Manual No. 015

Business Practices Manual

Generator Interconnection

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Revision History

Doc Number	Description	Revised by:	Effective Date
BPM-015-r29	Renumber section headers and pages	A.Godbole	JAN-22-2024
BPM-015-r28	Queue Reform Updates 4.2.2.1 Requirements 4.2.4.1 Deliverability only study 4.2.4.2 External NR Interconnection Service Study 4.2.4.6 Refunds of Study Deposits 5.1.2 Site Control Requirements Review Detail Continued Site Control for Generating Facilities; Site Control for Interconnection Facilities, and Network Upgrades 5.2.3 Interconnection Customer Decision Point I 5.2.4 The (M3) Milestone Calculation 5.3.4 The (M4) Milestone Calculation 5.3.4.1 True-down of Milestone Payments 6.2.9 Provisional Generator Interconnection Agreement 6.2.11 Refunds of Definitive Planning Phase Milestones (M2, M3, M4) Other Updates **6.4.3.1 Limitations on SPP Generators with Impacts on the MISO System** **6.4.3.2 Limitations on SPP Generators with Impacts on the MISO System** 6.6.3.1 Annual ERIS Evaluation Methodology	A.Godbole	JAN-22-2024

	6.6.4.1 Annual Interim Deliverability Study Methodology **6.7.1.2.Evaluation of Generating Facility Modification**		
BPM-015-r27	FAC-002-4	A Godbole	DEC-02-2023
BPM-015-r26	Annual Review Completed Figure 4-2 Reduced Timeline Update 5. Reduced Timeline Update 5.2 Generation Interconnection Process Diagram Reduced Timeline Update 5.1.2 Reduced Timeline Update 5.2 Reduced Timeline Update 5.2.1 Reduced Timeline Update 5.3 Reduced Timeline Update 5.4 Reduced Timeline Update 5.4.1 Reduced Timeline Update 6.2.7 Reduced Timeline Update 6.2.8 Reduced Timeline Update 6.2.10 Reduced Timeline Update Section 8 moved to new Section 9 New Section 8 Distributed Energy Resource Affected System Study • 8.1 • 8.2 • 8.3 • 8.3.1.1 • 8.3.1.2 • 8.3.1.3 • 8.3.2 • 8.3.2.1 • 8.3.2.2 • 8.3.2.3 • 8.3.2.4 • 8.3.2.5 • 8.3.3	A. Godbole	AUG-02-2023

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BPM-015-r24	Annual Review Completed 4.5.1 Local Planning Criteria update 7.3 GIA Milestone update 4.4, 3.2, 6.1.1.1 Updates	P. Van Schaack	May 12-2022
BPM-015-r23	Annual Review Completed Fixed typo in footnote 9 under section 6.1.1.1.2 Update to BPM-020 reference in section 6.1.1.1 Updates to 6.2.9.1 and 6.2.9.1.1 Updates for Affected System GIA contingent facility updates to section 6.6.5 Updates for the BPM for SNU cost allocation Further updates to section 6.1.1.1.2 Addition of section 8 and Appendix F for Non-Binding Dispute Resolution Update to DPP Process Flow Diagram Fixed typo in section 6.6.6.3 Addition of 6.7.3 for Surplus Interconnection Service	J. Phillips	MAY-12-2021
BPM-015-r22	Annual Review Completed	P. Muncy	MAY-13-2020

	Revised to reflect the December 4, 2019, FERC Order for Site Control/Milestones sections 2, 4.1, 4.2, 5, 5.1, 5.3 and 6.2 Generating Facilities Replacement Process revised section 6.7 Online Application revisions sections 4, and 4.2 EMT Model Requirements revisions section 5.2.3.1		
BPM-015-r21	NERC PRC-024 Requirements added to section 4.5. EMT Model requirements added section 5.2.3.1 Network Upgrade Cost Allocation language revisions sections 6.1.1.1.10.1- 6.1.1.1.10.5 Study Case Development added Hybrid Facility language section 6.1.1.1.2 Added Appendix E, Examples: Dispatch Assumption for Hybrid Facility	P. Muncy	OCT-16-2019
BPM-015-r20	Annual Review completed. Figure 2-1 updated section 2 Figure 3-1 updated section 3 Updated Figure 4-1 section 4 Moved language from section 4.1 to section 4. D1 Application Fee, D2 Study Deposit and Milestone M2 language revision section 4.2.1.1 Updated footnote hyperlinks section 4.2.1.2 Updated footnote hyperlinks section 4.2.4 Figure 4-1 updated section 4.2.4 Figure 4-2 updated section 4.2.4	P. Muncy	AUG-2-2019

	Figure 5-1 updated section 5 Updated footnote hyperlink section 6.1.4.2		
BPM-015-r19	Thermal Analysis language revision section 6.1.1.1 Bench Case Development language revision section 6.1.1.1.1 Study Case Development language revision section 6.1.1.1.2 Generation to Include language revision section 6.1.1.1.3 Refunds of Definitive Planning Phase Milestones (M2, M3, M4) language section 6.2.11 MISO Generation Deliverability Study Method language revision, Appendix C Updates to Figure 2-1, Figure 4-2 and Figure 5-1	P. Muncy	OCT-17-2018
BPM-015-r18	Annual Review completed. Annual ERIS and Annual Interim Deliverability Study language revision section 6.6. Deliverability Analysis language revision section 6.1.1.1.9. Inserted Appendix C Deliverability Study Method	P. Muncy	JUN-15-2018
BPM-015-r17	Revised Coordination language for studies between MH, MPC and MISO in Section 6.5. Inserted new Section 6.7 for language on Existing Generating Facility modification evaluation	N. Shah	SEP-27-2017
BPM-015-r16	GI Process Flow Diagram update, GI dispatch assumptions changes, application of local planning criteria and applicable reliability criteria.	P. Muncy N. Shah	AUG-01-2017

BPM-015-r15	Revised to reflect the January 4, 2017, FERC Order for Queue Reform and Annual Review.	P. Muncy	JUN-14-2017
BPM-015-r14	Correction to constraint criteria in Section 6.1.1.1.6	P. Muncy	MAR-15-2017
BPM-015-r13	Annual ERIS Evaluation and Interim Deliverability Study language revisions. Conditions to GIA (Appendix A10) language revisions. Annual Review Completed	P. Muncy	JAN-27-2017
BPM-015-r12	Annual Review completed. External Network Resource Interconnection Service Process and additional language, Applicable Reliability Criteria and Applicable Transmission Owner Criteria, Coordination of GI studies between SPP and MISO, Annual Deliverability and AERIS Study language revisions, Provisional Interconnection Agreement Limit Methodology.	D. Vasquez	FEB-12-2016
BPM-015-r11	Revised A10 Conditionality Methodology, Wind Generation Plant Power Factor and Low Voltage Ride Through criteria, Study of PJM Interconnection Requests, Modeling process updates, Generation to Include and Deposit Refunding to match Tariff changes. Added section on M2 Refunding Process & Annual ERIS and Annual Interim Deliverability Study.	C. Craven	MAR-19-2015
BPM-015-r10	Revised Backfill procedures	C. Craven	OCT-31-2014
BPM-015-r9	Revised to add language regarding MISO-PJM Coordination of GI Projects. Also updated Table of Contents. Annual Review completed.	S. Turner	JAN-17-2014

BPM-015-r8	Annual Review completed. Revised Midwest ISO to Midcontinent Independent System Operator, Inc.	P. Muncy	AUG-20-2013
BPM-015-r7	Revised to reflect the November 1st, 2011, filing of the modifications to the Generator Interconnection Procedures and Agreement.	E. Laverty	NOV-13-2012
BPM-015-r6	Annual Review completed	E. Laverty	SEP-11-2012
BPM-015-r5	MISO Rebranding Changes	E. Nicholson	MAR-21-2011
BP-015-r5	Revised to reflect the sixth M2 milestone option and separate deliverability analysis into its own subsection.	E. Laverty	MAR-21-2011
BPM-015-r4	Revised to reflect July 15th filing for Shared Network Upgrades	E. Laverty	JUL-16-2010
BPM-015-r3	Revised to reflect numbering protocol	E. Laverty	JAN-01-2010
TP-BPM-004-r2	Revised to reflect the Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest ISO, Inc. (Tariff) relating to implementation of the Day-Ahead and Real-Time Energy and Ancillary Services Markets and to integrate proposed changes to the Balancing Authority Agreement.	E. Laverty	JAN-06-2009
TP-BPM-004-r1	Revised to reflect the June 25th, 2008, filing of the modifications to the Generator Interconnection Procedures and Agreement.	J. Doner	AUG-25-2008

CONTENTS

Introduction

This introduction to the Midcontinent Independent System Operator, Inc. (MISO) *Business Practices Manual (BPM) for Generator Interconnection* includes basic information about this BPM and the other MISO BPMs. The first section (Section 1.1) of this Introduction provides information about MISO BPMs in general. The second section (Section 1.2) is an introduction to this BPM in particular. 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.

Purpose of the MISO Business Practices Manuals

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

Purpose of this Business Practices Manual

This *BPM for Generator Interconnection* contains the business practices of MISO in implementing Attachment X of its Open Access Transmission, Energy and Operating Reserves Markets Tariff (Tariff). These practices are intended to supplement the Tariff, and to the extent that there is a conflict between the Tariff and these practices, the Tariff controls.

