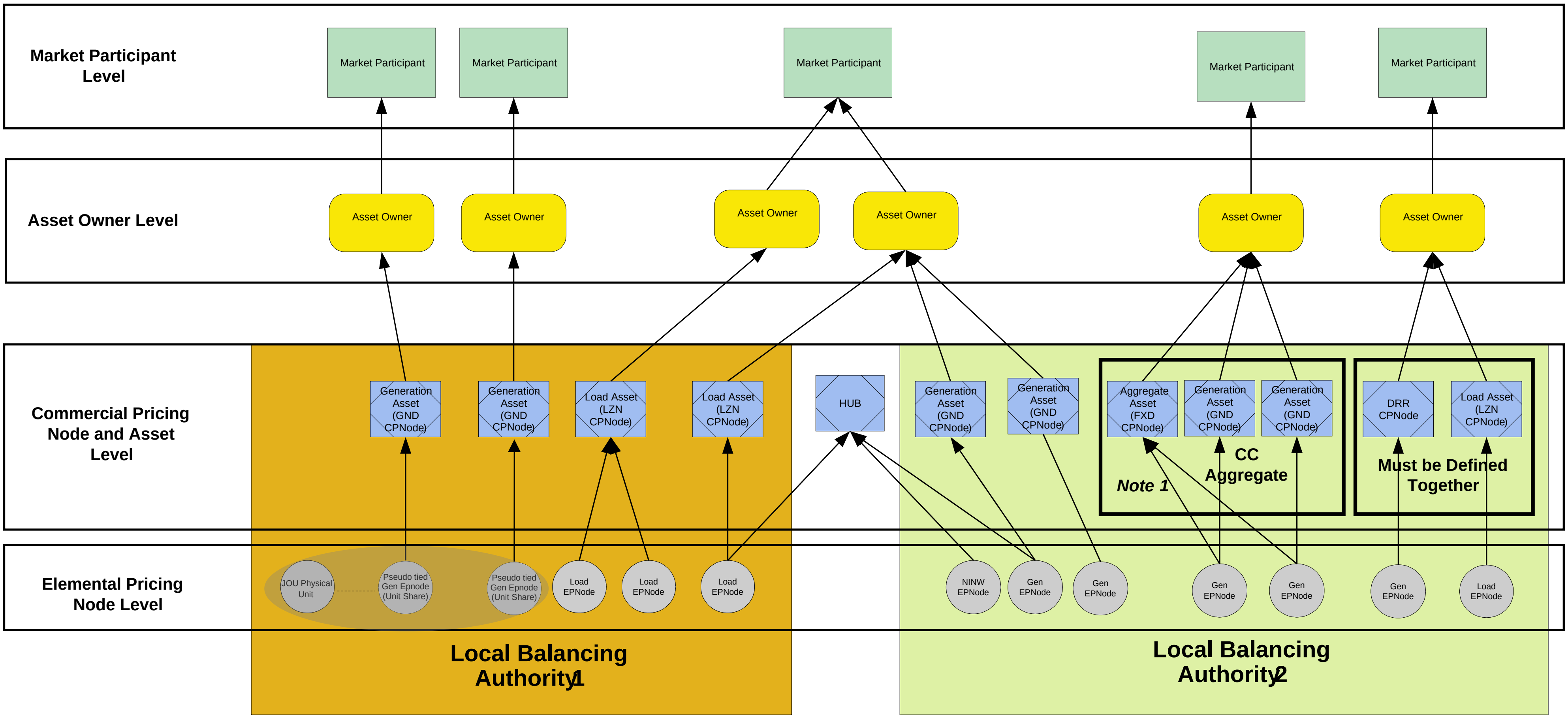
The Day-Ahead and Real-Time System (DART) provides Market Settlements with SE data that is used for alternate meter data.

For additional information on the MISO Network Model, see the *BPM for Network and Commercial Models*.

2.4.2 MISO Commercial Model

MISO Market Settlements utilizes the Commercial Model (illustrated in Exhibit 2-2 and 2-3) for settling MP financial charges and credits.

Exhibit 2-2: Commercial Model Data Hierarchy-Internal Local Balancing Authority

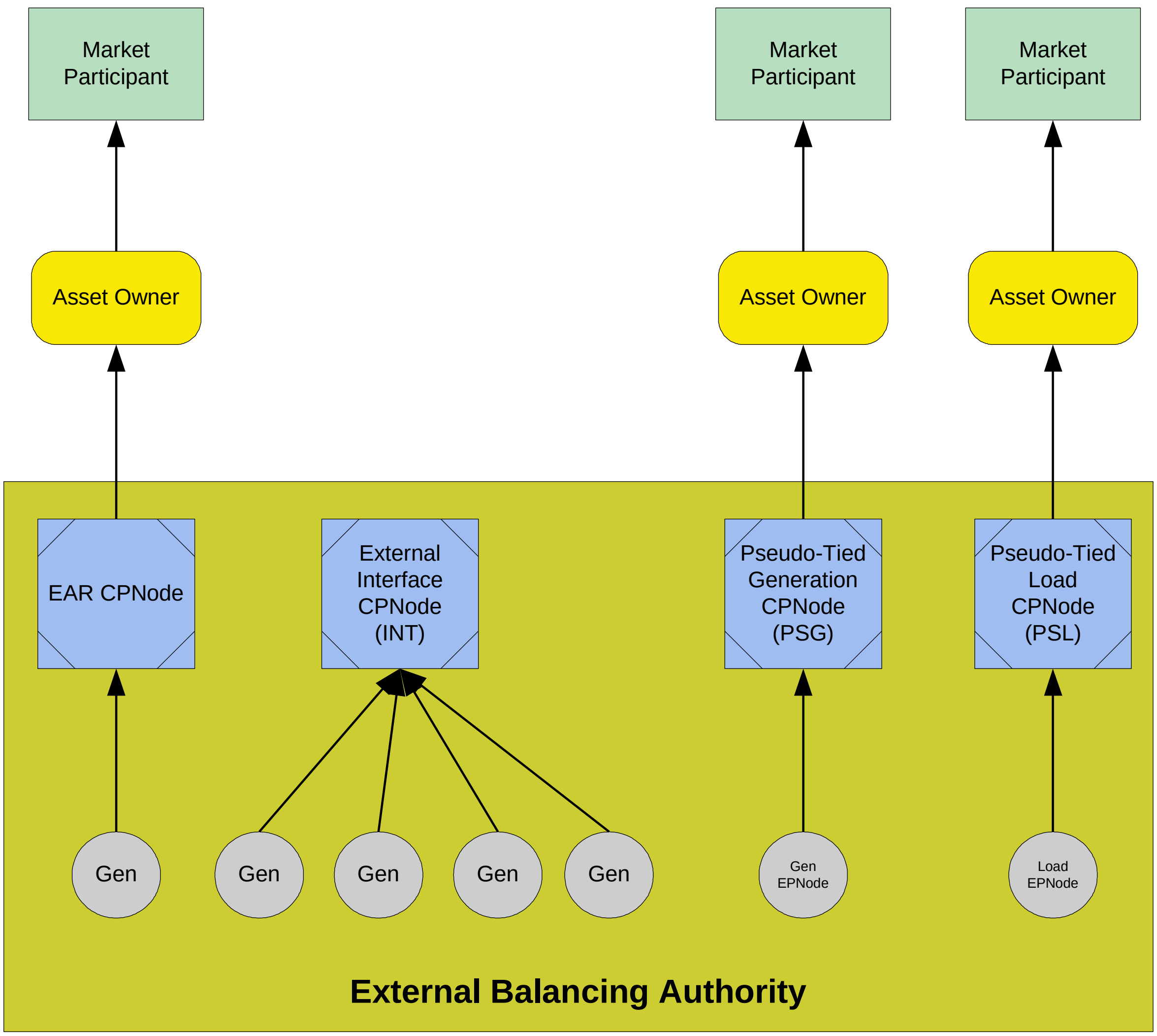


Note 1: **CC assets can be offered either individually or as an aggregate.**

Note 2: **EPNodes are commercially part of a CPNode in an LBA Area, but can be physically located in a different LBA Area.**

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Exhibit 2-3: Commercial Model Data Hierarchy-External Balancing Authority



The Commercial Model contains the following hierarchical levels and relationships:

- ***Elemental Pricing Node (EPNode)*** **–** The EPNode is the finest level of granularity in the Commercial Model. There are EPNodes modeled as part of the Physical Network Model representing points on the Transmission System where energy is injected or withdrawn. MISO calculates the LMP of supplying and consuming electric energy at each EPNode. The Market Settlement system does not use these nodes for settlement, and as such they will not be displayed in any Settlement Statement, except for Internal Commercially Pseudo-tied Loads which impact the load distribution in an LBA Area when calculating the Voltage and Local Reliability (VLR) portion of Revenue Sufficiency Guarantee (RSG) Distribution amounts for Day-Ahead and Real-Time.

- ***CPNode*** **–** The CPNode represents the next hierarchical level in the Commercial Model and consists of one or more EPNodes. All energy transactions, both physical and financial, are financially settled at the CPNode level. Operating Reserve supply is financially settled at the Resource CPNode level based on the appropriate CPNode MCPs. All Market Settlement activity is performed at a CPNode and is the level where LMPs and MCPs are publicly available.

There are twelve types of CPNodes used in Market Settlements:

- ○ ***Generation*** – Abbreviated "GND", a generation CPNode represents a generation unit or facility where all the generation is offered and reported as one point.
- ○ ***Aggregate Generation*** – Abbreviated "FXD", a single modeled aggregate generation point used in conjunction with either Combined Cycle or Cross Compound generation asset.
- ○ ***Load Zone*** – Abbreviated "LZN", a collection of one or more Loads that represent a single Bid and reported at one point.
- ○ ***Type I Demand Response Resource*** **–**Abbreviated "DRRNODE1", a modeled DRR-Type I that is linked to a specific Load Zone CPNode.
- ○ ***Type II Demand Response Resource*** **–** Abbreviated "DRRNODE2***",*** a modeled DRR-Type II that is linked to a specific Load Zone CPNode.
- ○ ***External Interface*** – Abbreviated "INT", a single modeled point where physical energy is scheduled into or out-of MISO.
- ○ ***External Asynchronous Resource (EAR)*** – a CPNode located within the MISO BA that is specifically associated with a Fixed Dynamic Interchange Schedule for the purposes EAR dispatch and settlement.
- ○ ***Hub*** – Abbreviated "HUB", a virtual modeled trading point where MPs can transact Financial Schedules and Virtual Schedules.
- ○ ***Pseudo-Tied Generation*** – Abbreviated "PSG", a single modeled generation point within MISO that is being pseudo-tied to an external BA.
- ○ ***Pseudo-Tied Load*** – Abbreviated "PSL", a single modeled load point within MISO that is being pseudo-tied to an external BA.

- ***Storage as Transmission Only Asset*** – Abbreviated "SATOA", a storage facility that withdraws and injects energy to perform transmission functions and provide transmission service.
- ***Electric Storage Resource*** **–** Abbreviated "ESR", a Resource that is capable of withdrawing, storing, and injecting energy.

Asset – The asset is the next higher hierarchical level in the Commercial Model. An asset represents a Resource within MISO that is registered to an MP in the Energy and Operating Reserve Markets. Each asset has a single CPNode assigned to it. There are nine types of assets:

- ***Generation*** – an asset that is designed to inject energy into MISO Transmission System which include: Generation Resources, Demand Response Resources – Type I, Demand Response Resources – Type II, Dispatchable Intermittent Resources, and External Asynchronous Resources.
- ***Load Zone*** – an asset that withdraws and consumes energy within MISO Transmission System.
- ***Type I Demand Response Resource*** – any Resource hosted by an energy consumer or Load Serving Entity that is capable of supplying a specific amount of Energy or Contingency Reserve, at the choice of the Market Participant, to the Energy and Operating Reserve Markets through physical load interruption.
- ***Type II Demand Response Resource*** – any Resource hosted by an energy consumer or Load Serving Entity that is capable of supplying a range of Energy and/or Operating Reserve, at the choice of the Market Participant, to the Energy and Operating Reserve Markets through behind-the-meter generation and/or controllable load.
- ***External Asynchronous Resource (EAR)*** – an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is represented within MISO Region through a Fixed Dynamic Interchange Schedule.
- ***Dispatchable Intermittent Resource (DIR)*** – Generation resources whose maximum limit is dependent on a forecast of their variable fuel source. DIRs are not eligible to provide Operating Reserves to the Day-Ahead or Real-Time Energy and Operating Reserves Markets.
- ***Stored Energy Resources (SER)*** – a resource that can store and deploy energy over a short period of time, but generally cannot supply energy on a sustained basis. Examples of Stored Energy Resources include flywheel technologies, batteries, and compressed air storage
- ***Storage as Transmission Only Asset (SATOA)*** – a storage facility that withdraws and injects energy to perform transmission functions and provide transmission service.
- ***Electric Storage Resource (ESR)*** – a Resource that is capable of withdrawing, storing, and injecting energy.

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Asset Owner – The AO is the next higher hierarchical level in the Commercial Model and typically, but not necessarily, represents a company. A company may choose to be registered as more than one AO. Within the Commercial Model, an AO can own any combination of assets and/or FTRs across any number of BAs. For an AO to participate in MISO's Market, the AO must be represented by a single MP.

MISO calculates charges and produces Market Settlements Statements for each AO. Each Settlement Statement provides the billing determinants for each transaction along with the AO's total financial obligation resulting from their transactions.

An AO may or may not own Assets in MISO. The term AO is used generically to refer to entities performing asset and non-asset related market activities.

MP – The MP is the highest hierarchical level in the Commercial Model and is the entity in the Commercial Model that is financially obligated to MISO for Market Settlements. An MP may represent one or more AOs. An MP may authorize other entities such as an AO to act as their agent. The MP always remains financially responsible for all of its agents. MPs receive Settlement Statements and a Settlement Statement Summary for each of their AOs. Additionally, the MP receives a single aggregated Settlement Statement Summary and invoice for all its AOs.

Local Balancing Authority Area (LBAA) – The LBAA is not part of the hierarchal financial model for MPs, but is an aggregation of assets into a common collection where an entity performs Local Balancing Authority (LBA) activities. All assets belong to a single LBAA where an entity maintains load, generation, and energy interchange in accordance with NERC/ERO established requirements.

Loss Pools – Loss Pools are a collection of one or more LBAAs and are used for the express purpose of determining the first of two allocation methods for distributing surplus collected loss revenue.

For additional information on the MISO Network Model, see the *BPM for Network and Commercial Models*.

2.5 Market Settlements Data

2.5.1 Public and Confidential Data

Market Settlements department of MISO maintains and discloses data depending upon its data type classification. There are two types of data in the Market Settlements process:

Public Data – This type of data is available to all MPs, is not confidential, and is not specific to an MP. Some examples of Public Data are: LMPs and MCPs for Day-Ahead and Real-Time Energy and Operating Reserve Markets, Market Wide Load Volume, Total Excessive/Deficient Energy Deployment Charges, and Total Financial Schedule Volumes.

Confidential Data – This type of data is specific to an MP and can cause financial harm to the MP if disclosed to the market. Confidential data includes but is not limited to: Bids and Offers, cleared asset schedules, meter data, Financial Schedules, Interchange Schedules, and settlement data.

Market Settlements does not disclose any MP Confidential Data to any other MP or entity without prior authorization, except per the requirements of the Tariff. The Market Settlements department adheres to all Confidentiality requirements as stated in this BPM and the Tariff.

2.5.2 Market Settlement Data Retention

Market Settlements maintains all settlement related Public and Confidential Data for a minimum of three years, or any longer applicable retention period, until such time that it is no longer mandated to do so by any regulatory requirement or MISO's data retention policies.

MISO takes all reasonable steps necessary to preserve settlement data, including maintaining data backups, ensuring copied data is maintained at more than one physical location to prevent destruction by a natural disaster, and to install sufficient hardware and software to prevent theft and corruption.

Market Settlement statements remain available to MPs with valid access certificates through the MISO Portal and through the automatic programmatic interface for a minimum of six months.

MP uploaded meter data and its status remain available to MPs with valid access certificates through the MISO Portal for a minimum of four months.

MP invoice statements remain available to MPs with valid access certificates through the MISO Portal for a minimum of one year.

2.5.3 Market Settlement Input Data Precision and Rounding

Market Settlements maintains a minimum input precision standard for settlement purposes. Input data may be provided to Market Settlements with a greater degree of precision than is supported by settlement calculations. In order to maintain consistency for all settlement input data, MISO truncates input data to the following precision level:

All schedules and transaction information are provided in MWs and truncated to the thousandth of a MW (1/1000). There are three value fields to the right of the decimal point.

All estimated and actual, injection and withdrawal meter data are provided in MWs and truncated to the thousandth of a MW (1/1000). There are three value fields to the right of the decimal point.

All non-scheduled rate data are provided in dollars per MW or transaction, and truncated to the hundredth (1/100) of a cent. There are four value fields to the right of the decimal point.

All dollar input data is truncated to the cent. There are two value fields to the right of the decimal point.

2.5.4 Market Settlement Calculation Data Precision and Rounding

The Market Settlements calculation processing adheres to the following data rounding and saving requirements except where explicitly stated otherwise:

All calculated schedule data is rounded and saved to the thousandth of a MW (1/1000). There are three value fields to the right of the decimal point.

All estimated, actual, and calculated data is expressed in MWs, rounded and saved to the thousandth (1/1000) of a MW. There are three value fields to the right of the decimal point.

All calculated non-schedule rate data is expressed in dollars per MW, rounded and saved to the hundredth (1/100) of a cent. There are four value fields to the right of the decimal point.

All calculated dollar data is rounded and saved to the nearest cent. There are two value fields to the right of the decimal point.

All calculated factor data is rounded and saved to the nearest one hundred millionths of a decimal (1/100,000,000). There are eight value fields to the right of the decimal point.

2.6 Market Settlement Process

2.6.1 Day-Ahead Energy and Operating Reserve Market Settlement Process

The Day-Ahead Energy and Operating Reserve Market clears during the day prior to the OD and is financially binding on MPs. An OD is defined as a 24-hour period beginning at Midnight Eastern Standard Time (EST).

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

For the Day-Ahead Energy and Operating Reserve Market, MISO schedules Resources for the next OD based on MP submitted Bids, Offers, physical schedules, and Self-Schedules. MISO clears the market based on a co-optimized least-cost, security constrained dispatch for each hour incorporating reliability and MISO Operating Reserve requirements.

Market Settlements produces a separate Day-Ahead Settlement Statement for every OD settled. Each Day-Ahead Settlement Statement contains charge types, market wide public data determinants, and confidential data determinants. The Day-Ahead settlement process is performed concurrently with the FTR and Real-Time Energy and Operating Reserve Market settlement processes.

2.6.1.1 Day-Ahead Energy and Operating Reserve Market Timeline

Day-Ahead settlement data comes from the Physical Scheduling System (PSS), DART, and the Financial Scheduling System (finSched). All MP Day-Ahead data, except for Day-Ahead Financial Schedules, must be submitted to MISO prior to 10:30 A.M. EST on the day prior to the OD. The Day-Ahead Energy and Operating Reserve Market is cleared thereafter and the resulting settlement determinant data is provided to Market Settlements. All Day-Ahead Financial Schedules are submitted to MISO and approved by the counterparty no later than noon EST on the sixth day following the OD. For example, a Financial Schedule for OD April 1, 2005 needs to be submitted and approved no later than noon EST on April 7, 2005.

2.6.1.2 Day-Ahead Energy and Operating Reserve Market Process Inputs

The following data is required to settle the Day-Ahead Energy and Operating Reserve Market:

- Day-Ahead LMPs by CPNode, expressed as Dollars per MWh;
- Day-Ahead MCPs by Resource CPNode, expressed as Dollars per MW;
- Day-Ahead Interchange Schedules by AO by CPNode, expressed in MWh;
- Day-Ahead Financial Schedules by AO by CPNode, expressed in MWh;
- Day-Ahead Schedules for Resources and Load by AO and CPNode, expressed in MWh;
- Day-Ahead Schedules for Virtual Bids and Virtual Supply Offers by AO by CPNode, expressed in MWh;
- Day-Ahead MCC and MLC of LMPs by CPNode, expressed in Dollars per MWh;
- Day-Ahead Revenue Sufficiency Guarantee (RSG) Production Costs (PCs) by asset by Hour expressed in Dollars;
- Day-Ahead RSG Independent Market Monitor (IMM) Mitigated PCs by asset by Hour expressed in Dollars as determined by the IMM; and
- Virtual transaction counts by AO by hour.

2.6.1.3 Day-Ahead Energy and Operating Reserve Market Charge Types

The following charge types are calculated for the Day-Ahead Energy and Operating Reserve Market:

Day-Ahead Asset Energy Amount (DA_ASSET_EN) – Net charges and credits expressed in Dollars related to all energy schedules and Day-Ahead Financial Schedules settled at an AO's asset-related CPNodes.

Day-Ahead Financial Schedule Congestion Amount (DA_FIN_CG) **–** Net Day-Ahead Financial Schedule congestion charges and credits expressed in Dollars.

Day-Ahead Financial Schedule Loss Amount (DA_FIN_LS) – Net Day-Ahead Financial Schedule loss charges and credits expressed in Dollars.

Day-Ahead Market Administration Amount (DA_ADMIN) – The total Day-Ahead Administration charges for an AO expressed in Dollars.

Day-Ahead Non-Asset Energy Amount (DA_NASSET_EN) – Net charges and credits expressed in Dollars related to all Day-Ahead Interchange Schedules and Day-Ahead Financial Schedules settled at CPNodes where the AO does not own an asset. The amount is expressed in Dollars.

Day-Ahead Congestion Rebate on Carved-Out Grandfathered Agreements (DA_GFACO_RBT_CG) – Net Carved-Out Grandfathered Agreement Transaction congestion rebate expressed in Dollars.

Day-Ahead Losses Rebate on Carved-Out Grandfathered Agreements (DA_GFACO_RBT_LS) – Net Carved-Out Grandfathered Agreement Transaction losses rebate expressed in Dollars.

Day-Ahead Congestion Rebate on Option B Grandfathered Agreements (DA_GFAOB_RBT_CG) – Net Option B Grandfathered Agreement Financial Schedule congestion rebate expressed in Dollars.

Day-Ahead Losses Rebate on Option B Grandfathered Agreements (DA_GFAOB_RBT_LS) **–** Net Option B Grandfathered Agreement Financial Schedule loss rebate expressed in Dollars.

Day-Ahead RSG Distribution Amount (DA_RSG_DIST) **–**The total Day-Ahead RSG Distribution amount obligation for an AO expressed in Dollars.

Day-Ahead RSG Make Whole Payment (MWP) Amount (DA_RSG_MWP) – The total Day-Ahead Revenue Sufficiency MWP credit for all assets of an AO expressed in Dollars.

Day-Ahead Virtual Energy Amount (DA_VIRT_EN) – Net charges and credits related to settling Day-Ahead Virtual Schedules expressed in Dollars.

Day-Ahead Schedule 24 Allocation Amount (DA_SCHD_24_ALC) – The total Day-Ahead Schedule 24 charges for an AO, expressed in Dollars.

Day-Ahead Regulation Amount (DA_ASM_REG) – The total daily amount due an AO that owns the Regulation Qualified Resources with Day-Ahead Schedules for Regulating Reserve.

Day-Ahead Spinning Reserve Amount (DA_ASM_SPIN) – The total daily amount due an AO that owns the Spin Qualified Resources with Day-Ahead Schedules for Spinning Reserve.

Day-Ahead Supplemental Reserve Amount (DA_ASM_SUPP) **–** The total daily amount due an AO that owns the Supplemental Qualified Resources with Day-Ahead Schedules for Supplemental Reserve.

Day-Ahead Ramp Capability Amount (DA_RC_AMT) **–** The total daily amount due an AO that clears Up Ramp Capability and/or Down Ramp Capability in the Day Ahead Market.

Day-Ahead Short-Term Reserve Amount (DA_ASM_STR) **–** The total daily amount due an AO that clears Short-Term Reserve in the Day Ahead Market.

For a complete list of the charge type billing determinants and the underlying calculations, please see the Market Settlements Calculation Guide.

2.6.2 Financial Transmission Rights Market Settlement Process

MISO operates an FTR market that permits MPs to hedge Day-Ahead congestion costs. This market facilitates annual and monthly FTR auctions along with mechanisms that permit MPs to reconfigure FTRs. MISO also allocates Auction Revenue Rights (ARRs) to MPs in an Annual ARR Allocation based on firm historical usage of the transmission network. ARRs are financial instruments that entitle their holders to a share of the revenue generated in the Annual FTR Auction.

Market Settlements produces a separate FTR Settlement Statement for every OD settled. After the Day-Ahead Energy and Operating Reserve Market is cleared, MISO calculates the hourly financial value of each FTR using Day-Ahead LMPs. FTR holders receive either credits or charges based upon the type of FTR and the amount of congestion present along their defined path. An ARR is settled based on the clearing price of its path in the Annual FTR Auction for the corresponding season and period.

FTR Settlement Statements contain charge types, market wide public type charge related determinants, and confidential data determinants. The FTR settlement process is performed concurrently with the Day-Ahead and Real-Time Energy and Operating Reserve Market settlement processes.

2.6.2.1 Financial Transmission Rights Market Timeline

FTR settlement data comes from:

The Integrated Control Center System (ICCS) for flowgate IDs;

The FTR System for FTR ownership records, auction award transaction Dollars, and FTR bundle information for ARRs; and

The FTR System for ARR nomination caps, allocation, ownership and price

The FTR System maintains all FTR ownership information, auction results, and all secondary FTR ownership change information and results of the Annual ARR Allocation. The ICCS maintains the active list of all Flowgates used in settlements. All MP FTR ownership changes must be completed and registered in the FTR System by the close of an OD in order to be settled for that day. For each OD, the FTR System passes all FTR ownership information including transaction data to Market Settlements.

For additional information on FTR Ownership, see the BPM for Financial Transmission Rights and ARRs.

2.6.2.2 Financial Transmission Rights Market Process Inputs

The following data is required to settle the FTR Market:

FTR ownership information including CPNodes, volume, Peak or Off-Peak designation, and whether it is an option or an obligation;

Day-Ahead MCC of the LMP by CPNode, expressed in Dollars per MWh;

The list of all valid Flowgates for the OD;

Any FTR Transactions information, including the buyer and seller, transaction record, and dollar charges or credits;

ARR ownership information including Stage, Peak flag, CPNodes, volume and price;

Results of the Annual ARR Allocation including nomination cap and allocation amounts;

Day-Ahead JOA Transactions.

2.6.2.3 Financial Transmission Rights Market Charge Types

The following charge types are calculated for the FTR Market:

FTR Hourly Allocation Amount (FTR_HR_ALC) **–** The total net charge or credit from the hourly settlement allocation of FTRs expressed in Dollars.

FTR Market Administration Amount (FTR_ADMIN) – The total FTR Administration charges for an AO expressed in Dollars.

FTR Monthly Allocation Amount (FTR_MN_ALC) – The total net charge or credit from the monthly revenue settlement allocation of FTRs expressed in Dollars.

FTR Transaction Amount (FTR_TXN) – The daily net charge or credit resulting from ownership transfers due to a monthly and/or yearly FTR auction expressed in Dollars.

FTR Yearly Allocation Amount (FTR_YR_ALC) – The total net charge or credit from the yearly revenue settlement allocation of FTRs expressed in Dollars.

FTR Monthly Transaction Amount (FTR_MO_TXN) – The monthly net charge or credit from FTRs purchased and/or sold in the monthly FTR Auction expressed in Dollars.

FTR Full Funding Guarantee Amount (FTR_FFG) – The credit amount added to the actual value of an FTR to bring its total to the target value expressed in Dollars.

FTR Guarantee Uplift Amount (FTR_GUL) – The charge to distribute the cost of the Full Funding Guarantee amount expressed in Dollars.

FTR Annual Transaction Amount (FTR_ARR_FTR_TXN) – The monthly net charge or credit for FTRs purchased, sold or self-scheduled from ARRs in the Annual FTR Auction expressed in Dollars.

ARR Transaction Amount (FTR_ARR_ARR_TXN) – The net charge or credit from the monthly revenue settlement of ARRs expressed in Dollars.

ARR Infeasible Uplift Amount (FTR_ARR_INF_UPL) – The monthly charge to LTTR holders for infeasible ARRs expressed in Dollars.

ARR Stage 2 Distribution Amount (FTR_ARR_STG2_DIST) – The monthly credit from residual auction revenue expressed in Dollars.

For a complete list of the charge type billing determinants and the underlying calculations, please see the Market Settlements Calculation Guide.

2.6.3 Real-Time Energy and Operating Reserve Market Settlement Process

In the Real-Time Energy and Operating Reserve Market, MISO dispatches Resources based on AO submitted Bids, Offers, Interchange Schedules, Self-Schedules, Day-Ahead cleared Offers, and Real-Time reliability requirements. The dispatch is based on a co-optimized least-cost, security constrained dispatch principle incorporating reliability and MISO Operating Reserve requirements. The Real-Time Energy and Operating Reserve Market takes place during the OD.

Market Settlements produces a separate Real-Time Settlement Statement for every OD settled. Each Real-Time Settlement Statement contains charge types, market wide public data determinants, and confidential data determinants. The Real-Time settlement process is performed concurrently with the FTR and Real-Time Energy and Operating Reserve Market settlement processes.

2.6.3.1 Real-Time Energy and Operating Reserve Market Timeline

Real-Time settlement data comes from the PSS, DART and finSched. After the conclusion of the OD, DART sends the settlement determinant data to Market Settlements. All Real-Time Financial Schedules must be submitted to MISO and approved by the counterparty no later than noon EST on the sixth day following the OD. For example, a Financial Schedule for OD September 9, 2008 needs to be submitted and approved no later than noon EST on September 15, 2008

2.6.3.2 Real-Time Energy and Operating Reserve Market Process Inputs

The following data is required for Real-Time Energy and Operating Reserve Market Settlements Statements:

- Hourly Regulating Reserve Delta MWs by AO by Resource CPNode;
- Hourly Spinning Reserve Delta MWs by AO by Resource CPNode;
- Hourly Supplemental Reserve Delta MWs by AO by Resource CPNode;
- Hourly Non-Excessive Energy by AO by Resource CPNode;
- Hourly Excessive Energy by AO by Resource CPNode;
- Hourly Excessive Energy Rate by AO by Resource CPNode;
- Awarded Real-Time generation Start-Up (SU) and no-load PCs, expressed in Dollars;
- Real-Time Interchange Schedules by AO by CPNode, expressed in MWh;
- Real-Time Financial Schedules by AO by CPNode, expressed in MWh;
- Real-Time LMPs by CPNode, expressed in Dollars per MWh;
- Real-Time MCPs by Resource CPNode, expressed in Dollars per MW;
- Real-Time MCC and MLC of Real-Time LMPs by CPNode, expressed as Dollars per MWh;
- Injection and withdrawal meter data for all assets, expressed in MWh;
- Day-Ahead LMPs by CPNode, expressed in Dollars per MWh;
- Day-Ahead Interchange Schedules by AO by CPNode, expressed in MWh;
- Day-Ahead Asset Schedules for Energy by AO by CPNode, expressed in MWh;
- LBAA Actual Net Interchange expressed in MWh;
- LBAA modeled losses, expressed in MWh;
- State Estimator Observed Flow for all assets expressed in MWh; and
- Day-Ahead and Real-Time JOA Transactions.

Meter Data Management Agents (MDMAs) provide meter data to MISO prior to noon EST the day before an OD is scheduled to be settled. If actual meter data is not available for the initial OD settlement, the MDMA provides estimated data and resubmits actual data as soon as it is available.

2.6.3.3 Real-Time Energy and Operating Reserve Market Charge Types

The following Charge Types are calculated for the Real-Time Energy and Operating Reserve Market:

Real-Time Asset Energy Amount (RT_ASSET_EN) – Net charges and credits expressed in Dollars related to all Actual Energy Withdrawals and Financial Schedules settled at an AO's asset related CPNodes.

Real-Time Distribution of Losses Amount (RT_LOSS_DIST) **–** Total AO distribution of surplus losses collected in the Hour expressed in Dollars.

Real-Time Financial Schedule Congestion Amount (RT_FIN_CG) – Net Real-Time Financial Schedule congestion charges and credits expressed in Dollars.

Real-Time Financial Schedule Loss Amount (RT_FIN_LS) – Net Real-Time Financial Schedule loss charges and credits expressed in Dollars.

Real-Time **Congestion Rebate on Carved-Out Grandfathered Agreements (RT_GFACO_RBT_CG) –** Net Carved-Out Grandfathered Agreement Transaction congestion rebate expressed in Dollars.

Real-Time **Losses Rebate on Carved-Out Grandfathered Agreements (RT_GFACO_RBT_LS)** – Net Carved-Out Grandfathered Agreement Transaction losses rebate expressed in Dollars.

Real-Time Market Administration Amount (RT_ADMIN) – The total Real-Time Administration charges for an AO expressed in Dollars.

Real-Time Miscellaneous Amount (RT_MISC) – The total Dollars charged from miscellaneous related activities. The amount is expressed in Dollars.

Real-Time Net Inadvertent Distribution Amount (RT_NI_DIST) – The prorated charge or credit that results from Net Inadvertent across MISO. The amount is expressed in Dollars.

Real-Time Non-Asset Energy Amount (RT_NASSET_EN) – Net charges and credits expressed in Dollars related to all Real-Time Interchange Schedules and Real-Time Financial Schedules settled at CPNodes where the AO does not own an asset. The amount is expressed in Dollars.

Real-Time Revenue Neutrality Uplift Amount (RT_RNU) – On an hourly basis, all charges and credits that have no other distribution method are summed, and the subsequent total charge or credit for the hour is distributed to AOs based on their load ratio share exclusive of Load served by Carved-Out GFAs. The amount is expressed in Dollars.

Real-Time RSG First Pass Distribution Amount (RT_RSG_DIST1) – The charge related to funding Real-Time RSGs expressed in Dollars.

Real-Time RSG MWP Amount (RT_RSG_MWP) – The total credits received for Real-Time RSG MWPs expressed in Dollars.

Real-Time Price Volatility Make Whole Payment Amount (RT_PV_MWP) – The total credits received from the combination of Day-Ahead Margin Assurance Preservation (DA_MAP) and Real-Time Offer Revenue Sufficiency Guarantee Payment (RT_ORSGP) expressed in Dollars.

Real-Time Virtual Energy Amount (RT_VIRT_EN) – Net charges and credits related to backing out Day-Ahead Virtual Schedules in the Real-Time Energy and Operating Reserve Market. The amount is expressed in Dollars.

Real-Time Schedule 24 Allocation Amount (RT_SCHD_24_ALC) – The total Real-Time Schedule 24 charges for an AO, expressed in Dollars.

Real-Time Schedule 24 Distribution (RT_SCHD_24_DIST) – The portion of the combined, total Day-Ahead and Real-Time Schedule 24 Allocation (collections) funds disbursed to each LBA, expressed in Dollars.

Real-Time Regulation Amount (RT_ASM_REG) – The total daily net charge or credit for an AO that owns Regulation Qualified Resources with cleared Hourly Real-Time Regulating Reserve Delta MWs, expressed in Dollars.

Real-Time Spinning Reserve Amount (RT_ASM_SPIN) – The total daily net charge or credit for an AO that owns Spin Qualified Resources with cleared Hourly Real-Time Spinning Reserve Delta MWs, expressed in Dollars.

Real-Time Supplemental Reserve Amount (RT_ASM_SUPP) – The total daily net charge or credit for an AO that owns Supplemental Qualified Resources with cleared Hourly Real-Time Supplemental Reserve Delta MWs, expressed in Dollars.

Real-Time Regulation Cost Distribution Amount (RT_ASM_REG_DIST) – The total daily charges or credits to an AO for Day-Ahead and net Real-Time Regulating Reserve procurement costs expressed in Dollars.

Real-Time Spinning Reserve Cost Distribution Amount (RT_ASM_SPIN_DIST) – The total daily charges or credits to an AO for Day-Ahead and net Real-Time Spinning Reserve procurement costs expressed in Dollars.

Real-Time Supplemental Reserve Cost Distribution Amount (RT_ASM_SUPP_DIST) – The total daily charges or credits to an AO for Day-Ahead and net Real-Time Supplemental Reserve procurement costs expressed in Dollars.

Excessive/Deficient Energy Deployment Charge Amount (RT_ASM_EXE_DFE_DEP) – The total daily AO Charge associated with the AOs that failed to follow Setpoint Instructions in four or more consecutive Dispatch Intervals within an Hour.

Non-Excessive Energy Amount (RT_ASM_NXE) – The total daily net charge or credit for an AO that owns Resources providing Actual Energy Injections less than or equal to the Resource Excessive Energy Threshold, expressed in Dollars.

Excessive Energy Amount (RT_ASM_EXE) – The total daily net charge or credit for an Asset Owner that owns Resources for the portion of Actual Energy Injections greater than the Resource Excessive Energy Threshold, expressed in Dollars.

Net Regulation Adjustment Amount (RT_ASM_NRGA) – The total daily net charge or credit for an AO that owns Resources providing Regulation Service where Energy provided associated with the Regulation Service is above or below the Resource's average Dispatch Target for Energy, expressed in Dollars.

Contingency Reserve Deployment Failure Charge Amount (RT_ASM_CRDFC) – The total daily net charge for an AO that owns Resources that failed to deploy the specified amount of Contingency Reserve within the Contingency Reserve Deployment Period following a Contingency Reserve Deployment Instruction, expressed in Dollars.

Demand Response Allocation Uplift Amount (RT_DRR_UPL) – The total daily charge to an AO to compensate Demand Response Resources deployed and deemed beneficial based on the Net Benefit Price Threshold (NBPT), expressed in Dollars.

Resource Adequacy Auction Amount (RT_RAA) – The total daily net charge or credit for an AO related to the procurement of capacity and planning resources for reliability purposes, expressed in Dollars.

Real-Time MVP Distribution (RT_MVP_DIST) – The total monthly credit for an AO from MISO held MVP ARRs, expressed in Dollars.

Real-Time Ramp Capability Amount (RT_RC_AMT) – The total daily net charge or credit for an AO that owns Resources that cleared Ramp Capability, expressed in Dollars.

Real-Time Schedule 49 Cost Distribution Amount (RT_SCHD_49_DIST) – The total monthly charge for an AO to recover the cost for Available System Capacity (ASC) Usage based on the methodology defined in Schedule 49.

Real-Time Short-Term Reserve Amount (RT_ASM_STR) – The total daily net charge or credit for an AO that owns Short-Term Reserve Qualified Resources with cleared Hourly Real-Time Short-Term Reserve Delta MWs, expressed in Dollars.

Short-Term Reserve Cost Distribution Amount (RT_ASM_STR_DIST) – The total daily charges or credits to an AO for Day-Ahead and net Real-Time Short-Term Reserve procurement costs, expressed in Dollars.

Short-Term Reserve Deployment Failure Charge Amount (RT_ASM_STRDFC) – The total daily net charge for an AO that owns Resources that failed to deploy the specified

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

amount of Short-Term Reserve within the Short-Term Reserve Deployment Period following a Short-Term Reserve Deployment Instruction, expressed in Dollars.

Real-Time Storage as Transmission Only Asset Amount (RT_SATOA) – The total daily net charge or credit for an AO that owns SATOA facilities that withdraw and/or inject energy in the Real-Time Market.

For a complete list of the charge type billing determinants and the underlying calculations, please see the Market Settlements Calculation Guide.

2.6.4 Market Settlement Statements

2.6.4.1 Market Settlement Financial Transmission Right, Day-Ahead and Real-Time Statements Overview

The Market Settlements process produces FTR, Day-Ahead Energy, and Real-Time Energy and Operating Reserve Market Settlement Statements at the AO level, together with Settlement Summary Statements at the AO and MP levels. Although Settlement Statements are produced at the AO level, Settlement Statements are only provided to MPs. Settlement Statements are provided for MPs' review and MP invoicing.

FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Market Settlement Statements are specific to an OD. Statements display charges by charge type along with charge determinants. Settlement Summary Statements are specific to a Calendar Day and display the incremental charges from all ODs settled during the scheduled Calendar Day. Settlement Summary Statements allow MPs to review the charges and credits that are billed to them on upcoming invoice statements.

Following MISO staff approval each day, Market Settlement Statements (FTR, Day-Ahead Energy and Operating Reserve, Real-Time Energy and Operating Reserve and Summary) are transferred to MISO's Market Settlement invoicing system, and published as XML files for each AO and their respective MP.

Each MP is responsible for retrieving their Market Settlement Statements from the Portal. For additional information on XML requirements and specifications, please see Sections 3, 4 and 5 of the MISO Extranet posted document titled, "Commercial Operation System: XML Interface Reference".

MISO provides XML Style Sheets to allow MPs to view Settlement Statements via their Internet browser. Each statement has a style sheet reference at the top of the statement that informs the Internet browser of the directory path for sheets. In order for the viewer to function, the Internet browser must have an Internet connection to MISO. The viewer is not intended to be a MP's sole source to view Settlement Statements. Additionally, the viewer is configured so that it functions after a MP has downloaded and saved its Settlement Statements. Some MPs may find that they can utilize the viewer without downloading Settlement Statements. This functionality is dependent upon how each individual company has configured its Internet security, and as such, this functionality is not under the control nor supported by MISO.

For each OD, MISO’s Market Settlements staff calculates an initial (S7) and three additional (S14, S55, and S105) Market Settlement Statements. ODs are settled at scheduled intervals to accommodate MP meter data submission.

MISO produces the following five types of Market Settlement Statements:

1) ***Market Settlement Statements for S7*** – Market Settlement calculates the initial scheduled standard settlement approximately 7 Calendar Days after the OD for the FTR, Day-Ahead and Real-Time Energy and Operating Markets. The S7 Settlement Statements include all validated data received by MISO prior to noon EST on the previous day.
2) ***Market Settlement Statements for S14*** – Market settlement calculates the second scheduled standard settlement approximately 14 Calendar Days after the OD for each of the three markets. The S14 Settlement Statements include all validated data received by MISO prior to noon EST on the previous day.
3) ***Market Settlement Statements for S55*** – Market settlement calculates the third scheduled standard settlement approximately 55 Calendar Days after the OD for each of the three markets. The S55 Settlement Statements include all validated data received by MISO prior to noon EST on the previous day.
4) ***Market Settlement Statements for S105*** – Market settlement calculates the final normally scheduled standard settlement approximately 105 Calendar Days after the OD for each of the three markets. The S105 Settlement Statements include all validated data received by MISO prior to noon EST on the previous day.
5) A single settlement summary statement identifying all invoice charge incremental changes that result from settling the FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Market for the scheduled settlement Calendar Day.

Additional Market Settlement Statements for the FTR, Day-Ahead and Real-Time Energy and Operating Reserve Markets are generated if there are additional nonstandard settlements scheduled for the Calendar Day.

MPs are provided a single summary statement per schedule date that combines all their AO summary statements.

AOs are provided a Day-Ahead, Real-Time, and FTR statement for each OD being settled along with one summary statement for all the ODs settled on the scheduled date. Assuming there are no nonstandard market settlements performed, AOs are provided a total of 13 Market Settlement Statements for each AO for a standard settlement day.

Settlement Statements are reviewed for accuracy, and once approved, are made available to the MP via the Portal.

MISO compresses all Settlement Statements by settlement date by MP and AO into a single zipped file. Settlement Date is the day the settlement is scheduled to be performed. If settlements are unable to be completed on a scheduled date, the files will still be aggregated by the original scheduled date. The zip file is posted on the MISO Portal and MPs with valid certificates can download the zip file using either the Portal or the automatic programmatic interface.

Each MP will have a single zipped file that will contain its Summary Statement. The MP Summary Statement presents the aggregate totals of all the AOs that it represents.

Each MP Zip File will have the following naming convention:

<Market Participant Short Name>_MP_<YYYYMMDD Scheduled Date>.zip

Example: ABCD123_MP_20060401.zip

The Schedule Date is being displayed in this format to permit proper sorting in the Portal.

Each AO will have a single zipped file that will contain their Summary Statement, Day-Ahead, Real-Time, and FTR OD statements for that Scheduled Date. The single zipped file will contain all of the AO statements, including any non-standard settlements performed on that Scheduled Date. Each AO Zip File will have the following naming convention:

<Asset Owner Short Name>_<YYYYMMDD Scheduled Date>.zip

Example: ABCD123_20060401.zip

2.6.4.2 Financial Transmission Right, Day-Ahead and Real-Time Settlement Statement Format

Each time an OD is settled, MISO Market Settlements staff produces a specific FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Market Settlement Statement. Separate Market Settlement Statements are produced for each AO. Market Settlement Statements are specific to an OD and the day they are scheduled to be calculated (i.e. S7, S14, S55, S105, or a nonstandard settlement Calendar Day).

Each Market Settlement Statement is assigned a Statement Identification (Statement ID) that also serves as its file name with an “XML” extension. The Statement Identifications for FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Market Settlement Statements are concatenated from the following information:

- Type of Settlement Statement (FTR, Day-Ahead or Real-Time);
- MP or AO registered identification at MISO;
- The scheduled day of the settlement in "MMDDYYYY" format;
- The OD settled in the “MMDDYYYY” format; and
  Whether the statement is for a standard settlement "S" or a nonstandard settlement "R" and the number of Calendar Days between the day the Market Settlement Statement was scheduled to be calculated and the OD.

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

The following Settlement Statement identifiers in Exhibit 2-3 are given as examples:

Exhibit 2-4: Example Market Settlement Statement File Name Definitions

File Name	Definition
RT_ AO123_06082005_06012005-S7	This Statement Identification indicates that this file is: ▪ A Real-Time Energy and Operating Reserve Market Settlement Statement ▪ The AO name based on MISO registered identification of "AO123" ▪ The statement scheduled date of June 8, 2005 ▪ The OD settled is June 1, 2005 ▪ The settlement calculation was performed 7 days after the OD for a standard settlement
DA_ABCD__10142005_07012005-S105	This Statement Identification indicates that this file is: ▪ A Day-Ahead Energy and Operating Reserve Market Settlement Statement ▪ The AO name based on MISO registered identification of "ABCD" ▪ The statement scheduled date of October 14, 2005 ▪ The OD settled is July 1, 2005 ▪ The settlement calculation was performed 105 days after the OD for a standard settlement
FTR_ ABC_123__04242005_04102005-S14	This Statement Identification indicates that this file is: ▪ An FTR Market Settlement Statement ▪ The AO name based on MISO registered identification of "ABC_123" ▪ The statement scheduled date of April 24, 2005 ▪ The OD settled is April 10, 2005 ▪ The settlement calculation was performed 14 days after the OD for a standard settlement

MISO uses the same Market Settlement Statement layout for the FTR, Day-Ahead, and Real-Time Energy and Operating Reserve Markets.

Day-Ahead, Real-Time, and FTR Header

Exhibit 2-5: Example Day-Ahead, Real-Time and FTR Settlement Statement Header

MISO	REAL TIME SETTLEMENT STATEMENT
Asset Owner Name:	LOAD-AO
Asset Owner ID:	1-LOAD-AO
Timestamp:	8/14/2011
Scheduled Date:	8/15/2011
Operating Date:	8/8/2011
Statement ID:	RT_LOAD-AO_08152011_08082011-S7

Exhibit 2-5 is a representation of the FTR, Day-Ahead, and Real-Time statement header section using the XML Style Sheets provided by MISO. The example above is for an MP with a registered name of "LOAD-AO" for the August 15, 2011 schedule date.

The header section contains the following general information:

1) AO Name – The abbreviated, registered identification name for the AO
2) AO ID – MISO assigned Asset Owner Identification Code
3) Timestamp – The date the settlement was processed
4) Scheduled Date – The date when this particular settlement calculation was scheduled
5) Operating Date – The OD that is being settled
6) Statement ID – The Settlement Statement identifier is the filename

FTR, Day-Ahead, and Real-Time Statement Line Items

Exhibit 2-6: Example FTR, Day-Ahead and Real-Time Settlement Line Items

Statement Line Items

Settlement Type	S7	Total
Real Time Market Administration Amount	0.00	0.00
Real Time Asset Energy Amount	0.00	0.00
Real Time Financial Bilateral Transaction Congestion Amount	0.00	0.00
Real Time Financial Bilateral Transaction Loss Amount	0.00	0.00
Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	0.00	0.00
Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	0.00	0.00
Real Time Distribution of Losses Amount	-248.37	-248.37
Real Time Miscellaneous Amount	0.00	0.00
Real Time Non-Asset Energy Amount	0.00	0.00
Real Time Net Inadvertent Distribution Amount	-300.92	-300.92
Real Time Revenue Neutrality Uplift Amount	11984.45	11984.45
Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	0.00	0.00

Hourly Settlement Amounts

Charge Type Total	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Real Time Market Administration Amount	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Time Asset Energy Amount	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Time Financial Bilateral Transaction Congestion Amount	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Time Financial Bilateral Transaction Loss Amount	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Real Time Distribution of Losses Amount	-139.7	-38.55	10.53	30.22	-82.3	459.12	137.7	1075.06	-17.12	601.22	140.15	-65.23	-305.36	-368.44	-139.4	-143.09	-401.77	-441.76	-330.36	-13.17	481.91
Real Time Non-Asset Energy Amount	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Exhibit 2-6 is a representation of the FTR, Day-Ahead, and Real-Time statement Line Items Section using the XML Style Sheets provided by MISO.

The statement line items section contains the charge types, the calculated total amounts, and hourly charge type amounts (when applicable) for the charge types. Since there are separate Market Settlement Statements for FTR, Day-Ahead Energy and Operating Reserve, and Real-Time Energy and Operating Reserve, only the charge types that are relevant to the Settlement Statement are provided in this section. Please see the Market Settlements Calculation Guide for a complete list of the charge types that are displayed in this section.

Each charge type is displayed as a running total for the OD and identifies, by settlement calculation run, when charges were posted to this charge type. A charge type can display the following information for a Market Settlement Statement calculated 105 days from the OD as shown in Exhibit 2-6:

Exhibit 2-7: Settlement Example #1

Settlement Statement	Amount (Dollar change from the previous statement total)	Total
S7	12,345.67	12,224.95
S14	–	
S55	–142.00	
S105	21.28	

This example shows that Market Settlement Statements have been produced at 7 days, 14, days, 55 days, and 105 days from the OD. Take note that the “Total” displayed is the sum of all the Settlement Statements and not the charge from the last Settlement Statement. The amount posted next to each Settlement Statement is not displayed as a total for each Settlement Statement, but the dollar change from the previous Settlement Statement total.

Exhibit 2-7 shows the corresponding Settlement Statement 55 where the charge of –142.00 (a credit to the MP) was first shown. The credit of 21.28 on Settlement Statement 105 is a correction to the –142.00 dollar change on Settlement Statement 55.

Exhibit 2-8: Settlement Example #2

Settlement Statement	Amount (Dollar change from the previous statement total)	Total
S7	12,345.67	12,203.67
S14	–	
S55	–142.00	

The hourly settlement amount display is a subset of each charge type and shows the calculated hourly total for the charge type. Depending upon the XML display used, these hourly charge amounts may display beneath each charge type total. Each hourly total is the result of the last settlement performed for the OD. The value in each hour is rounded to two decimal places and when summed across all hours of the day, is equal the total displayed for the charge type. Only charge types that are calculated on an hourly basis are displayed. The following charge types do not have hourly calculations and as such will not display hourly totals:

FTR Settlement Statements:

- FTR Monthly Allocation Amount
- FTR Transaction Amount
- FTR Yearly Allocation Amount

Real-Time Settlement Statements:

- Real-Time Miscellaneous Amount
- Real-Time Net Inadvertent Distribution Amount

Market Determinant Type (MKT_DET_TYP)

Exhibit 2-9: Market Determinant Type

Market Wide Determinants

Determinant Type	VALUE
MISO Net Inadvertent Amount: 21,522.67	21522.67
IMM Mitigated Make Whole Payment Tolerance Amount: 1,000	1000.0
IMM Mitigated Make Whole Payment Tolerance Percentage: 200	200.0

Determinant Type	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
MISO Real Time RSG Make Whole Payment Total Amount	0.0	0.0	0.0	0.0	0.0	-1.15	-1.15	0.0	0.0	-36.56	-36.56	0.0	-35.0	0.0	-34.94	0.0	-72.62
Generation Deviation Up Tolerance Minimum Megawatt Volume	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Generation Deviation Up Tolerance Maximum Megawatt Volume	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Generation Deviation Up Tolerance Percent	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10
Generation Deviation Down Tolerance Minimum Megawatt Volume	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Generation Deviation Down Tolerance Maximum Megawatt Volume	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25
Generation Deviation Down Tolerance Percent	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.
Uninstructed																	

Exhibit 2-9 is a representation of the Day-Ahead, Real-Time, and FTR statement Market Determinant Section using the XML Style Sheets provided by MISO.

This section displays AO common billing determinants used for this type of Market Settlement Statement. For example, on an FTR Settlement Statement, this section displays the “Financial Transmission Rights Market Administration Rate” and the “Financial Transmission Rights Hourly Allocation Factor.” These common billing determinants are displayed on every AO’s FTR Market Settlement Statement.

All LMPs used in calculating the MP’s statement will be displayed in this section of the statement.

Market Participant (MP)

This section displays the AO specific billing determinant data used to calculate charges and credits. Each transaction that occurred for the OD is displayed along with corresponding pricing information.

The Day-Ahead and Real-Time Settlement Statements are arranged so that non-asset related transactions are listed above asset related activity. All schedules and transactions performed by a MP at its asset related CPNode is shown together.

The Real-Time Settlement Statement will list all Real-Time Miscellaneous Charge Determinants at the end of the MP Section.

The FTR Settlement Statement will list all FTR Transactions at the end of the MP Section.

2.6.4.3 Settlement Summary Statements

A single Settlement Summary Statement is created every scheduled settlement day for each MP and AO. This Settlement Summary Statement shows each charge type result for all ODs settled on the scheduled day.

Each Settlement Summary Statement is assigned a Statement Identification (Statement_ID) that also serves as its file name with an "XML" extension. The Statement Identification is concatenated from the following information and is separated by an underscore:

- An identifier indicating whether the statement is for an MP "MP-SUMM" or an AO "AO-SUMM"; and
- MP or AO registered identification at MISO; and
- The scheduled day that the settlement calculation was performed in "MMDDYYYY" format.

The following Settlement Statement identifiers are given as examples in Exhibit 2-9:

Exhibit 2-10: Summary Market Settlement Statement File Name Definition

File Name	Definition
AO-SUMM_A1ENERGY_04122005	This Statement Identification indicates that this file is: ▪ An AO Summary Statement ▪ For an AO that is registered with MISO as “A1ENERGY” ▪ For scheduled settlement day April 12, 2005
MP-SUMM_A1ENERGY_09132005	This Statement Identification indicates that this file is: ▪ An MP Summary Statement ▪ For an MP that is registered with MISO as “A1ENERGY” ▪ For scheduled day September 13, 2005

MISO uses the following layout for the Settlement Summary Statements:

Summary Statement Header

Exhibit 2-11: Settlement Statement Summary Header

MISO	SETTLEMENT SUMMARY
Name:	MKT_MP
ID:	1-MKT_MP
Timestamp:	05/31/2011
Scheduled Date:	06/01/2011
Statement ID:	MP-SUMM_MKT_MP_06012011

Exhibit 2-11 is a representation of the MP and AO summary statement header section using the XML Style Sheets provided by MISO. The example above is for an MP with a registered name of "MKT_MP" for the June 1, 2011 schedule date.

The header section contains the following general information:

1) ***Name*** – The abbreviated, registered identification name for the MP or AO
2) ***ID*** – MISO assigned MP or Asset Owner identification code
3) ***Timestamp*** – The date the settlement was processed
4) ***Scheduled Date*** – The date when this particular settlement calculation was scheduled
5) ***Statement ID*** – The Settlement Statement identifier is the filename

Summary Line Items

Exhibit 2-12: Summary Settlement Statement Sample Line Items

Line Items					
Statement Type	S7 (Invoice)	S14 (Invoice)	S55 (Invoice)	S105 (Invoice)	Total (Invoice Total)
Operating Day	**9/24/2011**	**9/17/2011**	**8/7/2011**	**6/18/2011**	
Day Ahead Market Administration Amount	1888.68	0.00	0.00	0.00	1888.68
Day Ahead Regulation Amount	-557.42	0.00	0.00	0.00	-557.42
Day Ahead Supplemental Reserve Amount	-1077.75	0.00	0.00	0.00	-1077.75
Day Ahead Asset Energy Amount	112457.47	0.00	0.00	0.00	112457.47
Day Ahead Financial Bilateral Transaction Congestion Amount	-177.89	0.00	0.00	0.00	-177.89
Day Ahead Revenue Sufficiency Guarantee Distribution Amount	325.95	0.00	0.00	0.00	325.95
Day Ahead Schedule 24 Allocation Amount	261.27	0.00	0.00	0.00	261.27
Financial Transmission Rights Market Administration Amount	132.69	0.00	0.00	0.00	132.69
Financial Transmission Rights Hourly Allocation Amount	-219.69	0.00	0.00	0.00	-219.69
Real Time Market Administration Amount	165.19	0.00	-0.10	0.00	165.09
Real Time Regulation Amount	-6343.15	0.00	0.00	0.00	-6343.15
Regulation Cost Distribution Amount	1144.82	-1.63	1.25	3.03	1147.47
Real Time Spinning Reserve Amount	-2483.18	0.00	0.00	0.00	-2483.18
Spinning Reserve Cost Distribution Amount	544.44	-0.83	0.31	0.14	544.06
Supplemental Reserve Cost Distribution Amount	261.80	-0.39	0.01	0.09	261.51
Real Time Asset Energy Amount	48815.89	0.00	128.97	0.00	48944.86
Real Time Distribution of Losses Amount	-5299.52	0.85	-3.29	3.19	-5298.77
Real Time Net Inadvertent Distribution Amount	-313.32	0.11	-0.58	0.02	-313.77
Real Time Price Volatility Make Whole Payment Amt	-2982.33	0.00	0.00	0.00	-2982.33
Real Time Revenue Neutrality Uplift Amount	6582.05	-420.07	-29.56	-0.11	6132.31
Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	1230.32	-8.00	-661.79	1.16	561.69

Exhibit 2-12 is a sample representation of the MP and AO summary statement Line Items section using the XML Style Sheets provided by MISO.

The Line Items section has two major purposes:

1) Displays all the charges and credits calculated from all the scheduled settlement calculations for the schedule day for an MP or an AO. The displayed example shows the results of four sets of FTR, Day-Ahead, and Real-Time settlements calculated on the scheduled date.

2) Displays all charges and credits related to this scheduled date that will be invoiced. All ODs that are invoiced have the label "(Invoice)" next to the settlement type. The "Total (Invoice Total)" is the sum of all OD settlements with the "(Invoice)" label.

All positive values represent charges and all negative values represent credits.

2.6.5 Calculation and Statement Acceptance Assurance Validation

MISO Market Settlements department performs detailed validations on all calculated settlements to ensure they are accurate and valid prior to approving them. In the event that any validation questions the accuracy of the settlement results, MISO Market Settlement department investigates and resolves all major discrepancies prior to approving the settlement even if it causes a delay in posting the results.

2.6.6 Market Settlement Statement Availability

Market Settlements statements are normally expected to be available by 6:00 P.M. EST on their scheduled date and can be accessed using the Portal or the automatic programmatic interface. In the event Settlement Statements do not verify accurately, or if market wide critical data is not available for completing a scheduled settlement, MISO may either delay the completion of the settlement, or estimate the market wide data necessary to complete the settlement. If a settlement posting is delayed more than 12 hours (i.e., 6:00 A.M. the day following the settlement scheduled date), a notice will be posted to the Market Settlements website noting the delay and the time when statements are expected to be available. Settlement statement posting will be deemed "Late" when statements are not available to MPs by the close of business on the first MISO normal workday following the settlement scheduled date.

2.7 Asset Settlement Overview

This asset settlement overview is designed to assist MPs in their overall understanding of how assets are settled in the Day-Ahead and Real-Time Energy and Operating Reserve Markets. For a thorough understanding of each referenced charge type, please see the Market Settlements Calculation Guide.

2.7.1 Resource Asset Settlement

A Resource is an asset in MISO that is capable of injecting energy into the Transmission System. A Resource Offer is defined as a Self-Schedule, an Offer, or a combination of a Self-Schedule and an Offer submitted by an MP for the output of a specified Resource to supply Energy and/or Operating Reserve to the Energy and Operating Reserve Market.

2.7.1.1 Resource Asset Day-Ahead and Real-Time Distinction

There is a major distinction between Day-Ahead and Real-Time Resource settlement.

In the Day-Ahead Energy and Operating Reserve Market, cleared Resource Offers are provided by DART to Market Settlements for settling MP asset energy volumes.

In the Real-Time Energy and Operating Reserve Market, cleared Resource Offers are provided by DART to Market Settlements. The Real-Time Energy and Operating Reserve Market settles Resource asset energy volumes based on their Non-Excessive Energy and Excessive Energy amounts adjusted for actual submitted meter data. In the absence of meter data, MISO uses alternate meter data.

The Day-Ahead settlement of the Resource asset energy volumes tends to be very stable and is not normally expected to change between the S7, S14, S55, and S105 Settlement Statements. This is due to the fact that the volume used in the settlement process is from the Day-Ahead Energy and Operating Reserve Market case, which is static.

The Real-Time settlement of a Resource asset changes between Settlement Statements if the MP's MDMA resubmits meter data.

2.7.1.2 Resource Offer Settlement

Cleared Day-Ahead Resource Offers, including Self-Schedules, are passed from DART to Market Settlements for Day-Ahead Energy and Operating Reserve Market settlement. Cleared Resource Offers, including Self-Schedules, are settled in all Settlement Statements (S7, S14, S55, S105, and all nonstandard). The cleared energy volume is settled in the Day-Ahead Asset Energy Amount charge type and is subject to the Energy and Operating Reserve Markets Administration Rate in the Day-Ahead Administration Amount charge type. The cleared Operating Reserve volume is settled in the Day-Ahead Regulation Amount, Day-Ahead Spinning Reserve Amount and Day-Ahead Supplemental Reserve amount charge type, as applicable.

Real-Time Resource Offers do not determine the Real-Time energy volume settled. Actual Real-Time Resource volume deviations from Day-Ahead Schedules are obtained from each Resource's Non-Excessive Energy adjusted for submitted meter data and are settled in all Settlement Statements (S7, S14, S55, S105, and all nonstandard) as Real-Time Non-Excessive Energy volume. Resource Excessive Energy as adjusted for submitted meter data is settled in all Settlement Statements (S7, S14, S55, S105, and all nonstandard) as Real-Time Excessive Energy volume The Non-Excessive Energy volume is settled in the Non-Excessive Energy Amount charge type and is subject to the Energy and Operating Reserve Markets Administration Rate in the Real-Time Administration Amount charge type. The Excessive Energy volume is settled in the Excessive Energy Amount charge type and is subject to the Energy and Operating Reserve Markets Administration Rate in the Real-Time Administration Amount charge type. The cleared Operating Reserve volume deviations from Day-Ahead Schedules for Operating Reserve are settled in the Real-Time Regulation Amount, Real-Time Spinning Reserve Amount and Real-time Supplemental Reserve amount charge type, as applicable.

2.7.1.3 Day-Ahead Revenue Sufficiency Guarantee Start-Up (Shut-Down), No Load (Hourly Curtailment Offer), and Energy Offers Settlement

MP Generation Resources and Demand Response Resources – Type II committed by MISO in the Day-Ahead Energy and Operating Reserve Market are guaranteed their cleared PC recovery (Start-Up, No-Load, Energy, and Operating Reserve Offers). Demand Response Resources - Type I committed by MISO in the Day-Ahead Energy and Operating Reserve Market are also guaranteed their cleared PC recovery (Shut-Down, Hourly Curtailment, and Energy Offer). DART provides Market Settlements with hourly PCs and an eligibility flag indicating whether to provide the guarantee. In conjunction with DART, the IMM provides calculated mitigated PCs when it wants Market Settlements to perform an impact test. Market Settlements calculates the guarantee credit where applicable in the Day-Ahead RSG MWP Amount charge type. The guarantee credit is funded by all MPs that withdraw energy in the Day-Ahead Energy and Operating Reserve Market through the Day-Ahead RSG Distribution Amount charge type.

2.7.1.4 Real-Time Revenue Sufficiency Guarantee Start-Up (Shut-Down), No Load (Hourly Curtailment Offer), and Energy Offers Settlement

MP Generation Resources and Demand Response Resources – Type II committed by MISO in the Real-Time Energy and Operating Reserve Market as part of the Reliability Assessment Commitment (RAC) process are guaranteed their PC recovery (Start-Up, minimum No-Load, Energy, and Operating Reserve Offers). Demand Response Resources – Type I committed by MISO in the Real-Time Energy and Operating Reserve Market as part of the RAC process are also guaranteed their cleared PC recovery (Shut-Down, Hourly Curtailment and Energy Offer).

DART provides Market Settlements with hourly PCs and an eligibility flag indicating whether to provide the guarantee. In conjunction with DART, the IMM provides calculated mitigated PCs when it wants Market Settlements to perform an impact test. Market Settlements calculates the guarantee credit where applicable in the Real-Time RSG MWP Amount charge type. The guarantee credit is primarily funded by MPs that contributed to the cause of the commitment, through the Real-Time RSG First Pass Distribution Amount charge type. Any guaranteed credit funding shortfall is collected from all MPs based on their Load Ratio Share (LRS), exclusive of Load associated with Carve-out GFAs, in the Real-Time RSG Second Pass calculation, which is part of the Revenue Neutrality Uplift charge type.

2.7.1.5 Real-Time Offer Revenue Sufficiency Guarantee Payment Settlement (RT ORSGP)

Resources, excluding DRR-Type I, committed in the Day-Ahead or Real-Time Energy and Operating Reserve Markets and are not otherwise eligible for a Real-Time RSG, are guaranteed recovery of their Incremental Energy and Operating Reserve Costs provided they meet specified eligibility criteria. Since these Resources are either committed in the DA Energy and Operating Reserve Market or are Real-Time Must-Run Committed Resources, they are not eligible for Start-Up or No Load Offer cost recovery. On an hourly basis, the DA/RT System (DART) and the Post Operating Processor (POP) determine whether a Resource has met the eligibility requirements to have their Incremental Energy and Operating Reserve Costs guaranteed. RT ORSGP Amounts are funded through the RT_PV_MWP bucket of Revenue Neutrality.

2.7.1.6 Day-Ahead Margin Assurance Payment (DAMAP)

Resources that receive a Day-Ahead commitment from MISO can be dispatched in RT below their DA Schedule and be forced to settle at an LMP or MCP that erodes their DA Margin. This may be caused by Manual Redispatch or price volatility. Resources that meet certain eligibility criteria can receive a DAMAP that will restore this lost Day-Ahead Margin. DAMAP Amounts are funded through the RT_PV_MWP bucket of Revenue Neutrality.

2.7.1.7 Combined Jointly-Owned Unit Settlement

When a Jointly-Owned Unit (JOU) is registered as a combined unit (a single owner), Market Settlements settles the asset in the same manner as it does any other single generation asset.

2.7.1.8 Combined Cycle and Cross Compound Units Settlement

Combined Cycle or Cross Compound registered generation assets consist of more than one generation asset at a single location. Although each generation asset has a separately defined CPNode, an aggregate CPNode is also created that represents all the Combined Cycle generation assets. AOs can submit Generation Offers at the individual Generator level or at the aggregate level. For settlements, all individual Combined Cycle and Cross Compound generation asset information is rolled-up to the aggregate CPNode that represents the entire Combined Cycle or Cross Compound asset. Whether an AO has submitted individual or aggregate Offers, all asset related settlements are performed at the aggregate level. MPs submit aggregated meter volume for all the Combined Cycle and Cross Compound assets at the aggregate CPNode. MISO does not accept meter data for non-aggregate Combined Cycle and Cross Compound Assets.

2.7.1.9 System Support Resources Settlement

MISO utilizes the Real-Time Miscellaneous Amount charge type for compensating System Support Resource (SSR) owners and for charging MPs. Prior to charging MPs for SSR charges, MISO publishes to MPs the charge type calculation methodology.

2.7.1.10 Uninstructed Deviation Settlement

The Real-Time Uninstructed Deviation charge type will no longer be applicable once the Day-Ahead and Real-Time Energy and Operating Reserve Markets begin. The charge type will continue to be displayed on the Asset Owner Summary statements for historical purposes. Billing determinants specific to RT_UD will be suppressed on the Real-Time settlements statements. The Uninstructed Deviation Exemption flag will be replaced by the Excessive Energy Exemption Flag. Refer to RTO-OP-010 Generator Operator Communications with MISO for detailed information regarding this exemption.

2.7.2 Load Asset Settlement

A Load is an asset in MISO that withdraws energy from the Transmission System.

2.7.2.1 Load Asset Day-Ahead and Real-Time Distinction

There is a major distinction between Day-Ahead and Real-Time Load settlement.

In the Day-Ahead Energy and Operating Reserve Market, cleared Load demand Bids are provided by DART to Market Settlements for settling MP asset energy volumes.

In the Real-Time Energy and Operating Reserve Market, Load does not bid or get cleared; they withdraw energy as they need it. The Real-Time Energy and Operating Reserve Market settles Load asset energy volumes based on their submitted Actual Energy Withdrawal meter data, not their cleared Real-Time Offers. In the absence of meter data, MISO uses alternate meter data.

The Day-Ahead settlement of the Load asset energy volumes tends to very stable and is not normally expected to change between the S7, S14, S55, and S105 settlements. This is due to the fact that the volume used in settlements is from the Day-Ahead Energy and Operating Reserve Market case, which is static.

The Real-Time settlement of a Load asset changes between settlements if the MP's MDMA resubmits meter data.

2.7.2.2 Fixed Demand Load Bid (Price Taker) Settlement

Cleared Day-Ahead fixed demand Load Bids are passed from DART to Market Settlements for Day-Ahead Energy and Operating Reserve Market settlement. A fixed demand Load Bid can only be submitted in the Day-Ahead Energy and Operating Reserve Market by an MP with a Load Resource at the registered Load location. Load Bids are settled in all settlements (S7, S14, S55, S105, and all nonstandard). The energy volume is settled in the Day-Ahead Asset Energy Amount charge type and is subject to the Energy and Operating Reserve Markets Administration Rate in the Day-Ahead Administration Amount charge type.

In the Real-Time Energy and Operating Reserve Market, Load Resources do not bid; they withdraw energy as they need it. The Real-Time Energy and Operating Reserve Market settles Load Resource energy volumes based on their submitted CPNode Actual Energy Withdrawal meter data in the Real-Time Asset Energy Amount charge type. Real-Time Load is subject to the Energy and Operating Reserve Markets Administration Rate in the Real-Time Administration Amount charge type.

2.7.2.3 Price Sensitive Demand Load Bid Settlement

Cleared Day-Ahead price sensitive demand Load Bids are passed from DART to Market Settlements for Day-Ahead Energy and Operating Reserve Market settlement. A price sensitive demand Load Bid can only be submitted in the Day-Ahead Energy and Operating Reserve Market by an MP with a Load Resource at the registered Load location. Load Bids are settled in all settlements (S7, S14, S55, S105, and all nonstandard). The energy volume is settled in the Day-Ahead Asset Energy Amount charge type and is subject to the Energy and Operating Reserve Markets Administration Rate in the Day-Ahead Administration Amount charge type.

In the Real-Time Energy and Operating Reserve Market, Load Resources do not bid; they withdraw energy as they need it. The Real-Time Energy and Operating Reserve Market settles Load Resource energy volumes based on their submitted CPNode Actual Energy Withdrawal meter data in the Real-Time Asset Energy Amount charge type. Real-Time Load is subject to the Energy Markets Administration Rate in the Real-Time Administration Amount charge type.

2.7.3 Pseudo-Tied Generation Settlement

Pseudo-Tied Generation within the MISO BA to an external BA does not offer into either the Day-Ahead or Real-Time Energy and Operating Reserve Markets and is only applicable to the Real-Time Energy and Operating Reserve Market. During each hour of the Real-Time Energy and Operating Reserve Market, DART integrates Pseudo-Tied Generation Resource performance into hourly volumes. With these volumes, a Pseudo Real-Time Financial Schedule is created and provided to Market Settlements for settlement (S7, S14, S55, S105, and all nonstandard). AOs of Pseudo-Tied Generation Resources have up to Noon EST on the 54th day after the OD to update the DART supplied schedule values. Pseudo-Tied Generation Resources are subject to congestion and loss charges between their Resource and the Interface CPNode where the energy is being exported. The congestion cost is settled in the Real-Time Financial Schedule Congestion Amount charge type. The loss cost is settled in the Real-Time Financial Schedule Loss Amount charge type.

2.7.4 Pseudo Tied- Load Settlement

Pseudo-Tied Load does not bid into either the Day-Ahead or Real-Time Energy and Operating Reserve Markets, and is only applicable to the Real-Time Energy and Operating Reserve Market. During each hour of the Real-Time Energy and Operating Reserve Market, DART integrates Pseudo-Tied Load performance into hourly volumes. With these volumes, a Pseudo Real-Time Financial Schedule is created and provided to Market Settlements for settlement (S7, S14, S55, S105, and all nonstandard). AOs of Pseudo-Tied Load have up to Noon EST on the 54th day after the OD to update the DART supplied schedule values. Pseudo-Tied Load is subject to congestion and loss charges between their Interface CPNode where the energy is being imported and the pseudo-tied Load. The congestion cost is settled in the Real-Time Financial Schedule Congestion Amount charge type. The loss cost is settled in the Real-Time Financial Schedule Loss Amount charge type.

2.7.5 Internal Commercially Pseudo-Tied Load Settlement

Internal Commercially Pseudo-Tied Load (ICPSL) will impact the load ratio within a Local Balancing Authority (LBA) Area when calculating the VLR portion of RSG Distribution amounts for these two charge types: DA_RSG_DIST and RT_RSG_DIST1. The ICPSL EPNode's Actual Energy Withdrawal (AEW) that is commercially a part of a CPNode, but physically located in a different LBA Area, will be subtracted from the CPNode's AEW and added to the AO's AEW in the physical LBA Area. Meter data can be submitted for the ICPSL EPNode. When Meter Data is not submitted, the Daily Load Weighting Factor for the ICPSL EPNode will be multiplied by the CPNode's billable meter value to determine the AEW for the ICPSL EPNode.

2.7.6 Storage as Transmission Only Asset (SATOA)

SATOAs perform transmission functions and provide transmission services. They are prohibited from participating in the market except to the extent necessary to receive Energy from the Transmission System and to inject Energy into the Transmission System to provide the services for which the SATOA was included in the MTEP. SATOA do not submit offers and are price takers when charging/discharging in Real-Time. All injection/withdrawal volume will be treated as non-excessive energy and settled at RT LMP. The SATOA will not be eligible for any type of make-whole payment. The SATOA is not subject to any load-based charges or uplifts. SATOAs will pay Schedule 17 & 24 administrative fees. They are excluded from all other charge types. Their volume is included in the Residual Load calculation for the LBAA. Their transactions will not be included on Electric Quarterly Report (EQR) since SATOA are not considered to be participating in the Market.