1.3 References

Other reference information related to this BPM includes:

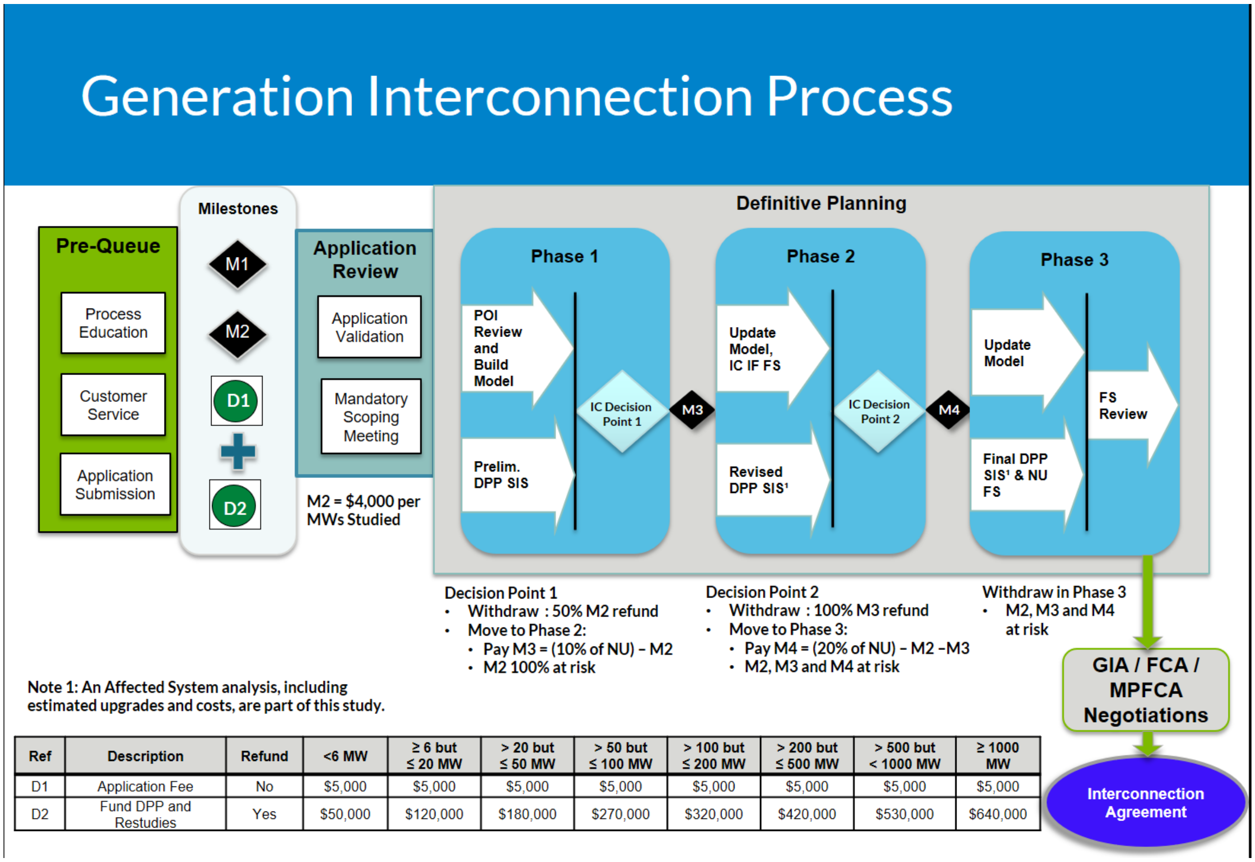
- BPM-001 Market Registration
- BPM-004 FTR and ARR
- BPM-010 Network and Commercial Model
- BPM-020 Transmission Planning
- Agreement of the Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation (MISO Agreement)
- The Tariff
- Attachment X (Generator Interconnection Procedures and Agreement) of the Tariff

Generator Interconnection Process Overview

The Generator Interconnection Process (GI) is divided into three phases:

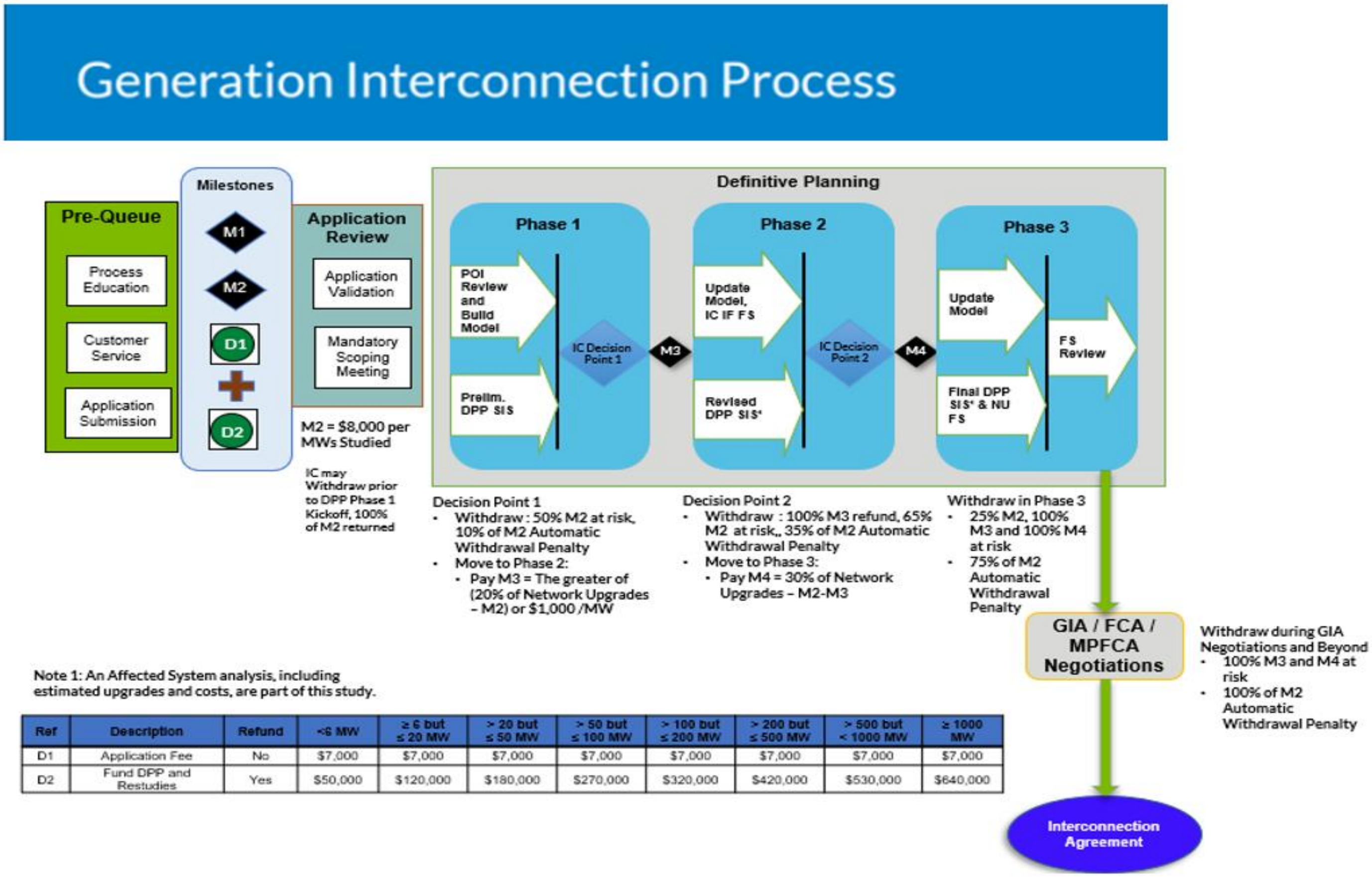
- Pre-Queue (represented by green in the diagram)
- Application Review (represented by aqua in the diagram)
- Definitive Planning (represented by blue in the diagram)

An overview of the process is shown in Figures 2-1 and 2-1a. The process incorporates interaction between generator Interconnection Customers (ICs) and MISO and uses Milestone achievement as a method of moving Interconnection Requests (IRs) through the queue. Milestones (represented by black diamonds in the diagram) serve as control checkpoints where MISO assesses IRs based on pre-defined criteria. Milestone achievement is a key determinant in how an IR is progressing through the process. Milestones may be technical (such as a stability model) or business-related (such as proof of Site Control).



Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but < 1000 MW	≥ 1000 MW
D1	Application Fee	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 0-1 Generator Interconnection Process Overview **– for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024**



Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but < 1000 MW	≥ 1000 MW
D1	Application Fee	No	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 0-2a Generator Interconnection Process Overview – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is after January 22, 2024

Pre-Queue Phase

The Pre-Queue Phase is designed to provide the ICs an overview of the process, timeline, and expectations pertaining to the output of the Generator Interconnection process. The goal of the Pre-Queue Phase is to provide various channels for communication between the IC and MISO so that the IC is well informed about the queue process and requirements in every phase of the process. Figure 3-1 outlines the steps involved in the Pre-Queue Phase.

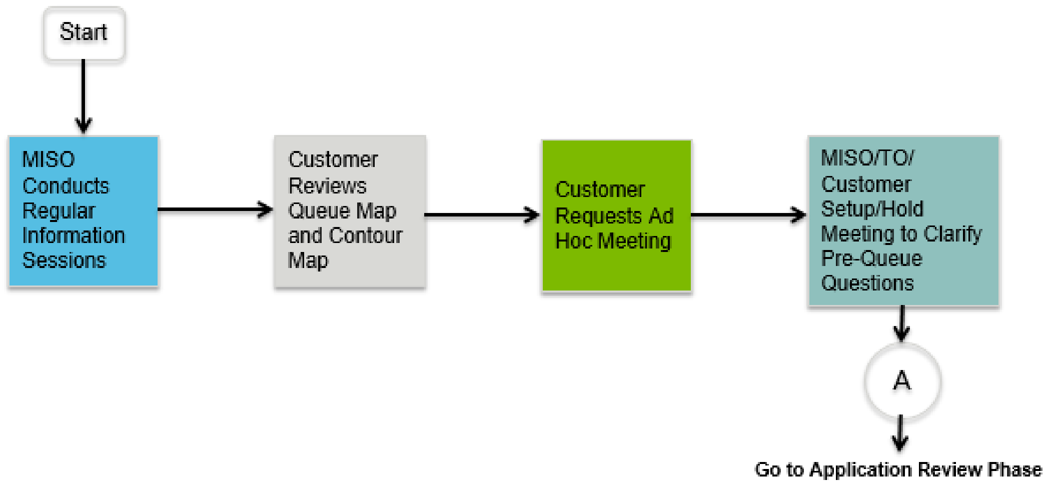


Figure 0-1 Overview of Pre-Queue Phase

3.1 Resources Available

Prior to entering the queue, an IC can utilize various resources available to familiarize themselves with the Tariff, queue processing and Milestones in the process. The MISO website will have online training programs, learning tools, contour maps indicating incremental transfer capability on the system, an interactive Queue Map, and other informational material. These programs are provided to help educate ICs about the queue rules, process steps and requirements in each phase, to prepare them for successful completion of the MISO Generator Interconnection process. Additionally, ICs can participate in the periodically scheduled information sessions or request a meeting to discuss specific issues.

Contour Map

MISO will post a contour map presenting an indicative estimate of the transmission capacity based on a relative pattern of incremental injection capability under first contingency conditions in the MISO footprint. The intent of this contour map is to provide ICs an indication of the time it would take to study and eventually connect their project at the desired location. Generally, an area with a large concentration of IRs will have a low or negative incremental transfer capability. Therefore, studies would take longer to mitigate constraints and construction would take longer to build new transmission, thereby prolonging the overall time to interconnect a project in that area. Note that the purpose of the contour map is to provide guidance to an IC for making an informed decision. The map should not be treated as a substitute for studies. There may be other complex and physical limitations on the Transmission System which will be revealed only after detailed planning and engineering studies.