The SATOA's annual net market revenue is used to offset the relevant Transmission Owner's annual revenue requirement in Attachment O. The Market Participant representing the SATOA is required to provide net revenue back to the Transmission Owner.

2.8 Bilateral Transaction Settlement Overview

2.8.1 Interchange Schedule Settlement

Interchange Schedules represent physical energy being sold into, purchased out of, or scheduled through MISO.

2.8.1.1 Day-Ahead and Real-Time Distinction

Day-Ahead Interchange Schedules carry forward to the Real-Time Energy and Operating Reserve Market as Real-Time Interchange Schedules. If a MP submits a day-ahead Interchange Schedule that does not clear the Day-Ahead Energy and Operating Reserve Market (gets adjusted to zero by DART), a corresponding real-time Interchange Schedule is still created with zero MW for all hours.

At the close of the Day-Ahead Energy and Operating Reserve Market, all day-ahead Interchange Schedules are sent to DART to be cleared in the Day-Ahead Energy and Operating Reserve Market. DART may clear the transactions as is, or adjust them based on their type (fixed, dispatchable, or Up-to-TUC). The Day-Ahead clearing results are tracked in the PSS and provided to Market Settlements for settling the Day-Ahead Energy and Operating Reserve Market. For all day-ahead Interchange Schedules, the PSS creates a corresponding real-time Interchange Schedule using the cleared day-ahead results. MPs are allowed to adjust the new real-time transaction volume. MPs can at any time create additional real-time Interchange Schedules. After

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

the close of an OD, all real-time Interchange Schedules are transferred to Market Settlements for settling the Real-Time Energy and Operating Reserve Market.

2.8.1.2 Fixed Interchange Schedule Settlement

The PSS passes to Market Settlements the fixed day-ahead and real-time Interchange Schedules.

Market Settlements settles the day-ahead transaction energy volume in all settlements (S7, S14, S55, S105, and all nonstandard) in the Day-Ahead Non-Asset Energy Amount charge type. The day-ahead transaction volume is subject to the Energy Markets Administration Rate in the Day-Ahead Administration Amount charge type.

Market Settlements settles the real-time transaction energy volume in all settlements (S7, S14, S55, S105, and all nonstandard) in the Real-Time Non-Asset Energy Amount charge type. The Real-Time transaction volume is subject to the Energy Markets Administration Rate in the Real-Time Administration Amount charge type.

2.8.1.2.1 Dispatchable Interchange Schedule Settlement

The PSS passes to Market Settlements the dispatchable day-ahead and real-time Interchange Schedules.

Market Settlements settles the day-ahead transaction energy volume in all settlements (S7, S14, S55, S105, and all nonstandard) in the Day-Ahead Non-Asset Energy Amount charge type. The day-ahead transaction volume is subject to the Energy Markets Administration Rate in the Day-Ahead Administration Amount charge type.

Market Settlements settles the real-time transaction energy volume in all settlements (S7, S14, S55, S105, and all nonstandard) in the Real-Time Non-Asset Energy Amount charge type. The Real-Time transaction volume is subject to the Energy Markets Administration Rate in the Real-Time Administration Amount charge type.

2.8.1.3 Up-to-TUC Interchange Schedule Settlement

The PSS passes to Market Settlements the Up-to-TUC day-ahead and real-time Interchange Schedules.

Market Settlements settles the day-ahead transaction energy volume in all settlements (S7, S14, S55, S105, and all nonstandard) in the Day-Ahead Non-Asset Energy Amount charge type. The Day-Ahead transaction volume is subject to the Energy Markets Administration Rate in the Day-Ahead Administration Amount charge type.

Market Settlements settles the real-time transaction energy volume in all settlements (S7, S14, S55, S105, and all nonstandard) in the Real-Time Non-Asset Energy Amount charge type. The real-time transaction volume is subject to the Energy Markets Administration Rate in the Real-Time Administration Amount charge type.

2.8.2 Financial Schedule Settlement

Financial Schedules may be scheduled between most CPNodes. The MP entering a Financial Schedule with MISO determines whether the transaction is for the Day-Ahead or Real-Time Energy and Operating Reserve Market along with the Source, Sink, and Delivery Point. Financial Schedules are a mechanism for MPs to trade energy within MISO. They have no impact, nor are they given any consideration, when solving for market generation dispatch.

Each day-ahead and real-time Financial Schedule has a definable Contract Name. MISO defines all Day-Ahead Grandfathered and Real-Time Pseudo related Financial Schedule contract names, but permits the AO to define all others. These definable contract names are not required to be unique across all AOs. As such in order to track all Financial Schedules, the finSched system assigns a unique 10-character identifier to every Financial Schedule. Day-Ahead and Real-Time Settlement Statements display each Financial Schedule as a defined Transaction Identifier that consists of the first thirty characters of the AO's defined Contract Name plus the ten character system defined unique identifier. Although the finSched System allows MPs to define contract names, the settlement system does not permit most special characters or lower case characters. As such, if an AO defines a finSched contract name using lower case characters, when data is passed to the settlement system, all other lower case characters are converted to dashes. Additionally, if the MP uses any special characters other than dashes, spaces, or underscores, when the data is passed to the settlement system, all other special characters are converted to dashes. The finSched system does not alter the MP provided contract name.

2.8.2.1 Day-Ahead and Real-Time Distinction

Financial Schedules do not flow from the Day-Ahead to the Real-Time Energy and Operating Reserve Market and only settle within each respective market.

2.8.2.2 Financial Bilateral Transaction Settlement

There are several different types of Financial Schedules. Please refer to the following referenced charge types to understand the settlement impact:

Day-Ahead congestion costs for non-Grandfathered Agreement and Grandfathered Agreement Financial Schedules – refer to Day-Ahead Financial Bilateral Congestion Amount charge type.

Day-Ahead loss costs for non-Grandfathered Agreement and Grandfathered Agreement Financial Schedules – refer to Day-Ahead Financial Bilateral Loss Amount charge type.

Day-Ahead congestion rebate for Day-Ahead Grandfathered Agreement Financial Schedules – refer to Day-Ahead Rebate of Congestion on Grandfathered Agreement charge type.

Day-Ahead losses rebate for Day-Ahead Grandfathered Agreement Financial Schedules – refer to Day-Ahead Rebate of Losses on Grandfathered Agreement charge type.

Day-Ahead non-Grandfathered Agreement and Grandfathered Agreement Financial Schedule source and sink energy obligation at a CPNode where the MP owns the asset – refer to Day-Ahead Asset Energy Amount charge type.

Day-Ahead non-Grandfathered Agreement and Grandfathered Financial Schedule source and sink energy obligation at a CPNode where the MP does not own the asset – refer to Day-Ahead Non-Asset Energy Amount charge type.

Real-Time congestion costs for pseudo and non-pseudo Real-Time Financial Schedules – refer to Real-Time Financial Bilateral Congestion Amount charge type.

Real-Time loss costs for pseudo and non-pseudo Real-Time Financial Schedules – refer to Real-Time Financial Bilateral Loss Amount charge type.

Real-Time (non-pseudo related) Financial Schedule source and sink energy obligation at a CPNode where the MP owns the asset – refer to Real-Time Asset Energy Amount charge type.

Real-Time (non-pseudo related) Financial Schedule source and sink energy obligation at a CPNode where the MP does not own the asset – refer to Real-Time Non-Asset Energy Amount charge type.

2.8.3 Virtual Schedule Settlement

Virtual Bids and Offers represent Load and generation assets that do not actually exist. This trading instrument enables an MP who does not own an asset at a CPNode to be able to affect the day-ahead price at that CPNode.

2.8.3.1 Day-Ahead and Real-Time Distinction

Virtual schedules can only be bid and offered into the Day-Ahead Energy and Operating Reserve Market. Any virtual Bid and Offer that clears in the Day-Ahead Energy and Operating Reserve Market is then backed out in the Real-Time Energy and Operating Reserve Market since it does not represent an actual asset.

2.8.3.2 Virtual Schedule Settlement

MP virtual Bids and Offers are netted at each CPNode by AO and are provided by DART to Market Settlements for settlement. The Day-Ahead energy volume is settled in the Day-Ahead Virtual Energy Amount charge type and is subject to the Energy Markets Administration Rate in the Day-Ahead Administration Amount charge type. The real-time energy volume that is backed out is settled in the Real-Time Virtual Energy Amount charge type.

2.9 Financial Transmission Rights Settlement Overview

The FTR is a financial instrument that entitles the holder to receive compensation, or possible charge depending on the type of FTR, for congestion along an energy flow path. This instrument can be used to help hedge day-ahead congestion costs. The revenue allocation process is funded from congestion charges collected in the Day-Ahead Energy and Operating Reserve Market. FTRs are owned by AOs.

Each FTR is assigned a unique identifier by the FTR System and is referred to as the "FTR_ID". The AO's FTR Settlement Statement displays each FTR by its FTR System assigned FTR_ID.

2.9.1 Day-Ahead and Real-Time Distinction

The FTR Market is settled separately from the Day-Ahead and Real-Time Energy and Operating Reserve Markets. FTRs are settled using the MCC of the Day-Ahead LMP and funded from congestion collected from Day-Ahead Energy and Operating Reserve Markets.

2.9.2 On-Peak and Off-Peak

An On-Peak type FTR only applies during the Hour ending from 0700 Hour through and including the Hour ending 2200 EST (no regard for DST) Monday through Friday. During Off-Peak times on Saturday, Sunday, New Year's, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Christmas Day or if the holiday occurs on a Sunday, then the Monday immediately following the holiday, On-Peak FTRs are set to zero.

2.9.3 Revenue Congestion Allocation Process

The FTR settlement dollar allocation (i.e., payments to FTR holders from MISO) occurs for an FTR in three processes: Hourly, Monthly, and Yearly.

Hourly Revenue Congestion Allocation Process

The hourly revenue allocation process determines the amount of congestion Dollars available in a single hour and then allocates those Dollars to holders of FTRs for the same hour. For each AO and MISO held FTR, Market Settlements calculates the hourly target revenue allocation value based on the Day-Ahead Energy and Operating Reserve Market. The hourly revenue allocation target is the amount of credit that an FTR is paid if there are sufficient congestion Dollars available. When there are sufficient congestion Dollars available to pay an FTR with its full credit, it is referred to as being a fully funded FTR. If less congestion Dollars are collected in an Hour than is needed to pay all FTR holders their target value, then all FTR holders are paid on a prorated basis for that hour. The difference between an AO's target revenue allocation and the actual credit paid is referred to as shortfall. When FTRs of AOs are not fully funded by the hourly available congestion Dollars, AOs are eligible to receive additional revenue allocations to cover their shortfall in the monthly and/or the yearly revenue allocations. For example, if $10,000 is collected in congestion for an Hour, but total FTRs are owed $20,000, then each FTR holder is only credited 50% of what they are owed during that hour. The hourly FTR revenue allocation process is performed each time an OD is settled, whether it is a normally scheduled settlement or an additional non-standard settlement.

The day-ahead hourly FTR revenue allocation process is funded from:

The hourly positive sum of (grouping A):

- Total Hourly Congestion Collections from the Day-Ahead Financial Schedule Congestion Amount; plus
- Total Hourly Congestion Collections from all Day-Ahead energy schedules; plus
- Total Hourly Congestion Collections from all Obligation FTRs.

Plus the following (grouping B):

- Hourly Day-Ahead Joint Operating Agreement (JOA) Excess Funds.

Less the following (grouping C):

- Hourly Day-Ahead JOA Shortfall.

Whenever the sum of grouping A is negative, this shortfall rolls over to the Day-Ahead Congestion Fund to be netted out during the monthly FTR revenue allocation process. The FTR hourly allocation process only occurs when there are positive funds available for an Hour; this occurs after grouping C is subtracted from groups A and B. Hourly FTR funding can still occur if the sum of grouping A is negative, provided the net of grouping C from grouping B is positive. At the conclusion of the hourly FTR funding, all unallocated Day-Ahead congestion funds roll into the Monthly FTR revenue allocation process.

The hourly FTR revenue allocation fund cannot be reduced below zero by Day-Ahead JOA Shortfall.

Monthly Revenue Congestion Allocation Process

The monthly revenue allocation determines the amount of excess congestion Dollars available in the calendar month and allocates those Dollars on a pro rata basis to all AO FTR holders who did not receive their full FTR target revenue allocation during the hourly process for the same calendar month. Excess congestion Dollars occur when the total congestion for an hour exceed the 100% FTR revenue allocation for that hour. The FTR Monthly Revenue Allocation Amount only calculates when the last OD of the month is settled for S7, S14, S55, and S105. The Monthly FTR revenue allocation process is never performed on a non-standard settlement nor causes the monthly revenue allocation process to occur.

The monthly FTR revenue allocation process is funded from the Day-Ahead hourly unallocated and shortfall congestion Dollars for the calendar month and the residual dollar amount from the monthly FTR auction for the calendar month.

The FTR monthly allocation process only occurs when there are positive funds available for the month. At the conclusion of the monthly FTR funding, all unallocated funds roll into the Yearly FTR revenue allocation process.

Yearly Revenue Congestion Allocation Process

After the last FTR Monthly Revenue Allocation is completed for a calendar month (day 105 settlement for the last Calendar Day of the month), any unallocated excess congestion Dollars go into the FTR Yearly Revenue Allocation process. Whenever a settlement is performed after the S105 for the last Calendar Day of the month has been completed, any congestion and FTR revenue allocation changes that occur impact the FTR Yearly Excess Congestion fund (whether positive or negative). The yearly revenue allocation determines the amount of excess congestion Dollars available as of December 31st, after the hourly and monthly revenue allocation has been completed for that day. Those Dollars are then allocated on a pro rata basis to all AO FTR holders who did not receive their full FTR target revenue allocation during the same calendar year. The yearly revenue allocation process is performed on the S7, S14, S55 and S105 of December 31st. Settlement changes from nonstandard settlements that occur after the last scheduled settlement (S105), impact the next year's yearly FTR revenue allocation process. Any positive congestion fund Dollars remaining after the Yearly Revenue Congestion Allocation Process has completed for the prior year are dispersed to transmission service customers in accordance with the Tariff.

2.9.4 Financial Transmission Rights Obligation Settlement

An obligation type FTR pays AOs when the energy flow path is from a lower cost congestion area to a higher cost congestion area, but it also requires AOs to pay congestion charges when the flow path is from a higher cost congestion area to a lower cost congestion area.

2.9.5 Financial Transmission Rights Options Settlement

An option type FTR pays AO when the energy flow path is from a lower cost congestion area to a higher cost congestion area, but never charges the AOs when congestion occurs in the opposite direction.

2.9.6 Flowgate Rights Settlement

A flowgate is the directional flow across a constrained interface in the Eastern Interconnection System. When a Flowgate becomes constrained, DART calculates the dollar value of the congestion and provides it to Market Settlements. Flowgate Rights holders are credited the product of their hourly volume multiplied by the calculated flowgate congestion price. Flowgate Rights FTRs can only be the option type and as such only receive credits.

2.9.7 Auction Revenue Rights (ARR) Settlement

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. An ARR is settled based on the clearing price of its path in the Annual FTR Auction for the corresponding season and period (peak or off peak). Each month, a portion of the ARRs value is settled based on the duration of the ARR (i.e. seasonal = 1/3). Feasible ARRs are funded by the revenue generated in the Annual FTR Auction and may be discounted if sufficient funds do not exist. If residual revenue exists after funding feasible ARRs, Stage 2 ARRs are funded pro-rata. Stage 2 MWs are based on the difference between a MPs nomination cap and their allocation. The cost of infeasible ARRs is uplifted to Long Term Transmission Rights (LTTR) holders. For the duration of the Second Planning Area transition period, the uplift of infeasible ARRs will be implemented regionally, such that the uplift ratio share denominator will only be those ARRs for a given region and the nominator will be an AO's share of those ARRs.

The settlement of FTR Annual Transaction Amount, ARR Transaction Amount, ARR Infeasible Uplift Amount and ARR Stage 2 Distribution Amount occurs on the first Operating Day of each calendar month.

2.9.8 Retail Load Shift Impact on ARR Settlement

ARRs allocated in the Annual ARR Allocation will follow the Load as the Load shifts from one AO to another. The ARRs are allocated by ARR Zone based on the Peak Usage of the AOs participating in the Annual ARR Allocation. The FTR market design calls for the redistribution of the ARR revenue due to Load shift. MISO will settle the ARRs on a monthly basis. A designated entity for an ARR Zone will report to MISO the adjusted Network Peak Load Forecast (NPLF) for each AO serving (or served) Load in that ARR Zone in the previous month.

When the adjusted NPLF reported for an AO is less than its original nomination cap in the ARR Zone, the AO is considered to have lost Load. The percent of Load lost is applied to each of the AOs shifting ARRs that sink in the ARR Zone as a volume adjustment. The value of those ARR adjustments is then made available to those AOs gaining Load in the ARR Zone.

When the adjusted NPLF reported for an AO is greater than its original nomination cap in the ARR Zone, the AO is considered to have gained Load. The percent of Load gained is determined by dividing their amount of increased NPLF by the total of all NPLF increases in the ARR Zone. The percent of Load gained is then applied to each of the volume adjustments for the ARRs that lost Load in the ARR Zone.

Finally, the AOs original nomination cap and allocation volumes are adjusted in order to calculate their Stage 2 distribution volume. The increase or decrease in NPLF is applied to the original nomination cap. The volume of ARRs lost or gained is applied to the original allocation volume. The difference between the nomination cap and allocation volume is the AOs Stage 2 distribution volume.

Each month when ARR Transaction Amount, ARR Infeasible Uplift Amount and ARR Stage 2 Distribution Amount are settled, the adjustments to redistribute ARR revenue due to Retail Load Shift are included in the calculations.

2.10 Metering Settlement Overview

All MPs that own assets within MISO, report through their designated MDMA hourly Real-Time actual meter (RT_ACT_MTR) injection and withdrawal volumes for each of their asset CPNodes and ICPSL EPNodes. If the MP does not have actual meter data available for the OD, the MP estimates the data. When actual meter data becomes available, the MP is required to submit the actual data prior to the next scheduled settlement. If no actual or estimated meter data is provided by the MP, or if the submitted meter data is unreasonable or erroneous, MISO relies upon alternate (MISO estimated) meter data for the asset.

Meter installation and ownership, along with meter data quality, remain the responsibility of the MP. MISO reserves the right to independently audit MP metering equipment, meter data records, and meter data determination methodology to ensure that it accurately and correctly represents settlement quality meter data for its registered assets. All meter data submitted to MISO becomes the property of MISO.

The MDMA is responsible for producing and submitting to MISO 'Settlement Quality Meter Data' in accordance with the practices defined within this document. The MDMA must also establish and maintain the MWh high/low parameters for each CPNode via the Web Portal. The meter data is required to be:

- Accurate and complete measurement or estimation of actual hourly MWh injection and withdrawal volumes for each of their designated MP's asset CPNodes, including any required adjustments to account for Demand Response Resource Type I and Type II modeling.
- Aggregated (from EPNodes) to the Asset Resource level (CPNode) consistent with the MISO Commercial Model, including sub-transmission distribution losses and station auxiliary Load where applicable.
- ICPSL EPNode meter data should be submitted separately for use in the VLR RSG Distribution methodology.
- Meter Data values are to be within the MWh high/low parameters that are established and maintained by the MDMA through the Web Portal.
- Validated by the MDMA using Validation, Estimation, and Editing (VEE) to ensure accuracy and completeness prior to submittal to MISO.
- Able to pass Market Settlement's automatic validation controls – Initial (Portal) and Internal (preliminary data acquisition) validation process controls.
- Able to meet the above listed requirements with timely electronic submittal to Market Settlements in advance of S7, S14, S55 and S105, allowing for settlement of the market.

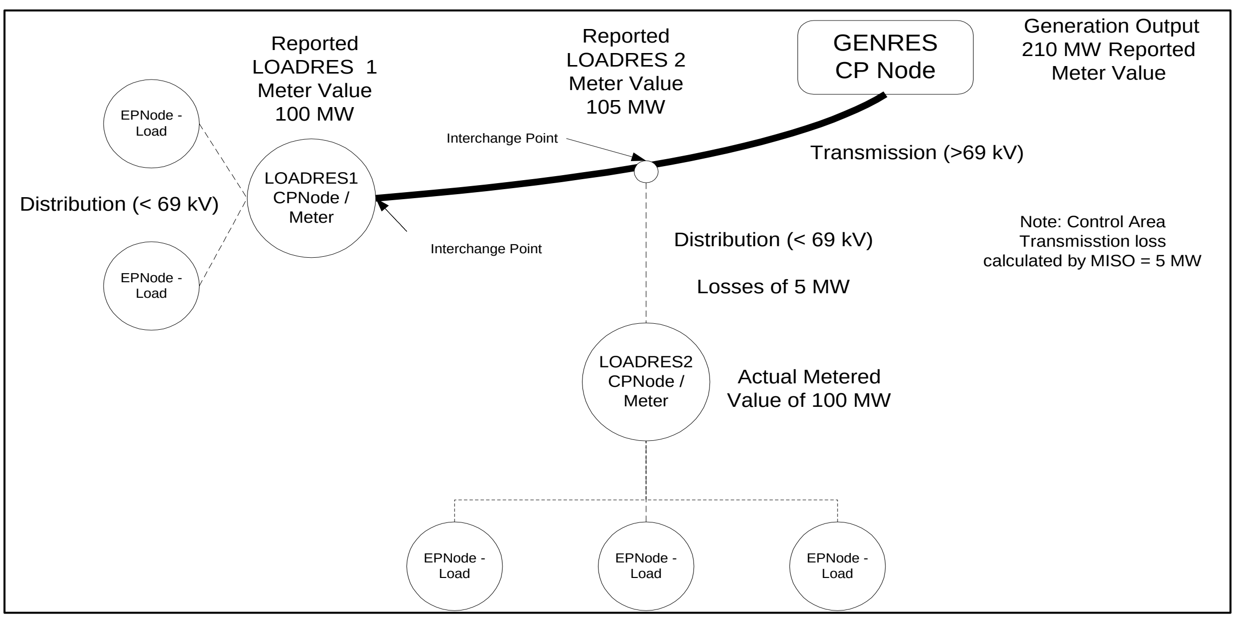
MISO is responsible for monitoring the quality of submitted meter data to ensure compliance with settlement quality meter data requirements. Where no meter data is submitted by the MDMA or the submitted meter data is found to be unreasonable or erroneous, MISO will rely upon alternate

(MISO SE) meter data for settlement of the market until the issues with the data are resolved. Alternate meter data used in market settlement will be provided to the MP and/or MDMA. Failure of the MP and/or MDMA to comply with the metering settlement specifications and settlement quality meter data standards contained herein, may preclude their participation in MISO Market Activities.

2.10.1 Metering Requirement

Each MP is responsible for ensuring proper metering equipment is installed and maintained in order to provide MISO settlement ready meter data. The metering equipment measures MWh as the standard unit of measurement (or be capable of being adjusted to the MWh level) and has bi-directional capability where applicable. The preferred location of the meter equipment is at the exact point of interchange and accounts for distribution and transformer losses up to the actual interchange point as illustrated in the diagram below:

Exhibit 2-13: Preferred Metering Locations



This simple diagram illustrates the concept of losses to be included and excluded in meter data submitted for market settlement in a LBA with one generation unit and two load Resources. The reported meter values for LOADRES 1 (with metering at the exact interchange point) is 100 MWh, LOADRES 2 (with metering remote from the interchange point that takes into account 5 MWh of estimated distribution losses) is 105 MWh, and GENRES metering measuring 210 MWh of output. MISO supplied LBA transmission losses in this simple illustration are 5 MWh.

The metering equipment is required to have sufficient memory to record the amount of interval data specified in the polling period or schedule. Interval meter data processing (collection, validation, editing) and aggregation for the Asset's CPNodes is performed by the MP's designated MDMA.

2.10.2 Metering Standards

MPs are required to install, operate, maintain and periodically test appropriate metering and related equipment capable of accurately recording injections and withdrawals for the assets of their assigned CPNodes. The resulting recorded interval meter data (e.g., 5, 15, 30 minute interval basis) is aggregated into integrated hourly (60-minute) meter data (in MWh) for submission to MISO.

2.10.3 Metering Accuracy

Each MP is responsible for procuring, installing, and maintaining metering equipment that provides accurate meter data in accordance with applicable American National Standards Institute (ANSI) Code for Electrical Metering minimum standards. Current transformers and voltage transformers used for metering are required to meet or exceed an accuracy class of 0.3%. Metering equipment required for MISO transactions do not supersede more restrictive or specific standards as dictated by the MP's local or state regulatory jurisdictional requirements.

2.10.4 Meter Data Monitoring

MISO reserves the right to independently audit or review the MP's designated MDMA processes potentially affecting submitted meter data, estimation methodology and/or associated metering equipment to ensure settlement quality meter data standards. MISO will share with the MP and MDMA the results of any audit pertaining to their meter data processes. MISO monitors for under and over reporting of asset CPNode meter data. MISO conducts a series of automatic and manual validation measures in conjunction with Market Settlements meter data processing in review of submitted meter data.

When a significant meter data quality issue is identified that potentially adversely affects the settlement of the market, whether as the result of a meter data validation or a separate review process or audit, a MISO's representative contacts the MP's designated MDMA by an established formal process in an attempt to resolve any data quality issues. Meter files exhibiting potential problems will be withheld from processing until the accuracy of the submitted meter data and the appropriateness of using the data for settlement can be determined. Failure of the MP to comply with meter data requirements, and/or where meter data irregularities or anomalies are identified and not remedied, may preclude participation in MISO activities.

2.10.5 Meter Data Validation

MDMA submitted meter data is subjected to a series of Market Settlements meter data validation measures in conjunction with Market Settlements. The meter data validation measures are:

Portal Validation – automated checks performed during the meter data upload process (both Portal and Programmatic Interface). The MDMA receives an instantaneous message indicating whether each meter file was successfully uploaded or rejected. The primary focus of initial validation is Portal user security, XML meter data file structure integrity and MWh high/low parameters of meter values. Some examples of reasons that Meter Data files may fail Initial Validation are: Invalid XML Schema, Invalid MP – MDMA and/ or Asset Relationship, Invalid Characters in Meter File name, files without 24 hourly values per OD or meter values are outside the MWh high/low parameters.

Internal Validation – Internal validation measures are performed by Market Settlements Analysts to verify consistency with the Commercial Model and SE.

Demand Response Tool Validation **–** automated checks performed during the meter data upload process. The MDMA receives an instantaneous message indicating whether each meter file was successfully uploaded or rejected. Some examples of reasons that Meter Data files may fail are: Invalid Asset Owner and/ or Asset Relationship, Invalid Characters in Meter File name, files without 24 hourly values per OD, Invalid Baseline Type.

2.10.6 Meter Data Submission and Processing

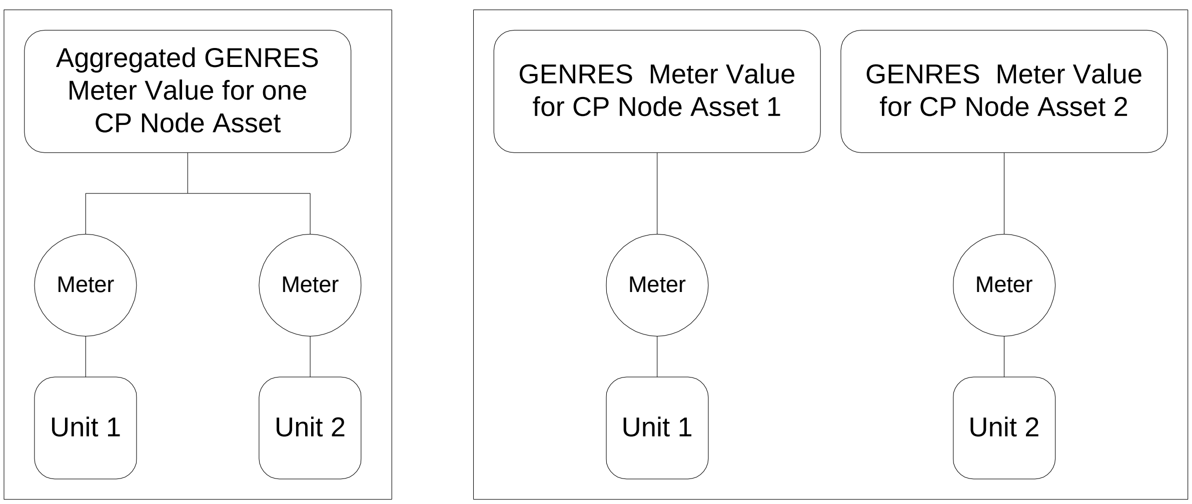
MDMAs are responsible for submitting actual meter data values (in MWh) via the Web Portal or Programmatic Interface, or the Demand Response Tool for DRR Type I or DRR Type II resources. MDMAs are responsible for establishing MWh high/low parameters for each CPNode and maintaining those values via the Web Portal. Meter values submitted outside of the MWh high/low parameters will be considered erroneous and rejected by the Portal validation. Reported meter data values are to be provided for:

Generation Assets – Injection volume (in MWh) represented by negative (-) values for energy injection and positive (+) value for energy withdrawals. As a general rule, auxiliary Loads for generation stations can be modeled explicitly with gross generation, or the auxiliary Load and gross generation can be modeled as net generation. The exception to this rule is when the auxiliary Load is served from a different Bus than the Generator interconnection Bus. In that case, the auxiliary Load must be explicitly modeled as gross generation (for more information on station auxiliary Load in Generation Modeling, see Section 3 – 'Network Model' of the BPM for Network and Commercial Models).

Demand Response Resources – Type I and Type II are required to submit meter data in the Demand Response Tool, in accordance with their registered baseline type. The expected volume, in kWh, is represented as a positive (+) value for energy withdrawal. Meter data requirements for JOUs are required to be consistent with the Commercial Model definition and be submitted by one MDMA for all AOs' shares of the unit to MISO for settlement purposes. The owners must agree internally on this methodology for submission of meter data. MISO is not involved in dividing the metered energy among the owners. Each AO's share is settled separately and sums to the amount corresponding to the total output of the JOU.

Where multiple Generators have been registered as a single asset (e.g., single CPNode), such as a Combined Cycle Combustion Turbine (CT) Generation Resource, all generation output volume will be summed for the units and reported by the MDMA at that single aggregated CPNode. Generation assets with multiple units that are registered as individual units will report meter data for each unit. Therefore the reporting of the meter values should be consistent with the registration of these units in the Commercial Model definition. These concepts are illustrated in the following diagrams with two generation assets:

Exhibit 2-14: Combined Cycle Unit Metering



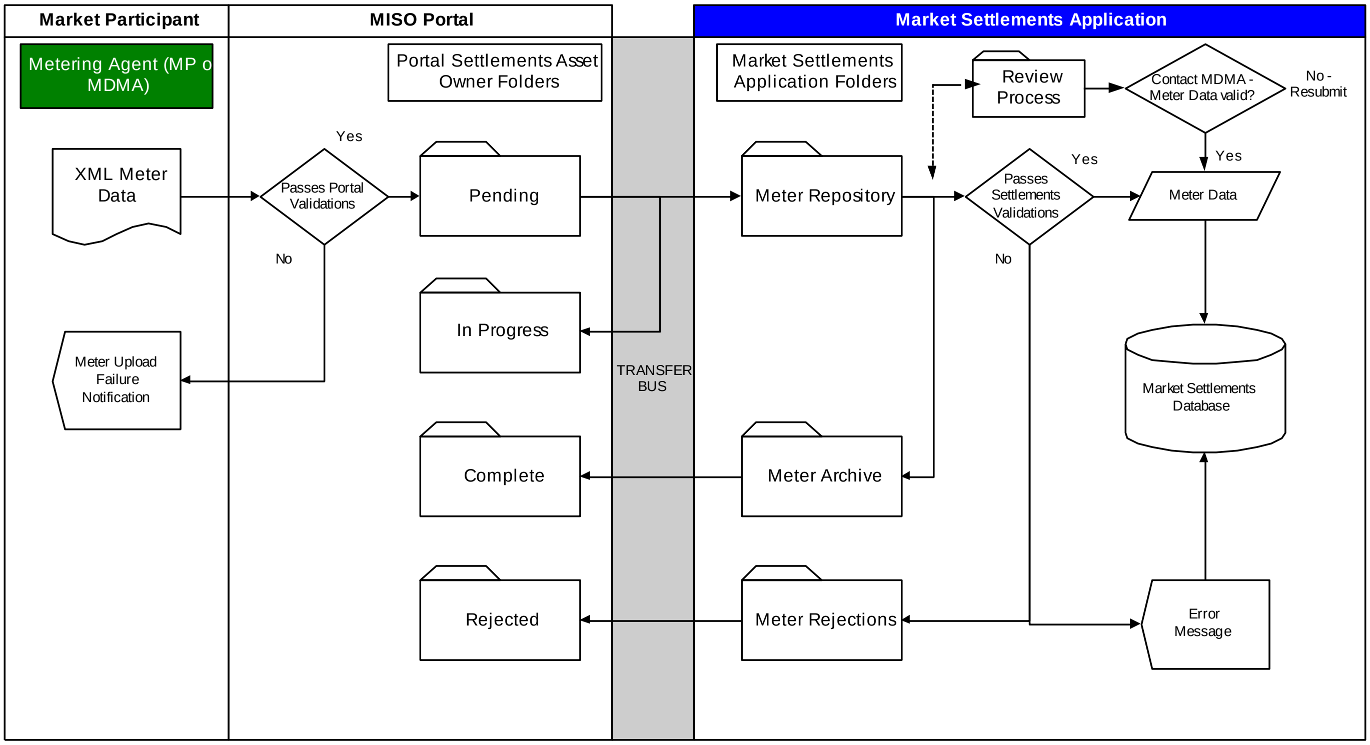
Load Assets – Withdrawal volume (in MWh) represented by positive (+) value for energy withdrawals that excludes transmission losses and backs out non-registered Loads and/or generation. Load asset Actual Energy Withdrawal meter data submitted to the Settlement system is required to be net of behind the meter generation used to serve Load unless the generation is registered separately with MISO as a Generation Resource, a Demand Response Resource – Type I or a Demand Response Resource – Type II. Load data used for market settlement include sub-transmission or distribution losses (generally below 69kV) that are consistent with the MISO Network Model.

In the absence of actual meter data values, MDMAs submit estimated values until actual meter data values are available. Initial meter data values are submitted by the MDMA to MISO by noon EST on the 6th Calendar Day following the OD. MDMAs are expected to submit the most accurately available, actual or estimated, meter data prior to each scheduled settlement. All validated actual (and estimated) meter data values submitted by noon EST one day prior to the scheduled settlement day are included in the next scheduled settlement. Specifically, meter data submitted by:

- Noon EST on the 3rd Calendar Day following the OD is used for the day 4 estimated Credit exposure.
- Noon EST on the 6th Calendar Day following the OD is used for the day 7 Settlement Statement.
- Noon EST on the 13th Calendar Day following the OD is used for the day 14 Settlement Statement.
- Noon EST on the 54th Calendar Day following the OD is used for the day 55 Settlement Statement.
- Noon EST on the 104th Calendar Day following the OD is used for the day 105 Settlement Statement.

MDMA submitted settlement quality meter data is processed daily. The meter data process flow is illustrated in the following diagram:

Exhibit 2-15: Meter Data Process Flow



The MP or designated MDMA will be able to view submitted meter data in the MISO Portal during the various stages of processing. The following is a description of each step in meter data file processing:

> ***Pending*** – successfully submitted meter files, either by manual or programmatic interface, may be viewed in the 'Pending' Folder until noon when the files are moved to the meter repository. Meter files in the Pending folder may be deleted by the MP/MDMA until the transfer to the 'In Progress' folder has taken place, after which an exchange in ownership of the meter files has occurred and they may not be deleted.
>
> ***In Progress*** – meter files are in the process of being transferred to the meter repository folder pending market settlement data acquisition.
>
> ***Completed*** – the processing of the meter files in data acquisition is complete and the files are moved to the 'Completed' folder.
>
> ***Rejected*** – meter data files not passing initial and internal validation measures are moved to the 'Rejected' folder and not processed during market settlement data acquisition.

The most recently submitted meter data is always used for settlements. An MDMA is permitted to submit meter data multiple times for the same OD. Meter data submitted after noon EST on the 104th day following the OD is accepted and retained by Market Settlements, but not utilized for settling the OD unless a nonstandard settlement is performed thereafter and MISO determines that updated meter data will be utilized in that nonstandard settlement.

Meter files submitted to MISO are tracked and uniquely identified. To create a unique identifier for each file, MISO takes submitted files and truncates the file name to 50 characters and appends a unique identifier to the end of it. If an MDMA submits a meter file that is longer than 50 characters, all additional characters beyond 50 are lost. The MDMA should limit its file naming convention to 50 characters; otherwise, it may not be able to track the processing of the file through MISO's computer system. Meter file names cannot contain any special characters other than dashes or underscores. Files submitted with special characters other than dashes or underscores will be rejected upon submission to MISO.

For more detailed information regarding actual meter data file submission specifications and requirements see: "Volume 4 – Commercial System Programmatic Interface Reference" and/or "Volume 5 – Commercial Operating System: XML Interfaces Reference."

2.11 Schedule 16 and 17 Settlement Overview

MISO has two administrative cost recovery schedules for funding the Services of operating and settling the FTR, Day-Ahead and Real-Time Energy and Operating Reserve Markets. Both schedules charge an MP based on its related Market Activity volumes.

Schedule 16 recovers the cost of the FTR Market and is assessed during the settlement process with the FTR Administration Amount charge type.

Schedule 17 recovers the costs of both the Day-Ahead and Real-Time Energy and Operating Reserve Markets and is assessed during the settlement process with the Day-Ahead Administration Amount and the Real-Time Administration Amount charge types.

Both Schedule 16 and 17 administration rates are calculated for a month and are applicable to MP activity conducted on ODs during that month. Each monthly rate is based on the budgeted schedule cost for the month, including a true-up amount from the prior months, divided by the estimated Market Activity expected to occur during the month.

2.11.1 Schedule 16

Tariff Schedule 16, FTR Administrative Service Cost Recovery Rider, allows MISO to recover costs associated with providing the FTR Service that includes, but is not limited to, the following:

1) Coordination of FTR bilateral trading;
2) Administration of FTRs through allocation, assignment, auction or any other process accepted by the Commission;
3) Support of the Transmission Provider’s on-line, internet-based FTR tool;
4) “Simultaneous feasibility” analyses to determine the total combination of FTRs that can be outstanding and accommodated by the Transmission System at a given point in time; and
5) The administration of FTRs and revenue distribution.

The recovery of costs associated with this service is from a single administrative rate that is collected using the FTR Administration Amount charge type. The rate is calculated and set for a calendar month. The monthly rate is set so that the total amount estimated to be collected during the calendar month is equal the budgeted cost to provide the service for the month including a true-up for prior months.

The administrative rate applicable to Schedule 16 is the FTR Market Administration Rate.

2.11.1.1 Schedule 16 Applicability

Schedule 16 is applicable to all MPs' related FTR Market Activities. MPs are financially responsible to MISO. Within the MISO Commercial Model, the MP is the financial entity, and the AO is the represented entity capable of engaging in Market Activities through its MP. As such, MPs are responsible for the activities along with the charges and credits incurred by their AOs.

AOs incur the Schedule 16 administrative rate charge through two FTR-related Market Activities:

Owning FTRs and/or Owning Flowgate Rights.

AOs that own FTRs and/or Flowgate Rights at the time the Day-Ahead Energy and Operating Reserve Market are cleared for an OD are charged the FTR Market Administration Rate. The rate is applied each hour to their total ownership volume.

Acting as the transaction buyer on scheduled Day-Ahead Grandfathered Agreement Financial Schedules.

MPs that are a party to a Grandfathered Agreement that have chosen Section 38.8.3.b. (Option B) of the Tariff are permitted through an AO to schedule Day-Ahead Grandfathered Agreement Financial Schedules. The transaction volume is validated by Market Settlements to ensure that the transaction has sufficient supply and Load obligation to at least equal the volume scheduled. The AO that is on record as the transaction buyer is considered by Market Settlements to be the market entity responsible for the transaction and is subject to the FTR Market Administration Rate. The rate is charged on the validated transaction volume by hour.

2.11.1.2 Schedule 16 Administration Rate

The Schedule 16 FTR Market Administration Rate is set for a calendar month. Whenever an OD is settled, whether it is for the first time or thereafter, the rates in effect for the OD are used for settlements and not the rates in effect on the Execution Date.

2.11.1.3 Schedule 16 Charge Type Calculation Methodology

The FTR Market Administration Rate is assessed per MW of FTR Profile Volume and per MWh of scheduled, validated Grandfathered Agreement Financial Schedule volume. The charge is summed by AO for the OD. The administration charge rate is subject to change based on costs incurred by MISO.

The Grandfathered Agreement Financial Schedule buyer is considered to be the GFA Responsible Entity for the collection of the administration amount for Tariff Schedule 16.

2.11.2 Schedule 17

Tariff Schedule 17, Energy Market Support Administrative Service Cost Recovery Rider, allows MISO to recover costs associated with providing the Day-Ahead and Real-Time Energy and Operating Reserve Market Services that include, but are not limited to, the following:

1) Market modeling and scheduling functions;
2) Market bidding support;
3) LMP/MCP support;
4) Market settlements and billing;
5) Market monitoring functions; and
6) Enabling the co-optimized least-cost, security-constrained commitment and dispatch of Resources to serve Load and Operating Reserve requirements in the MISO BA while also establishing a spot Energy and Operating Reserve Market.

The recovery of costs associated with this service is from two administrative rates:

- Transaction Administration Rate; and
  Energy and Operating Reserve Market Administration Rate

The Transaction Administration Rate is assessed on the number of hourly bid and offered virtual schedules in the Day-Ahead Energy and Operating Reserve Market and is collected in the Day-Ahead Administration Amount charge type. The Energy and Operating Reserve Market Administration Rate is assessed on MP related activity volumes in the Day-Ahead and Real-Time Energy and Operating Reserve Markets and collected in the Day-Ahead and Real-Time Administration Amount charge types. Both rates are calculated and set for a calendar month. Each rate is set so that the total amount estimated to be collected during the calendar month is equal to the budgeted cost to provide the service for the month, including a true-up for prior months.

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

2.11.2.1 Schedule 17 Applicability

Schedule 17 is applicable to MP related Day-Ahead and Real-Time Energy and Operating Reserve Market Activities. MPs are financially responsible to MISO. Within MISO Commercial Model, the MP is the financial entity and the AO is the represented entity capable of engaging in Market Activities through its MP. As such, MPs are responsible for the activities along with the charges and credits incurred by their AOs.

AOs incur Schedule 17 Energy and Operating Reserve Market Administration Rate charges through the following Day-Ahead and Real-Time Energy and Operating Reserve Market Activities:

- Number of hourly bid and offered virtual schedules;
- Cleared awarded Day-Ahead asset schedule volumes;
- Cleared awarded Day-Ahead Virtual bid and offer volumes;
- Cleared Day-Ahead Interchange Schedule volumes;
- Day-Ahead Carved-Out Grandfathered Agreement Transaction volumes;
- Buying and selling Day-Ahead Financial Schedule volumes (including those related to Option B Grandfathered Agreements);
- The difference between actual asset volumes and day-ahead cleared asset schedule volumes;

  Buying and selling real-time Financial Schedule volumes (including those related to Pseudo-tied generation and Load);

  The net CPNode difference between Day-Ahead Interchange Schedule volumes and Real-Time Interchange Schedule volumes; and

  The net CPNode difference between Day-Ahead Carved-Out Grandfathered Agreement Transaction volumes and Real-Time Carved-Out Grandfathered Agreement Transaction volumes.

In accordance with the Tariff, all assets meeting the administrative charge exemption are not subject to the Day-Ahead and Real-Time Market Administrative Amount charge type for the asset volume, Financial Schedule volumes, Option B Grandfathered Financial Schedule volumes and Carved-Out Grandfathered Agreement Transaction volumes at the asset CPNode. Virtual transactions are not exempted.

AOs that bid and offer virtual schedules in the Day-Ahead Energy and Operating Reserve Market are charged the Transaction Administration Rate on the total number of hourly schedules submitted. Until further notice, the Transaction Administration Rate is set to zero.

AOs that have schedule and transaction volumes in the Day-Ahead and Real-Time Energy and Operating Reserve Markets are charged the Energy Market Administration Rate according to the rate calculation methodology described below.

2.11.2.2 Schedule 17 Administration Rate

The two administrative rates related to Schedule 17 are set for a calendar month. Whenever an OD is settled, whether it is for the first time or thereafter, the rates in effect for the OD are used for Settlements and not the rates in effect on the Execution Date.

2.11.2.3 Schedule 17 Charge Type Calculation Methodology

The charge type calculation methodology differs slightly between the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Each calculation is separately described.

Schedule 17 Day-Ahead Charge Type Calculation Methodology

The charge type calculation methodology for assessing the Day-Ahead Administration Amount includes both the Transaction Administration Rate and the Energy and Operating Reserve Market Administration Rate.

The Transaction Administration Rate is assessed on the total hourly number of submitted Day-Ahead Virtual Bid and Offer Schedules for an OD. A transaction is defined as a single Bid or Offer by hour by AO. On an hourly basis by AO, the number of transactions are counted and multiplied by the Transaction Administration Rate.

The Energy Market Administration Rate is assessed on an AO's hourly participation volume in the Day-Ahead Energy and Operating Reserve Market. The AO's Day-Ahead Energy and Operating Reserve Market participation volume is calculated at each CPNode for each hour and summed for the entire OD. The resulting daily market participation volume is multiplied by the Energy and Operating Reserve Market Administration Rate. An AO's Day-Ahead participation volume at a CPNode is based on the total directional energy volume, into and out of the CPNode, by the AO. The directional volume methodology permits the AO to utilize day-ahead Financial Schedules in conjunction with either Interchange Schedules or cleared day-ahead asset (Resource, Load,) schedules, and not be assessed an administration charge on both the Financial Schedule volume and the corresponding Interchange Schedule or asset schedule.

Schedule 17 Real-Time Charge Type Calculation Methodology

The Energy Market Administration Rate is assessed on an AO's hourly participation volume in the Real-Time Energy and Operating Reserve Market. The AO's Real-Time Energy and Operating

Reserve Market participation volume is calculated at each CPNode for each hour and summed for the entire OD. The resulting daily market participation volume is multiplied by the Energy and Operating Reserve Market Administration Rate. An AO's Real-Time participation volume at a CPNode is based on the total directional energy volume, into and out of the CPNode, by the AO. The directional volume methodology permits the AO to utilize non-pseudo Real-Time Financial Schedules in conjunction with either Interchange Schedules or Real-Time asset (generation, Load, or DRR) imbalances, and not be assessed administration charges on both the Financial Schedule volume and the corresponding Interchange Schedule or asset schedule.

2.12 Schedule 24 Settlement Overview

Tariff Schedule 24 is a vehicle for LBAs to recover costs incurred as a result of implementing and operating in the Energy and Operating Reserve Market. LBAs shall be defined as entities performing certain balancing functions as listed in the Amended BA Agreement either directly or indirectly through an agent or contractor, and which are signatories to the aforementioned agreement (other than the Transmission Provider).

2.12.1 Schedule 24 Applicability

Schedule 24 charges will be assessed to any MP relative to their Day-Ahead and Real-Time Energy and Operating Reserve Market Activity. For Schedule 24 purposes, Market Activity is defined in the same manner that is defined and captured for Schedule 17 calculations (see Section 2.11.2.1 of this document).

2.12.1.1 Costs to be Recovered

LBA costs include daily operation and maintenance costs, administrative and general costs, capital costs, costs for systems-in-place, training of personnel, and any costs that result from the performance of obligations imposed by the Tariff on LBAs; provided, however, that all costs to be recovered under this Schedule must be related to LBA actions in performing obligations under the Tariff, and shall not include any costs reimbursed by MISO to LBAs or costs otherwise already recovered under the Tariff.

Each LBA must maintain account(s) which allow all applicable costs to be recovered to be readily identified and audited. Please see the Tariff for specifics on the cost accounting requirements regarding Schedule 24.

2.12.2 Schedule 24 Allocation Rate

The allocation rate related to Schedule 24 is set for each calendar month. The date used to determine the effective Schedule 24 Allocation Rate during settlement is the OD, not the Execution Day.

Annually, LBAs are required to submit the previous year's applicable costs to MISO by May 1st. These figures will be used to calculate the Schedule 24 $/MW Allocation rate(s) for the upcoming Schedule 24 year (spanning from June 1st through May 31st).

2.12.3 Schedule 24 Calculation Methodology

The charge type calculation methodology differs slightly between the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Each calculation is separately described.

Schedule 24 Day-Ahead Allocation Charge Type Calculation Methodology

The Schedule 24 Allocation Rate is assessed on an AO's hourly participation volume in the Day-Ahead Energy and Operating Reserve Market. The AO's Day-Ahead Energy and Operating Reserve Market participation volume is calculated at each CPNode for each hour and summed for the entire OD. The resulting daily market participation volume is multiplied by the Schedule 24 Allocation Rate. An AO's Day-Ahead participation volume at a CPNode is based on the total directional energy volume, into and out of the CPNode, by the AO. The directional volume methodology permits the AO to utilize day-ahead Financial Schedules in conjunction with either Interchange Schedules or cleared day-ahead asset (Resource, Load) schedules, and not be assessed an allocation charge on both the Financial Schedule volume and the corresponding Interchange Schedule or asset schedule.

Schedule 24 Real-Time Allocation Charge Type Calculation Methodology

The Schedule 24 Allocation Rate is assessed on an AO's hourly participation volume in the Real-Time Energy and Operating Reserve Market. The AO's Real-Time Energy and Operating Reserve Market participation volume is calculated at each CPNode for each hour and summed for the entire OD. The resulting daily market participation volume is multiplied by the Schedule 24 Allocation Rate. An AO's Real-Time participation volume at a CPNode is based on the total directional energy volume, into and out of the CPNode, by the AO. The directional volume methodology permits the AO to utilize non-pseudo real-time Financial Schedules in conjunction with either Interchange Schedules or real-time asset (generation, Load) imbalances, and not be assessed an allocation charge on both the Financial Schedule volume and the corresponding Interchange Schedule or asset schedule.

Schedule 24 Real-Time Distribution Charge Type Calculation Methodology

Annually, LBAs are required to submit the previous year's applicable costs to MISO by May 1st. These figures will be used to calculate each LBA's share of total costs. This share is used to distribute the total collected dollars for each OD. The total Dollars collected is the sum of the Dollars collected in the Schedule 24 Day-Ahead Allocation Charge Type and Schedule 24 Real-Time Allocation Charge Type and are added up by OD and allocated to the LBAs based on their pro rata share on a daily basis.

2.13 Local Balancing Authority Inadvertent Settlement Overview

LBA energy inadvertent interchange occurs when there is a difference between net actual energy interchange and net scheduled energy interchange. This difference results from an imbalance within the LBA of generation, load, scheduled energy imports and schedule energy exports. NERC policies require LBAs to minimize and account for all inadvertent energy interchanges. MISO monitored inadvertent account balances for LBAs that occurred prior to the start of the Real-Time Energy Market and worked with each LBA to arrange the required physical energy payback. After the start of the Real-Time Energy Market, MISO is responsible for minimizing and paying back inadvertent energy with the rest of the Eastern Interconnect (the rest of the electric grid East of the Rocky Mountains). MISO provides each LBA within MISO a Net Scheduled Interchange (NSI) value to follow. The total inadvertent, actual less scheduled, that occurred from all MISO LBAs per Hour is summed and represents the total MISO inadvertent with the Eastern Interconnect. MISO dispatches generation as necessary to adjust for payback to and from MISO. Each LBA's hourly inadvertent MWh causes a charge or a credit to the Real-Time Energy Market regardless of whether MISO has any total inadvertent. Market Settlements values each LBA's inadvertent by multiplying the hourly inadvertent value by the average generation LMP within the LBA. The hourly cost of all energy inadvertent from all MISO LBAs is summed and the total is assessed hourly to all AOs based upon their total Day-Ahead and Real-Time Energy Market Participation volumes.

2.13.1 Net Scheduled Interchange

NSI is the summation of all scheduled energy flowing into and out of a LBA via all interconnected tie points. Positive NSI indicates a LBA is a net exporter of scheduled energy and a negative NSI indicates a LBA is a net importer of scheduled energy. NSI for each LBA in MISO is calculated during Real-Time Operations in the DART and provided to Market Settlements through the PSS as a single integrated hourly value.

2.13.2 Net Actual Interchange

Net Actual Interchange (NAI) is the summation of all actual energy flow into and out of a LBA via all interconnected tie points. Positive NAI indicates a LBA is a net exporter of energy and a negative NAI indicates a LBA is a net importer of energy. NAI is reported to MISO from each LBA based on meter data from interconnection tie points. The PSS maintains the NAI data and provides the data to the Market Settlements System. In the event actual NAI data has not been provided by the LBA to MISO in time for the initial settlement calculation, MISO substitutes NSI until the data is provided.

2.13.3 Net Inadvertent Calculation Methodology

The value of all Net Inadvertent Interchange is determined for each LBA for each hour by averaging the LMP of generation for the LBA and multiplying it by the difference between NAI and NSI. The hourly Net Inadvertent Interchange for all LBAs is summed up to a MISO daily total. This daily total is distributed through the Real-Time Net Inadvertent Distribution charge type to all MPs based on their participation volume in the Day-Ahead and Real-Time Energy Market for the OD.

2.14 Residual Load Settlement Overview

MISO uses the term Residual Load to define the amount of over or under claimed Energy in a LBAA. Residual Load is equal to the combined following inputs multiplied by negative one: 1) the reported amount of injections (-), 2) the reported amount of withdrawals (+), 3) the LBAA Actual Net Interchange, and 4) the amount of SE determined Losses (+) for the LBAA. MISO assigns the Residual Load to an asset, and thus an AO, in each LBAA. The AO's MP for the asset is financially responsible for the effect of the Residual Load.

2.14.1 Net Actual Interchange

Net Actual Interchange (NAI) is the summation of all actual energy flow into and out of an LBA via all interconnected tie points. Positive NAI indicates a LBA is a net exporter of energy and a negative NAI indicates a LBA is a net importer of energy. NAI is reported to MISO from each LBA based on meter data from interconnection tie points. The PSS maintains the NAI data and provides the data to the Market Settlements System.

2.14.2 Residual Load Volume Determination

Residual Load is calculated hourly for each LBA and is equal to:

$$(BA\_BLL\_MTR + NAI_{BA} + LBA\_LOSS) * (-1)$$

Where:

BA_BLL_MTR =	Sum of all asset CPNode meter data within the given LBAA. Injections are represented by negative values and Load is represented by positive values.
NAI_{BA} =	The NAI for the given LBAA. A positive value represents energy flowing out of the area while a negative value represents energy flowing into the area.
BA_LOSS =	The SE losses for the given LBAA. Losses are positive values.

2.14.3 Residual Load Owner Assignment

Each LBA is expected to reach an agreement with a single MP for the Residual Load assignment. The selected MP is required to identify to MISO the asset where the Residual Load is assigned and settled. The assigned asset and related CPNode must be within the LBAA and must be owned by an AO that the MP represents. The assigned asset and related CPNode must be a Load Zone asset.

If a LBA cannot reach an agreement with an MP, MISO assigns the Residual Load to an asset (which assigns it indirectly to an MP).

2.14.4 Residual Load Asset Impact

The hourly-calculated Residual Load value is added to the assigned asset's actual reported meter data (MISO meter estimated when actual data has not been reported) and is used for settlement. The AO's Real-Time Settlement statement displays:

1) The actual submitted meter data;
2) The alternate estimated MISO provided meter data from the SE that is used when no actual data has been provided;
3) The Residual Load calculated volume; and
4) The real-time billable meter volume that is used for settlements.

Residual Load is only calculated and settled in the Real-Time Energy and Operating Reserve Market. Residual Load affects the following charge types:

Real-Time Asset Energy Amount – The assigned asset has its meter data values adjusted by the Residual Load value and as such it changes the volume of energy settled.

Real-Time Non-Excessive Energy Amount – The assigned Generation asset has its meter data values adjusted by the Residual Load value and as such it changes the volume of Non-Excessive Energy settled.

Real-Time Excessive Energy Amount **–** The assigned Generation asset has its meter data values adjusted by the Residual Load value and as such it changes the volume of Excessive Energy settled.

Real-Time Distribution of Losses Amount – Asset meter data is used to determine Loss Pool allocation and LRS factors. Additional positive Residual Load increases the AO's allocation, thus increasing its hourly loss distribution amount.

Real-Time Market Administration Amount – Real-Time cost recovery rider is charged on the net directional energy volume of an asset. When the Residual Load volume offsets the asset volume, then administration charges may decrease. When the Residual Load volume causes the asset's volume to increase, then administration charges may increase also.

Real-Time Net Inadvertent Distribution – This charge type uses the Real-Time Administrative volume as one of the inputs for determining Real-Time Net Inadvertent Distribution allocation. If Residual Load increases an AO's administrative volume, then their allocation in this charge type increases.

Real-Time Revenue Neutrality Uplift Amount **–** Residual Load is included in the AOs total LRS factor. If the Residual Load increases a Load asset's volume, then the AO has a greater allocation of credits in this charge type.

Real-Time RSG First Pass Distribution Amount **–** Real-Time RSG is primarily funded by volume discrepancies between the Real-Time and the Day-Ahead Energy and Operating Reserve Markets. Although Real-Time Billable Meter Data is used in this calculation, the Residual Load effect is subtracted and as such there is no impact from Residual Load in this charge type.

Real-Time Revenue Sufficiency MWP Amount – When a generation AO is awarded Real-Time Revenue Sufficiency and is also assigned as the Residual Load holder, the Residual Load is removed prior to determining any MWP. Including Residual Load in this calculation prior to calculating the MWP defeats part of the purpose of this charge type.

2.14.5 Local Balancing Authority Residual Load Account Statements

2.14.5.1 Local Balancing Authority Residual Load Account Statement Overview

The Market Settlements process produces a LBA Residual Load Account (RLA) statement for each LBA for each OD settled. These statements provide LBAs with all the data elements needed in order to calculate a residual load volume. With the report, a LBA has the capability to review all alternate and submitted meter data for validity. The LBA is not responsible for the costs of the Residual Load, nor will an invoice be issued to the LBA for the Residual Load.

Following MISO staff approval each day, LBA Residual Load Statements are published as XML files for each LBA for each OD settled. Each statement has the following naming convention:

RLA_<Local Balancing Authority NERC Name>_<MMDDYYYY Schedule Date>_
<MMDDYYYY Operating Date>-<Settlement Type>.xml

The Schedule Date is the day the settlement run is scheduled to complete. The OD is the date being settled. The Settlement Type consists of: 1) either the letter “S” for standard settlement or “R” for non-standard, and 2) the number of days between the Operating Date and the Schedule Date. All statements produced for a single schedule date are compressed together per LBA into a single zip file. The zip file naming convention is as follows:

RLA_<Local Balancing Authority NERC Name>_< YYYYMMDD Scheduled Date >.zip

The Schedule Date is being displayed in this format to permit proper sorting in the Portal.

LBAs are able to download their RLA Statements using an automatic programmatic interface or by logging into the Portal and downloading them manually. MISO will not support opening the statements directly from the Portal.

Once the RLA Statements are available on the Portal, each LBA will be responsible for retrieving their own statements. For additional information on XML requirements and specifications, please see the MISO Extranet posted document titled, “COS XML Specifications - Residual Load Statement.”****

MISO will provide XML style sheets to allow LBAs to view statements via using an Internet browser. These style sheets are provided in each daily LBA zipped file. To use the internet browser to view the statement, the LBA is required to: 1) unzip the downloaded file and keep the style sheets in the same directory as the downloaded statements, and 2) then open the XML statements using the internet browser.

2.14.5.2 Residual Load Account Settlement Statement Format

Each time an OD is settled, the MISO Market Settlements staff produces a specific RLA Settlement Statement. Separate Market Settlement Statements are produced for each LBA for each OD settled. Daily, LBAs will receive statements for each S7, S14, S55, S105 and any non-standard settlement for the execution day.

Exhibit 2-16: Example of Residual Load Account Settlement Statement Header

MISO	Residual Load Account Statement
Balancing Authority Name:	NE-CONTROL-AREA
Balancing Authority ID:	1-NE-CONTROL-AREA
Timestamp:	6/30/2011
Scheduled Date:	7/1/2011
Operating Date:	6/24/2011
Settlement Code:	S7
Statement ID:	RLA_NE-CONTROL-AREA_07012011_06242011-S7

Exhibit 2-17 is a representation of the RLA statement header section using the XML Style Sheets provided by MISO. The example above is for the LBA “NE-Control-Area” for the S7 for June 24, 2011 Operating Date.

The header section contains the following general information:

- ***Local Balancing Authority Name*** **–** The abbreviated, registered identification name for the LBA;
- ***Local Balancing Authority ID*** – MISO assigned Identification Code for the LBA;
- ***Timestamp*** – The date the statement was processed;
- ***Scheduled Date*** – The date when this particular statement was scheduled;
- ***Operating Date*** – The OD that was settled relative to the data in the statement;
- ***Settlement Code*** – The type of settlement run (S7, S14, S55, S105 or resettlement); and
- ***Statement ID*** – The Statement identifier which is also the filename.

Exhibit 2-17: Example of Residual Load Account Settlement Statement Local Balancing Authority Totals

Balancing Authority Totals

Determinant HREND	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Losses	2.0	2.0	1.0	1.0	1.0	1.0	1.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	4.0	3.0	3.0	3.0	3.0	3.0	2.0	2.0	2.0
Withdrawal	130.0	113.0	110.0	116.0	119.0	136.0	136.0	156.0	187.0	223.0	241.0	248.0	247.0	285.0	291.0	293.0	274.0	278.0	243.0	229.0	203.0	172.0	154.0	142.0
Injection	-246.0	-247.0	-242.0	-250.0	-251.0	-239.0	-244.0	-243.0	-225.0	-233.0	-229.0	-225.0	-216.0	-216.0	-199.0	-193.0	-196.0	-185.0	-161.0	-149.0	-145.0	-145.0	-145.0	-135.0
Net Actual Interchange	58.0	84.0	95.0	88.0	76.0	53.0	14.0	-23.0	-84.0	-40.0	-48.0	-66.0	-35.0	-72.0	-59.0	-78.0	-40.0	-72.0	-35.0	-96.0	-90.0	-79.0	-22.0	15.0
Residual Load Adjustment	56.0	48.0	36.0	45.0	55.0	49.0	93.0	108.0	120.0	48.0	33.0	40.0	1.0	0.0	-36.0	-26.0	-41.0	-24.0	-50.0	13.0	29.0	50.0	11.0	-24.0
Net Scheduled Interchange	63.0	89.0	100.0	93.0	81.0	58.0	19.0	-18.0	-79.0	-35.0	-43.0	-61.0	-30.0	-67.0	-54.0	-73.0	-35.0	-67.0	-30.0	-91.0	-85.0	-74.0	-17.0	20.0
Day 1 Net Inadvertent Payback	0.0	2.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Exhibit 2-18 is a representation of the RLA LBA Statement Totals Section using the XML Style Sheets provided by MISO.

This section provides LBAs with total hourly OD data in MWhs. The hourly totals in this section provide the LBA with the information necessary to calculate the Residual Load Adjustment value for each hour. The data is displayed in EST in hour ending format. The determinants provided are as follows:

Losses – Hourly Real-Time MWh losses for a LBA as calculated by DART. Losses are shown as a positive value and represent an energy Load to the LBA.

Withdrawal – The total hourly MWh amount of energy withdrawal for all assets in a LBAA. These values are the sum of all positive meter values, regardless of whether the asset is a Resource or Load. Actual meter data is used when provided; otherwise the alternate meter data value is used. The complete list of all of the meter data used to calculate these values is provided in the “Participant Data” section of the report.

Injection **–** The total hourly MWh amount of energy injection for all assets in a LBAA. These values are the sum of all negative meter values regardless of whether the asset is a Resource or Load. Actual meter data is used when provided; otherwise the alternate meter data value is used. The complete list of all of the meter data used to calculate these values is provided in the “Participant Data” section of the report.

NAI – The hourly LBA provided NAI in MWhs used in calculating the settlement for the OD. A negative value represents an import into the LBA whereas a positive volume represents an export from the LBA.

- ***Residual Load Adjustment*** – The hourly calculated LBA Residual Load in MWhs. A positive value represents unreported Load and/or over reported generation. A negative number represents under reported Load and/or over under reported generation. The hourly value is the sum of Losses, Withdrawal, Injection, and NAI. Residual Load is calculated as follows:

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

= (Losses + Withdrawal + Injection + NAI) * (-1)

***NSI* –** The hourly MWh LBA NSI calculated by DART used in settling the OD. A negative value represents an import into the LBA whereas a positive volume represents an export from the LBA.. This value has no impact on the Residual Load calculation, but is being provided to allow the LBA the ability to review the data being used in the settlement calculations for the OD.

Participant Data

Exhibit 2-18: Example of Residual Load Account Settlement Statement Participant Data

Participant Data

State Estimator HREND	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
NE-LOAD/NE-LOAD	128.0	111.0	108.0	115.0	118.0	135.0	135.0	155.0	186.0	222.0	240.0	247.0	246.0	284.0	290.0	292.0	273.0	277.0	241.0	227.0	201.0	170.0	152.0	140.0
NE-GENRES/NE-GENRES	-247.0	-248.0	-243.0	-227.0	-228.0	-215.0	-220.0	-219.0	-202.0	-210.0	-205.0	-201.0	-193.0	-194.0	-176.0	-169.0	-174.0	-162.0	-162.0	-150.0	-146.0	-146.0	-146.0	-136.0
NE-DRR/NE-DRR	0.0	0.0	0.0	-25.0	-25.0	-26.0	-26.0	-26.0	-25.0	-25.0	-26.0	-26.0	-25.0	-24.0	-25.0	-26.0	-24.0	-25.0	0.0	0.0	0.0	0.0	0.0	0.0

MDMA Submissions HREND	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
NE-LOAD/NE-LOAD	129.0	112.0	109.0	116.0	119.0	136.0	136.0	156.0	187.0	223.0	241.0	248.0	247.0	285.0	291.0	293.0	274.0	278.0	242.0	228.0	202.0	171.0	153.0	141.0
NE-GENRES/NE-GENRES	-246.0	-247.0	-242.0	-226.0	-227.0	-214.0	-219.0	-218.0	-201.0	-209.0	-204.0	-200.0	-192.0	-193.0	-175.0	-168.0	-173.0	-161.0	-161.0	-149.0	-145.0	-145.0	-145.0	-135.0
NE-DRR/NE-DRR	1.0	1.0	1.0	-24.0	-24.0	-25.0	-25.0	-25.0	-24.0	-24.0	-25.0	-25.0	-24.0	-23.0	-24.0	-25.0	-23.0	-24.0	1.0	1.0	1.0	1.0	1.0	1.0

Exhibit 2-19 is a representation of the RLA LBA Statement Participant meter data using the XML Style Sheets provided by MISO.

This Participant Data section provides LBAs with hourly OD alternate and actual meter data in MWhs by asset. The data is displayed in EST in hour ending format. The report is divided into two subsections: 1) SE, and 2) MDMA Submissions.

The SE section is the hourly DART integrated 5 minute SE results that are provided to Market Settlements for use as alternate meter data. Every asset assigned in the Commercial Model to the LBA for the OD will have a SE provided alternate meter data. The alternate meter data is only used in settlements when the MDMA has not provided actual meter data.

The MDMA Submissions section displays the MP MDMA submitted actual meter data. Hourly data will only display if the MDMA has submitted meter data prior to noon one day before the OD is scheduled to be settled. If the MDMA has submitted data for an OD multiple times, only the last submitted data is used in the calculations and listed on this report.

2.15 Miscellaneous Charge Settlement Overview

The miscellaneous charge is a mechanism that allows MISO to issue charges and/or credits based on specific requirements to either one AO or to the entire market. This charge is applied to MPs through the Real-Time Miscellaneous Amount charge type. The use of this charge type to collect or disperse funds due occurs from an entity having legal authority and/or oversight.

2.15.1 Miscellaneous Charge Applicability

The miscellaneous charge, although showing on the Real-Time Settlement Statement, is not limited to imposing charges and/or credits related to Real-Time Energy and Operating Reserve Market Activities, but is used for FTR and Day-Ahead Energy and Operating Reserve Market activities as well. MISO maintains detailed records of the use of this charge type and provides MPs with a yearly non-confidential report showing how this charge type has been used along with the disposition of any excess funds. For each miscellaneous charge that occurs, MPs are given the following information on their Real-Time Settlement Statements:

- A reference identifier;
- The reason for the charge and/or credit;
- Whether the charge or credit is for a single AO or the entire market;
- The ratio share (Market LRS, Market Ratio Share (MRS), FTR Ratio Share (FRS) or LBA-specific LRS) if applicable; and
  The amount of the charge or credit.

2.15.2 Miscellaneous Charge Capability

The miscellaneous charge can be used to apply a single charge or credit to a single AO, and/or it can be used to apply market wide charges and credits to all AOs. The specific capability related to the miscellaneous charge is as follows:

- Apply a charge or credit to a single AO.
- Apply a charge or credit to a single AO with the opposite charge or credit spread to all other AOs based on an OD's:
  - Market LRS;
  - LBA-specific LRS;
  - MRS; or
  - FRS.
- Apply a charge or credit to all AOs based on an OD's:
  - Market LRS;
  - LBA-specific LRS;
  - MRS; or
  - FRS.

The use of a ratio share to disperse or collect funds is much quicker than having Market Settlements manually calculate all AO daily ratios. The definitions of the four ratio methods are:

- Market LRS is determined by:
  - Summing the volumes of the AO's assets that are consuming energy (acting as Load) for an hour plus the sum of all real-time Interchange Schedules volume where the AO is buying the transaction volume for export out of MISO (these are wheel out schedules from MISO and do not include wheel through schedules); and
  - Dividing the result by the sum of all AO assets that are consuming energy during the same hour plus the sum of all real-time Interchange Schedules volume where AO's are buying the transaction volume for export out of MISO (these are wheel out schedules from MISO and do not include wheel through schedules),
- MRS is equal to an AO's total hourly Day-Ahead and Real-Time Administration Volume divided by the total hourly Day-Ahead and Real-Time Administration Volume for all MISO.
- FRS is equal to an AO's total hourly FTR Profile Volume divided by the total hourly FTR Profile Volume for all MISO.
- LBA-specific LRS is determined by:

- Summing the volumes of an AO's assets that are consuming energy (acting as Load) for an hour in a specific LBA; and
- Dividing the result by the sum of all AO assets that are consuming energy during the same hour in the specified LBA.

2.15.3 Miscellaneous Charge Settlement

Each miscellaneous charge is assigned to a specific OD settlement. A miscellaneous charge could be applied to the 55th day (S55) settlement for an OD when there was none on the prior 14th day (S14) settlement. Likewise a miscellaneous charge can be assigned to a nonstandard settlement for an OD with the sole purpose to have that day's settlement recalculated.

2.16 Marginal Losses Distribution Overview

Real-Time Distribution of Losses Amount is the charge type that distributes surplus collected losses to Load Zone AOs. Marginal Losses Surplus is distributed into LBAAs and then allocated to the AOs within the LBAAs.

2.16.1 Applicability

All MPs with Load volumes in the Real-Time Energy and Operating Reserve Market, excluding Load scheduled by Option B and Carved-Out Grandfathered Agreements, are eligible to receive Marginal Losses Surplus distribution from the amount that was allocated to the corresponding Loss Pool.

2.16.2 Charge Type Calculation Methodology

On an hourly basis, MISO calculates the Real-Time Over-Collected Losses as the Day-Ahead Marginal Loss Surplus plus the Incremental Real-Time Marginal Loss Surplus.

On an hourly basis, MISO calculates the Marginal Loss Surplus as the sum of:

The total Real-Time Over-Collected Losses; plus

The total Day-Ahead Losses Rebate on Option B Grandfathered Agreements Financial Schedules Amount; plus

The total Day-Ahead Losses Rebate on Carved-Out Grandfathered Agreements Charge Type Amount; plus

The total Real-Time Losses Rebate on Carved-Out Grandfathered Agreements Charge Type Amount;

Less any amount that cannot be distributed because every LBAA's normalized Overall Loss Factor is zero in a given hour.

MISO regional transmission area is divided into Loss Pools. A Loss Pool is defined as a collection of LBAs for the purpose of distributing loss surplus. The relationships between LBAs and Loss Pools may vary over time and are maintained historically by ODs. Currently, each LBA is defined as a separate Loss Pool under the Tariff.

The Marginal Losses Surplus is allocated to each Loss Pool on a pro rata basis per the cost of supplying losses to Load scheduled by MPs, excluding any Load scheduled by Option B and Carve-Out Grandfathered Agreements.

The Marginal Losses Surplus Loss Pool share is distributed to the MPs within each Loss Pool on a pro rata basis per the Market LRS of the total Load in the Loss Pool served by the MP, excluding any Load scheduled and served by Grandfathered Agreements.

The cost of supplying losses to Load is calculated in each LBAA as:

> The estimated cost of Marginal Losses by the Load within the Loss Pool excluding any Load scheduled by GFAs;
> Minus: The estimated cost of Marginal Losses by the portion of generation that was used to serve Load within the Loss Pool excluding any generation scheduled by GFAs;
> Minus: The average cost of Marginal Losses of the energy imported into MISO.

Whenever the estimated cost of Marginal Losses incurred by the Load within a given Loss Pool does not exceed the cost of Marginal Losses of its generation and imports, no Marginal Losses Surplus is allocated to the Loss Pool.

2.16.3 Over-Collected Losses Revenue Methodology

2.16.3.1 Day-Ahead Over-Collected Losses Revenue Summary

Day-Ahead Over-Collected Losses is a dollar value calculated by the DART every hour in the Day-Ahead Energy and Operating Reserve Market cleared solution as follows:

OCL_{DA} = - MECr * $LossOffset_{DA}$

Where:

OCL_{DA} = Over-Collected Losses in the Day-Ahead Energy and Operating Reserve Market for the hour in question.

MECr = Marginal Energy Cost at the Reference Bus in the Day-Ahead Energy and Operating Reserve Market for the hour in question (i.e., the LMP at the reference bus).

$LossOffset_{DA}$ = The MW amount that must be added to Marginal Losses to obtain average losses for the hour in question. $LossOffset_{DA}$ is a negative value since Marginal Losses exceed average losses.