Once the Base Case for the Definitive Planning Phase (DPP) SIS is finalized, the updated assumptions will be used to refresh the contour map. The contour map will be developed for the near term and out year scenario. The contour map represents the incremental injection capacity at each bus in the MISO footprint under N-1 condition. The following steps are involved in developing the contour map:

- The power flow model developed for the current SISs will be used for the purpose of this analysis.
- A transfer of 10,000 megawatts (MWs) (subject to change in future as the network topology changes) is simulated from each bus in each MISO Local Balancing Authority (LBA) to the whole MISO footprint and a First Contingency Incremental Transfer Capability (FCITC) analysis is performed using a load flow software tool. A distribution factor (DF) cutoff of three percent (3%) is used for the purpose of this analysis. This gives the incremental injection capacity at each bus.
- The injection capacity at each bus is decremented by the existing and queued generation at the bus to obtain the net injection capacity that is available. For this purpose, the nameplate rating of the generation (Pmax) is considered.
- The net injection capacity at each bus is mapped to the Geographical Information Systems (GIS) coordinates and the information is fed into the PowerWorld Corporation's PowerWorld Simulator tool to generate the contour map.
- A sample contour map is shown in Appendix A of this BPM.

3.1.2 Ongoing Efforts

MISO will continue to review the process and business practices for potential improvements on an ongoing basis. To address the transmission limitations in highly constrained areas, MISO will coordinate the upgrades to the transmission system to accommodate the queued requests. MISO will continue to coordinate the Generator Interconnection process with the other planning activities outside the queue to provide the IC with more cost-efficient and timely solutions to their IR.

3.2 Regularly Scheduled Information Sessions

MISO conducts on-the-road workshops on a periodic basis for ICs with a desire to participate and become familiar with the interconnection process and/or ask questions. All workshops are open to any potential or existing ICs, TOs, Affected Systems, and other RTOs/ISOs wishing to learn about the MISO Generator Interconnection process. The workshops will address topics such as Milestones in the process, study timelines, IC inputs, requirements to enter each phase, estimated costs, IC responsibilities, etc. The schedule for all workshops will be posted in advance on the MISO website, at the Generator Interconnection page.

The workshops will be conducted in either the Carmel, IN or Eagan, MN MISO offices or be held virtually and will move based on an alternating schedule or at the request of the potential participants. Depending on interest and requests in the queue, locations may be revised in the future to include locations outside MISO offices.

3.3 Ad Hoc Information Sessions

The IC can request an ad hoc information session with MISO and likely affected TOs the following circumstances:

i. IC has identified a site location for a potential project.
ii. IC has questions unique to his situation.
iii. IC wants to get a better understanding of the available Points of Interconnection (POI) near their project site and any known issues on the local Transmission System
iv. If IC's questions or concerns were not addressed in the monthly update calls or during the on-the-road workshops

To request an ad hoc information session, the IC will submit an online request. The request will entail filling out a form which would include a tentative agenda for the meeting and specific questions. MISO will review the request for a meeting and decide which TOs to invite for the meeting. Within five (5) Business Days of receiving the request, MISO will send an email notification to IC with earliest available dates/times for the meeting, which will be scheduled within thirty (30) Calendar Days of receiving the request, unless another date is agreed upon by MISO and IC. An example of the template form to request a meeting is included in Appendix B of this manual.

MISO may review the following information in the meeting with the IC:

i. Contour map details in the area
ii. Existing loadings on the transmission outlet from the project site
iii. General stability and short circuit issues in the area
iv. General voltage issues including the ride through capabilities of the Generating Facility
v. General power quality issues including voltage flicker and harmonics.
vi. General local and regional reliability issues
vii. Results of any previously completed study at or near the same location.
viii. Estimated timing of request proceeding to the DPP
ix. Estimated in-service date for the IR.
x. Any other existing information which could be helpful for the IC

Application Review Phase

An IC or an MHVDC Connection Customer wishing to join the next Definitive Planning Phase shall submit their IR to the Transmission Provider no later than the application deadline, which will be at least ninety (90) Calendar Days prior to the scheduled start of the next Definitive Planning Phase cycle, published on the MISO public website. ICs must initiate IRs through the online application tool. ICs must establish a profile on the MISO website prior to requesting access to the online application tool via the MISO Generator Interconnection page. The online application tool, instructions for establishing a profile, and an IC training module may be accessed through MISO’s website at: https://www.misoenergy.org/planning/generator-interconnection/. The online application tool contains all data required by Tariff Attachment X, Appendix 1 and enables ICs to submit data to MISO in the form of Appendix 1. MISO will only accept IRs completed using the online application tool. In the event that MISO experiences an outage or other technical difficulty that prevents Interconnection Customers from completing and submitting IRs, MISO will communicate an alternative method for affected Interconnection Customers to submit their IR. MHVDC Connection Customers shall follow the process for submitting an MHVDC Transmission Connection Request specified in Appendix GGG to the Tariff instead of the online application tool described in this section.

The Application Review Phase, as depicted in Figure 4-1, will include preliminary work required before a study can begin. During information review, MISO will communicate with the IC to verify the information provided in the application and clarify any ambiguity. Upon receiving a new IR, MISO will send an acknowledgement to the IC of receiving the request within five (5) Business Days. An IR will not be accepted until all of the required sections are completed in the application. MISO will inform the IC that an IR is valid or explain deficiencies within fifteen (15)

Business Days of receiving application. If the IR is deficient the IC must provide any additional information requested to constitute a valid request no later than ten (10) Business Days after the MISO notice of deficiency is made. Proposed modifications to a submitted IR may be requested by ICs in writing as described in Attachment X, Section 4.4 *et. seq.* Upon approval of a proposed IC-requested modification, or if MISO identifies a modification required to correct a deficiency or otherwise comply with the Tariff, MISO shall provide the IC with instructions for updating its Interconnection Request to reflect the approved modification using the online application tool. Within ten (10) Business Days after notifying IC that an IR is valid, or an application modification is made, MISO will provide a summary of the request to the IC and likely affected TOs. Affected TOs may also access IC request summaries through the online application tool via MISO's Generator Interconnection page along with a TO training module at the following link at: https://www.misoenergy.org/planning/generator-interconnection/. TOs must have a profile on the MISO website prior to requesting access to the online application tool via the MISO Generator Interconnection page.

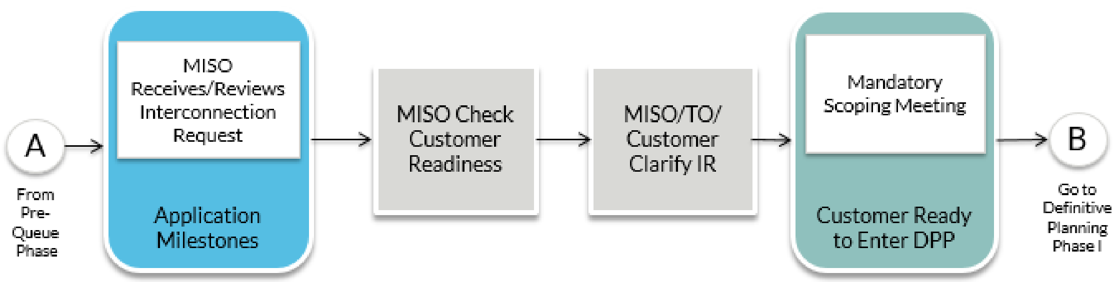


Figure 0-1 Overview of Application Review Phase

4.1 Scoping Meeting

MISO shall establish a date that is agreeable to the IC and the TO for a mandatory Scoping Meeting. That date will be at least five (5) Business Days prior to and no more than forty-five (45) Calendar Days prior to the kick-off of the DPP, unless mutually agreed upon by MISO, the TO and the IC. MISO, the IC, and the TO must attend the Scoping Meeting. MISO shall use Reasonable Efforts to include any other Affected System Operators in the Scoping Meeting.

Topics for discussion during the Scoping Meeting may include, but are not limited to:

i. Consider a reasonable number of alternative interconnection options to determine potential feasible POIs.
ii. General Facility loadings

iii. General stability and short circuit issues in the area
iv. General voltage issues including the ride through capabilities of the Generating Facility
v. General power quality issues including voltage flicker and harmonics.
vi. General local and regional reliability issues
vii. Diagrams and/or layout of applicable substations and transmission lines

The IC may as a result of the Scoping Meeting modify its POI. The IC will have five (5) Business Days from the date of the Scoping Meeting to submit the modified POI to MISO. Any issues or questions that arise during the Scoping Meeting will be addressed by the responsible parties within a timeframe agreed upon by the meeting participants before the end of the Scoping Meeting.

4.2 Initial Screening

All IRs will go through a set of screenings before they can enter the DPP This screening will include verifying the application submitted has the required technical information, met the necessary Milestones, and study deposits.

4.2.1 Application Milestones (M1)

The IC must meet the requirements of Milestone (M1) in order for the application to be determined valid by MISO. The application Milestone (M1) will include *all* of the requirements in Section 4.2.1.1, Section 4.2.1.1.1, and Section 4.2.1.2.

4.2.1.1 Non-Technical Requirements

- Complete Application (Appendix 1 with Attachments A, B and C).
- The (D1) Application Fee must be received no later than the application deadline published on the Transmission Provider website.
- The (D2) DPP Study Funding deposit must be received no later than the application deadline published on the Transmission Provider website.
- W-9 form and banking information for accounting purposes.
-

4.2.1.2 Technical Requirements

- Definitive gross and net generator output (MW) as measured at the POI.
- Definitive non-zero Interconnection Service request for a proposed new Generating Facility
- Definitive POI

    - Only one POI may enter into DPP, unless required by State regulations to take two POI's.
- Definitive one-line diagram for the POI
    - Information shall include:
        - Breaker layout and bus configuration (if available)
        - Number of generators
        - The zero-sequence impedance for the generators (if available)
        - Distance from the collector substation to the POI, referenced in miles, including line impedance.
        - If the POI is a line tap: the distance from the tap to the endpoints of the existing line, referenced in miles.
        - Generator step up (GSU) transformer data and the collector substation transformer data (if applicable)
        - For inverter-based generators, FERC Order 827[1] requires:
            - Location and size of any dynamic and/or static VAR compensation devices
            - Equivalent collector system impedance
- All Generator Types: Library Stability Model representing the dynamics of the Generating Facility in a .dyr format. Models submitted must be acceptable and recommended in the NERC Acceptable Model List[2] and also comply with MISO's Model Data Requirements and Reporting Procedures[3].
    - FERC Order 842[4] requires newly interconnecting units to install, maintain and operate equipment capable of providing primary frequency response as a condition of interconnection. Accordingly, ICs should provide a plant controller for inverter-based generation or a governor model for thermal units in the dynamics model submitted to MISO.
    - For inverter based/non-synchronous generators, FERC Order 827[5] requires:

[1] https://cdn.misoenergy.org/2016-08-30%20Docket%20No.%20ER16-2374-00150851.pdf
[2] https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx
[3] https://www.misoenergy.org/planning/planning-modeling/mod-032-1/
[4] https://cdn.misoenergy.org/2018-02-15%20162%20FERC%20¶%2061,128%20Docket%20No.%20RM16-6-000133298.pdf

[5] https://cdn.misoenergy.org/2016-08-30%20Docket%20No.%20ER16-2374-00150851.pdf

    - Demonstration that the plant can meet a Power Factor (PF) of 0.95 lead/lag at the high side of the main Generator Step Up Transformer (The TO's Local Planning Criteria[6] will supersede if they require a more stringent PF)
    - Base turbine or inverter reactive capability
  - For inverter based (wind or solar) generators, the IC shall provide the short circuit modeling instruction manual and associated model data.
- All Generator Types: A Power Flow model describing the generator in an IDEV or PSSE raw the format which comply with MISO's Model Data Requirements and Reporting Procedures[7] may be requested to clarify the Interconnection Request.
- All Generator Types: **All applicable information requested in Attachment A, Appendix 1**

**The IC must submit one application for each site. Additionally, multiple IRs can be submitted for a single site (each application will require a separate deposit in this case and each application for a proposed new Generating Facility will result in a separate Generator Interconnection Agreement for each application).*

- Financial Milestones:
  There are no financial Milestones attached to the Milestone (M1) submission. (However, there are the (D1) Application fee and (D2) DPP Study Funding deposit which occur at the same time; please refer to Section 4.2.4).