MISO net Marginal Loss revenue in the Day-Ahead Energy and Operating Reserve Market for a specific hour is equal to the product of MISO Marginal Losses for that hour and the MECr for that hour. Therefore, over-collected loss revenue in the Day-Ahead Energy and Operating Reserve Market for a specific hour is due to the difference between MISO Marginal Losses and MISO average losses for that hour, which is represented by the Day-Ahead Loss Offset.

In the Day-Ahead Energy and Operating Reserve Market, $LossOffset_{DA}$ is calculated as follows for the hour in question:

$LossOffset_{DA}$ = $PDemand_{DA}$ * $PLossOffset_{DA}$ * MTLF

Where:

$PDemand_{DA}$ = Percentage of Forecasted Demand estimated to clear the Day-Ahead Energy and Operating Reserve Market.

$PLossOffset_{DA}$ = The loss offset estimate as a percentage of the Day-Ahead Cleared Demand.

MTLF = Total Load forecasted for the hour in question.

$PLossOffset_{DA}$ is set equal to the estimated MISO average loss rate multiplied by –1 since Marginal Losses are theoretically equal to average losses multiplied by a factor between 1 and 2.

2.16.3.2 Incremental Real-Time Over-Collected Losses Revenue Summary

Incremental Real-Time Over-Collected Losses are hourly dollar values calculated by the Market Settlement System as each OD is settled. The calculation is as follows:

$OCL_{\square RT} = \square_{i \in CPN} \square [(P_{RTi} - P_{DAi}) * (LMP_{RTi} - MCC_{RTi})]$

Where:

$OCL_{\square RT}$ = Incremental Over-Collected Losses in the Real-Time Energy and Operating Reserve Market for the hour in question.

i = A CPNode in MISO.

CPN = The entire set of CPNodes in MISO.

P_{RTi} = Real-Time financial MW flow at CPNode i, sign convention is Injection >0 and Withdrawal > 0.

P_{DAi} = Day-Ahead financial MW flow at CPNode i, sign convention is Injection >0 and Withdrawal > 0.

LMP_{RTi} = Real-Time full LMP at CPNode i.

MCC_{RTi} = Real-Time MCC of LMP at CPN i.

The incremental financial MW flow, (P_{RTi} - P_{DAi}), can be represented as any combination of 6 different market instruments:

Billable Meter MW less Day-Ahead Cleared MW at market Assets;

0 minus Cleared Virtual MW;

-1 * (Real-Time Physical Schedule MW – Day-Ahead Physical Schedule MW) at the source Interface of Import Schedules and Through Schedules where all MW are > 0;

(Real-Time Physical Schedule MW – Day-Ahead Physical Schedule MW) at the sink Interface of Export Schedules and Through Schedules where all MW are > 0;

-1 * (Real-Time Carved-Out Schedule MW – Day-Ahead Carved-Out Schedule MW) at the source Interface of Import Schedules and Through Schedules where all MW are > 0; and

(Real-Time Carved-Out Schedule MW – Day-Ahead Carved-Out Schedule MW) at the sink Interface of Export Schedules and Through Schedules where all MW are > 0.

2.17 Grandfathered Agreement Settlement Overview

The Tariff identifies four options for MPs that are parties to Grandfathered Agreement(s) that intend to continue maintaining Transmission Service under the agreements. Each option specifies a separate scheduling and settlement method. Each option with its settlement impact is briefly discussed below:

Option A **–** The MP elects to receive FTRs for the Grandfathered Agreement. There is no special settlement treatment required for this option since the MP has elected to use FTRs. The MP is responsible for all credits, charges, rights, and responsibilities associated with FTRs.

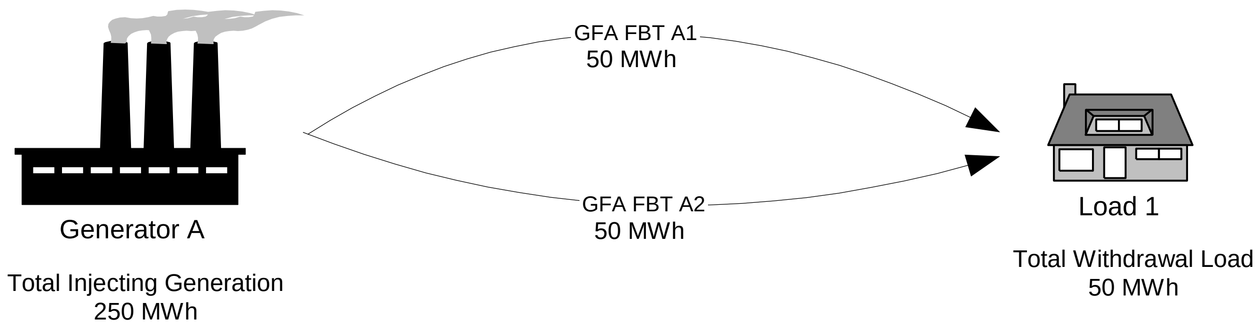
Option B – The MP utilizes and schedules Option B Grandfathered Agreement Financial Schedules in lieu of FTRs. For these special transactions, MISO holds FTRs to account for the capacity being allocated against the Financial Schedules. After congestion rebates are paid, any excess congestion fund Dollars remaining from MISO held FTRs for Option B Grandfathered Agreements are rolled into the Monthly and Yearly Revenue Allocation Charge Types.

The buying and selling MPs of Option B related Grandfathered Agreements are refunded the cost of congestion paid. MISO funds the congestion rebates using MISO held FTRs, and when they are insufficient, collects the remaining funds from Load AOs using the Real-Time Revenue Neutrality Uplift Amount charge type.

The buying and selling MPs of Option B Grandfathered Agreements are refunded a portion of their loss charges (and credits). The refund rate is fixed in the Tariff and is set in the Market Settlement System as a factor that displays on the Day-Ahead Settlement Statement. MISO funds the loss rebates from the Day-Ahead Over-Collected Losses fund.

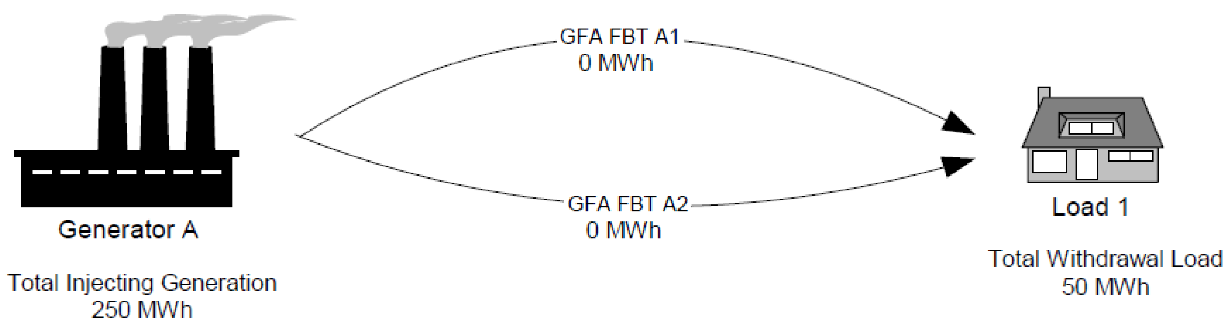
All scheduled volumes related to Option B Grandfathered Agreements are validated to ensure that the MP has sufficient generation supply volume for the transaction at the source CPNode and a sufficient Load obligation at the sink CPNode. If the MP does not have sufficient volume at either CPNode, then the related transactions are reduced to zero volume. The generation supply volume must be provided by an injecting generation asset at an asset CPNode or by physical transaction imports at an Interface node. The Load obligation volume must be consumed by physical transaction exports at an Interface node, or by the combination of Load asset withdrawal and cleared net virtual volume by the AO for the Load asset. For additional clarification on how Option B Grandfathered Agreements are validated, please see the Market Settlements Calculation Guide. If an MP is scheduling more than one transaction from a source CPNode, or providing more than one transaction to a sink CPNode, then the total supply volume along with the total consumed volume must be greater than the total transaction volume. In Example 1 (Exhibit 2-20) below, Generator A is injecting 250 MWh and the Load 1 is withdrawing 50 MWh. There are two Option B Grandfathered Agreement Financial Schedules (abbreviated as GFA Financial Schedule A1 and GFA Financial Schedule A2) scheduled between the two assets of 50 MWh each. Since the Load 1 is only consuming 50 MWh and the total transaction volume to Load 1 is 100 MWh, both transaction volumes are reduced during the validation process to zero.

Exhibit 2-19: Example 1 – Prior to GFA Validation



Example 2 (Exhibit 2-21) below shows the results of the validation process performed on the Example 1.

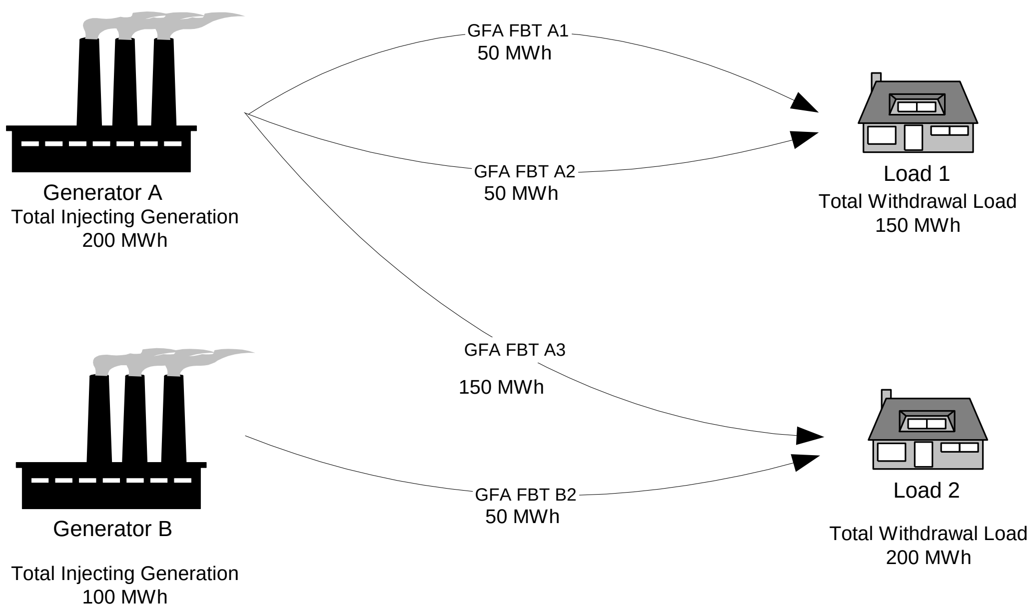
Exhibit 2-20: Example 2 – After GFA Validation for Example 1



In Example 3 (Exhibit 2-22) below, Generator A is injecting 200 MWh, Generator B is injecting 100 MWh, Load 1 is withdrawing 150 MWh, and the Load 2 is withdrawing 200 MWh. There are four Option B Grandfathered Agreement Financial Schedules scheduled between the assets. In the following example, Generator A is trying to supply more transaction volume than it is injecting. As such the following transactions are reduced during the validation process to zero: GFA

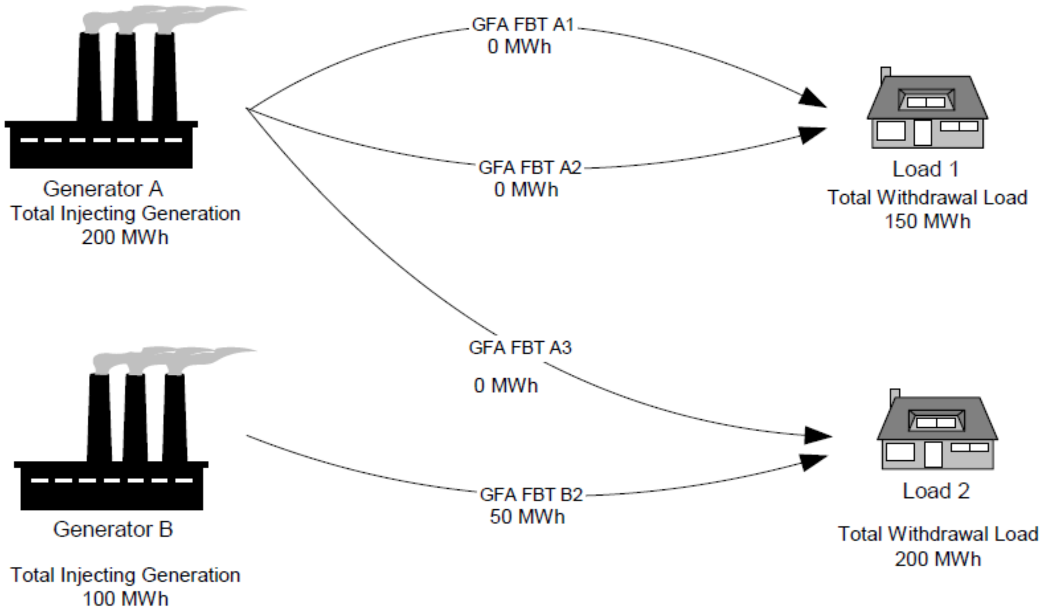
Financial Schedule A1, GFA Financial Schedule A2, and GFA Financial Schedule A3. If Generator A was only supplying any two of the three transactions, none of the volumes would be reduced to zero.

Exhibit 2-21: Example 3 – Prior to GFA Validation



Example 4 (Exhibit 2-23) below shows the results of the validation process performed on the Example 3. It is important to note that the Grandfathered Agreement Financial Schedule GFA Financial Schedule B2 is not reduced to zero.

Exhibit 2-22: Example 4 – After GFA Validation of Example 3



In both Example 1 and Example 3, the MP attempted to schedule greater transaction volume than the asset could utilize and as such the volumes were reduced to zero. The MP could have utilized non-Grandfathered Agreement Financial Schedules and would have avoided invalidation since those transactions are not validated.

Option B Grandfathered Financial Schedule MPs (buyer and seller) are subject to the Day-Ahead Market Administration Amount charge type. The transaction buyer is also subject to the FTR Administration Amount charge type.

Option C – MPs that choose this option, continue to use Transmission Service, but do not nominate or receive FTRs, nor do they use Grandfathered Agreement Financial Schedules. There is no settlement impact with this option.

Option Carve-Out – The MP utilizes and schedules Carved-Out Grandfathered Agreement transactions using the PSS. MISO creates Open Access Same-Time Information System (OASIS) reservations whereby MPs can schedule against these agreements in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. These transactions are transferred to the settlement system in the same manner as day-ahead and real-time Interchange Schedules. Carved-Out Grandfathered Agreement Transactions have an identified buyer and seller along with a source and sink CPNode as determined by the agreement. The buyer and seller can be any registered AO and the source and sink can be any defined, settlement CPNode. For these special transactions, MISO holds FTRs to account for the capacity being allocated against the Financial Schedules. After congestion rebates are paid, any excess congestion fund Dollars remaining from MISO held FTRs for Carved-Out Grandfathered Agreements are rolled into the Monthly and Yearly Revenue Allocation Charge Types.

The buying MP of Carved-Out Grandfathered Agreement Transactions (i.e., the entity receiving the energy) is charged both the marginal cost of congestion and the marginal cost of losses between the sink and source CPNodes. These charges are assessed in the Day-Ahead and Real-Time Financial Schedule Congestion and Losses Amount charge types. The buying MP is fully refunded these charges in the Day-Ahead and Real-Time Congestion and Loss Rebate on Carved-Out Grandfathered Agreement charge types. The congestion rebate is funded from MISO held FTRs for Carved-Out Agreements and when this is insufficient, the remaining funding comes from MPs through LRS in the Real-Time Revenue Neutrality Uplift Amount charge type. The losses rebate is funded from the Day-Ahead and Real-Time Over-Collected Losses funds.

2.17.1 Grandfathered Agreement Applicability

Grandfathered Agreements are only applicable to agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of the Tariff consistent with the Commission's policies. These agreements must have been previously identified to MISO and set forth in Attachment P to the Tariff.

2.17.2 Grandfathered Agreement Charge Impacts

Option A or C Grandfathered Agreements do not impose any special settlement provisions. Option B Grandfathered Agreements require some unique settlement provisions. There are three significant provisions related to Option B:

MP Grandfathered Agreement Financial Schedules are verified to have sufficient supply and consumption volume otherwise they are reduced to zero volume.

- All Day-Ahead calculations that reference Grandfathered Agreement Financial Schedules are affected by this provision since it involves transaction volume. When a Grandfathered Agreement Financial Schedule is found to have insufficient volume and is reduced to zero, all calculations treat it as if the transaction never existed. Invalidated transactions are not charged any administration charges. The Day-Ahead Settlement Statement shows each transaction before and after validation.

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

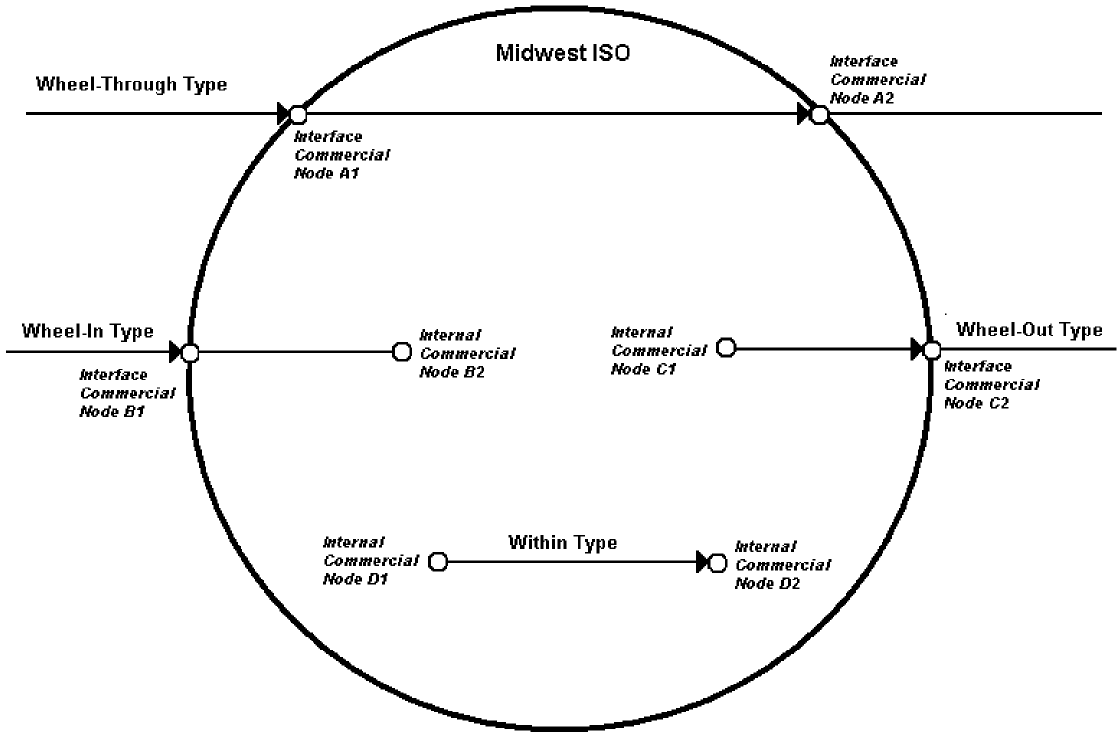
MPs are charged and then rebated the cost of congestion on their Grandfathered Agreement Financial Schedules.

The Day-Ahead Financial Schedule Congestion Amount charge type charges congestion to the MP and the Day-Ahead Rebate of Congestion on Grandfathered Agreement charge type provide a rebate of the charges. The congestion rebate is primarily funded by MISO held FTRs with any shortfall collected from MPs using the Real-Time Revenue Neutrality Uplift Amount charge type.

MPs are charged and then partially rebated the cost of losses on their Grandfathered Agreement Financial Schedules.

The Day-Ahead Financial Schedule Loss Amount charge type charges losses to the MP and the Day-Ahead Rebate of Losses on Grandfathered Agreement charge type provides a rebate of the portion of losses that exceed the system average value. The losses rebate is funded from the excess losses fund.

Exhibit 2-23: GFA Carved-Out Transaction Types



Carved-Out Grandfathered Agreement Transactions can be settled in one of four manners depending upon the type of transaction. The four types of transactions are: Wheel-Through, Wheel-In, Wheel-Out, and Within.

The Wheel-Through Type transaction identified in the Exhibit 2-24 is an example of a Carved-Out Grandfathered Agreement Transaction and depicts energy entering into and then exiting out of MISO. For this transaction the following settlement occurs:

The transaction seller is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node A1.

The transaction buyer is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node A2.

The transaction buyer is assessed the Marginal Congestion difference between nodes A2 less A1 in the Day-Ahead/Real-Time Financial Schedule Congestion Amount charge type.

The transaction buyer is assessed the Marginal Losses difference between nodes A2 less A1 in the Day-Ahead/Real-Time Financial Schedule Losses Amount charge type.

The transaction buyer is refunded the Marginal Congestion difference between nodes A2 less A1 in the Day-Ahead/Real-Time Congestion Rebate on Carved-Out Grandfathered Agreement charge type.

The transaction buyer is refunded the Marginal Losses difference between nodes A2 less A1 in the Day-Ahead/Real-Time Losses Rebate on Carved-Out Grandfathered Agreement charge type.

There is no energy settlement at nodes A1 and A2 because the energy is assumed to be flowing into, through, and out of MISO.

All Real-Time settlement is based on the volume differences between Real-Time and what was scheduled in the Day-Ahead Energy and Operating Reserve Market.

The Wheel-In Type transaction identified in the Exhibit 2-19 is an example of a Carved-Out Grandfathered Agreement Transaction and depicts energy entering into MISO. For this transaction the following settlement occurs:

The transaction seller is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node B1.

The transaction buyer is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node B2.

The transaction buyer is assessed the Marginal Congestion difference between nodes B2 less B1 in the Day-Ahead/Real-Time Financial Schedule Congestion Amount charge type.

The transaction buyer is assessed the Marginal Losses difference between nodes B2 less B1 in the Day-Ahead/Real-Time Financial Schedule Losses Amount charge type.

The transaction buyer is refunded the Marginal Congestion difference between nodes B2 less B1 in the Day-Ahead/Real-Time Congestion Rebate on Carved-Out Grandfathered Agreement charge type.

The transaction buyer is refunded the Marginal Losses difference between nodes B2 less B1 in the Day-Ahead/Real-Time Losses Rebate on Carved-Out Grandfathered Agreement charge type.

There is no energy settlement at node B1 because the energy is assumed to be flowing into MISO from an external node and travels through to node B2. The energy volume at B2 is settled the same as any other injection volume. If the AO owns the asset at B2, the energy is settled in the Day-Ahead/Real-Time Asset Energy Amount charge type, otherwise it is settled in the Day-Ahead/Real-Time Non-Asset Energy Amount charge type.

All Real-Time settlement is based on the volume differences between real-time and what was scheduled in the Day-Ahead Energy and Operating Reserve Market.

The Wheel-Out Type transaction identified in the Exhibit 2-19 is an example of a Carved-Out Grandfathered Agreement Transaction and depicts energy exiting out of MISO. For this transaction the following settlement occurs:

- The transaction seller is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node C1.
- The transaction buyer is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node C2.
- The transaction buyer is assessed the Marginal Congestion difference between nodes C2 less C1 in the Day-Ahead/Real-Time Financial Schedule Congestion Amount charge type.
- The transaction buyer is assessed the Marginal Losses difference between nodes C2 less C1 in the Day-Ahead/Real-Time Financial Schedule Losses Amount charge type.
- The transaction buyer is refunded the Marginal Congestion difference between nodes C2 less C1 in the Day-Ahead/Real-Time Congestion Rebate on Carved-Out Grandfathered Agreement charge type.
- The transaction buyer is refunded the Marginal Losses difference between nodes C2 less C1 in the Day-Ahead/Real-Time Losses Rebate on Carved-Out Grandfathered Agreement charge type.
- The energy volume at C1 is settled the same as any other withdrawal volume. If the AO owns the asset at C1, the energy is settled in the Day-Ahead/Real-Time Asset Energy Amount charge type, otherwise it is settled in the Day-Ahead/Real-Time Non-Asset Energy Amount charge type. There is no energy settlement at node C2 because the energy is assumed to be flowing out of MISO to an external consumer.
- All Real-Time settlement is based on the volume differences between real-time and what was scheduled in the Day-Ahead Energy and Operating Reserve Market.

The Within Type transaction identified in the Exhibit 2-19 is an example of a Carved-Out Grandfathered Agreement Transaction and depicts energy sourcing and sinking within MISO. For this transaction the following settlement occurs:

- The transaction seller is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node D1.
- The transaction buyer is assessed Schedule 17, Day-Ahead/Real-Time Market Administration Amount charge type, on the transaction volume at node D2.
- The transaction buyer is assessed the Marginal Congestion difference between nodes D2 less D1 in the Day-Ahead/Real-Time Financial Schedule Congestion Amount charge type.
- The transaction buyer is assessed the Marginal Losses difference between nodes D2 less D1 in the Day-Ahead/Real-Time Financial Schedule Losses Amount charge type.

The transaction buyer is refunded the Marginal Congestion difference between nodes D2 less D1 in the Day-Ahead/Real-Time Congestion Rebate on Carved-Out Grandfathered Agreement charge type.

The transaction buyer is refunded the Marginal Losses difference between nodes D2 less D1 in the Day-Ahead/Real-Time Losses Rebate on Carved-Out Grandfathered Agreement charge type.

The energy volume at D1 is settled the same as any other injection volume. If the AO owns the asset at D1, the energy is settled in the Day-Ahead/Real-Time Asset Energy Amount charge type, otherwise it is settled in the Day-Ahead/Real-Time Non-Asset Energy Amount charge type. The energy volume at D2 is settled the same as any other withdrawal volume. If the AO owns the asset at D2, the energy is settled in the Day-Ahead/Real-Time Asset Energy Amount charge type, otherwise it is settled in the Day-Ahead/Real-Time Non-Asset Energy Amount charge type.

All Real-Time settlement is based on the volume differences between real-time and what was scheduled in the Day-Ahead Energy and Operating Reserve Market.

2.18 Independent Market Monitor Settlement Overview

The IMM performs extensive monitoring and analysis of MISO and MP activities. At the discretion of the IMM, market mitigation measures may be implemented when market activities are found to violate standards and thresholds specified in the Tariff.

2.18.1 Independent Market Monitor Applicability

There are five general Independent Market Mitigation Measures that impact Market Settlements:

- IMM mitigated bid and offer schedules for MPs found to have met the cause and impact provisions specified in the Tariff;
- Imposition of financial penalties on MPs found to have engaged in conduct specified in the Tariff;
- Disposition of the financial penalties collected to appropriate MPs;
- Mitigation of Day-Ahead Offer RSG Payments that exceed IMM determined threshold Reference Levels; and
- Mitigation of Real-Time Offer RSG Payments that exceed IMM determined threshold Reference Levels.

2.18.2 Independent Market Monitor Effected Charge Calculation Methodology

MISO Market Settlements, at the discretion of the IMM, implements the following charge types based on the calculation methodologies identified below:

Real-Time Miscellaneous Amount – The IMM computes financial penalties and provides these to Market Settlements. This charge type assesses and distributes these amounts to appropriate MPs.

Day-Ahead RSG MWP – The IMM provides Reference Level determinants for Generation Resource PCs (SU, No-Load, and Offer Curve). These values are provided to Market Settlement via the DART for Generation Resources eligible to recover these PCs. The IMM does not provide reference values every day and in absence of values, the settlement system will display zero values for the day. When the IMM provides Resource PCs, then Market Settlements calculates both an unmitigated MWP and a mitigated MWP for each eligible hour for each Generation Resource. Market Settlements determines that IMM Day-Ahead PCs have been provided when the sum of the IMM PCs for the Calendar Day is greater than zero. When unmitigated Daily MWPs exceed mitigated values by the specified thresholds, mitigated MWP amounts are substituted for the entire day. Whenever an AO's Day-Ahead MWP is mitigated, the AO's Day-Ahead statement for the asset indicates that the "IMM Mitigation" equals "Y" meaning mitigation occurred. This indication represents the Tariff required formal notification from the IMM to the AO that mitigation took place. The Settlement Statement displays all hourly provided PCs billing determinants as provided by DART and the IMM.

Real-Time RSG MWP – The IMM provide Reference Level determinants for Generation Resource PCs (SU, No-Load, and Offer Curve). These values are provided to Market Settlement via the DART for Generation Resources eligible to recover these PCs. The IMM does not provide reference values every day and in absence of values, the settlement system will display zero values for the day. When the IMM provides Resource PCs, then Market Settlements calculates both an unmitigated MWP and a mitigated MWP for each eligible hour for each Generation Resource. Market Settlements determines that IMM Day-Ahead PCs have been provided when the sum of the IMM PCs for the Calendar Day is greater than zero. When unmitigated Daily MWPs exceed mitigated values by the specified thresholds, mitigated MWP amounts are substituted for the entire day. Whenever an AO's Real-Time MWP is mitigated, the AO's Real-Time statement for the asset indicates that the "IMM Mitigation" equals "Y" meaning mitigation occurred. This indication represents the Tariff required formal notification from the IMM to the AO that mitigation took place. The Settlement Statement displays all hourly provided PCs' billing determinants as provided by DART and the IMM.

2.19 Financial Transmission Rights and Auction Revenue Rights Settlement

ARR refers to the right held by an AO, as represented by an MP, to receive the net FTR auction revenue value from another AO who sold, or may sell, FTRs related to supplying energy for customers the latter AO is obligated to serve. MISO developed a Portal interface that permits the original AO to assign FTR action revenue values to other AOs that have assumed the energy supply obligation. This functionality is available to the original AO for the term of the related FTR. The original AO can assign for a calendar month any percentage of the FTR auction revenue value to other AOs, including making negative percentage adjustments. The monthly FTR revenue value is determined by the FTR auction each month.

The main purpose of this FTR/ARR settlement functionality is to facilitate, for the originally allocated AO's FTRs in electric deregulation states, the ability to financially assign all or a portion of the FTR auction value to energy suppliers that assume the energy supply obligation that was associated with an FTR when it was awarded.

The FTR system determines the ARRs, the original owner, and the FTRs related to that right and creates an FTR ARR bundle each month. The bundles are provided to the Market Settlement system where the total value is calculated. The calculated value and the bundles are displayed on the Portal for the original AO (*i.e.*, the original FTR owner) to redistribute if needed. When the original AO makes a revenue reassignment, the Portal system creates an FTR Transaction that is sent back to Market Settlements. Market Settlements then settles the FTR Transaction on the next initial settlement (S7) calculated. The settlement is performed using the FTR Transaction Amount charge type and the FTR Transaction will display on both the original and reassigned AO FTR Settlement Statement.

2.20 Nonstandard Settlement Overview

MISO settles each OD a minimum of four times. The standard settlement calendar has MISO calculating an OD's initial settlement 7 days (S7) after the OD and then recalculating the settlement again at 14 (S14), 55 (S55), and 105 (S105) days after the OD. Events can occur that make it necessary for MISO to settle an OD additional times outside the standard settlement calendar timeline. Any additional nonstandard settlement is labeled "R" plus the number of days since the OD. For instance a nonstandard settlement for 180 days following an OD has the designation of R180. All nonstandard settlements are displayed as a continuation of the standard scheduled settlements and show all prior settlement charge type calculation results in the same way that a 105th day (S105) settlement is displayed following the 55th day (S55) settlement.

This section describes:

- What events might trigger the nonstandard settlement;
- The notifications MISO provides to MPs prior to the nonstandard settlement execution;
- A description of how and when data is submitted for the nonstandard settlement; and
- When the results of the nonstandard settlement are invoiced.

2.20.1 Nonstandard Settlement Applicability

A nonstandard settlement would only be triggered by an extraordinary event. MISO recognizes that there is a cost to be borne by both MISO and the MPs for the creation and verification of nonstandard settlements. Therefore, the cost in both real dollars and time is evaluated against need for a nonstandard settlement. There are several examples of events that may trigger a nonstandard settlement:

- Market-wide data discrepancy that had material affect on MPs' statements.
- A material data or calculation error that would result in the insolvency of an MP.
- A material dispute resulting from the 105th day settlement or a nonstandard settlement.
- Per court order or FERC order.
- Per direction from the Alternative Dispute Resolution (ADR) Process.

Standard Settlement disputes do not normally cause a nonstandard settlement to occur unless it was of a magnitude that fell into the scope of the discussion identified previously. In most cases, changes to market data are simply incorporated into the next scheduled settlement.

2.20.2 Nonstandard Settlement Notifications

Prior to a nonstandard settlement, the MISO Market Settlements staff notifies all MPs of the pending settlement execution. At a minimum the following information is conveyed:

- The event that triggered the nonstandard settlement;
- The nonstandard settlement meter data submission deadline;
- The date on which the nonstandard settlement is to be scheduled;
- The date on which the Settlement Statement for the nonstandard settlement is to be posted for MPs; and
- The date on which the nonstandard Settlement Statement is to be invoiced.

2.20.3 Nonstandard Settlement Data Submission

When a nonstandard settlement is scheduled, MISO will determine if updated meter data will be used. MPs are notified of the deadline for submitting updated meter data, if applicable. All meter data for nonstandard settlements are submitted through the normal meter data submission process. Meter data previously submitted by an MP's MDMA is used for the nonstandard settlement unless the MDMA submits revised meter data prior to the nonstandard settlement meter data submission deadline.

Any non-meter data changes that have been received by Market Settlements since the last processed settlement are also included in the nonstandard settlement. Nonstandard settlements represent a full recalculation of all settlement charges and are not exclusive to the charge or charges that triggered the nonstandard settlement event. As a result, when a nonstandard settlement is performed, it may represent an opportunity for all MPs to provide updated meter data.

2.20.4 Invoices for Nonstandard Settlement

Nonstandard Settlement Statements are invoiced in the normal invoice cycle for the week in which the nonstandard Settlement Statement is scheduled.

2.20.5 De Minimis Threshold

The purpose of the De Minimis Threshold, in MISO Tariff Module A Section 12.A.g, is to establish thresholds at or below which MISO is not required to perform corrective resettlements for Continuing Errors. MISO has established the following thresholds to be assessed against a consecutive 12-month period:

1. Less than or equal to $7,500 per Market Participant
2. Less than or equal to $100,000 for all affected Market Participants

The 12-month period for financial impact is determined based on the following:

1. The date of the initial finding of the continuous error. For example, if an error is determined to have occurred on November 1, 2020 – that is the initial finding date.
2. The resettlement period is 2 years prior to the initial finding date. Using November 1, 2020 as the initial date, then the resettlement period is November 1, 2018 to November 1, 2020.
3. Determine the 12-month period. There are 3 possibilities:
    a. If the error occurred prior to or on November 1, 2018, then the 12-month period to determine the financial impact is November 1, 2018 – November 1, 2019.
    b. If the error originally occurred during the first year of the resettlement period, then the 12-month period would start at the first occurrence of the error. For example, if the error first occurred February 1, 2019, then the 12-month period would be from February 1, 2019 to February 1, 2020.
    c. If the error occurred for less than 12 months, the entire period the error occurred will be evaluated.

If either of the thresholds above are true for the 12-month period, resettlement by MISO will be required.

2.21 Joint Operating Agreements

JOAs are arrangements with MISO and bordering ISOs that enable one ISO on an hourly basis to request the other to redispatch to relieve, or make available, additional transmission flowgate capacity for use by the requesting ISO. There are hours when it may be more economical for a bordering ISO to make additional flowgate capacity available than it is for an ISO to redispatch its own Resources. This capability is available in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets, but it works slightly differently between the two markets. The costs incurred to redispatch is paid for by the ISO that utilized the additional capacity.

For the Day-Ahead Energy and Operating Reserve Market, either ISO can request from the other additional flowgate capacity. Both ISOs will coordinate their requests when they are solving for their Day-Ahead Energy and Operating Reserve Markets. When this occurs, it is expected that the flowpath will be bound and congestion will occur across the flowpath. The responding ISO will bill the requesting ISO the amount of MW capacity made available multiplied by the Flowgate Shadow Price (FSP). The FSP is equal to the per MW cost to redispatch generation to make available the additional flowgate capacity. For MISO, any funds received for Day-Ahead Energy and Operating Reserve Market coordination will be added to the Day-Ahead Congestion Fund and any funds paid will reduce the Day-Ahead Congestion Fund. If during an hour there is not sufficient funds in the Day-Ahead Congestion Fund to pay for requested additional flowgate capacity, the additional funds are collected as an uplift in this charge type. For specific information on the impact of Day-Ahead JOA charges and credits to the Day-Ahead Congestion Fund, please see the FTR Hourly Allocation Amount charge type in the Market Settlements Calculation Guide.

For the Real-Time Energy and Operating Reserve Market, only the monitoring flowgate ISO can request additional flowgate capacity. The JOA defines for each flowgate who is designated as the monitoring ISO. When a monitoring ISO requests additional capacity, the responding ISO bills the requesting ISO the capacity made available multiplied by the FSP. If a responding ISO has its flowgate capacity at less than its designated limit, and the requesting ISO is also less than its designated limit, then the responding ISO pays the requesting ISO the capacity difference between the requestor's limit and the requestor's actual flowgate volume multiplied by the requesting ISO's shadow price. For MISO, any funds received for real-time coordination will be added to the Real-Time Congestion Fund and any funds paid will reduce the Real-Time Congestion Fund. If during an hour there is not sufficient funds in the Real-Time Congestion Fund to pay for requested additional flowgate capacity, the additional funds are collected as an uplift in this charge type. For specific information on the impact of Real-Time JOA charges and credits to

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

the Real-Time Congestion Fund, please see the Real-Time Revenue Neutrality Uplift Amount charge type in the Market Settlements Calculation Guide.

2.22 Settlement Revenue Neutrality

MISO Market Settlements remains revenue neutral over time except for administrative charges collected for services of the FTR, Day-Ahead and Real-Time Energy and Operating Reserve Markets. The charge types related to administrative services are:

- FTR Administration Amount;
- Day-Ahead Administration Amount; and
- Real-Time Administration Amount.

On a daily basis, Market Settlements is not expected to be revenue neutral due to the design of the market charge types. On an hourly basis the Day-Ahead and Real-Time Energy and Operating Reserve Markets are corrected for revenue inadequacy; any excess or shortfall is funded by MPs through the Real-Time Revenue Neutrality Uplift charge type. Revenue inadequacy corrections do not balance the excess congestion fund nor do they balance the following:

- Negative total market wide hourly Day-Ahead congestion;
- Monthly and Yearly Congestion Revenue Allocation;
- FTR Transaction Auction Revenue;
- Real-Time Miscellaneous Amounts; or
  Calculation Rounding.

Negative total market wide hourly Day-Ahead congestion rolls into the monthly and yearly FTR Revenue Allocation process. Rarely are market conditions expected to occur where the Day-Ahead congestion fund is negative for the entire market prior to any payout to FTR holders. When this occurs, the negative impact is funded by the monthly day-ahead and real-time congestion fund.

The Monthly and Yearly Congestion Revenue Allocation process causes a daily revenue inequality since all excess congestion dollars are not distributed each day. Due to the design of the FTR Monthly and Yearly Allocation Amount charge types, any excess congestion dollars remaining after the hourly revenue allocation process are not distributed to FTR and Flowgate Rights holders that have had less than full hourly funding until:

1) For the monthly revenue allocation, the settlement of the last day of the calendar month.
2) For the yearly revenue allocation, the S105 Settlement of the final day of the calendar year.

Available congestion dollars can exceed all funding requirements for a calendar year. Excess congestion funds are dispersed according to the requirements of the Tariff only after Annual Allocation is performed.

FTR Transaction Auction Revenue can lead to daily revenue over-adequacy from the FTR auction process. This excess is the basis of the FTR Transaction Amount charge type. There are three potential causes of FTR transaction auction revenue:

1) When there are paying entities selling FTRs and paying entities that acquire FTRs at a negative price (counter-flow FTRs);
2) When residual FTR capability is sold through an auction; or
3) From an FTR reconfiguration when the set of FTRs sold in the auction is limited by different transmission constraints than those that limited the FTR set that was valid prior to the auction.

All revenue surpluses resulting from the FTR Transaction Amount charge type are held until after the last yearly scheduled settlement has been completed, then the funds are dispersed according to the requirements of the Tariff.

Real-Time Miscellaneous Amount can lead to a daily revenue inequality. The use of this charge type to collect or disperse funds can occur from the request of an entity having MISO authority and/or oversight. MISO maintains detailed records of the use of this charge type and provides MPs with a yearly non-confidential report showing how this charge type has been used along with the disposition of any excess funds.

Calculation Rounding can cause daily revenue inequalities. Due to the number of charge types and MPs, there can be expected to be small daily revenue inequities from calculation rounding. These small inequities are tracked and monitored over time.

MISO tracks and accounts for all charge types by day, month, and year to ensure that overall revenue neutrality is being maintained in accordance with the Tariff market design.

2.23 Roles and Responsibilities

2.23.1 MISO Responsibilities

MISO settles the FTR, Day-Ahead Energy and Real-Time Energy and Operating Reserve Markets according to the market settlements calendar.

Some of MISO's specific Market Settlements responsibilities are as follows:

- Maintain the Commercial Model updated in the Market Settlements Software.
- Validate that the Commercial Model CPNodes, AOs, and MPs are properly related, with no unassociated points and/or entities.
- Transfer to the Market Settlements system all FTR Market, Day-Ahead Energy and Operating Reserve Market and Real-Time Energy and Operating Reserve Market information necessary to perform the settlement calculations.
- Monitor for missing Market Settlement data.
- Accept and validate injection and withdrawal meter data by CPNode.
- Estimate injection and withdrawal asset meter data when it is unavailable for Market Settlements.
- Calculate Residual Load Zone values for each LBA.
- Calculate, publish, accept, and post the FTR, Day-Ahead Energy and Operating Reserve, Real-Time Energy and Operating Reserve and Summary Market Settlement Statements for standard and nonstandard settlements.
- Reasonably assist MPs in resolving potential Market Settlement discrepancies and concerns.
- Reasonably assist MPs in understanding the Market Settlements processes.
- Transfer all Market Settlement data to the MISO MP Invoicing system.

2.23.2 Market Participant Role

The role of the MP is to represent, and be responsible for, all Resource and Load assets along with energy transactions and schedules from Asset (and non-asset) Owners to MISO. The MP is the highest hierarchical level in the Commercial Model and is the only entity in the Commercial Model that is financially obligated to MISO for Market Settlements. As such, MPs are responsible not only for their own actions, but for those of all AOs they represent. In the event MPs have agents acting on their behalf, the MP is responsible for all actions of their agents. MPs may have Scheduling Agents (SAs), Settlement Agents, and MDMAs.

MPs have the following Market Settlement responsibilities in the MISO Markets:

- Maintain a comprehensive understanding of the FTR, Day-Ahead and Real-Time Energy and Operating Reserve Markets and how they settle.
- Accept financial responsibilities to MISO for all their MP transactions, including those performed by agents acting on their behalf.
- Ensure that the Commercial Model accurately reflects their AOs, CPNodes, and EPNodes.

Assure that MDMAs acting on their behalf are providing accurate and timely data along with maintaining all MISO standards.

Assure that SAs acting on their behalf are providing accurate and timely data along with maintaining all MISO standards.

Assure that Settlement Agents acting on their behalf are providing accurate and timely data along with maintaining all MISO standards.

Ensure that all MP agency relationships are on record with MISO with current contact information.

Retain responsibility to ensure that actual data is submitted as soon as is reasonably practical and in the absence of actual data, estimated data is submitted.

Maintain all meter data standards and requirements as adopted and approved by the MISO governing board.

Retrieve Market Settlement Statements from their AO's assigned area of the Portal.

Inform MISO if they fail to receive Market Settlement Statements.

Perform a timely audit of all their AO's Market Settlement Statements, and contact MISO if they find any error in them.

Assist MISO with the investigation of any Market Settlement discrepancies.

Resolve any internal issues related to discrepancies.

Assist and support MISO audits of MP activities related to upholding MP requirements.

- Report to MISO executive management or governing board, any MISO activities that could be perceived as unlawful, unethical or inappropriate related to:
  - MISO Standards of Conduct;
  - Other company policies and procedures; or
  - All applicable laws and regulations.

2.23.3 Asset Owner Responsibilities

AOs are responsible and accountable to their MPs. MISO holds the MP financially responsible for all actions by their AOs. AOs have the following Market Settlement responsibilities in the MISO Markets:

Maintain a comprehensive understanding of the FTR, Day-Ahead and Real-Time Energy and Operating Reserve Markets and how they settle.

Assist MISO with the investigation of any Market Settlement discrepancies.

Resolve any internal issues related to discrepancies.

Assist and support MISO audits of MP activities related to upholding MP requirements.

- Report to MISO executive management or governing board, any MISO activities that could be perceived as unlawful, unethical or inappropriate related to:
  - MISO Standards of Conduct;

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

- Other company policies and procedures; or
- All applicable laws and regulations.

2.23.4 Meter Data Management Agent (MDMA) Responsibilities

MPs are required to have an MDMA identified for every MISO registered asset.

Meter Data Management Agents (MDMAs) provide meter data to MISO prior to noon EST the day before an OD is scheduled to be settled. If actual meter data is not available for the initial OD settlement, the MDMA provides estimated data and resubmits actual data as soon as it is available.

MDMAs have the following requirements for meter data submission and data standards:

- Adhere to the meter data submission requirements and specifications, identified in the MISO's Extranet posted documents entitled, "Commercial Operation System: XML Interface Reference" and/or "Commercial Operation System: Programmatic Interface";
- Maintain all meter data standards and requirements as adopted and approved by the MISO governing board
- The MDMA must also establish and maintain the MWh high/low parameters for each CPNode via the Web Portal.:
- The MDMA must also establish and maintain accurate Contact information such as Name, Phone Number and E-mail addresses for each Agent submitting Meter Data: and
- Adhere to all requirements identified in the Metering Settlement Overview section of this BPM.

MISO has the right to independently audit all MP/MDMA records and associated documentation related to meter data within a period of seven years from date of submittal.

The MP is responsible for the reporting, or for ensuring that the MDMA reports, all Load and generation data for each of the CPNodes for which it is responsible, to MISO. The MP is responsible for any and all data supplied by its designated MDMA. Any dispute between the MDMA and the MP concerning the actual and estimated values reported or the methodologies employed must be resolved between the two parties without any involvement of MISO.

MISO uses the data provided by the MDMA until such time that the MP revokes the designation of the MDMA and identifies a replacement. The replaced MDMA cannot provide data to MISO after the date of the replacement. The newly designated MDMA is then able to provide meter data on behalf of the MP (and updated meter data prior to the replacement date if necessary).

MISO has a financial, legal and operational relationship only with the MP, not the MDMA. The MP is bound by the actions of the MDMA.

The MP has responsibility for the quality, accuracy and timeliness of data submitted by the MDMA on its behalf. An MP can have more than one MDMA, but only one designated MDMA per registered asset.

2.23.5 Scheduling Agent

The MP is responsible for the scheduling, or for ensuring that the SA schedules, all applicable transactions to MISO. The MP is responsible for any and all data supplied by its designated SA.

MISO has a financial, legal and operational relationship only with the MP, not the SA. The MP is bound by the actions of the SA.

The MP has responsibility for the quality, accuracy and timeliness of data submitted by the SA on its behalf.

2.23.6 Market Settlement Agent

An MP may designate a Market Settlement Agent to act on its behalf.

MISO has a financial, legal and operational relationship only with the MP, not the Market Settlement Agent.

The MP is bound by the actions of the Market Settlement Agent regarding all market settlement transactions and in fulfilling the Market Settlements responsibilities of the MP.

2.23.7 Billing Agent

An MP may designate a Billing Agent to accept invoices and make payments on behalf of the MP.

MISO has a financial, legal and operational relationship only with the MP, not the Billing Agent. The MP is bound by the actions of the Billing Agent regarding payment of invoices for market transactions.

2.23.8 Local Balancing Authority Responsibilities

The LBA supports Market Settlements by providing timely hourly NAI data.

3. Invoices

MISO Market Settlements produces regular Settlement Statements for each OD. The first Settlement Statement occurs seven Calendar Days after the OD. Subsequent statements occur 14 Calendar Days, 55 Calendar Days and 105 Calendar Days after the OD. These Settlement Statements are not considered to be invoices and they do not directly trigger cash flow.

MISO prepares weekly net settlement invoices based on the charges and credits that result from the Market Settlement Statements. For each invoice, the MP is either a net payee or net payer. MISO's cost reimbursement charges (Schedules 16 and 17) are invoiced separately from the net charges and credits of the Energy and Operating Reserve Markets and FTRs. Transmission charges are also billed separately.

MISO publishes invoices on Tuesdays. In the event Tuesday is not a MISO Business Day, invoices are published on the next Business Day. Weekly invoices contain the Market Settlement Statements for Day 7, 14, 55, and 105 published the previous week (Saturday through Friday). See the settlement matrix in Exhibit 3-1.

Exhibit 3-1: Settlement Matrix

Settlement Date (Date Settlements are Posted)		Operating Dates Being Settled			
		S7	S14	S55	S105
10/29/2011	Sat	10/22/2011	10/15/2011	9/4/2011	7/16/2011
10/30/2011	Sun	10/23/2011	10/16/2011	9/5/2011	7/17/2011
10/31/2011	Mon	10/24/2011	10/17/2011	9/6/2011	7/18/2011
11/1/2011	Tue	10/25/2011	10/18/2011	9/7/2011	7/19/2011
11/2/2011	Wed	10/26/2011	10/19/2011	9/8/2011	7/20/2011
11/3/2011	Thu	10/27/2011	10/20/2011	9/9/2011	7/21/2011
11/4/2011	Fri	10/28/2011	10/21/2011	9/10/2011	7/22/2011
11/5/2011	Sat	10/29/2011	10/22/2011	9/11/2011	7/23/2011
11/6/2011	Sun	10/30/2011	10/23/2011	9/12/2011	7/24/2011
11/7/2011	Mon	10/31/2011	10/24/2011	9/13/2011	7/25/2011
11/8/2011	Tue	11/1/2011	10/25/2011	9/14/2011	7/26/2011
11/9/2011	Wed	11/2/2011	10/26/2011	9/15/2011	7/27/2011
11/10/2011	Thu	11/3/2011	10/27/2011	9/16/2011	7/28/2011
11/11/2011	Fri	11/4/2011	10/28/2011	9/17/2011	7/29/2011
11/12/2011	Sat	11/5/2011	10/29/2011	9/18/2011	7/30/2011
11/13/2011	Sun	11/6/2011	10/30/2011	9/19/2011	7/31/2011
11/14/2011	Mon	11/7/2011	10/31/2011	9/20/2011	8/1/2011
11/15/2011	Tue	11/8/2011	11/1/2011	9/21/2011	8/2/2011
11/16/2011	Wed	11/9/2011	11/2/2011	9/22/2011	8/3/2011
11/17/2011	Thu	11/10/2011	11/3/2011	9/23/2011	8/4/2011
11/18/2011	Fri	11/11/2011	11/4/2011	9/24/2011	8/5/2011

The Market Settlements Day 7 Settlement Statements are created seven days after the OD and posted to the Portal the same day. That same methodology applies to the remainder of the matrix for Day 14, 55 and 105 settlements.

In comparison, MISO publishes invoices on Tuesday as illustrated in Exhibit 3-2. Weekly invoices contain the Market Settlement Statements for Day 7, 14, 55, and 105 published the previous week (Saturday through Friday).

Exhibit 3-2: Published Invoice Content

Settlement Date (Date Settlements are Posted)		Operating Dates Being Settled				Invoice Date
		S7	S14	S55	S105	
10/29/2011	Sat	10/22/2011	10/15/2011	9/4/2011	7/16/2011	Tuesday, November 08, 2011
10/30/2011	Sun	10/23/2011	10/16/2011	9/5/2011	7/17/2011	
10/31/2011	Mon	10/24/2011	10/17/2011	9/6/2011	7/18/2011	
11/1/2011	Tue	10/25/2011	10/18/2011	9/7/2011	7/19/2011	
11/2/2011	Wed	10/26/2011	10/19/2011	9/8/2011	7/20/2011	
11/3/2011	Thu	10/27/2011	10/20/2011	9/9/2011	7/21/2011	
11/4/2011	Fri	10/28/2011	10/21/2011	9/10/2011	7/22/2011	
11/5/2011	Sat	10/29/2011	10/22/2011	9/11/2011	7/23/2011	Tuesday, November 15, 2011
11/6/2011	Sun	10/30/2011	10/23/2011	9/12/2011	7/24/2011	
11/7/2011	Mon	10/31/2011	10/24/2011	9/13/2011	7/25/2011	
11/8/2011	Tue	11/1/2011	10/25/2011	9/14/2011	7/26/2011	
11/9/2011	Wed	11/2/2011	10/26/2011	9/15/2011	7/27/2011	
11/10/2011	Thu	11/3/2011	10/27/2011	9/16/2011	7/28/2011	
11/11/2011	Fri	11/4/2011	10/28/2011	9/17/2011	7/29/2011	
11/12/2011	Sat	11/5/2011	10/29/2011	9/18/2011	7/30/2011	Tuesday, November 22, 2011
11/13/2011	Sun	11/6/2011	10/30/2011	9/19/2011	7/31/2011	
11/14/2011	Mon	11/7/2011	10/31/2011	9/20/2011	8/1/2011	
11/15/2011	Tue	11/8/2011	11/1/2011	9/21/2011	8/2/2011	
11/16/2011	Wed	11/9/2011	11/2/2011	9/22/2011	8/3/2011	
11/17/2011	Thu	11/10/2011	11/3/2011	9/23/2011	8/4/2011	
11/18/2011	Fri	11/11/2011	11/4/2011	9/24/2011	8/5/2011	

Invoice charges and credits are triggered by Market Settlement Statement charge type dollar net changes, not on the individual total statement amounts. The amount ultimately charged or credited is always the change between the current charge/credit and the amount previously charged or credited. As such, an initial Market Settlement Day 7 statement's charge type totals are fully invoiced since there are no previous charges invoiced for that statement.

For example, if the Day 7 initial charge is $500, then the change between the current charge ($500) and the previous charge ($0) is the initial charge of $500, which is the amount invoiced. If the subsequent Market Settlement Statement for Day 14 has no changes from the prior Day 7 Settlement Statement, no additional charges and credits are invoiced related to that Day 14 Settlement Statement. Meaning, if the Day 14 resettlement is calculated to be $500, then the Day 14 charge is $0 because there is no difference between the Day 7 and the Day 14 charge. However, if the Day 14 resettlement is determined to be $575, then the Day 14 charge is $75 because that is the difference between the initial Day 7 charge and the updated Day 14 charge.

3.1 Market Net Invoices

MISO settles for market services resulting from the Tariff.

Market charge and revenue classifications are invoiced at the MP level. These charge and revenue classifications are subtotaled (on separate pages) by S7, S14, S55, S105 and non-standard resettlements groupings. On each individual page, the charge and revenue classifications are further sorted and subtotaled by 1) Charge/Revenue description, 2) the Settlement Date and Operating Date, and 3) Real-Time, Day-Ahead or Other classifications. The charge and revenue classifications are not further sorted by AO on the invoice document. Detailed Settlement Statements are required to perform that task.

Two invoices are created for each MP. MISO Administration Fees (Schedules 16 and 17) are not included in the net market invoices and are charged on a separate invoice.

Electronic copies of the invoices are presented to the customer billing contacts via the portal in PDF format. The PDF format is to be used for viewing and routing for payment. MPs are responsible for accessing the invoices in a timely manner and must notify MISO if any invoice is unavailable. MPs are also responsible for reviewing the invoices from MISO to verify their accuracy.

MISO prepares weekly net settlement invoices based on the charges and credits that result from the Market Settlement Statements. For each invoice, the MP is either a net payee or net payer. Each invoice could potentially consist of numerous pages, but is separated into five sections. For every invoice, the Summary Page will always be the first page. However, if a certain classification of revenue or charge does not exist, then the appropriate page will not print on the invoice. For example, if an MP does not have S105 settlement charges or revenue, that page will not print on the invoice.

Net Invoice Summary Page – The first page is a summary of the following pages.

Current Billing Period Page – The next page (if applicable charges exist) documents the MP's revenue and charge settlement for the current billing period (Day 7 Settlement Statements). This section may be carried over onto more than one page.

S14 Prior Period Adjustment Page – The next page (if applicable charges exist) documents the MP's revenue and charge settlements for a previous billing period.

S55 Prior Period Adjustment Page – The next page (if applicable charges exist) documents the MP's revenue and charge settlements for a previous billing period.

S105 Prior Period Adjustment Page – The next page (if applicable charges exist) documents the MP's revenue and charge settlements for a previous billing period.

Non-Standard Resettlement Prior Period Adjustment Page – The next page (if applicable charges exist) documents the MP's revenue and charge settlements for any non-standard resettlement (resettlements other than S7, S14. S55 and S105, normally noted with an "R" instead of an "S").

3.1.1 Net Invoice Summary Page

Exhibit 3-3 presents the Net Invoice Summary page, the first page of the invoice.

Exhibit 3-3: Net Invoice Summary Page

MISO 1

MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.
P.O. Box 4202
Carmel, IN 46082-4202

Invoice

Market Participant: MISO
P.O Box 4202 2
Carmel, IN 46082

5 **Invoice Number:** XXXX:XXXXXX

6 **For Statements Issued:** 07/30/2011-08/05/2011

7 **Invoice Date:** 08/09/2011

Participant ID: MISO 3

8 **Payment Due Date:** 08/16/2011

Invoice Type: Market Invoice 4

Invoice Summary:	**Total:**
9 Current S7 Net (Revenue)/Charge of Real Time and Day Ahead Markets:	10.31
10 S14 Prior Period Adjustments:	10.31
11 S55 Prior Period Adjustments:	343.33
12 S105 Prior Period Adjustments:	(52.50)
13 Other Adjustments:	0.00
Total Net Charge (Revenue):	14 **($4,748.34)**

15 The Net Revenue for this invoice is greater than the Net Charge. This amount will be electronically sent to the Market Participant©s bank account within 24 to 48 hours of the payment due date.

Electronic Banking Instructions:

ACH Payments	**Wire Instructions**	**International Wire Instructions**
JP Morgan Chase Bank, NA	JP Morgan Chase Bank, NA	JP Morgan, Chase Bank, NA
Indianapolis, IN	Indianapolis, IN	Indianapolis, IN
ABA: 074000010	ABA: 021000021	Swift Code: CHASUS33
ACCT: 693193260	ACCT: 693193260	ABA: 021000021
		ACCT: 693193260

For all inquiries contact:
16 MISO Accounts Receivable
accountsreceivable@midwestiso.org

The Net Invoice Summary Page contains the following:

1) MISO corporate logo.
2) The customer billing address as provided to MISO through the customer registration process. This information, in addition to the invoice number and contact person, is also used for invoice identification purposes.
3) The MP NERC ID as provided to MISO through the customer registration process. This information, in addition to the invoice number and contact person, is also used for invoice identification purposes.
4) The invoice type describes the category of charges and revenue contained on the invoice. If this field notes “Administration Fee Invoice”, then the charges and revenue

on the statement relate to Schedules 16 and 17. If the field notes “Market Invoice”, then the charges and revenue on the statement relate to all other Market Activity.

5) MISO invoice number, which is used as an external and internal tracking identification tool.
6) The seven-day period for which the daily Settlement Statements are invoiced. This period runs from Saturday through Friday. Any Day 7, 14, 55 or 105 Settlement Statements that are posted during that Saturday through Friday period are invoiced on the following Tuesday.
7) The invoice date documents at which point the period for payment starts. As such, the invoice in this example would be due for remittance within 7 Calendar Days from August 9, 2011. In this example, the Payment Due Date is August 16, 2011. If the due date falls on a Saturday, Sunday or any other MISO non-business day, the actual due date would fall on the next Business Day.
8) The payment due date, which is the date on which net invoice charges are due to be paid to MISO in immediately available funds.
9) The Net Revenue/Charge line under the Invoice Summary is the total on the second page carried forward to the Summary page (if applicable charges/revenue exist). The amount represents the net Revenue or Charge that the MP receives or owes for the seven-day billing period. A negative number represents net revenue to be received by the MP and a positive number represents net charges to be paid by the MP.
10) The S14 Prior Period Adjustments line under the Invoice Summary is the total from the third page carried forward to the Summary page (if applicable charges/revenue exist). This amount represents the net prior period adjustments for the S14 resettlement that were posted for the seven-day billing period. A negative number represents net revenue to be received by the MP and a positive number represents net charges to be paid by the MP.
11) The S55 Prior Period Adjustments line under the Invoice Summary is the total from the fourth page carried forward to the Summary page (if applicable charges/revenue exist). This amount represents the net prior period adjustments for the S55 resettlement that were posted for the seven-day billing period. A negative number represents net revenue to be received by the MP and a positive number represents net charges to be paid by the MP.
12) The S105 Prior Period Adjustments line under the Invoice Summary is the total from the fifth page carried forward to the Summary page (if applicable charges/revenue exist). This amount represents the net prior period adjustments for the S105 resettlement that were posted for the seven-day billing period. A negative number

represents net revenue to be received by the MP and a positive number represents net charges to be paid by the MP.

13) The Other Adjustments line under the Invoice Summary is the total from the sixth page carried forward to the Summary page (if applicable charges/revenue exist). This amount represents the net prior period adjustments for the non-standard resettlements that were posted for the seven-day billing period. A negative number represents net revenue to be received by the MP and a positive number represents net charges to be paid by the MP.

14) The Total Net Charge (Revenue) line under the Invoice Summary is the complete net invoice total. If the amount is negative, it represents the total net revenue expected to be received by the MP within 24-48 hours after the Payment Due Date. If the amount is positive, it represents the total net charges that are payable to MISO in immediately available funds on the Payment Due Date (see note 15).

15) This description line summarizes the net financial position of the invoice and provides the MP with a conclusion on next step. It will either say, 1) “The Net Charge for this invoice is greater than the Net Revenue. Please make payment in immediately available funds on the payment due date” or 2) “The Net Revenue for this invoice is greater than the Net Charge. This amount will be electronically sent to the MP’s bank account within 24-48 hours of the Payment Due Date.”

16) MISO contact, which is information for help in reading and understanding the invoice, is documented at the bottom center of the invoice.

3.1.2 Current Billing Period Page

If applicable charges/revenue exists, the second page(s) documents the MP's revenue and charge settlement for the current billing period (Day 7 Settlement Statements). Given the level of detail provided, this page will probably carry over to subsequent pages.

Exhibit 3-4: Current Billing Period Page 1

MISO 1

MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.
P.O. Box 4202
Carmel, IN 46082-4202

Invoice

Market Participant: MISO
P.O Box 4202 2
Carmel, IN 46082

5 **Invoice Number:** XXXX:XXXXXX

6 **For Statements Issued:** 07/30/2011 - 08/05/2011

7 **Invoice Date:** 08/09/2011

Participant ID: MISO 3

Invoice Type: Market Invoice 4

8 **Payment Due Date:** 08/16/2011

Description 9	Settlement Date	Operating Date	Real-Time	Day-Ahead	Other	Total
Billing Period: Current S7	15	16	10	11	12	13
Net Inadvertent Distribution Amount	08/02/2011	07/26/2011	($3.76)	$0.00	$0.00	($3.76)
Net Inadvertent Distribution Amount	08/03/2011	07/27/2011	(1.00)	0.00	0.00	(1.00)
Net Inadvertent Distribution Amount	08/05/2011	07/29/2011	(1.49)	0.00	0.00	(1.49)
Revenue Sufficiency Guarantee First Pass Dist Amount	08/02/2011	07/26/2011	806.93	0.00	0.00	806.93
Revenue Sufficiency Guarantee First Pass Dist Amount	08/03/2011	07/27/2011	290.15	0.00	0.00	290.15
Revenue Sufficiency Guarantee First Pass Dist Amount	08/05/2011	07/29/2011	56.99	0.00	0.00	56.99
Schedule 24 Allocation Amount	08/02/2011	07/26/2011	0.00	1.27	0.00	1.27
Schedule 24 Allocation Amount	08/03/2011	07/27/2011	0.00	0.42	0.00	0.42
Schedule 24 Allocation Amount	08/05/2011	07/29/2011	0.00	1.27	0.00	1.27
Virtual Energy Amount	08/02/2011	07/26/2011	7,707.00	(9,830.25)	0.00	(2,123.25)
Virtual Energy Amount	08/03/2011	07/27/2011	2,191.50	(2,481.00)	0.00	(289.50)
Virtual Energy Amount	08/05/2011	07/29/2011	6,055.50	(9,843.01)	0.00	(3,787.51)
						14
Total Net (Revenue)/Charge of Real Time and Day Ahead Markets:			**$17,101.82**	**($22,151.30)**	**$0.00**	**($5,049.48)**

Page 2

The Current Billing Period Page(s) contains the following:

1) MISO corporate logo.
2) The customer billing address as provided to MISO through the customer registration process. This information, in addition to the invoice number and contact person, is also used for invoice identification purposes.
3) The MP NERC ID as provided to MISO through the customer registration process. This information, in addition to the invoice number and contact person, is also used for invoice identification purposes.
4) The invoice type describes the category of charges and revenue contained on the invoice. If this field notes "Administration Fee Invoice", then the charges and revenue on the statement relate to Schedules 16 and 17. If the field notes "Market Invoice", then the charges and revenue on the statement relate to all other Market Activity.
5) MISO invoice number, which is used as an external and internal tracking identification tool.
6) The seven-day period for which the daily Settlement Statements are invoiced. This period runs from Saturday through Friday. Any S7 settlement statements that are posted during that Saturday through Friday period, are invoiced on the following Tuesday.
7) The invoice date documents at which point the period for payment starts. As such, the invoice in this example would be due for remittance within 7 Calendar Days from August 9, 2011. In this example, the Payment Due Date is August 16, 2011. If the due date falls on a Saturday, Sunday, or any other MISO non-business day, the actual due date would fall on the next Business Day.
8) The payment due date, which is the date on which net invoice charges are due to be paid to MISO in immediately available funds.
9) The Charge and Revenue Type Description provides a general explanation of what type of activity is contained in each line item. In addition, the settlement charge type is also included in the left hand column to allow MPs to tie their invoices back to their daily summary Settlement Statements.
10) Real-Time Revenues and Charges are specifically broken out from the Day-Ahead and Other Revenues and Charges and are documented in this column.
11) Day-Ahead Revenues and Charges are specifically broken out from Real-Time and Other Revenues and Charges and are documented in this column.
12) Other Revenues and Charges are specifically broken out from Real-Time and Day-Ahead Revenues and Charges and are documented in this column.
13) The total column takes all Revenue types and adds them together into a subtotal amount. It also takes all Charge types and adds them together into a sub-total amount.

14) The Total Net Revenue/Charge for Real-Time and Day-Ahead Energy and Operating Reserve Markets is documented at the bottom of the Total column. This is the net amount that is carried forward to the Invoice Summary on the first page.

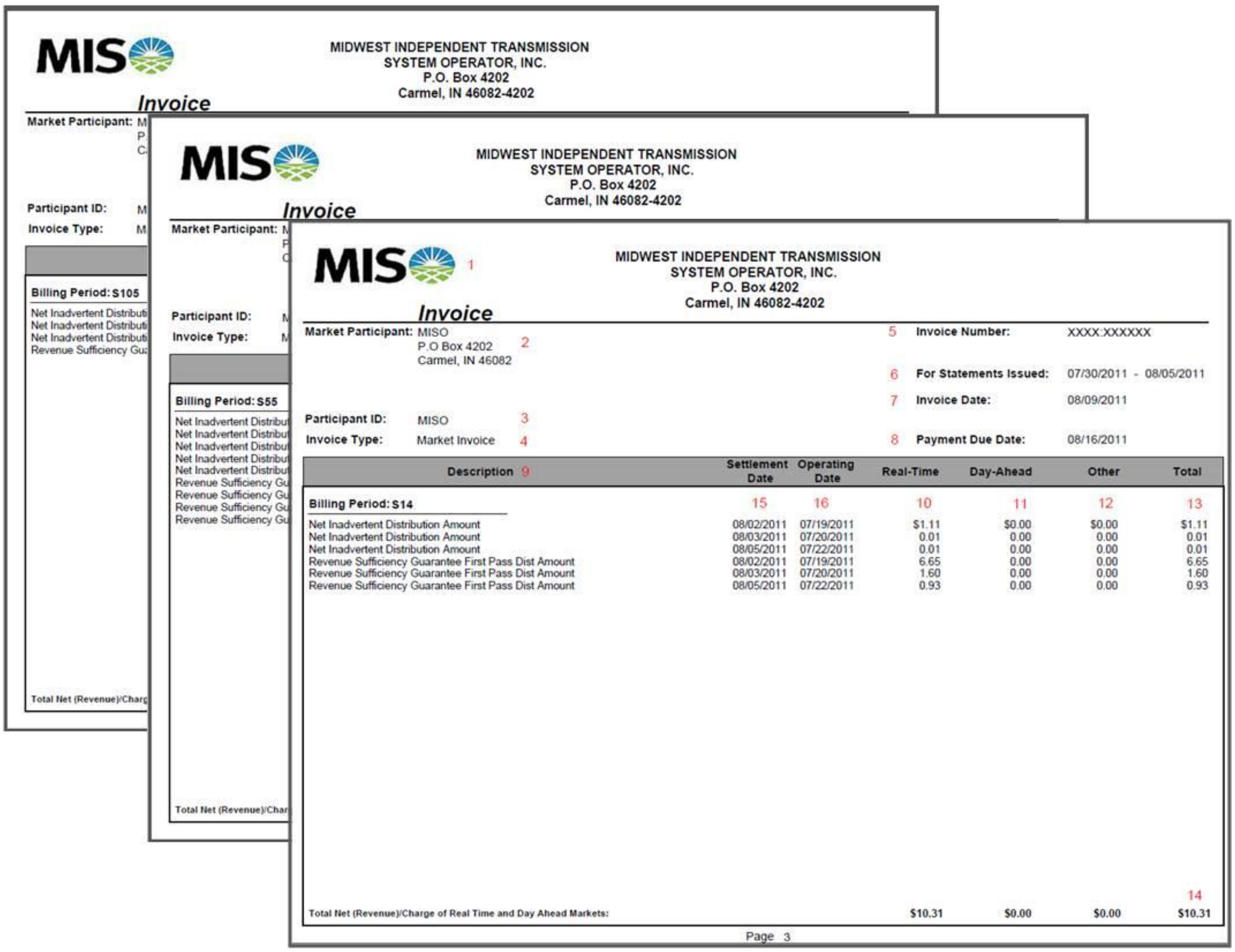
15) The Settlement date that corresponds with this invoice line item. This is the date that the charge/revenue was originally settled on. This information provides MPs the ability to tie their invoices back to their daily summary Settlement Statements.

16) The Operating Date that corresponds with this invoice line item. This information provides MPs the ability to tie their invoices back to their daily summary Settlement Statements.

3.1.3 S14, S55, S105, and Other (Non-Standard Resettlements) Prior Period Adjustment Pages

If applicable charges/revenue exist, the remaining invoice pages document the MP's revenue and charge settlement for the S14, S55, S105, and any non-standard resettlement periods.

Exhibit 3-5: Prior Period Adjustment Pages



MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.
P.O. Box 4202
Carmel, IN 46082-4202

1

Invoice

Market Participant: MISO
P.O Box 4202
Carmel, IN 46082 2

5 Invoice Number: XXXX:XXXXXX
6 For Statements Issued: 07/30/2011 - 08/05/2011
7 Invoice Date: 08/09/2011

Participant ID: MISO 3
Invoice Type: Market Invoice 4
8 Payment Due Date: 08/16/2011

Description 9	Settlement Date	Operating Date	Real-Time	Day-Ahead	Other	Total
Billing Period: S14	15	16	10	11	12	13
Net Inadvertent Distribution Amount	08/02/2011	07/19/2011	$1.11	$0.00	$0.00	$1.11
Net Inadvertent Distribution Amount	08/03/2011	07/20/2011	0.01	0.00	0.00	0.01
Net Inadvertent Distribution Amount	08/05/2011	07/22/2011	0.01	0.00	0.00	0.01
Revenue Sufficiency Guarantee First Pass Dist Amount	08/02/2011	07/19/2011	6.65	0.00	0.00	6.65
Revenue Sufficiency Guarantee First Pass Dist Amount	08/03/2011	07/20/2011	1.60	0.00	0.00	1.60
Revenue Sufficiency Guarantee First Pass Dist Amount	08/05/2011	07/22/2011	0.93	0.00	0.00	0.93
						14
Total Net (Revenue)/Charge of Real Time and Day Ahead Markets:			$10.31	$0.00	$0.00	$10.31

Page 3

The Prior Period Adjustment Pages contain the following:

1) MISO Corporate logo.
2) The customer billing address as provided to MISO through the customer registration process. This information, in addition to the invoice number and contact person, is also used for invoice identification purposes.
3) The MP NERC ID as provided to MISO through the customer registration process. This information, in addition to the invoice number and contact person, is also used for invoice identification purposes.
4) The invoice type describes the category of charges and revenue contained on the invoice. If this field notes “Administration Fee Invoice”, then the charges and revenue

on the statement relate to Schedules 16 and 17. If the field notes “Market Invoice”, then the charges and revenue on the statement relate to all other Market Activity.

5) MISO invoice number, which is used as an external and internal tracking identification tool.

6) The seven-day period for which the daily Settlement Statements are invoiced. This period runs from Saturday through Friday. Any S14, S55, S105 settlement statements, plus any non-standard resettlement statements, that are posted during that Saturday through Friday period, are invoiced on the following Tuesday.

7) The invoice date documents at which point the period for payment starts. As such, the invoice in this example would be due for remittance within 7 Calendar Days from August 9, 2011. In this example, the Payment Due Date is August 16, 2011. If the due date falls on a Saturday, Sunday, or any other MISO non-business day, the actual due date would fall to the next Business Day.

8) The payment due date, which is the date on which net invoice charges are due to be paid to MISO in immediately available funds.

9) The Charge and Revenue Type Description provides a general explanation of what type of activity is contained in each line item. In addition, the settlement charge type is also included in the left hand column to allow MPs to tie their invoices back to their daily summary Settlement Statements.

10) Real-Time Revenues and Charges are specifically broken out from the Day-Ahead and Other Revenues and Charges and are documented in this column.

11) Day-Ahead Revenues and Charges are specifically broken out from Real-Time and Other Revenues and Charges and are documented in this column.

12) Other Revenues and Charges are specifically broken out from Real-Time and Day-Ahead Revenues and Charges and are documented in this column.

13) The total column takes all Revenue types and adds them together into a subtotal amount. It also takes all Charge types and adds them together into a sub-total amount.

14) The Total Net Revenue/Charge for Real-Time and Day-Ahead Energy and Operating Reserve Markets is documented at the bottom of the Total column. This is the net amount that is carried forward to the Invoice Summary on the first page.