4.2.2 Definitive Planning Phase Entry Milestones (M2)

The requirements for the DPP Entry Milestone (M2) are comprised of the items that follow. At the (M2) Milestone submission stage, the IC must meet *all* of the (M1) requirements, plus *the DPP Entry Milestone* in the form of a cash deposit or an irrevocable Letter of Credit in the amount of eight thousand dollars ($8,000) per MW. If an IC is required by a state regulatory body to take two POIs through the study process, satisfaction of the non-technical Milestones is not required for the second IR. All technical and non-technical Milestones and study deposits must be received by MISO no later than the application deadline published on the Transmission Provider website.

[6] https://www.misoenergy.org/planning/transmission-planning/

[7] https://www.misoenergy.org/planning/planning-modeling/mod-032-1/

4.2.2.1 Requirements

- (M2) DPP Entry Milestone Deposit
  - Cash or irrevocable Letter of Credit in the amount of eight thousand dollars ($8,000) per MW for the project.

**(M2) cash deposit or irrevocable Letter of Credit would be fifty percent (50%) refundable upon withdrawal prior to IC Decision Point I. Please see section 6.2.11 for more information. For details on Letter of Credit requirements, see Section 4.2.3.*

***For Interconnection Requests for which the application deadline to enter the DPP is on or after January 22nd, 2024 - (M2) cash deposit or irrevocable Letter of Credit would be forty percent (40%) refundable upon withdrawal prior to IC Decision Point I. Please see section 6.2.11 for more information. For details on Letter of Credit requirements, see Section 4.2.3.*

When the (M1) and (M2) Milestones are received and validated, a project will be placed in the DPP active Queue cycle.

4.2.3 Letter of Credit Requirements

The Letter of Credit should clearly specify the “Issuer,” the “Account Party”, “Beneficiary (MISO),” the term for which the Letter of Credit will remain open, and the dollar amount available. It should also include a statement as to the instructions and terms for funds disbursement. The party issuing the Letter of Credit must have a minimum corporate debt rating of “A-” by S&P, “A3” by Moody’s, and “A-” by Fitch. All costs associated with obtaining the Letter of Credit will be the responsibility of the IC. If the Letter of Credit option is chosen to fulfill the DPP Entry Milestone it would need to remain open until submission of the first GIA Milestone payment or withdrawal.

4.2.4 Study Deposits and Refunds

Study deposits are those deposits from the IC that are put towards the cost of performing the interconnection studies. As depicted in Figure 4-2 and described in the following Sections, there is the (D1) Application Fee, (D2) Study Funding deposit, and (M2) DPP Entry deposit required for an IR to proceed through the process.

Thirty (30) Calendar Days after the execution of a permanent GIA with conditions, IC may replace any non-encumbered balance of the study deposits with an irrevocable Letter of Credit reasonably acceptable to MISO. After MISO acceptance of the Letter of Credit, MISO will refund the cash remaining in the IC's study deposits.

In the event of restudy, MISO shall notify the IC providing the option to submit the cash equivalent of the Letter of Credit within thirty (30) Calendar Days; thereby reducing the Letter of Credit in the amount of their deposit. Should the IC fail to respond within the requested timeframe, MISO shall draw upon the Letter of Credit as necessary to cover incurred restudy expenses.

Additional studies available for projects:

4.2.4.1. Deliverability Only Study

Deposit for a deliverability only study – The study funding deposit for an IR to change ER Interconnection Service (ERIS) to NR Interconnection Service (NRIS) for a Generating Facility in Commercial Operation or with an executed GIA shall be the same as for a new IR, per Section 3.3 of the GIP. The (D1) Application Fee and (D2) DPP Study Funding deposit is also required at the time of application for a deliverability only study request. The (M2) DPP Entry Milestone deposit is required as well, in the form of eight thousand dollars ($8,000) per MW, and it must be received no later than the application deadline published on the Transmission Provider website.

4.2.4.2. External NR Interconnection Service Study

The study funding deposit for an IR to determine availability of NRIS for a Generating Facility external to MISO shall be the same as for a new IR, per Section 3.3 of the GIP. The (D1) Application Fee and (D2) DPP Study Funding deposit is also required at the time of application for an External NRIS study request. The (M2) DPP Entry Milestone deposit is required as well, in the form of eight thousand dollars ($8,000) per MW, and it must be received no later than the application deadline published on the Transmission Provider website. To be eligible for study, a Generating Facility must meet at least one of the following criteria:

i. In-service
ii. Under Construction

Must have an Interconnection Agreement with the Transmission Provider to which it directly physically connects.

Deliverability study for External Resources will be processed in the same manner as for any other Generating Facility that has existing injection rights and is requesting NRIS on the MISO system.

Upon receiving a valid application, MISO will place the request in the next applicable DPP cycle and evaluate it for deliverability service only. No additional analysis will be performed.

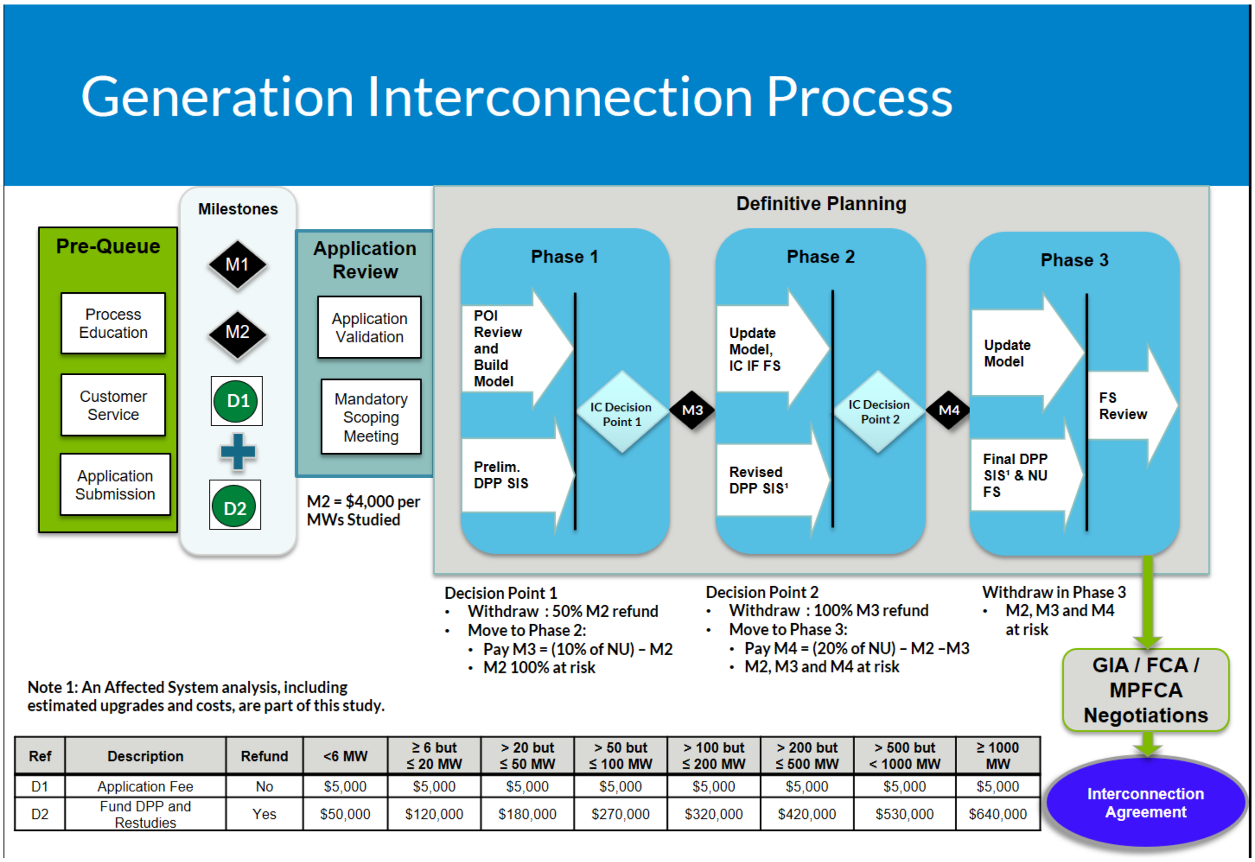
Generating Facilities that are granted a Service Agreement for External NRIS will be required to procure Transmission Service to the MISO border in order to validate the External NRIS request.

4.2.4.3. Optional Interconnection Study

The IC can request an Optional Interconnection Study for their project solely to get additional information/results to help them in making business decisions on their project. Request for a study can be made on a standalone basis or in parallel with an ongoing Interconnection Study. The studies will be performed based on the assumptions outlined by the IC. Results of such informational studies will be non-binding. IC shall execute the Optional Interconnection Study Agreement Appendix 5 of the GIP within ten (10) Business Days from receipt and deliver the Optional Interconnection Study Agreement Appendix 5 of the MISO Tariff, the technical data, and a deposit of sixty thousand dollars ($60,000) to MISO. MISO will use reasonable efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement.

If MISO determines that it will not meet the required time frame for completing the Optional Interconnection Study, MISO shall notify the IC regarding:

i. The schedule status of the Optional Interconnection Study,
ii. An estimated completion date and an explanation of the reasons why additional time is required, and
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised.



Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but < 1000 MW	≥ 1000 MW
D1	Application Fee	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 0-2 Application Fee and Study Deposits **– for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024.**

Note 2: Without a written request from the Interconnection Customer prior to DPP SIS release to delay negotiations, GIA negotiations will begin with Final DPP SIS release.

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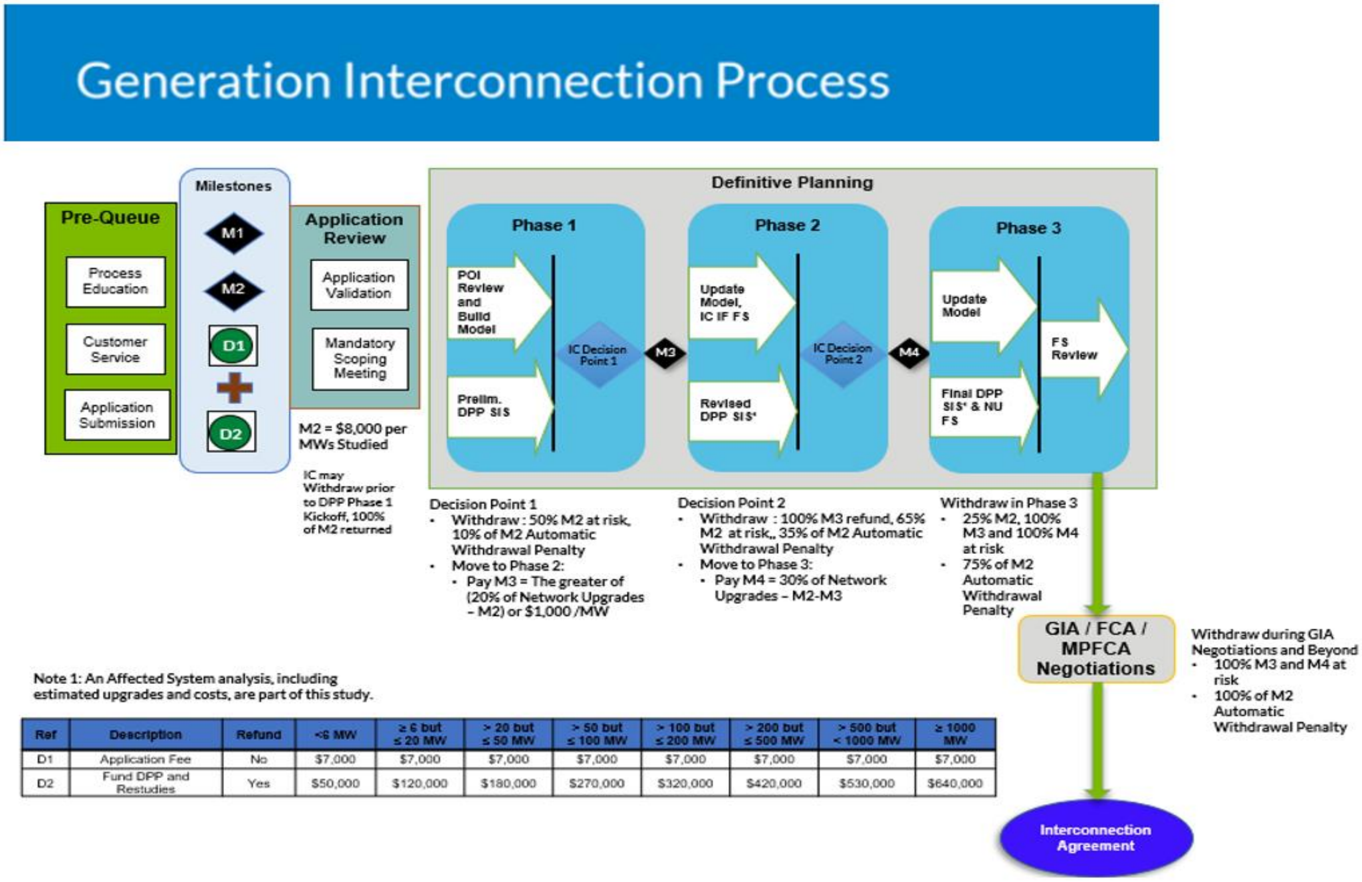

Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but < 1000 MW	≥ 1000 MW
D1	Application Fee	No	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 0-3a Application Fee and Study Deposits – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 22, 2024.

Note 2: Without a written request from the Interconnection Customer prior to DPP SIS release to delay negotiations, GIA negotiations will begin with Final DPP SIS release

4.2.4.4. Application Fee (D1)

The amount of the Application Fee (D1) is seven thousand dollars ($7,000) for all project sizes. The Application Fee is used to offset the cost of the Pre-Queue expenses and is non-refundable. Failure to pay the (D1) Application Fee will result in withdrawal of the IR.

4.2.4.5. DPP Study Funding Deposit (D2)

Deposit amounts to fund the DPP studies will be the same for projects in a certain MW range (i.e., < 6, 7-20 …), which are shown in Figure 4-2 and in Table 4-1 below. The amount of the study deposit is representative of the expected costs associated with completing the study for projects in those ranges. Prior to entry into the DPP, the IC will have to select a single POI, unless they are required by a state regulatory body to take two POIs through the study process, in which case they will have to submit study deposits for each POI. Failure to pay the (D2) DPP Study Funding deposit will result in withdrawal of the IR.

Table 4-1: D2 Definitive Planning Phase Study Funding Deposit Amounts

D2 DPP Study Funding Deposit	
< 6 MW	$50,000
≥ 6 but ≤ 20 MW	$120,000
> 20 but ≤ 50 MW	$180,000
> 50 but ≤ 100 MW	$270,000
> 100 but ≤ 200 MW	$320,000
> 200 but ≤ 500 MW	$420,000
> 500 but < 1000 MW	$530,000
≥ 1000 MW	$640,000

4.2.4.6. Refunds of Study Deposits

For additional details of the information contained in the following paragraphs regarding withdrawals and any refunds of the (M2), (M3), and (M4) deposits, refer to Section 6.2.11 of this BPM and GIP Section 7.6.1, Section 7.6.2, and Section 7.8 of Attachment X.

If the IC withdraws prior to entry into DPP Phase I, then the remaining (D2) DPP Study Funding Deposit pursuant to Section 7.6 of the GIP and the (M2) DPP Entry Deposit will be refunded one hundred percent (100%). Any refunds due to the IC will occur once MISO has been notified of the withdrawal.

If the IC withdraws by the end of IC Decision Point I, then the (D2) DPP Study Funding Deposit will be refunded, less the actual cost of the applicable Interconnection Study performed during DPP Phase I. In addition, if this withdrawal occurs, the (M2) DPP Entry Deposit will be refunded percent (50%). For Interconnection Requests for which the application deadline to enter the DPP is on or after January 22nd, 2024 - if this withdrawal occurs, the (M2) DPP Entry Deposit will be refunded forty percent (40%) An IC withdrawing during DPP Phase I but before IC Decision Point

I will be responsible for its pro rata portion of the group Interconnection Study costs for DPP Phase I. Any refunds due to the IC will be processed after IC Decision Point I. Once the IC pays the (M3) deposit and enters DPP Phase II, the (M2) deposit becomes one hundred percent (100%) at risk.

If the IC withdraws by the end of IC Decision Point II, then the (M3) Milestone will be refunded one hundred percent (100%). Any (D2) DPP Study Funding Deposit will be refunded, less the actual cost of the applicable Interconnection Study performed during DPP Phase II. An IC withdrawing during DPP Phase II but before IC Decision Point II will be responsible for its pro rata portion of the group Interconnection Study costs for DPP Phase II. Any refunds due to the IC will be processed after IC Decision Point II. Once the IC pays the (M4) deposit and enters DPP Phase III, the (M2), (M3), and (M4) Milestone deposits become at risk.

If the IC withdraws any time during DPP Phase III, and MISO determines that an Interconnection Study restudy is required, then the withdrawing IC will be responsible to fund all such restudies in DPP Phase III, up to the amount of any remaining study deposits. However, if MISO determines that no Interconnection Study restudy is required due to the withdrawal of the ICs IR, then the withdrawing IC will not be responsible to fund any further Interconnection Studies during DPP Phase III and MISO shall refund any unused portion of the study deposit paid to enter the DPP.

4.2.4.7. Determination of Project Linkages and Potential Grouping

MISO may perform a power flow analysis and use in-house post processing tools to determine project grouping. Each project will be dispatched against the generation in the MISO footprint and a DF cut-off of five percent (5%) will be used for the purpose of this analysis. All projects contributing to any common constraint will be grouped together for study. Additionally, the following guidelines will be used to form a study group:

i. Group Studies will not be limited by size. Upgrades for Group Studies will be determined in incremental blocks of MW capacity. The size of each block will depend on the factors such as the constrained area, transmission voltage, Right of Way availability, room for expansion in the existing substations etc. The blocks of MW (sub-groups) will be selected based on the queue position, the impact of Generation IR on the limiting constraints, loading on the limiting constraint, available study work and engineering judgment.
ii. Other factors such as number/type of projects, queue position, electrical proximity of the POIs, etc. will be considered when defining a study group.

4.4 Queue Position

The initial queue position for the DPP will be based on the date and time that the IC satisfies all of the requirements to enter the DPP cycle. MISO will record the dates Milestones are received for each project. Within a study group, the queue positions for projects will be determined based on the date they met the last Milestone in the process. The queue position will be used to determine the cost responsibility of Network Upgrades for a project, except if the project was part of a Group Study, in which case cost responsibility will be determined according to Section 6.1.1.1.10 of this BPM.

4.5 Applicable Reliability Criteria

NERC Standard FAC-002-2 requires a reliability impact assessment of a new or materially modified generating facility on the transmission system, which is to be undertaken and results coordinated with TOs, Load Serving Entities, Transmission Providers, and other Affected Systems. Attachment FF of the Tariff provides that the Transmission Provider shall evaluate the transmission system to address transmission issues to meet applicable planning criteria, including accepted NERC reliability standards, reliability standards adopted by Regional Entities, local transmission planning criteria of the TO, transmission planning criteria required by State or local authorities, and any applicable laws and regulations.

To ensure compliance with the latest NERC reliability standards, Attachment FF of the Tariff, FERC Form 715, and additional applicable laws and regulations, all applicable Regional, sub-Regional, and individual system local transmission planning criteria will be used to ensure that the assessment includes steady state, short circuit, and dynamic studies as necessary to evaluate system performance under both normal and contingency conditions. The Transmission Provider, in applying the local transmission planning criteria, will comply with the Tariff, ISO Agreement and applicable FERC orders governing the provision of access to and use of the Transmission System on terms that are open, transparent, comparable, and not unduly discriminatory.

Each inverter-based resource must adhere to the requirements set forth in the latest effective version of NERC PRC-024. This ensures the generating units remain connected during defined frequency and voltage excursions.