15) The Settlement date that corresponds with this invoice line item. This information provides MPs the ability to tie their invoices back to their daily summary Settlement Statements.

16) The Operating Date that corresponds with this invoice line item. This information provides MPs the ability to tie their invoices back to their daily summary Settlement Statements.

3.2 MISO Responsibilities

MISO publishes binding Market Settlement invoices every Tuesday for each MP. If Tuesday is not a MISO Business Day, invoices are published on the next Business Day. Specifically, MISO performs the following activities:

- Posts the PDF invoices out on the portal by 5:00 pm on Tuesday; and
- Forwards revenues to MPs with net credit invoices 24-48 hours following the Payment Due Date.

3.3 Market Participant Responsibilities

MPs are responsible for accessing invoices in a timely manner and must notify MISO if any invoice is unavailable. Specifically, MPs perform the following activities:

- Review the invoices from MISO to verify their accuracy; and
- Pay net invoice charges with immediately available funds within seven Calendar Days of the invoice date.

4. Payment and Revenue Distribution

Payments from MPs are due to MISO net seven days after the invoice date (on the Payment Due Date), and must be remitted in U.S. Dollars with immediately available funds. Payments by MISO to MPs are made in U.S. Dollars within 24-48 hours following Payment Due Date. As specified by the Tariff, all MP invoices with net charges are required to be paid in full by the Payment Due Date.

4.1 Payment of Net Invoice Charges

For all Automated Clearing House (ACH) Debit customers, a MISO accounts receivable analyst is responsible for executing electronic transfers from the MP's authorized bank account to MISO at the beginning of the sixth Calendar Day in order to pay all outstanding invoices. Due to the nature of ACH Debit transactions, the funds are withdrawn from the MP's account on the morning of the seventh day (Payment Due Date).

The accounts receivable analyst is also responsible for resolving any transaction errors in the execution of the ACH transfer. If an exception is not a transaction error, the customer is notified for proper handling.

For all customers that decide to wire settlement funds directly to MISO, a MISO accounts receivable analyst is responsible for posting the cash payment in the accounts receivable system. The following wire instructions should be used for Market Settlements payments only:

JP Morgan Chase Bank, NA
Indianapolis, IN
ABA: 021000021
Account Number: 693193260

All MPs are required to supply information regarding a bank account number and routing number during the customer registration process, which MISO has access to for billing and payment transfers. The authorization forms, included in the customer registration packet, must be completed and returned to MISO prior to starting market related activities. The authority remains in effect unless the entity notifies MISO or the bank in writing to cancel it in a reasonable amount of time.

Because of the required seven-day payment period, checks are not accepted as an allowable method of payment. Checks are not considered immediately available funds and cannot clear for payment in the allowable payment period.

4.2 Payment of Net Invoice Revenue

MISO disburses revenues to MPs with net invoice credits 24-48 hours following the invoice Payment Due Date. The funds used to make this disbursement are those collected from MPs invoiced for net charges owed to MISO. In the event that revenue collections are insufficient to fully pay all MP credits in an invoice cycle, MISO will short pay the MPs with net invoice credits on a pro rata basis. At the sole discretion of MISO, MISO may elect to borrow funds against its revolving credit facility in order to fully disperse to MPs all funds owed during a weekly invoicing cycle instead of short-paying revenue recipients.

Payments made to all net revenue MPs are sent via ACH. On the same day that payments are sent to an entity's bank account, an electronic remittance advice, in PDF format, is emailed to the contact(s) that the entity has designated during the customer registration process.

4.2.1 Electronic Remittance Advice Email and Document

Exhibit 4-1: Remittance Advice Email

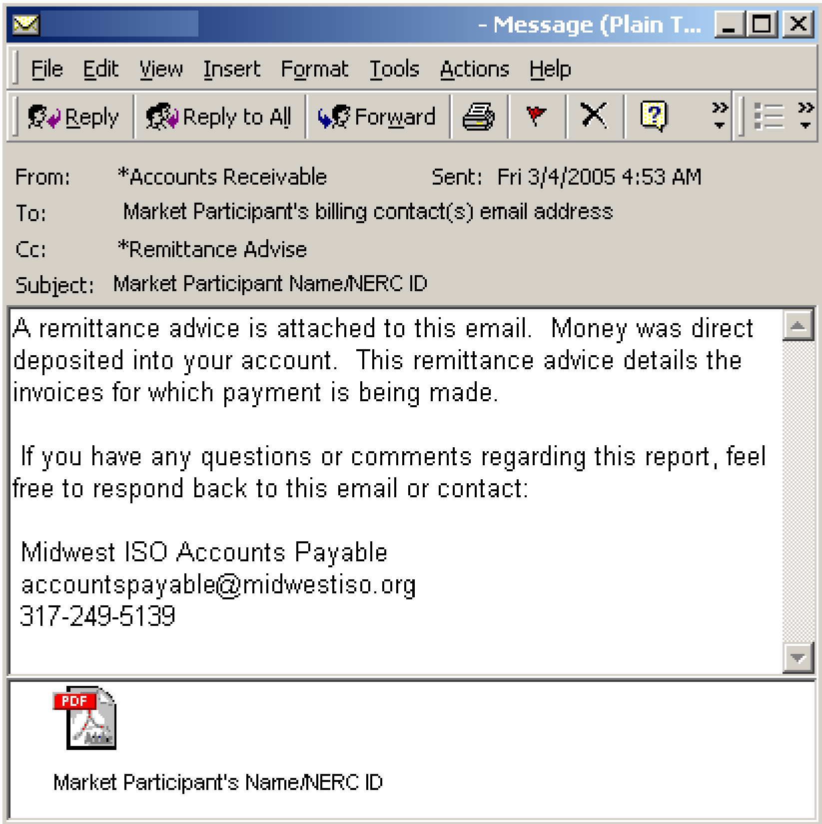


Exhibit 4-2: Remittance Advice

Miso

Date of report: 04-MAR-2005 12:00

PAYEE / NERC ID:
Ipp-Mp / IPP-MP
100 Main Street
Fishers,IN 46038

Invoice #	Description	Date of Creation	Full Value of Invoice
295:8664	Batch #:295 Created on:01-MAR-05	01-FEB-2005	$58,308.42
Report Total:			$58,308.42

PAGE 1 of 1

4.3 Late Payments and Default

If the balance of the net charge invoice is not paid on the Payment Due Date, the MP has two Business Days to submit the late payment or they are in default of payment and are subject to the Default/Uplift Procedures. Late payments are subject to interest charges as outlined in the Tariff and calculated using the interest rate prescribed in 18 C.F.R. Section 35.19a(a)(2)(iii) (FERC rate).

MISO takes the necessary actions against the defaulting MP, including but not limited to initiating proceedings with the appropriate dispute resolution mechanisms, FERC, and court actions.

MISO uses any and all rights of set-off or recoupment, or any monies to which the defaulting MP is entitled, to the extent necessary to pay the Default amount, including interest accrued and late charges due. If this is not sufficient, MISO uses the financial assurances provided by the MP under the Financial Assurance Policies to the extent necessary to pay off the outstanding default amount, interest and late charges immediately upon Default.

As amounts in Default are received, the line of credit is paid off, including interest charges.

If any amount remains in Default after four invoices or in the case of bankruptcy proceeding notification being received, MISO calculates the amount of the Default plus interest and:

Uplifts a charge to eligible MPs for the Default amount plus interest based on their participation in the Day-Ahead Energy and Real-Time Energy and Operating Reserve Markets and based on the Uncollectible Obligation Allocation Methodology set forth in the Tariff.

The uncollectible obligation is allocated to the MPs that had been invoiced during the same period of time as the unpaid invoice(s) of the MP whose unpaid past due amount has been declared an uncollectible obligation.

4.4 Notice and Suspension

If all of the above steps are insufficient to collect funds, and MISO believes that all or any part of the amount due is not or has not been paid as due, MISO notifies such MP of the default.

If notification of the Default is before 11:00 a.m. Indianapolis, Indiana time and the Default amount is not paid by the next Business Day, or if notification is after 11:00 a.m. Indianapolis, Indiana time and the Default amount is not paid by the second Business Day, the MP is considered in Default.

In accordance with Section 7.8 of the Tariff, upon the occurrence of a Default, the Transmission Provider initiates a filing with the Commission to terminate the MP Agreement, but the MP Agreement does not terminate until the Commission so approves any such request. In addition, the Transmission Provider provides notice to the MP of its intention to initiate a filing with the Commission to terminate the MP Agreement, in accordance with Commission policy.

In accordance with Section 7.14 of the Tariff, if at any time a Default occurs and is continuing, the Transmission Provider may:

1) Suspend an MP's access to submit FTR auction Bids and/or Offers;
2) Suspend a Tariff Customer's participation in any other services under the Tariff;
3) Terminate any and all services and/or agreements;
4) Terminate and settle any and all FTRs held by defaulting party; and
5) Liquidate all or a portion of the Tariff Customer's Financial Security.

The Transmission Provider's right to exercise any or all of the first four rights above is predicated in each case on obtaining the requisite Commission approval. Commission approval to liquidate all or a portion of the Financial Security is provided for under the Tariff and requires no filing.

An MP that is in Default is required under Section 7.13 of the Tariff to take all possible measures to mitigate the continued impact of the Default, including, but not limited to, loading its own Generation Resources to supply its own Load to the maximum extent possible.

4.5 Bankruptcy Filings

In the event that any MP files bankruptcy, and MISO is required to return any payments made by such MP to the bankruptcy court, MISO may avail itself of any emergency funding provisions in MISO Agreement to collect the amounts returned by MISO.

4.6 MISO Responsibilities

MISO is responsible for validating the receipt of MP payments and notification to MPs when payment is incorrect or not received.

4.7 Market Participant and Billing Agent Responsibilities

The MP is the highest hierarchical level in the Commercial Model and is the only entity in the Commercial Model that is financially obligated to MISO for Market Settlements invoices. As such, MPs are responsible not only for their own actions, but those of AOs they represent along with actions performed by Billing Agents that they assign.

4.7.1 Market Participant Responsibilities

MPs must submit the full amount of the invoiced amount owed to MISO in immediately available funds on the Payment Due Date.

MPs may authorize Billing Agents to act on their behalf to receive, validate, and transfer funds related to Market Settlements invoices.

MPs that receive payment from MISO are required to verify that MISO transfers the correct amount to them within 24-48 hours after the Payment Due Date.

4.7.2 Billing Agent Responsibilities

The MP is responsible for the receipt, validation, and funds transfer of Market Settlements invoices and for ensuring that the Billing Agent receives, validates, and transfers funds of invoices to MISO. The MP is responsible for any and all data and funds supplied by its designated Billing Agent. Any dispute between the Billing Agent and the MP concerning the information reported or funds transferred or the methodologies is resolved between the two parties without any involvement of MISO.

MISO uses the data and accepts funds provided by the Billing Agent until such time that the MP revokes or changes the designation of the Billing Agent and transfers digital certification and contact information to a replacement.

An MP can have more than one Billing Agent, but there can only be one designated Billing Agent per AO.

MISO has a financial, legal and operational relationship only with the MP, not the Billing Agent. The MP is bound by the actions of the Billing Agent.

The MP has responsibility for the quality, accuracy and timeliness of data submitted and funds transferred by the Billing Agent on its behalf.

5. Market Disputes

The purpose of this section is to describe the Market Settlement process used to resolve FTR, Day-Ahead and Real-Time Energy and Operating Reserve Market statement and invoice disputes. A dispute is a point of disagreement between the MP and MISO on a statement or invoice. The discrepancies should be filed with MISO at the determinant level. Disputes without supporting documentation are subject to suspension.

5.1 Categories of Disputes

MISO's Market Settlements Department has the responsibility to review, evaluate, research, and resolve certain market related disputes. There are two categories of disputes that MISO's Market Settlements Department can address:

1) Statement disputes cover any calculation, determinant data, or process issues regarding the MP's Market Settlement Statements; and

2) Invoice disputes are discrepancies between the statement totals and the invoice; however, when an invoice is disputed the total amount of the invoice must be paid by the due date or the MP is considered to be in default. Individual items on the statements should not be part of the invoice disputes.

The following issues are not considered covered disputes:

1) Matters regarding Transmission Settlement issues, which are processed by MISO's Transmission Settlements Department;

2) Disagreements between individual MPs, which should be resolved between the two parties outside of MISO (e.g., mediation, arbitration, or courts); and

3) Disagreements and matters between an MP and their agent.

5.1.1 Dispute Timeline

Market Settlements Disputes must be submitted no later than one hundred and twenty (120) Calendar Days from the Operating Day, in order to be considered for further evaluation. Market Settlement Disputes for Resettlement Statements must be submitted no later than fifteen (15) Calendar Days from the date of resettlement. Such disputes shall be limited to incremental changes between the previous statement and the resettlement statement. If an incremental change occurs as a result of a resettlement, a new dispute should be submitted.

Disputes not meeting these criteria will be rejected.

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

5.1.2 Tariff Set Determinants That Are Not Market Disputable

The following items and calculations are set by the Tariff, filed with FERC, and are not market disputable:

1) The Administration Fee rates for FTR, Day-Ahead and Real-Time are determined by calculations set forth in the Tariff and the rates are recalculated periodically.
2) The IMM continually observes the market for conduct that is anti-competitive or that would be harmful to MISO market or other markets. IMM imposed mitigations are not disputable in the settlements process (see Tariff, Module D, Tariff Sheet Nos. 701-807).
3) Excessive/Deficient Energy has predetermined limits defined in the Tariff (see Tariff 40.3.4). The limits are not disputable.

5.1.3 Communication

MISO's Help Center is the MP's first point of contact for all matters including Settlements and MISO's issues. The MP may submit a question through the Help Center or contact its Client Relations Representative by telephone .

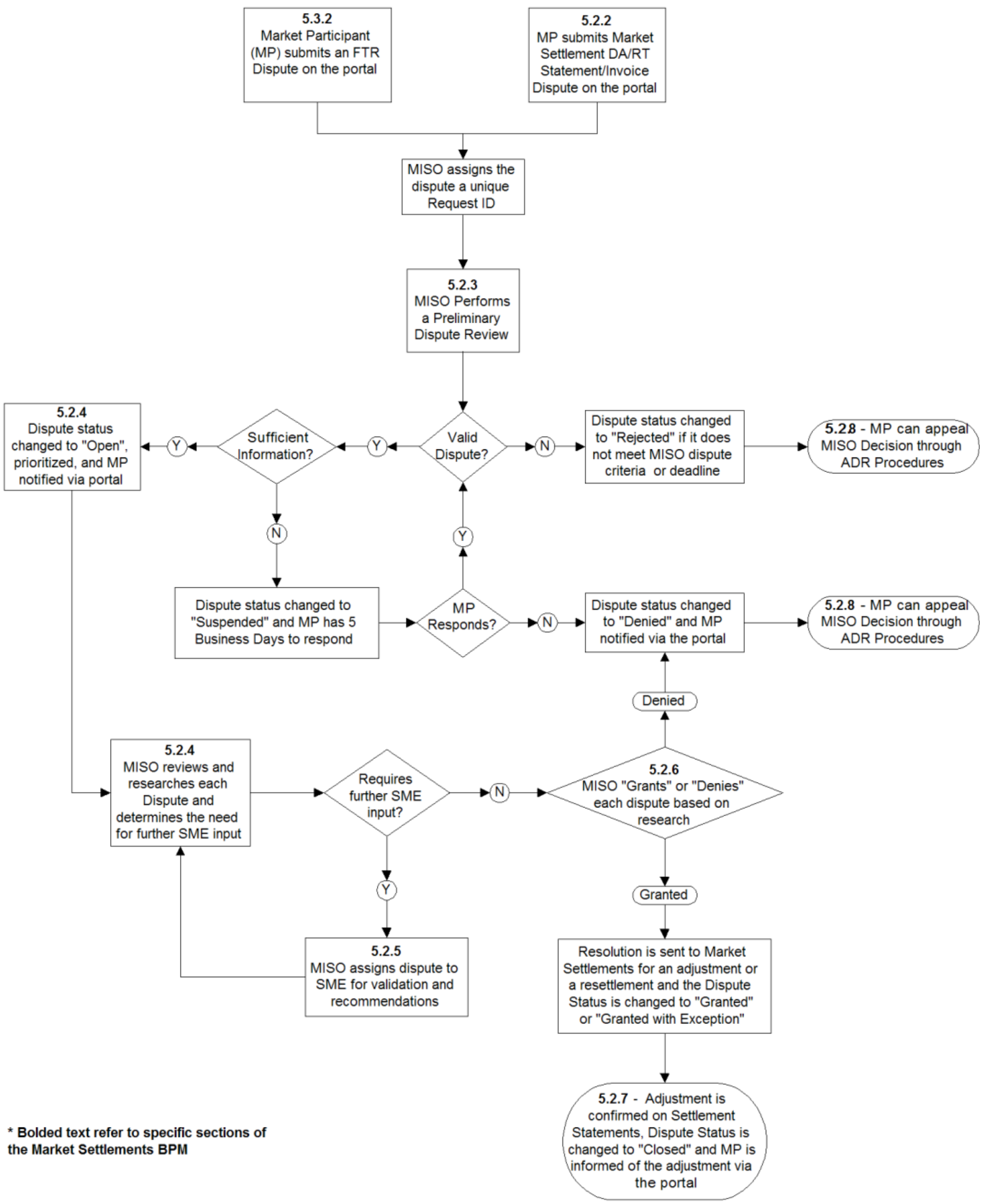
Daily updates, FAQs, charges, changes, and system updates are posted on the Market Settlement webpage and through Market Settlements Notifications.

5.2 Submitting a Market Settlement Dispute

A dispute must be submitted via the Help Center when an MP discovers a discrepancy in a Settlement Statement or Invoice. The dispute submitted will be filed in relation to a specific determinant. Each determinant will directly or indirectly affect one or more charge types, resulting in a positive or negative impact upon the disputed item. The other charge types impacted will be automatically adjusted during the settlement rerun. It is not necessary for a dispute to be filed for each charge type that will be impacted. If the MP has specific comments regarding the other areas impacted, please mention them in the "Description" field of the Dispute Case. The MP must provide justification and supporting evidence that an error or omission has occurred on its statement or invoice. Exhibit 5-2 details MISO dispute process.

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Exhibit 5-1: Market Settlement Dispute Process



Case No. 2023-00102
Attachment 1 to Response PSC 1-6

5.2.1 Dispute Registration

1) To initiate a dispute, the MP must log onto the MISO Help Center, select 'My Support', choose 'Create a Case', and select category "Settlement Dispute" or for an "FTR Dispute", select category "DA/RT Markets & Operations", Type "Financial Transmission Rights (FTR)" and sub-type "Financial Transmission Rights (FTR) Dispute".

2) The MP must have a MISO Help Center profile to submit a Market Settlement Dispute. If access is denied, the MP should contact its Client Representative to gain access to the Help Center.

5.2.2 Completing a Settlement Dispute

The following headings are the required fields on the online MISO dispute form:

1) ***Statement ID:*** Statement identification number located on the statement. (For example: *DA_AOWN_12312005-S7.*)
2) ***Transaction/Schedule ID:*** This is either the E-Tag or MISO schedule ID. This is used to identify Interchange Schedules.
3) ***Interval (Hour Ending):*** The hour or hours in question. One hour or a range may be entered. EST is required (e.g., 2:00 P.M. to 5:00 P.M. or 1400 to 1700 or HE 2, HE 3, HE 7, and HE 8).
4) ***Node ID:*** Requests the node id (name) related to the dispute.
5) ***Charge Type:*** This is a required field that identifies the disputed charge type.
6) ***Bill Determinants:*** This is a required field that lists all the bill determinants for an MP to select from.
7) ***Asset Owner:*** Lists the AO that relates to a particular MP.
8) ***Operating Date:*** This is a required field that identifies the OD of the dispute.
9) ***Invoice ID:*** This is the invoice identification number. This is required when disputing invoices.
10) ***Invoice Date:*** Identifies the Invoice date in dispute. It is specific to a Settlements invoice dispute.
11) **Title:** This is the name of the dispute being submitted in the MISO Help Center.
12) ***Description:***
    a) Subject is a brief explanation of the issue.
    b) Description is a detailed description of the issue with supporting evidence that identifies the determinant discrepancy. Supporting evidence may include:
        - Voice logs with time and date;
        - OASIS number;
        - OATi E-Tag;

- Meter Data; and
- Bids and Offers Curve.

13) ***Attachment:*** This is for additional information and supporting evidence. Multiple (5) attachments must be zipped (e.g., WinZip) before attaching them to the dispute. Each dispute is specific to an OD. If multiple ODs are affected by the same condition, each affected OD must be filed as a separate dispute. Attachments may be submitted after the initial case requirements have been submitted in the MISO Help Center.

The following is an example of an invalid Settlement dispute:

"On March 15, 2004, we found the following discrepancy in Hour Ending 13 with Charge Type DA_NASSET_EN. The E-Tag for HE13 was 50 MWh. We were paid for 48 MWh and should have received payment for all 50 MWh."

This settlement dispute would be suspended for insufficient supporting evidence. This dispute failed to provide the E-Tag or Schedule ID to identify the schedule in question.

The following suggestions for a successful dispute are offered:

- Fill out the form completely;
- Understand how the Settlement Charge Types function;
- Give as much supporting information as possible (e.g., voice logger confirmation with time, date, and name of persons involved; OASIS and OATi tag numbers);
- Keep records of all electronic and verbal transactions with MISO;
- Monitor MISO settlements changes and updates regularly;
- Provide submitted record of Bids/Offers for each schedule;
- Verify with the Metering Agent that the correct set of meter data has been forwarded to MISO;
- Provide supporting data showing MWh and pricing; and
  Verify Day-Ahead and Real-Time LMPs after they are finalized on the fifth business day.

5.2.3 Preliminary Dispute Review

1) MISO subject matter experts, trained in each of the different Charge Type areas, review the dispute to ensure that it meets all of MISO's Dispute Criteria and deadlines, including supporting evidence.

2) Invalid disputes are rejected via the Help Center.

3) If a dispute does not have sufficient evidence, the dispute is "Suspended". The MP is notified via The Help Center and has five business days to provide the requested information. If there is no response within 5 business days, the dispute is "Denied". Upon validation of the supplied information, the MP is notified via The Help Center that the dispute has been assigned an "In Progress" status.

5.2.4 Dispute Prioritization

The Market Settlement Department's goal is to resolve disputes in an efficient and effective manner. To achieve this goal, the "Opened" disputes are prioritized in the following manner:

Critical **–** Disputes with a market-wide implication

High – Disputes approaching the 30-day resolution deadline
Medium – Disputes that impact multiple MPs
Low – All other disputes

5.2.5 Verification

1) MISO reviews the MP's supporting information for consistency and accuracy against internal and external systems. All discrepancies are researched and traced back to the source department's subject matter expert for review, correction, and recommendation.
2) If a dispute cannot be resolved within 30 days, MISO informs the MP via the Help Center about the delay..

5.2.6 Dispute Resolution

MISO informs the MP of its decision (granted, granted with exception, denied, rejected, withdrawn, or suspended) based on its research and findings.

1) ***Granted*** – If MISO agrees with an MP that an error or omission has occurred, MISO changes the status to "granted" and notifies the MP via the Help Center.
2) ***Granted with Exception*** – If MISO agrees partially with an MP that an error or omission has occurred, MISO changes the status to "granted with exception" and notifies the MP via the Help Center.
3) ***Denied*** – If MISO concludes that the statement is correct or the MP does not supply the necessary documentation within 5 business days of suspension, MISO denies the dispute and provide reasons why the dispute is denied.
4) ***Rejected*** – If the dispute is not filed within one hundred and twenty (120) Calendar Days from the Operating Day covered by the respective Settlement Statement that is being disputed, or if the dispute is not within the scope of the dispute process, MISO rejects the dispute. In addition, all disputes regarding Resettlement Statements must be submitted within fifteen (15) Calendar Days from the date of resettlement otherwise, MISO will reject the dispute.
5) ***Withdrawn*** – If an MP feels its dispute is no longer valid or is resolved by other means, the MP should withdraw its dispute by changing the status to "withdrawn" in the Help Center. MISO encourages the MP to withdraw its dispute once it is no longer an issue in order for MISO to devote its resources to active disputes.
6) ***Suspended*** – If MISO determines more information is required from the MP, the MP is notified that the dispute has been suspended. The MP has 5 business days to provide the additional information. The information should be added to the original dispute case as an attachment.

5.2.7 Billing Adjustments

1) All approved disputes are corrected or adjusted in the next statement cycle for the given OD.
2) MISO may approve a nonstandard settlement before the next billing cycle if extraordinary circumstances exist.
3) This nonstandard settlement requires the MISO Market Settlement Manager's approval. The date of the nonstandard settlement execution is published.

5.2.8 Appeal Process

An MP that does not reach a satisfactory resolution with MISO may file a request for ADR in accordance with Section 12 (Dispute Resolution Procedures) of the Tariff and Appendix D (Dispute Resolution) of the MISO Agreement to appeal MISO's decision. The MP must file a dispute prior to filing an ADR regarding billing and settlement issues.

5.3 Financial Transmission Rights Dispute

FTR market disputes are related to FTR allocations or distributions in the market. FTR statement disputes are related to the financial settlements of the FTR as it appears on the MP's statement.

5.3.1 Filing a Financial Transmission Rights Dispute Case

To initiate a dispute, the MP must log onto the MISO Help Center, select 'My Support', choose 'Create a Case', and select category "DA/RT Markets & Operations", Type "Financial Transmission Rights (FTR)" and sub-type "Financial Transmission Rights (FTR) Dispute".

5.3.2 Completing a Financial Transmission Rights Dispute Case

An FTR Dispute Case is filed when the MP believes there is a discrepancy between MISO and the MP regarding an FTR, whether through market, statement or invoice.

The following headings are the fields on the MISO FTR dispute form:

1) ***Sink***: CPNode at which the FTR terminates. This is specific to an FTR market dispute case.

2) ***Quantity***: MW that the MP believes MISO has under or over allocated (profile volume) on the specified FTR. The MW can be zero if the MP is disputing financial charges.
3) ***FTR ID***: A unique number that identifies each FTR and is assigned at the time when the FTR is allocated, awarded, or purchased.
4) ***Statement ID***: Identifying FTR statement in dispute (e.g., FTR_IPP-AO_01032004-S14).
5) ***Dispute Amount:*** Dollar amount that the MP believes MISO has under- or over-charged a particular charge type.
6) ***Acquire Method***: Identifies whether the FTR was acquired from allocation, auction, or secondary market.

7) ***Dispute Type***: Selection menu that identifies the following types of disputes:
   a. ***Tariff Interpretation*** – The MP has evidence that MISO has incorrectly applied the Tariff.
   b. ***Allocation Dispute*** – The MP has evidence that MISO has incorrectly allocated a charge or credit. (For example: the administration charge is too high based on the number of FTRs.)
   c. ***General Software Algorithm*** – The MP has evidence that there is a calculation error. (For example: a formula requires an absolute value; however, the calculation did not use the absolute value of the transaction.)
   d. ***Schedule Data*** – The MP has evidence that there is a difference in physical, virtual, or financial schedule volumes. (For example: MISO used the incorrect meter data.)
   e. ***Meter Data*** – The MP has evidence that the meter data used in the Settlement is incorrect. (For example: the Meter Agent submitted the wrong data for a particular asset.) This type of dispute would mostly likely be denied. The MP may submit the correct meter data through the portal to be corrected on the next statement.
   f. ***Registration Dispute*** – The MP has evidence that MISO has incorrectly assigned an asset to an MP or AO to which it does not belong.
   g. ***Dispatch Dispute*** – The MP has evidence that MISO Settlement statement does not reflect the MISO Setpoint Instruction.
   h. ***Other*** - The MP has evidence of another type of dispute.
8) ***Operating Date:*** This is a required field that identifies the Operating Date of the dispute.
9) ***Asset Owner:*** Owner of the Asset that relates to the particular dispute.
10) ***Invoice ID***: Identifies the MP's weekly invoice in dispute. This is specific to an FTR invoice dispute case.
11) ***Effective Start Date:*** Registered activation date of the FTR in question. This is specific to an FTR market dispute case.
12) ***Effective End Date***: Registered disposition date of the FTR in question. This is specific to an FTR market dispute case.
13) ***Source***: CPNode at which the FTR originates. This is specific to an FTR market dispute case.
14) ***Charge Type:*** This is a required field that identifies the disputed charge type. This is specific to an FTR statement disputecase.

15) ***Bill Determinants:*** This is a required field that lists all the bill determinants for an MP to select from. This is specific to an FTR statement disputecase.

16) **Description:**
    a. Title is a brief explanation of the issues.
    b. Description is a detailed description of the issue with supporting evidences that identifies the determinant discrepancy and explains the reasons for it.

5.4 Locating an Existing Dispute Case

The Help Center provides a page, My Support, for the MP to search its disputes based on several criteria. This a useful tool to find the status of the MP's disputes.

5.5 Responsibilities

5.5.1 Market Participant's Responsibilities:

- Possess a working knowledge of the Settlement formulas and calculations;
- Retrieve statements and invoices from the portal;
- Inform MISO if statements or invoices are missing according to the statement schedule;
- File disputes through the Help Center no later than 120 Calendar Days from the OD or 15 Calendar Days from the date of resettlement being disputed; and
  Provide supporting documents.

5.5.2 MISO Responsibilities:

- Resolve disputes within 30 days of registration;
- Provide reasons for rejected, denied, or suspended disputes;
- Notify the MP with the expected length of time to resolve the dispute if it requires additional research and/or information;
- Correct errors and omissions;
- Post known errors and omissions that affect the market

Case No. 2023-00102
Attachment 1 to Response PSC 1-6

Frequently Asked Questions – Real-Time Revenue Sufficiency Guarantee

What is Revenue Sufficiency Guarantee (RSG)?

Midwest ISO has the responsibility to ensure that adequate capacity is available and committed to meet demand and reserve obligations within the Market Footprint. RSG is a mechanism that ensures Generation Resources that are committed by the Midwest ISO are guaranteed cost recovery of their three-part offer described as start-up costs, no load costs, and incremental energy offer, collectively referred to as production costs, when appropriate. These payments are reflected as part of the Day-Ahead and Real-Time RSG Make Whole Payment Amounts and funded through the Day-Ahead and Real-Time RSG Distribution Amounts.

The following charge calculations below are described separately in this document:

1) Real-Time RSG Make Whole Payment Amount (RT_RSG_MWP)
2) Real-Time RSG First Pass Distribution Amount (RT_RSG_DIST1)
3) Real-Time RSG Make Whole Payments Second Pass Distribution Uplift (Component of RT_RNU)

Reference: BPM for Coordinated Reliability Dispatch and Control, Section 2, BPM for Market Settlements, Section B.10, D.12, D.13

Real-Time RSG Make Whole Payment Amount (RT_RSG_MWP)

Generation Resources that are eligible and committed by the Midwest ISO and scheduled for commitment in the Real-Time Energy Market, beyond cleared Day-Ahead Market commitments, shall be guaranteed cost recovery of their production costs, when appropriate.

The three-part costs (a.k.a. Production Costs) are defined as follows:

1) **Start-up** – Costs that are incurred per start-up over the run-time of the unit.
2) **No Load** – Costs for operating a Generation Resource at zero MWs.
3) **Energy Offer** – Area under the price curve at which a Resource has agreed to sell the next increment of Energy.

The Midwest ISO performs the RAC process and may commit additional Resources beyond those cleared in the Day-Ahead Energy Market to meet the forecasted needs within the Midwest ISO. A generation resource is **NOT** eligible for the Real-Time RSG Make Whole Payment in hours the unit cleared in the Day-Ahead Market.

The Real-Time RSG Make Whole Payment Amount revolves around the concept of a Commitment Period (CP) for a Resource. In the Real-Time Market, a CP is a period of continuous MISO instructed commitment bounded by a MISO instructed start-up and MISO instructed shut-down. Eligibility during a CP is governed by two key indicators:

1) If any hours in the CP have a Must-Run commit status, then the generation resource is not eligible for start-up cost recovery in the CP.
2) Any hours in the CP that have a Must-Run commit status will not be eligible for recovery of no load costs and incremental energy costs.

Case No. 2023-00102
Attachment 2 to Response PSC 1-6

The Real-Time related RAC process may commit a generation Resource multiple times in a single Operating Day. As noted, the contiguous hours that a generation Resource is committed is referred to as a Commitment Period. Each Commitment Period must be separated by at least one Hour where the asset was scheduled to be off-line by MISO to receive a Revenue Sufficiency Make Whole Payment. Production Costs are guaranteed by Commitment Period.

Example of a Commitment Period (CP):

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A

Commitment Period (CP)

Scheduled Start-Up (HE 1)

Scheduled Start-Up (HE 12)

Example of a Continuous Period (CP) where HE 6 has a commit status of Must-Run:

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	A	A	A	A	A	MR	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A

(CP 1)

(CP 2)

Continuous Period

Scheduled Start-Up (HE 1)

Scheduled Start-Up (HE 12)

In the above example, HE 6 has a commit status of Must-Run. If any hour within a CP contains a commit status of Must-Run, this asset is not eligible to recover start-up costs in this CP. Additionally, the Market Participant is not eligible to recover No Load costs and incremental energy costs for HE 6.

Can there be more than one (1) CP over the course of an Operating Day?

Yes, there can be more than one CP over the course of an Operating Day. When this occurs Real-Time RSG Make Whole Payments are evaluated for each CP independently. Below is an example of an Operating Day with multiple CPs:

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A

(CP 1)

Scheduled Start-Up (HE 1)

(CP 2)

(CP 3)

Scheduled Shut-Down (HE 6)

Who is eligible for Real-Time RSG Make Whole Payment?

Generating Resources that are committed by the Midwest ISO and meet the Real-Time Make Whole Payment Eligibility Criteria are eligible for Real-Time RSG Make Whole Payments. Real-Time RSG Make Whole Payment Eligibility Scenarios include some of the following:

NOTE: Day-Ahead and Real-Time RSG Eligibility Guide can be found by going to www.midwestmarket.org /documents/ Market Settlement Helpful document and files.

MISO

#	Scenarios	Illustration / Resolution	Day-Ahead Eligibility			Real-Time Eligibility		
			Start-Up	No-Load	Incremental Costs	S tart-Up	No-Load	Incremental Costs
1	Generating Unit was committed in the Real-Time Market by the Midwest ISO.	**Real-Time** MISO Commit HE 1-10	Not Eligible	Not Eligible	Not Eligible	√	√ HE 1-10	√ HE 1-10
2	Market Participant specified a Real-Time Must-Run prior to the Generating Unit being committed in the Day-Ahead Market by the Midwest ISO.	**Real-Time** MP specifies MR HE 1-10 | **Day-Ahead** MISO Commit HE 11-24	√ HE 11-24	√ HE 11-24	√ HE 11-24	Not Eligible	Not Eligible	Not Eligible
3	Market Participant specified a Real-Time Must-Run after the Generating Unit was committed in the Day-Ahead Market by the Midwest ISO.	**Day-Ahead** MISO Commit HE 1-10 | **Real-Time** MP specifies MR HE 11-24	√ HE 1-10	√ HE 1-10	√ HE 1-10	Not Eligible	Not Eligible	Not Eligible
4a	Midwest ISO committed the Generating Unit in Real-Time prior to the Market Participant specified Real-Time Market Must-Run period.	**Real-Time** MISO Commit HE 1-10 | **Real-Time** MP specifies MR HE 11-24	Not Eligible	Not Eligible	Not Eligible	Not Eligible	√ HE 1-10	√ HE 1-10
4b	Midwest ISO committed the Generating Unit in Real-Time prior to the Market Participant specified Day-Ahead Market on-line period.	**Real-Time** MISO Commit HE 1-10 | **Day-Ahead** MP / MISO Commit HE 11-24	√ HE 11-24 (ONLY if MISO Commit)	√ HE 11-24 (ONLY if MISO Commit)	√ HE 11-24 (ONLY if MISO Commit)	Not Eligible	√ HE 1-10	√ HE 1-10
5a	Midwest ISO committed the Generating Unit in Real-Time after the Market Participant specified Real-Time Market Must-Run period.	**Real-Time** MP specifies MR HE 1-10 | **Real-Time** MISO Commit HE 11-24	Not Eligible	Not Eligible	Not Eligible	Not Eligible	√ HE 11-24	√ HE 11-24
5b	Midwest ISO committed the Generating Unit in Real-Time after the Market Participant specified Day-Ahead Market on-line period.	**Day-Ahead** MP / MISO Commit HE 1-10 | **Real-Time** MISO Commit HE 11-24	√ HE 1-10 (Only if MISO Commit)	√ HE 1-10 (Only if MISO Commit)	√ HE 1-10 (Only if MISO Commit)	Not Eligible	√ HE 11-24	√ HE 11-24
6a	Midwest ISO committed the Generating Unit in Real-Time through a Market Participant specified Real-Time Market Must-Run period.	**Real-Time** MISO Commit MR HE 1-8 | HE 9 | HE 10-24	Not Eligible	Not Eligible	Not Eligible	Not Eligible	√ HE 1-8, 10-24	√ HE 1-8, 10-24
6b	Midwest ISO committed the Generating Unit in Real-Time through a Market Participant specified Day-Ahead Market on-line period.	**Real-Time** MISO Commit HE 1-6 | **Day-Ahead** MP / MISO Commit HE 7-9 | **Real-Time** MISO Commit HE 10-24	√ HE 7-9 (Only if MISO Commit)	√ HE 7-9 (Only if MISO Commit)	√ HE 7-9 (Only if MISO Commit)	Not Eligible	√ HE 1-6, 10-24	√ HE 1-6, 10-24
7	Midwest ISO committed Resources that are not following dispatch instructions in the Real-Time Market. "Following Dispatch" is defined the same as for Uninstructed Deviation Penalties.	**Real-Time** MISO Commit HE 1-10 Market Participants not following dispatch will be subject to Uninstructed Deviation Amount.	Not Eligible	Not Eligible	Not Eligible	√*	(Not eligible for the hours not following dispatch)	(Not eligible for the hours not following dispatch)
8	Revenue Sufficiency Guarantee for a JOU will be allocated based on the commitment for the Commercial Unit of each of the Asset Owners.	**Day-Ahead or Real-Time** **JOU** - MISO Commit HE 1-10 Asset Owner 1 - 50% | Asset Owner 2 - 50%	Subject to Day-Ahead and Real-Time eligibility rules for all parties	Subject to Day-Ahead and Real-Time eligibility rules for all parties	Subject to Day-Ahead and Real-Time eligibility rules for all parties	Subject to Day-Ahead and Real-Time eligibility rules for all parties	Subject to Day-Ahead and Real-Time eligibility rules for all parties	Subject to Day-Ahead and Real-Time eligibility rules for all parties
9	Midwest ISO commits a Generating Unit in Real-Time and then cancels the Start-up prior to the unit Start-up time beginning.	**Real-Time** MP (4-Hour) Start-Up | MISO Commit MISO Cancels start prior to unit Start-up | HE 11-24	Not Eligible	Not Eligible	Not Eligible	Case by Case Basis	Not Eligible	Not Eligible
10	Midwest ISO commits a Generating Unit and then cancels the Start-up after the unit begins Start-up.	**Real-Time** MP (4-Hour) Start-Up | MISO Commit MISO Cancels start (HE 8) after the unit begins Start-up | HE 11-24	Not Eligible	Not Eligible	Not Eligible	Prorated	Not Eligible	Not Eligible
11	Midwest ISO commits a Generating Unit and then cancels the Start after the unit comes online**.	**Real-Time** MISO Commit HE 11-24 MISO Cancels Start HE 14	Not Eligible	Not Eligible	Not Eligible	√	√ HE 11-14 (Per Hour Online**)	√ HE 11-14 (Per Hour Online**)
12	Midwest ISO commits a Generating Unit and then Market Participant cancels the Start-up.	**Real-Time** MP Start-Up | MISO Commit MP Cancels Start HE 8 | HE 11-24	Not Eligible	Not Eligible	Not Eligible	Not Eligible	Not Eligible	Not Eligible
13	Market Participant cancels a Must Run commitment.	**Real-Time** MP specifies Must-Run | MISO Commit | MP Cancels Must-Run HE 1-10 | HE 11-24 | HE 1-10	Not Eligible	Not Eligible	Not Eligible	Not Eligible	√ HE 11-24 (RT if MISO Commit)	√ HE 11-24 (RT if MISO Commit)
14	Midwest ISO commits a Generating Unit but the Generating Unit comes online** prior to the Midwest ISO scheduled commit time minus Cold Startup Time minus 1 hour.	**Real-Time** MP Start-Up | MISO Commit MP comes online HE 02 | HE 11-24 Example: Cold Start = 6 Hours	Not Eligible	Not Eligible	Not Eligible	Not Eligible	√ HE 11-24 (Only if MISO Commit)	√ HE 11-24 (Only if MISO Commit)

* All Real-Time Start-up Eligibility assumes that the unit is online and available.
** Online is defined as SE (State Estimator) MW is greater than 0.

Case No. 2023-00102
Attachment 2 to Response PSC 1-6

How can a Market Participant determine whether or not they are eligible to receive Real-Time RSG Make Whole Payment?

On an hourly basis, the Day-Ahead Real-Time System (DART) determines whether a generation Resource that was committed by MISO during the Real-Time related RAC process has met the eligibility requirements. If the generation Resource is eligible for Real-Time RSG Make Whole Payment, the eligibility is represented on the Settlement Statement as the Real-Time Revenue Sufficiency Guarantee Eligibility flag (*RT_RSG_ELIGIBILITY).

Does the Midwest ISO calculate Production Cost based on data submitted by the Market Participant for the Generator Resource or some other source?

Once a start notification is issued for a resource to operate in the Real-Time, the Day-Ahead Real-Time system (DART) takes a snapshot of the startup costs, hourly no load cost, and energy offer for the committed hours. The Day-Ahead Real-Time System (DART) calculates a generator's hourly production costs based on its start-up cost uniformly distributed over the eligible portion of the Commitment Period, its no load cost for each eligible hour of the Commitment and its incremental energy cost based on an hourly average of 5-minute snapshots of its incremental energy offer cost for the Real-Time State Estimated MW value for each hour of the Commitment Period. The calculation is performed for both the resource's as-committed snapshot offer costs and for the as-dispatch offer costs. DART provides Market Settlement with the minimum of the eligible as-committed costs and eligible as-dispatch costs over the operating day as hourly production cost values for each generator.

Separately, the Independent Market Monitor (IMM) may perform an Impact Test if they believe that Conduct occurred that caused substantial change in the LMPs or unjustifiably increased the value of ORSGPs (Offer RSG Payments). Mitigated Production Costs are calculated based on Reference Levels. Reference Levels are intended to reflect a Generation Resource's marginal costs, including legitimate risk and opportunity costs or justifiable technical characteristics for physical offer parameters. In addition to the production cost value based on Market Participant submitted offer costs, Market Settlements is provided with the total mitigated hourly eligible production cost value for each generator identified by the IMM for potential mitigation.

If Production Costs have not been received from the IMM, only the values calculated from Market Participant are used to assess the Real-Time RSG Make Whole Payment.

Reference: BPM for Market Monitoring and Mitigation_R2, Section 12

How does one calculate the amount an asset is expected to receive for the Real-Time RSG Make Whole Payment?

On an hourly basis, DART calculates and passes to Market Settlements a generator's production cost. Assuming it is not mitigated, the Midwest ISO allocates this Production Cost over the CP. It then compares the Production Cost to the Real-Time Market Energy Amount (RT_RSG_EN_VAL_CP) or the "Market Value" of the cleared schedule over the Commitment Period. The Real-Time Market Energy Amount or "Market Value" is the defined as the Real-Time Actual Meter Data (*RT_ACT_MTR) or Real-Time Alternate Meter Data (*RT_ALT_MTR) (when Actual Meter Data is not available) multiplied by the Real-Time LMP (*RT_LMP_EN). If the "Market Value" of the schedule is less than the Production

Case No. 2023-00102

Attachment 2 to Response PSC 1-6

Cost, the difference is the amount that is credited to the Asset Owner as a Real-Time RSG Make Whole Payment Amount.

Example: Generator Unit On for a CP of 4 Hours

Real-Time Market

	"Market Value"			Cost					Make Whole Payment
HE	Actual or Alternate Meter	LMP	Revenue	Startup	No Load	Incremental	Total	Net	
1	135	$50.65	$6,837.75	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
2	135	$60.25	$8,133.75	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
3	135	$63.44	$8,564.40	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
4	135	$58.21	$7,858.35	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
	Totals:		$31,394.25	$2,425.80	$400.00	$38,167.20	$40,993.00	-$9,598.75	

The above example shows that in addition to the $31,394.25 in Revenue the generation resource receives based on its Real-Time Actual Meter Value multiplied by the Real-Time LMP for each hour, the generation resources make whole payment of $9,598.75 makes it whole on the additional production costs incurred during the 4-hour period.

How does the Midwest ISO calculate the Real-Time RSG Make Whole Payment if there are hours within a CP that has a status of Must-Run?

Example of a Continuous Period (CP) where HE 18 has a commit status of Must-Run:

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	MR	A	A	A	A	A	A

(CP 1) (CP 2)

Continuous Period (CP) #2

Scheduled Start-Up (HE 13) Scheduled Shut-Down (HE 24)

Real-Time Market (Real-Time RSG Make Whole Payment for CP #1)

	"Market Value"			Cost					Make Whole Payment
HE	Actual or Alternate Meter	LMP	Revenue	Startup	No Load	Incremental	Total	Net	
13	176	$91.17	$16,045.92	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
14	176	$91.82	$16,160.32	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
15	176	$90.21	$15,876.96	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
16	176	$89.04	$15,671.04	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
17	176	$96.30	$16,948.80	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
	Totals:		$80,703.04	$0.00	$500.00	$63,962.25	$64,462.25	$16,240.79	

Real-Time Market (Real-Time RSG Make Whole Payment for CP #2)

	"Market Value"			Cost					Make Whole Payment
HE	Actual or Alternate Meter	LMP	Revenue	Startup	No Load	Incremental	Total	Net	
19	176	$90.98	$16,012.48	$0.00	$100.00	$12,792.45	$12,892.45		-$2,695.24
20	143	$72.47	$10,363.21	$0.00	$100.00	$10,708.28	$10,808.28		-$2,695.24
21	135	$48.49	$6,546.15	$0.00	$100.00	$9,541.80	$9,641.80		-$2,695.24
22	135	$41.02	$5,537.70	$0.00	$100.00	$9,541.80	$9,641.80		-$2,695.24
23	135	$28.93	$3,905.55	$0.00	$100.00	$9,541.80	$9,641.80		-$2,695.24
24	135	$27.64	$3,731.40	$0.00	$100.00	$9,541.80	$9,641.80		-$2,695.24
	Totals:		$46,096.49	$0.00	$600.00	$61,667.93	$62,267.93	-$16,171.44	

Case No. 2023-00102

Attachment 2 to Response PSC 1-6

As shown in the above example, if any hour within a CP contains a commit status of Must-Run, this asset is **NOT** eligible to recover start-up costs during this CP. Additionally; the Market Participant is **NOT** eligible to recover No Load costs and incremental energy costs for HE 18. When this situation occurs, Real-Time RSG Make Whole Payments are evaluated for each CP independently. In this example, the Market Participant is in essence "Made Whole" through the "Market Value" for CP 1 (HE 13 – HE 17), so will not receive any additional Real-Time RSG Make Whole Payment for that CP. However, during CP 2 (HE 19- HE 24), the "Market Value" is less than the Production Cost, therefore the difference is the amount that will be credited to the Asset Owner as a Real-Time RSG Make Whole Payment Amount.

How does the Midwest ISO calculate the Real-Time RSG Make Whole Payment if the Commitment Period of a unit crosses over two days?

Example of a 20-Hour Commitment Period (CP) that crosses over two days:

	OD 1										OD 2									
HE	15	16	17	18	19	20	21	22	23	24	1	2	3	4	5	6	7	8	9	10
	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A

Commitment Period (CP)

Scheduled Start-Up (HE 15)

Scheduled Shut-Down (HE 10)

Real-Time Market - OD 1

HE	"Market Value" Actual or Alternate Meter	LMP	Revenue	Cost Startup	No Load	Incremental	Total	Net	Make Whole Payment
15	176	$90.21	$15,876.96	$242.58	$100. 00	$12,792.45	$13,135.03		-$490.10
16	176	$89.04	$15,671.04	$242.58	$100. 00	$12,792.45	$13,135.03		-$490.10
17	176	$96.30	$16,948.80	$242.58	$100. 00	$12,792.45	$13,135.03		-$490.10
18	176	$95.28	$16,769.28	$242.58	$100. 00	$12,792.45	$13,135.03		-$490.10
19	176	$90.98	$16,012.48	$242.58	$100. 00	$12,792.45	$13,135.03		-$490.10
20	143	$72.47	$10,363.21	$242.58	$100. 00	$10,708.28	$11,050.86		-$490.10
21	135	$48.49	$6,546.15	$242.58	$10 0.00	$9,541.80	$9,884.38		-$490.10
22	135	$41.02	$5,537.70	$242.58	$10 0.00	$9,541.80	$9,884.38		-$490.10
23	135	$28.93	$3,905.55	$242.58	$10 0.00	$9,541.80	$9,884.38		-$490.10
24	135	$27.64	$3,731.40	$242.58	$10 0.00	$9,541.80	$9,884.38		-$490.10
Totals:			$111,362.57	$2,425.80	$1,000.00	$112,837.73	$116,263.53	-$4,900.96	

Real-Time Market - OD 2

HE	"Market Value" Actual or Alternate Meter	LMP	Revenue	Cost Startup	No Load	Incremental	Total	Net	Make Whole Payment
1	135	$50.65	$6,837.75	$0.00	$100.00	$12,792.45	$10,248.25		-$3,290.08
2	135	$60.25	$8,133.75	$0.00	$100.00	$12,792.45	$10,248.25		-$3,290.08
3	135	$63.44	$8,564.40	$0.00	$100.00	$12,792.45	$10,248.25		-$3,290.08
4	135	$58.21	$7,858.35	$0.00	$100.00	$12,792.45	$10,248.25		-$3,290.08
5	135	$48.54	$6,552.90	$0.00	$100.00	$12,792.45	$10,248.25		-$3,290.08
6	135	$43.02	$5,807.70	$0.00	$100.00	$10,708.28	$10,248.25		-$3,290.08
7	135	$44.54	$6,012.90	$0.00	$100.00	$9,541.80	$10,248.25		-$3,290.08
8	135	$47.55	$6,419.25	$0.00	$100.00	$9,541.80	$10,248.25		-$3,290.08
9	135	$48.92	$6,604.20	$0.00	$100.00	$9,541.80	$10,248.25		-$3,290.08
10	135	$50.30	$6,790.50	$0.00	$100. 00	$9,541.80	$10,248.25		-$3,290.08
Totals:			$69,581.70	$0.00	$1,000.00	$ 112,837.73	$102,482.50	-$32,900.80	

Case No. 2023-00102

Attachment 2 to Response PSC 1-6

If the CP of a unit crosses two Operating Days, Start-Up Costs are prorated over the hours in the first Operating Day.

How does the Midwest ISO distribute the Real-Time RSG Make Whole Payment, in one lump sum or over the Commitment Period (CP)?

Make Whole Payment credits that are due to the generator are broken out by commitment period and by hour.

How does the Midwest ISO calculate the Real-Time RSG Make Whole Payment when there are multiple Commitment Periods (CP)?

When a resource has multiple CPs in an Operating Day, each CP is evaluated separately. The following example describes the situation where a generation resource had two separate and distinct CPs in an Operating Day separated by hours where the generation resource was not committed and not on-line.

Example of an Operating Day with multiple CPs:

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A	A

CP #1

Scheduled Start-Up

Scheduled Shut-Down

Scheduled Start-Up (HE 12)

CP #2

Scheduled Shut-Down (HE 24)

Real-Time Market (Real-Time RSG Make Whole Payment for CP #1)

	"Market Value"			Cost					
HE	Actual or Alternate Meter	LMP	Revenue	Startup	No Load	Incremental	Total	Net	Make Whole Payment
5	135	$50.65	$6,837.75	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
6	135	$60.25	$8,133.75	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
7	135	$63.44	$8,564.40	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
8	135	$58.21	$7,858.35	$606.45	$100.00	$9,541.80	$10,248.25		-$2,399.69
	Totals:		$31,394.25	$2,425.80	$400.00	$38,167.20	$40,993.00	-$9,598.75	

Real-Time Market (Real-Time RSG Make Whole Payment for CP #2)

	"Market Value"			Cost					
HE	Actual or Alternate Meter	LMP	Revenue	Startup	No Load	Incremental	Total	Net	Make Whole Payment
12	151	$85.00	$12,835.00	$186.60	$100.00	$11,335.48	$11,622.08		$0.00
13	151	$91.17	$13,766.67	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
14	176	$91.82	$16,160.32	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
15	176	$90.21	$15,876.96	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
16	176	$89.04	$15,671.04	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
17	176	$96.30	$16,948.80	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
18	176	$95.28	$16,769.28	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
19	176	$90.98	$16,012.48	$186.60	$100.00	$12,792.45	$13,079.05		$0.00
20	143	$72.47	$10,363.21	$186.60	$100.00	$10,708.28	$10,994.88		$0.00
21	135	$48.49	$6,546.15	$186.60	$100.00	$9,541.80	$9,828.40		$0.00
22	135	$41.02	$5,537.70	$186.60	$100.00	$9,541.80	$9,828.40		$0.00
23	135	$28.93	$3,905.55	$186.60	$100.00	$9,541.80	$9,828.40		$0.00
24	135	$27.64	$3,731.40	$186.60	$100.00	$9,541.80	$9,828.40		$0.00
	Totals:		$154,124.56	$2,425.80	$1,300.00	$149,758.11	$153,483.91	$640.65	

If there are multiple CPs in a given Operating Day, the Real-Time settlement compares whether the generating asset's value for a CP exceeds the guaranteed productions costs for those hours. If the total energy value ("Market Value") is less than the guaranteed production cost amount, the difference is credited to the Asset Owner as a Real-Time RSG Make Whole Payment Amount.

In the above example, CP #1 for HE 5-8, since the "Market Value" is less than the Production Cost, the Asset Owner receives the difference as a Real-Time RSG Make Whole Payment Amount. As noted above, this amount is allocated evenly across all committed hours in the CP. For CP #2 for HE 12-24, since the "Market Value" was greater than the Production Cost, the Asset Owner was essentially "Made Whole" and does not receive additional credits from the Midwest ISO.

If a Generating Unit was committed in the Day-Ahead Market for HE 1-10 and was further committed for HE 11-24 during the RAC Process, what would the Asset Owner be eligible for with respect to Real-Time RSG Make Whole Payment?

Generation Resources that are eligible and committed by the Midwest ISO and scheduled in the Day-Ahead Energy Market are guaranteed cost recovery of their production costs. All Resource Offers **except** for Must-Run that have been committed by the Midwest ISO are eligible for Day-Ahead RSG Make Whole Payment.

NOTE: Day-Ahead and Real-Time RSG Eligibility Guide can be found by going to www.midwestmarket.org /documents/ Market Settlement Helpful document and files

Day-Ahead MISO Commit	**Real-Time** MISO Commit
HE 1-10	HE 11-24

Hours in the same CP that were not committed in the Day-Ahead Market, but committed for the Real-Time Market and meet the Real-Time RSG Eligibility Criteria, are eligible for Real-Time Make Whole Payment. Since Start-up costs for the CP were guaranteed in the Day-Ahead Market, the generating unit is only eligible for No Load and Incremental Energy Costs in Real-Time for the hours that were committed for the Real-Time Market by the Midwest ISO provided that the generating unit met all Real-Time RSG Eligibility Criteria during these hours.

Day-Ahead Market

	"Market Value"			Cost					
HE	MW	LMP	Net Market Revenue	Startup	No Load	Incremental	Net Production Cost	Net RSG Make Whole Payment	Make Whole Payment
1	30	$18.99	$569.70	$45.76	$4.00	$667.14	$716.90		-$164.36
2	30	$17.90	$537.00	$45.76	$4.00	$667.14	$716.90		-$164.36
3	30	$17.33	$519.90	$45.76	$4.00	$667.14	$716.90		-$164.36
4	30	$17.23	$516.90	$45.76	$4.00	$667.14	$716.90		-$164.36
5	30	$17.32	$519.60	$45.76	$4.00	$667.14	$716.90		-$164.36
6	30	$17.63	$528.90	$45.76	$4.00	$667.14	$716.90		-$164.36
7	30	$18.19	$545.70	$45.76	$4.00	$667.14	$716.90		-$164.36
8	30	$19.28	$578.40	$45.76	$4.00	$667.14	$716.90		-$164.36
9	30	$19.86	$595.80	$45.76	$4.00	$667.14	$716.90		-$164.36
10	30	$20.45	$613.50	$45.76	$4.00	$667.14	$716.90		-$164.36
	Totals:		$5,525.40	$457.60	$40.00	$6,671.35	$7,168.95	-$1643.55	

Case No. 2023-00102

Attachment 2 to Response PSC 1-6

Real-Time Market

	"Market Value"			Cost					
HE	Billable Meter	LMP	Net Market Revenue	Startup	No Load	Incremental	Net Production Cost	Net RSG Make Whole Payment	Make Whole Payment
11	151	$52.33	$7,901.83	$0.00	$100.00	$11,335.48	$11,435.48		$0.00
12	151	$76.00	$11,476.00	$0.00	$100.00	$11,335.48	$11,435.48		$0.00
13	176	$91.17	$16,045.92	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
14	176	$91.82	$16,160.32	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
15	176	$90.21	$15,876.96	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
16	176	$89.04	$15,671.04	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
17	176	$96.30	$16,948.80	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
18	176	$95.28	$16,769.28	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
19	176	$90.98	$16,012.48	$0.00	$100.00	$12,792.45	$12,892.45		$0.00
20	143	$72.47	$10,363.21	$0.00	$100.00	$10,708.28	$10,808.28		$0.00
21	135	$48.49	$6,546.15	$0.00	$100.00	$9,541.80	$9,641.80		$0.00
22	135	$41.02	$5,537.70	$0.00	$100.00	$9,541.80	$9,641.80		$0.00
23	135	$28.93	$3,905.55	$0.00	$100.00	$9,541.80	$9,641.80		$0.00
24	135	$27.64	$3,731.40	$0.00	$100.00	$9,541.80	$9,641.80		$0.00
	Totals:		$143,568.81	$0.00	$1,200.00	$138,422.63	$139,622.63	$3,946.18	

How is the Incremental Cost calculated?

Incremental Cost, also known as the "Area under the Curve" is used in determining the revenue guaranteed to Midwest ISO committed units. In Real-Time, the incremental cost is based on the offer curve up to the State Estimated Hourly Output.

Incremental Cost is calculated with the following:

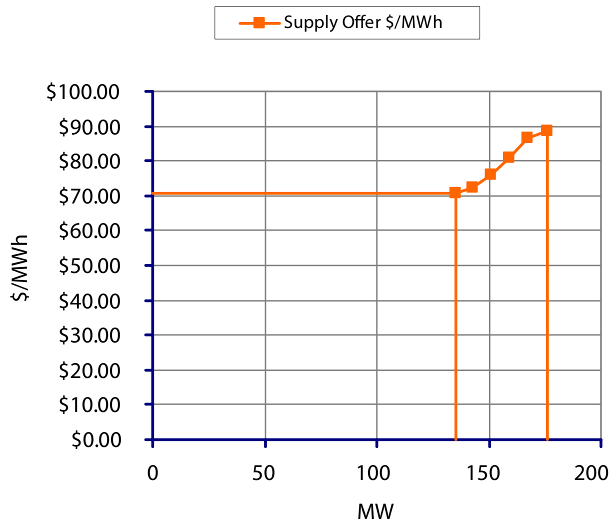
1) Resource Supply Offer Curve – Submitted and/or updated by the Market Participant. In this example, the curve uses the sloped offer curve option.

Resource Supply Offer		
Segment	MW	$/MWh
1	135	$70.68
2	143	$72.47
3	151	$76.00
4	159	$80.80
5	167	$86.50
6	176	$88.56

Case No. 2023-00102
Attachment 2 to Response PSC 1-6

MISO

2) Resource Supply Offer Curve – Plotted



3) Calculate the "Area under the Curve" at 176 MWs

Start Point MW	Start Point $/MWh	End Point MW	End Point $/MWh	Average of Increment $/MWh	Cost/h (Average * Total MW)
0	$70.68	135	$70.68	$70.68	$9,541.80
135	$70.68	143	$72.47	$71.58	$572.60
143	$72.47	151	$76.00	$74.24	$593.88
151	$76.00	159	$80.80	$78.40	$627.20
159	$80.80	167	$86.50	$83.65	$669.20
167	$86.50	176	$88.56	$87.53	$787.77
				Total:	$12,792.45

- **Average $ for each Increment** = [(Start Point $/MWh + End Point $/MWh)/2]
- **Cost / HR** = [Average $ for each Increment * (End Point MW – Start Point MW)]

4) In Real-Time, the Incremental Cost is based on the offer curve at the State Estimated Hourly Output.

EXAMPLE: SE Observed MW = Actual Meter

Real-Time Market

	"Market Value"			Cost						
HE	Actual Meter	LMP	Revenue	SE Observed MW	Startup	No Load	Incremental	Total	Net	Make Whole Payment
1	135	$50.65	$6,837.75	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
2	135	$60.25	$8,133.75	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
3	135	$63.44	$8,564.40	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
4	135	$58.21	$7,858.35	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
	Totals:		$31,394.25		$2,425.80	$400.00	$38,167.20	$40,993.00	-$9,598.75	

EXAMPLE: SE Observed MW ≠ Actual Meter

Real-Time Market

	"Market Value"			Cost						
HE	Actual Meter	LMP	Revenue	SE Observed MW	Startup	No Load	Incremental	Total	Net	Make Whole Payment
1	135	$50.65	$6,837.75	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
2	144	$60.25	$8,676.00	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
3	144	$63.44	$9,135.36	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
4	144	$58.21	$8,382.24	135	$606.45	$100.00	$9,541.80	$10,248.25	-$2,399.69	
	Totals:		$33,031.35		$2,425.80	$400.00	$38,167.20	$40,993.00	-$7,961.65	

Is No Load prorated if a generating unit's start and stop time occur at a partial hour?

Yes. No Load is prorated if Start and Stop Times occur at a partial hour. For example, if a unit follows the MISO instruction to start at 01:30 and the No Load for that unit is $100.00, No Load for HE 2 is $50.00 ($100 * 30/60).

Does a generating unit receive Real-Time RSG Make Whole Payment when the unit is not following dispatch?

No. No Load and Incremental Costs are not eligible for Real-Time RSG Make Whole Payment for the hours that the generating unit is not following dispatch. The generation resource is eligible for recovery of Start-Up Costs through the Real-Time RSG Make Whole Payment provided that the unit is online and available.

Real-Time RSG Eligibility for generating units not following dispatch is determined as follows:

1) Determine Tolerance Band – Defined the same as for the Real-Time Uninstructed Deviation Amount (*RT_UD).

TOLERANCE BAND Up	(*GEN_SP x 10%) = (130 x 10%) = 13 MWhs
REGULATION CAPACITY Regulation Up	*REG_UP = 5 MWhs
	Generation Set Point (*GEN_SP) = 130 MWhs
REGULATION CAPACITY Regulation Down	*REG_DOWN = 5 MWhs
TOLERANCE BAND Down	(*GEN_SP x 10%) = (130 x 10%) = 13 MWhs

***UD_TOL_UP** = (*GEN_SP+*REG_UP+ Up Tolerance Band (UP))
= (130 + 5 + 13)
= 148 MWhs

***UD_TOL_DN** = (*GEN_SP -*REG_DN - Up Tolerance Band (DN))
= (130 - 5 - 13)
= 112 MWhs

NOTE: Tolerance Band Up / Down volume is equal to 10% of the Generation Set Point Volume bounded by an up / down maximum volume limit of 25 MWs and up / down minimum volume limit of 5 MWs.

MISO

2) Real-Time RSG Eligibility Flag is determined as follows:

If ***UD_TOL_UP ≤ State Estimator Observed MWs ≤ *UD_TOL_DN**, then the generating unit satisfies the following dispatch criterion to be eligible for Real-Time Make Whole Payment for that hour.

3) Example of Real-Time RSG Make Whole Payment

EXAMPLE: In HE 2 and HE 3, Generating Unit was NOT "Following Dispatch", therefore will NOT be eligible for Real-Time RSG Make Whole Payment during those hours that were not "Following Dispatch".

HE	Billable Meter	SE Observed MW	RT RSG Eligibility
1	135	135	Y
2	153	135	N
3	153	135	N
4	135	135	Y

Real-Time Market

	"Market Value"			Cost						
HE	Actual or Alternate Meter	LMP	Revenue	SE Observed MW	Startup	No Load	Incremental	Total	Net	Make Whole Payment
1	135	$50.65	$6,837.75	135	$2,425.80	$100.00	$9,541.80	$12,067.60		-$5,229.85
	Totals:		$6,837.75		$2,425.80	$100.00	$9,541.80	$12,067.60	-$5,229.85	

	"Market Value"			Cost						
HE	Actual or Alternate Meter	LMP	Revenue	SE Observed MW	Startup	No Load	Incremental	Total	Net	Make Whole Payment
4	135	$58.21	$7,858.35	135	$0.00	$100.00	$9,541.80	$9,641.80		-$1,783.45
	Totals:		$7,858.35		$0.00	$100.00	$9,541.80	$9,641.80	-$1,783.45	

In the above example, since HE 2 and HE 3 were not following dispatch, they will not be eligible for Real-Time RSG Make Whole Payment during these hours. When this situation occurs, it creates two commitment periods where Real-Time RSG Make Whole Payments will be evaluated for each of these CP's independently. In this example, the "Market Value" is less than the Production Cost for each of the two CP's (HE 1 and HE 4), therefore the difference is the amount that will be credited to the Asset Owner as a Real-Time RSG Make Whole Payment Amount.

Real-Time RSG First Pass Distribution Amount (RT_RSG_DIST1)

The Real-Time Revenue Sufficiency Guarantee Make Whole Payment (MWP) Amount, by which MISO compensates RAC-committed generators, is funded hourly by MISO primarily through the Real-Time RSG First Pass Distribution Amount charge type.

Why was RSG Distribution redesigned?

The previous rate, the so-called interim rate, in effect since Market Launch on April 1, 2005, until the redesigned RSG distribution was implement on April 1, 2011, was deemed to be inadequate because its major methodology was to allocate the cost of RSG to Day-Ahead vs. Real-Time deviations, regardless of and with no effort or means to account for cost causation. To remedy this failing, MISO, in conjunction with Market Participants, developed a new rate methodology that was based entirely on cost causation.

Who is charged RT_RSG_DIST1?

The RT_RSG_MWP credits are paid to compensate generators called on by MISO in its RAC process to cover shortfalls in Real-Time generation output from Day-Ahead Schedules and also to manage Active Transmission Constraints. As previously stated, the responsibility for paying for these credits is meted out to Market Participants' for their assets and schedules determined to by cost causative by any of 35 different calculations. 17 of these calculations pertain to causation for Constraint Management call-ons and 18 for Day-Ahead Deviation and Headroom call-ons. The major bill determinants for these two types of charges are respectively **CMC_DIST** (for Constraint Management Charge Distribution) and **DDC_DIST** (for Day-Ahead Deviation and Headroom Charge Distribution).

How is the distribution rate for CMC_DIST calculated?

For CMC_DIST, there is a separate rate for each Active Transmission Constraint (ATC) managed. The sum of payments to generation committed for the management of each ATC, proportional to the percentage that each's generation provided relief to that ATC, is divided by the greater of the sum of deviation volume plus topological adjustment and derate volume related to the ATC or the economic dispatch maximum of all generation committed because of that ATC.

What is a Constraint Contribution Factor?

For CMC_DIST calculations, the Constraint Contribution Factor is the means of associating a commercial pricing node to a given ATC in a manner which proportions the effect of their injection or withdrawal activity to it. This percent of contribution is factored into their deviation volume.

How is the distribution rate for DDC_DIST calculated?

One distribution rate is calculated for all DDC deviations. The rate numerator is all make-whole payments less those made for constraint management and the management cost for topology adjustments and derates. The rate denominator is:

- the greater of the sum of:
  - DDC deviation volume and
  - the lesser of headroom or all RAC generator maximum economic dispatch volume

  or

  - All RAC generator maximum economic dispatch volume minus constraint management RAC generator maximum economic dispatch volume.

What is the RSG Second Pass Distribution?

Any portion of RSG Make-Whole Payments not recovered in the First Pass Distribution (the sum of CMC_DIST and DDC_DIST), along with make-whole payments for cancelled RAC commitments and money dedicated to topology adjustments, transmission derates and headroom, will be collected with RSG Second Pass Distribution which is apportioned to all Asset Owners by their Load Ratio Share.

Where can I find a more granular explanation of RSG Distribution?

The Market Settlements Business Practices Manuals Calculation Guide, at the following link:

https://www.midwestiso.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF PROPOSED CHANGES TO ITS QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES TARIFFS
CASE NO. 2023-00102

Response to the Commission Staff's
First Request for Information
dated April 12, 2023

April 28, 2023

Item 7) ***Refer to the Wolfram Testimony, page 3, lines 12–17, page 4, lines 16–20 and page 5, lines 1–6. Refer to the March 22, 2021 Order in Case No. 2021-00198.[3] Also refer to the October 26, 2021 Order in Case No. 2021-00198.[4] Finally, refer to the November 30, 2021 Order in Case No. 2021-00198.[5]***

a. Explain how BREC's use of the MISO Planning Resource Auction (PRA) Auction Clearing Price (ACP) for the Big Rivers zone for the applicable resource auction time period as the basis for its capacity credit satisfies the Commission's findings in Case No. 2021-00198.

b. Explain how Big Rivers believes that using the MISO PRA ACP is comparable to the characteristics attributable to its generation unit(s) for its avoided costs.

[3] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Mar. 22, 2021).

[4] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Oct. 26, 2021) at 9.

[5] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Nov. 30, 2021) at 5.

c. Provide the current avoided capacity and energy costs used to determine the QF rates.

Response) Big Rivers objects to this request on the grounds that Big Rivers was not a party to Case No. 2021-00198, and therefore, the findings in that case are not applicable to Big Rivers. Big Rivers further objects to any requirement to satisfy findings in a case to which it was not a party and that did not go through the proper rulemaking process. Without waiving these objections, Big Rivers responds as follows:

a. In the October 26, 2021, Order in Case No. 2021-00198 at 9, the Commission found for EKPC that "the use of the most recent BRA capacity market clearing price is more appropriate and should be used as the proxy for the avoided capacity cost component of the COGEN/SPP tariffs." This finding and the corresponding language in the approved EKPC tariff was the basis for Big Rivers' proposal to rely on the MISO PRA ACP for avoided capacity costs in the QF tariff.

That being said, Big Rivers recognizes that in the October 26, 2021, Order in Case No. 2021-00198, the Commission also noted in footnote 10 that the Commission "places a greater emphasis on calculating avoided generation capacity cost, and thus value, on a proxy unit calculation" and that the "Commission has no interest in allowing [dependence] on the market for generation or capacity for any sustained period of time."

Big Rivers satisfies its capacity obligations in MISO by participating in the MISO Resource Adequacy process, which culminates in the annual MISO PRA. Because of this, the benefit to Big Rivers of purchasing capacity from a QF is to reduce the amount of capacity Big Rivers is required to purchase in

[3] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Mar. 22, 2021).

[4] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Oct. 26, 2021) at 9.

[5] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Nov. 30, 2021) at 5.

the PRA. Thus, the cost Big Rivers avoids is the ACP multiplied by the accredited capacity of the QF.

Additionally, under Big Rivers' proposed QF tariff, the QF Member is obligated to enter into a contract with the Member Cooperative and Big Rivers. That contract has an initial contract term of one year that continues from year-to-year thereafter unless cancelled by a party after giving proper notice. This means that the capacity obligation of the QF Member is a one-year obligation, not a long-term obligation. Thus, the QF capacity is not a resource upon which Big Rivers may depend "for a sustained amount of time" and does not replace "steel in the ground" or long-term Power Purchase Agreement assets.

For these reasons, Big Rivers believes that its proposed tariff is consistent with the Commission's findings in Case No. 2021-00198.

b. Big Rivers does not believe that using the MISO PRA ACP is comparable to the characteristics attributable to its generation unit(s) for its avoided costs. The MISO PRA ACP pricing and the Big Rivers' generation unit(s) or proxy units for its avoided capacity costs are not the same. The MISO PRA ACP prices relate to annual auctions and are short-term (*e.g.*, one year) while the proxy unit pricing relates to the construction of a power plant and is long-term (*e.g.*, thirty year book life). For the QF tariff, the MISO PRA ACP is the more appropriate method for determining avoided capacity costs. This is because the QF is obligated under the proposed tariff to enter into a contract with Big Rivers with an initial term of one year that may continue from year-to-year thereafter. The QF is obligated to provide capacity just one year at a time, not for the full long-term life of a physical resource. For this reason, the QF capacity does not replace "steel in the ground," and the MISO

[3] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Mar. 22, 2021).

[4] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Oct. 26, 2021) at 9.

[5] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Nov. 30, 2021) at 5.

PRA ACP is the more appropriate tool for determining the avoided costs for that limited time period. Also, please see the response to part a.

c. Recall that the current tariffs were last modified in Case No. 2013-00199, and that most of the language contained in the QFS tariff was developed prior to BREC's membership in MISO and is therefore outdated. This is a driver for the instant case.

The current QFP tariff states for capacity payments that "as long as Big Rivers has surplus generation from its owned coal fired generation and power available from SEPA and the Henderson Municipal Power and Light's Station Two,[1] the Capacity Purchase Rate (CPR) will be zero. At such time Big Rivers has no longer has surplus generation from its owned coal fired generation and power available from SEPA and the Henderson Municipal Power and Light's Station Two, the hourly avoided capacity cost (ACC) in $ per megawatt hour, which is payable to a QF for delivery of capacity, will be equal to the effective purchase price for power available to Big Rivers from

[1] Station Two was retired in 2019.

the Inter-Utility Market (which includes both energy and capacity charges) less Big Rivers' actual variable fuel expense.

The current QFP tariff also states for energy that the "Energy Purchase Rates (EPR) in $ per megawatt hour, which is payable to a QF for delivery of energy, shall be equal to Big Rivers' actual variable fuel expenses for Big Rivers' owned coal fired production facilities, divided by the associated

[3] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Ky. PSC Mar. 22, 2021).

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megawatt-hours of generation, as determined for the previous month." The EPR for the past 3 months was:

Month	EPR
January 2023	$0.01790/kWh
February 2023	$0.02326/kWh
March 2023	$0.02326/kWh

Witness) John Wolfram