4.5.1. Applicable Transmission Owner Planning Criteria - General

TO has the exclusive authority to establish and modify its local transmission planning criteria at any time. Annually, the TO files updates to its local transmission planning criteria as part of the

FERC Form 715 filing. In addition, whenever the TO updates its local transmission planning criteria, the TO provides the updated local transmission planning criteria to MISO sufficiently in advance of when the TO intends for it to be effective to enable MISO to evaluate the potential impacts of such modifications on pending IRs and their relationship to other Tariff processes in order to facilitate the Transmission Providers obligations to provide transmission access on a non-discriminatory basis. As the Transmission Provider, MISO will post the new TO criteria on the Planning page of the MISO website or provide a link to the TO's web site. Concurrently, MISO will post a notice on the Planning page of MISO's web site indicating MISO has received updated local TOs' planning criteria.

The following describes the process for TOs to update their Local Planning Criteria and when those updates will be used in planning studies:

i. The effective date of the TO's local transmission planning criteria will be the date that the TO submits revised criteria to MISO. The TO should use best efforts in notifying MISO that the TO is in the process of modifying its local transmission planning criteria 30 days or more, prior to when the TO expects to submit the modified criteria to MISO.
ii. The TO's local transmission planning criteria in effect prior to the (M2) Milestone deadline will be applied to the immediate DPP cycle. Modified local transmission planning criteria in effect after the (M2) Milestone deadline, but before the beginning of a DPP SIS phase, will be reviewed on a case-by-case basis as to whether it will be applied to the immediate DPP study phase. Modified local transmission planning criteria submitted after the start date of the DPP study phase will not be applied to the immediate or ongoing DPP SIS phase but will be applied to subsequent DPP cycles and may be applied to the subsequent DPP SIS phase, on a case-by-case basis. However, if the immediate DPP SIS undergoes a restudy and the modified local transmission planning criteria is submitted prior to the start of the restudy, the modified local transmission planning criteria will be reviewed on a case-by-case basis as to whether it will be applied to the restudy of the immediate DPP cycle.
iii. MISO will coordinate with the TO when necessary to understand newly posted local transmission planning criteria so that MISO is able to apply the criteria.
iv. MISO will inform, in writing, the projects/requests to which newly posted local transmission planning criteria will be applied in accordance with i, ii, and iii of this section.
v. Any changes in Local Planning Criteria that require additional studies in the DPP process will be applied to DPP cycles in which the MTEP base cases have also been evaluated under the changed Local Planning Criteria

In the event that a modification to a TO local transmission planning criteria conflicts with any provisions of an established MISO BPM, in addition to the process in this section, MISO will work directly with the TO discuss and attempt to resolve the differences. If necessary, MISO will convene the applicable MISO stakeholder forum to address the necessary modifications to the BPM to enable consistency with the specific TO modification to local transmission planning criteria.

Definitive Planning Phase

All DPP Entry Milestones (M1 and M2) and the DPP Study Funding deposit (D2) must be received no later than the application deadline published on the Transmission Provider website. These Milestones and deposits have been described in Section 4.2.1 and 4.2.2. MISO will strive to conduct one DPP cycle every year. The DPP cycle will consist of three (3) DPP Phases, as described in the following sections. MISO will utilize Reasonable Efforts to complete the DPP cycle within three hundred seventy-three (373) Calendar Days.

An overview of the DPP is shown in Figure 5-1 on the following page.

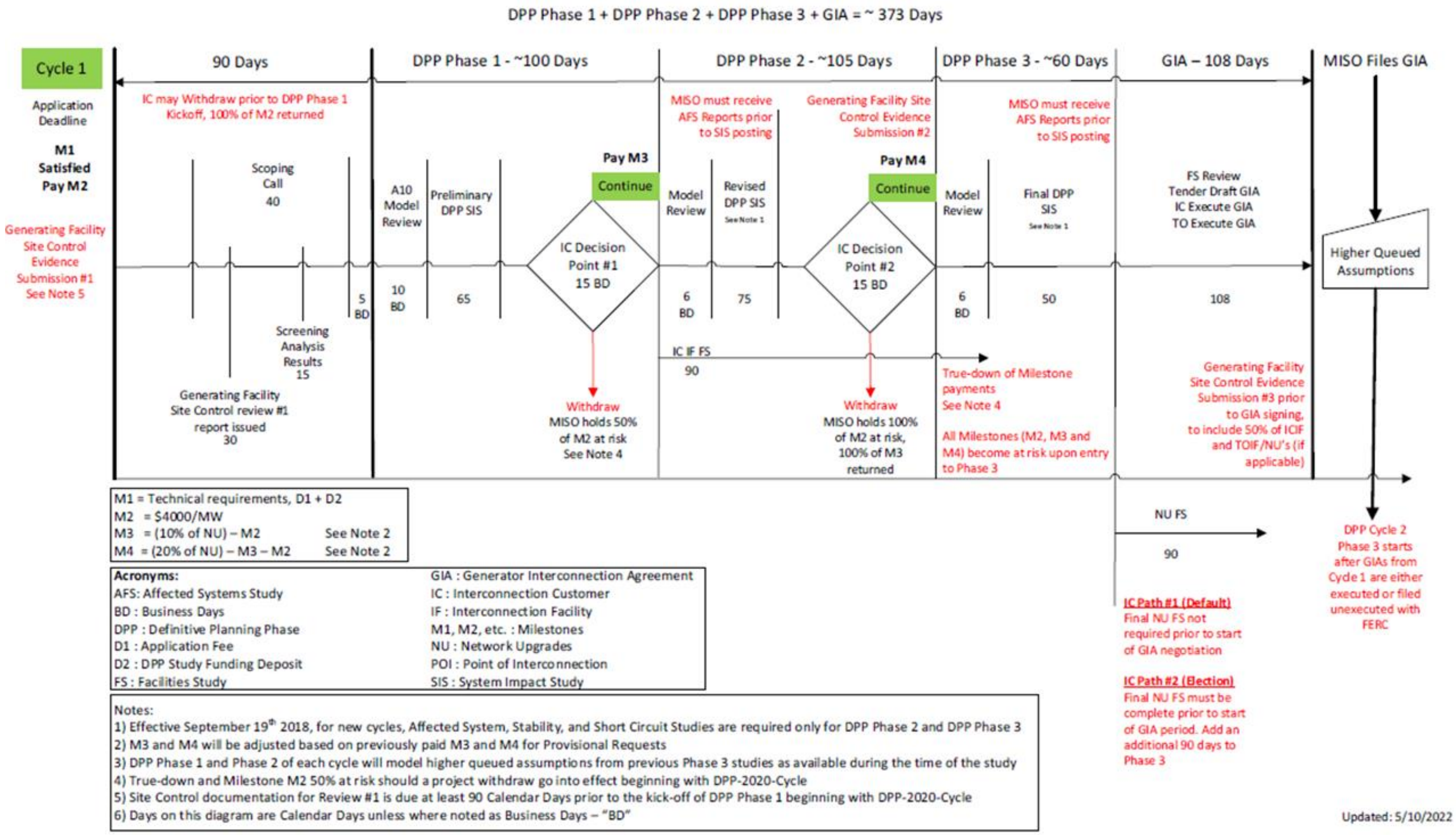

Figure 5-1 Overview of Definitive Planning Phase - for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024

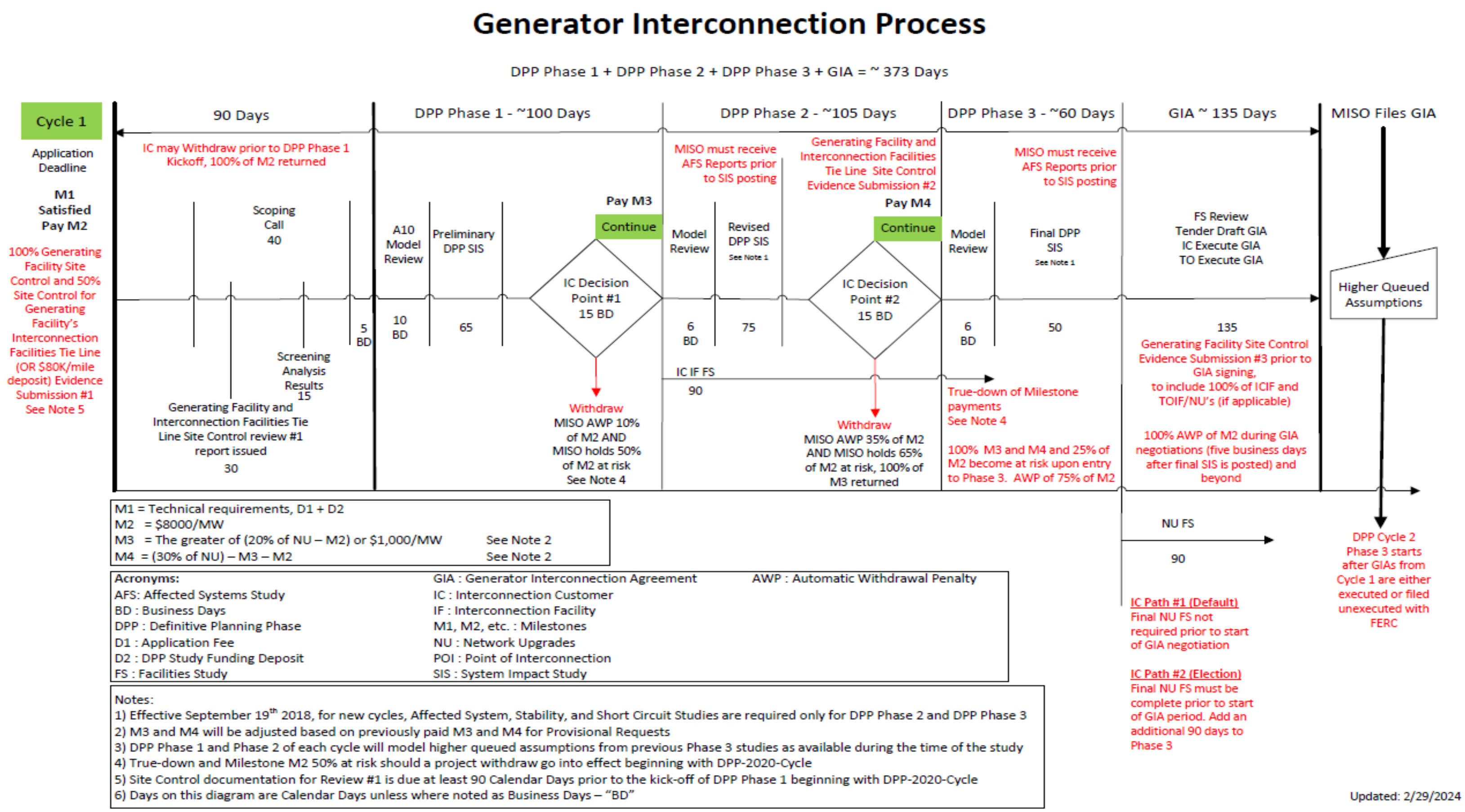

Figure 5-1a 1 Overview of Definitive Planning Phase - for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 2024

5.1. Definitive Planning Phase Entry

When the IC satisfies the (M1) requirements and provides the (D1) Application Fee, (D2) DPP Study Funding deposit, and the (M2) DPP Entry Milestone deposit must be received no later than the application deadline published on the Transmission Provider website. The project will enter into the DPP as described in the following sections, providing the deliverables for each phase. Details of each of the DPP processes and methodologies are discussed in Section 6 below. If the IC elects not to meet the (M1) requirements and the (M2) Milestone deposit, the project will be considered withdrawn.

5.1.1. Screening Analysis Prior to Definitive Planning Phase

Transmission Provider will perform an indicative non-binding screening analysis to identify potential thermal and voltage constraints and publish the results of that analysis for Interconnection Customers and MHVDC Connection Customers entering the Definitive Planning Phase at least fifteen (15) Calendar Days prior to the kick-off of the DPP Phase I.

Screening Analysis Study

MISO will use the Definitive Planning Phase model that was published prior to the kickoff of DPP Phase I to perform its Screening Analysis Study. All new GI Projects will undergo an AC screening, utilizing the full list of contingencies, to determine both thermal and voltage issues. Refer to section 6.1.1.1.8 of this Business Practice Manual for additional study details. Raw study results will be published for review by the ad-hoc study group. Potential mitigations and corresponding costs will not be included in these results. The results of this screening analysis will be non-binding.

5.1.2. Site Control Requirements Review Detail

1. Except as otherwise provided in Section 5.7 of the GIP, at least ninety (90) Calendar Days prior to the scheduled kick-off of DPP Phase I published on the MISO public website as of the application deadline for entry into the next Definitive Planning Phase Cycle, the Interconnection Customer shall submit one of the following to the Transmission Provider: To demonstrate that an Interconnection Customer has Site Control in accordance with Section 7.2.1(i)(a) and 7.2.1 (ii) of the GIP, a Geographic Information System (GIS) site plan map, data files, and documentation that shows the following information:

   a. Sufficient land to meet the acreage requirements set forth in this Generator Interconnection Business Practices Manual;
   b. Boundary for the proposed project indicating the boundaries of the Interconnection Customer's leasehold/ownership interests for the site.
      i. Individual parcel boundaries within the Generating Facility boundary with a reference back to the lease agreements/ownership interest documentation should also be included;
   c. The proposed location of each of the following: the Collector Substation, the proposed generator tie line, the Point of Interconnection, and the Interconnection Facilities based on the Point of Interconnection.
2. To demonstrate that an Interconnection Customer has obtained Site Control in accordance with Section 7.2.1(i)(b) of the GIP, Interconnection Customer must submit a Geographic Information System (GIS) site plan map, data files, and documentation that meets the requirements specified in Section 7.2.1.1(i)(b) and (c) of the GIP and show the following additional information:
   a. Sufficient land to accommodate the proposed Generating Facility based on the location and approximate land utilization requirements of proposed electrical devices (*i.e.*, turbine, solar panel, battery storage, inverter), local spacing and setback requirements, and the proposed location of the feeder routes to the Collector Substation; and
   b. In the event that Interconnection Customer elects to share a site with other projects in accordance with Section 7.2.1(i)(b) of the GIP, Interconnection Customer shall include with its Interconnection Request documentation demonstrating that the project referenced in the Interconnection Request is concurrently feasible with the development of any other projects that will share Site Control over all or a portion of the same site. Such proof of concurrent feasibility shall include:
      i. An identification of any other Interconnection Requests or projects that will share all or a portion of the same site; and
      ii. Identification of the proposed location and space utilization of all projects that will share the site together with any related technical information specified in the Generator Interconnection Business Practices Manual to enable the Transmission Provider to determine that development of the project referenced in the submitted Interconnection Request is not inconsistent with development of any of the other projects that will share all or a portion of the same site.

All documentation establishing proof of Site Control under Sections 7.2.1 of the GIP shall be accompanied by a signed affidavit from an officer or an agent of the Interconnection Customer. Such affidavit shall adhere to the form specified in Attachment E of Appendix 1 of Attachment X.

Sufficient land to meet the acreage requirements

The Transmission Provider shall determine the acreage volume of Site Control that is achieved by reviewing the documentation submitted in accordance with Section 7.2.1(i)(a) of the GIP. In order to determine the Site Control actually achieved by an Interconnection Customer for a Generating Facility for the purpose of satisfying the requirements of Section 7.2.1(i)(a) of the GIP, the Transmission Provider shall compare the acreage volume of Site Control submitted in accordance with Section 7.2.1(i)(a) of the GIP against the following resource-specific acreage requirements:

Table 5-1 Site Control Acreage Requirements

Site Control Acreage Requirements	
Fuel Type	**Land Required**
Wind	Fifty (50) acres per MW
Solar	Five (5) acres per MW
Battery	One tenth (0.1) acres per MW
Conventional	Ten (10) acres for the proposed facility
Hybrid	Summation of the various fuel types represented in the Hybrid facility based on each fuel type's acres per MW show above

In order to determine the Site Control actually achieved by an Interconnection Customer for an Interconnection Customer Interconnection Facility for the purpose of satisfying the requirements of Section 7.2.1(i)(a) of the GIP, the Transmission Provider shall compare the acreage volume of Site Control actually obtained by the Interconnection Customer for the Interconnection Customer Interconnection Facility to the amount of land required for the Interconnection Customer Interconnection Facility, as described in the Interconnection Customer's Interconnection Request.

1. Verify whether IC has provided lease/ownership agreements for each parcel.
2. Identify Deficiencies and provide comments if there are any.

Insufficient land to meet the acreage requirements:

Interconnection Customer is to provide documentation of sufficient land to accommodate the proposed Generating Facility based on the location and approximate land utilization requirements of proposed electrical devices (*i.e.*, turbine, solar panel, battery storage, inverter), local spacing and setback requirements, and the proposed location of the feeder routes to the Collector

Substation. In order to determine the Site Control actually achieved by an Interconnection Customer for an Interconnection Customer Interconnection Facility for the purpose of satisfying the requirements of Section 7.2.1(i)(b) of the GIP, the Transmission Provider shall evaluate the Site Control documentation using sound engineering judgement and in a non-discriminatory manner:

1. Verify that a detailed justification is provided by either the Interconnection Customer or a third-party consultant.
2. Verify the IC provided documentation for the project specifications: a) location; b) MW; c) available footprint; d) shortest distance between any two turbines; and e) the justification for reduced footprint.
3. Verify that there is sufficient land to accommodate the proposed Generating Facility based on the location and approximate land utilization requirements of proposed electrical devices (i.e., turbine, solar panel, battery storage, and inverter) and local spacing and setback requirements.
4. Verify that the lease/ownership agreements provided match the available footprint mentioned by either the Interconnection Customer or a third-party consultant in their assessment, if applicable.
5. Identify Deficiencies and provide comments if there are any.

Continued Site Control for Generating Facilities; Site Control for Interconnection Facilities and Network Upgrades – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 22, 2024.

After the start and prior to the end of Interconnection Customer Decision Point II, proof that Interconnection Customer continues to maintain Site Control for the Generating Facility and Interconnection Facilities in accordance with terms in Section 7.2.1.1 of the GIP. In addition to what is specified in 7.2.1.iii of Attachment X, the Interconnection Customer will be required to demonstrate 50% of the switchyard site control if requested by the Transmission Provider. ;and

1. Prior to conclusion of the Interconnection Customer's GIA execution period, as defined in Section 11 of the GIP, or within 180 days of GIA execution with an approved exception, proof of the following: (a) continued Site Control for the Generating Facility in accordance with terms in Section 7.2.1.1 of the GIP; and (b) 100% Site Control for all Interconnection Customer's Interconnection Facilities (including demonstration of the switchyard site

control if requested by the Transmission Provider), and, if applicable (*i.e.*, when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the POI that the Interconnection Customer will develop.

Any changes to the Interconnection Customer's previously provided documentation establishing proof of Site Control for the Generating Facilities under Sections 7.2.1 of the GIP shall be provided to the Transmission Owner at either Decision Point II, at conclusion of the Interconnection Customer's GIA execution period, or within 180 days of GIA execution with an approved exception by the Transmission Provider.

The exception to provide GIA Site Control within 180 days includes, but is not limited to, local permitting issues, delays in the procurement process or longer than expected timeframes for site control review. This exception is subject to the Transmission Provider's approval

All changes to documentation establishing proof of Site Control under Sections 7.2.1 of the GIP or at the time of inclusion of Site Control for the Generating Facility shall be accompanied by an updated signed affidavit from an officer or an agent of the Interconnection Customer. Such affidavit shall adhere to the form specified in Attachment E of Appendix 1 of Attachment X.

Continued Site Control for Generating Facilities; Site Control for Interconnection Facilities and Network Upgrades – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024.

After the start and prior to the end of Interconnection Customer Decision Point II, proof that Interconnection Customer continues to maintain Site Control for the Generating Facility in accordance with terms in Section 7.2.1.1 of the GIP;and

2. Prior to conclusion of the Interconnection Customer's GIA execution period, as defined in Section 11 of the GIP, proof of the following: (a) continued Site Control for the Generating Facility in accordance with terms in Section 7.2.1.1 of the GIP; and (b) 50% Site Control for all Interconnection Customer's Interconnection Facilities, and, if applicable (*i.e.*, when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the POI that the Interconnection Customer will develop.

Any changes to the Interconnection Customer's previously provided documentation establishing proof of Site Control for the Generating Facilities under Sections 7.2.1 of the GIP shall be provided to the Transmission Owner at either Decision Point II or conclusion of the Interconnection Customer's GIA execution period..

All changes to documentation establishing proof of Site Control under Sections 7.2.1 of the GIP or at the time of inclusion of Site Control for the Generating Facility shall be accompanied by an updated signed affidavit from an officer or an agent of the Interconnection Customer. Such affidavit shall adhere to the form specified in Attachment E of Appendix 1 of Attachment X.

Demonstrating Site Control for Applicable Interconnection Facilities and Network Upgrades.

In order to demonstrate Site Control for the Interconnection Customer's Interconnection Facilities and, if applicable (*i.e.*, when the Interconnection Customer is providing the site for such facilities), the Transmission Owner's Interconnection Facilities and Network Upgrades at the POI, Interconnection Customer shall submit a site plan map by the deadline specified in Section 7.2.2.1 of the GIP. Such site plan map shall demonstrate land that is sufficient to accommodate 50% of the total land acreage required for the Interconnection Customer's Interconnection Facilities for the proposed Generating Facility (including the total linear miles for the associated lead line required to electrically interconnect the Generating Facility to the Transmission System) and, if applicable (*i.e.*, when the Interconnection Customer is providing the site for such facilities), 50% of the total land acreage required for the Transmission Owner's Interconnection Facilities and the Network Upgrades at the POI for the proposed Generating Facility.

The 50% total land acreage requirement is necessary for both the Transmission Owner's Interconnection Facilities as well as the Network Upgrades at the POI for the proposed Generating Facility and will be determined separately.

The Site Plan submitted in accordance with Section 7.2.2 of the GIP shall identify the specific locations within the site for which Site Control is achieved, and those locations for which Site Control is not yet achieved.

To the extent that the Interconnection Customer intends to locate its Interconnection Facilities in a public right of way, Interconnection Customer shall also submit proof of submission of all requisite state and local permits.

The Transmission Provider shall evaluate the Site Control documentation using sound engineering judgement and in a non-discriminatory manner:

1. Verify whether IC has provided lease/ownership agreements for each parcel.
2. Identify Deficiencies and provide comments, if there are any.

5.2. Definitive Planning Phase I

The DPP I will start on a defined, periodic basis. Phase I of the DPP is designed to provide the IC with a preliminary detailed analysis of their IR's impact on the reliability of the Transmission System and will be approximately one hundred (100) Calendar Days in length. During this phase MISO will perform the initial Model Building and Review, which is scheduled for ten (10) Calendar Days. Following this, a preliminary Interconnection SIS will be performed and is scheduled for sixty-five (65) Calendar Days. Once the analysis is done, the IC will enter into IC Decision Point I, which will last fifteen (15) Business Days.

5.2.1. Model Building and System Impact Study

Prior to starting the preliminary SIS, MISO will distribute the study models to the IC and the TO. The IC and the TO may recommend changes to the study model by providing a completed Interconnection Study Model Review Form, Appendix 10 to the GIP within ten (10) Business Days after receipt of the study models. The proposed changes will be incorporated into the study models after mutual agreement on the changes by MISO, the IC, and the TO, such agreement not to be unreasonably withheld. The preliminary SIS in Phase I will begin the day after the final model is posted and is scheduled to take place up to sixty-five (65) Calendar Days. Failure of the IC to provide a completed Interconnection Study Model Review Form within ten (10) Business Days of receipt of the study models will result in withdrawal of the IR pursuant to Section 3.6 of the GIP.

5.2.2. Delays to Phase I Timeline

At the request of the IC, or at any time MISO determines that it will not meet the required time frame for completing the preliminary Interconnection SIS, MISO shall notify the IC regarding:

i. The schedule status of the preliminary Interconnection SIS
ii. An estimated completion date and an explanation of the reasons why additional time is required.
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised. If required, the IC must provide an additional deposit equal to the difference between the initial and revised cost estimate within thirty (30) Calendar Days of MISO's notice. Failure of the IC to provide this additional deposit will result in withdrawal of the IR pursuant to Section 3.6 of the GIP.

5.2.3. Interconnection Customer Decision Point I

Once the preliminary SIS, including estimated upgrades and costs, is delivered, the IC will pass through the IC Decision Point I. The IC Decision Point I will last for fifteen (15) Business Days and the IC can either proceed to DPP II or withdraw its IR. During the IC Decision Point I, the IC may reduce the size of its IR by as much as one hundred percent (100%), but the required DPP II Milestone (M3) calculation will be based on the DPP I results. If the IC decides to withdraw its IR during, or at any time before the end of the IC Decision Point I, then pursuant to Section 7.6 of the GIP, MISO will refund the IC forty percent (40%) of the DPP I Milestone (M2) and any remaining study deposits. If the IC decides to proceed to the DPP II, then it will be required to pay the DPP II Milestone (M3), pursuant to Section 7.3.1.4.1 of the GIP.

5.2.3.1. EMT Model Requirements

MISO will identify projects that need to provide a PSCAD model for the active DPP study at DPP Kickoff. By the end of Decision Point 1, the IC for identified inverter-based Projects will submit a PSCAD model of the entire project, including any STATCOM, D-VAR, SVC or other applicable equipment. The model provided is to comply with the PSCAD Model Requirements Supplier Checklist located at: https://www.electranix.com/the-electranix-library/. Inverter-based projects that are not going to be studied in the active DPP cycle are to be submitted at a minimum the following by GIA execution: manufacturer provided parameterized PSCAD models of the inverter and the plant controller. The model should comply with recommended requirements in the Technical Memo – PSCAD Requirements document located at: https://www.electranix.com/the-electranix-library/.

This is required for any project in the 2019 DPP cycle and all subsequent cycles. The PSCAD models are to have parameters consistent with the PSS®E Library dynamics models to be submitted for dynamic-stability analyses for the Phase 2 studies and beyond. The IC will also be required to update the PSCAD model as changes are made to the facilities over the life of the DPP process and the life of the project after Commercial Operation. The purpose of this is to allow MISO and the Transmission Owners to readily include the project's PSCAD model in any detailed PSCAD studies of the area near the project and avoid delays.

Local Planning Criteria in combination with MISO's evaluation will be followed to determine the need for a detailed EMT study of individual interconnection requests or of the applicable group of requests.

5.2.4. The (M3) Milestone Calculation – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 22, 2024

The DPP II Milestone (M3) will be calculated as the greater of twenty percent (20%) of the amount of Network Upgrades identified in the DPP Phase I SIS less the amount previously provided at (M2) or $1,000/MW, but in no event shall (M3) be less than zero dollars. Network Upgrades are all of the upgrades identified on the MISO system. Network Upgrades do not include Interconnection Facilities or Affected System (external to MISO) upgrades. The (M3) Milestone will be in the form of either cash or irrevocable Letter of Credit reasonably acceptable to the Transmission Provider and must be received prior to the start of DPP II.

The (M3) Milestone Calculation – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024

The DPP II Milestone (M3) will be calculated as the ten percent (10%) of the amount of Network Upgrades identified in the DPP Phase I SIS less the amount previously provided at (M2), but in no event shall (M3) be less than zero dollars. Network Upgrades are all of the upgrades identified on the MISO system. Network Upgrades do not include Interconnection Facilities or Affected System (external to MISO) upgrades. The (M3) Milestone will be in the form of either cash or irrevocable Letter of Credit reasonably acceptable to the Transmission Provider and must be received prior to the start of DPP II.

5.2.5. Withdrawal from DPP Phase I

If MISO does not receive written confirmation from the IC regarding whether it wants to proceed to the DPP II or withdraw its IR, during the IC Decision Point I, MISO will deem the IR as withdrawn. After the IC enters the DPP II, the DPP I (M2) Milestone payment becomes one hundred percent (100%) non-refundable, pursuant to Section 7.6.2 of the GIP.

5.3. Definitive Planning Phase II

The DPP II will start the next day after the fifteen (15) Business Days IC Decision Point I window expires. Phase II of the DPP is designed to provide the IC a revised and detailed analysis of their Interconnection Project's impact on the reliability of the Transmission System after incorporating updated generation assumptions resulting from the withdrawal of IRs during DPP I, and it will be approximately one-hundred and five (105) Calendar Days in length. MISO will perform an update to the Model Building and Review results done DPP I, scheduled for six (6) Calendar Days. Following this, MISO will conduct a revised SIS, scheduled for seventy-five (75) Calendar Days. At the beginning of the DPP II, MISO will also conduct the Interconnection Facilities Study, scheduled for ninety (90) Calendar Days.

5.3.1. Revised Model Building and Revised System Impact Study

Prior to starting the revised SIS, MISO will update the study models built during Phase I by removing all the IRs that did not proceed to the DPP II. MISO will distribute the study models to the IC and the TO for final review. Any comments or corrections from the TO or IC to the revised study models must be submitted to MISO within five (5) Business Days after receipt of the revised study models. Should the TO or the IC fail to provide feedback on the revised study models within five (5) Business Days after receipt of the revised study models, MISO shall deem the models acceptable. After this point, the revised SIS can begin.

5.3.2. Delays to Phase II Timeline

At the request of the IC, or at any time MISO determines that it will not meet the required time frame for completing the revised Interconnection SIS, MISO shall notify the IC regarding:

i. The schedule status of the revised Interconnection SIS
ii. An estimated completion date and an explanation of the reasons why additional time is required.
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised. If required, the IC must provide an additional deposit equal to the difference between the initial and revised cost estimate within thirty (30) Calendar Days of MISO's notice. Failure of the IC to provide this additional deposit will result in withdrawal of the IR pursuant to Section 3.6 of the GIP.

5.3.3. Interconnection Customer Decision Point II

Once the revised SIS and Affected System analysis, including estimated upgrades and costs, is delivered, the IC will pass through the IC Decision Point II. The IC Decision Point II will last for fifteen (15) Business Days, and the IC can either proceed to DPP III or withdraw its IR. During the IC Decision Point II, the IC may reduce the size of its IR by as much as ten percent (10%), but the (M4) Milestone calculation will be based on the DPP II results. If the IC decides to proceed to the DPP III, then it will be required to pay the DPP III Milestone (M4), pursuant to Section 7.3.1.4.1 of the GIP prior to the end of IC Decision Point II.

5.3.4. The (M4) Milestone Calculation – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 22, 2024

The DPP III Milestone (M4) will be calculated as thirty percent (30%) of the amount of Network Upgrades identified in the revised SIS less the amount previously provided at (M2) and (M3),. The (M4) Milestone will be in the form of either cash or irrevocable Letter of Credit reasonably acceptable to the Transmission Provider and must be received prior to the start of DPP III.

The (M4) Milestone Calculation – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024

The DPP III Milestone (M4) will be calculated as twenty percent (20%) of the amount of Network Upgrades identified in the revised SIS less the amount previously provided at (M2) and (M3),. The (M4) Milestone will be in the form of either cash or irrevocable Letter of Credit reasonably acceptable to the Transmission Provider and must be received prior to the start of DPP III.

5.3.4.1 True-down of Milestone Payments - for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 22, 2024

Within ten (10) Business Days from the start of DPP Phase III, Transmission Provider shall notify the Interconnection Customer if the total posted M3 and M4 milestone payments (*i.e.*, the sum of the M3 and M4 payments) for the Interconnection Request exceed thirty percent (30%) of the total Network Upgrade cost assigned to such Interconnection Request in the revised System Impact Study. Transmission Provider shall refund such excess amounts to the Interconnection Customer as soon as practicable.

True-down of Milestone Payments - for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024

Within ten (10) Business Days from the start of DPP Phase III, Transmission Provider shall notify the Interconnection Customer if the total posted M2, M3 and M4 milestone payments (*i.e.*, the sum of the M2, M3 and M4 payments) for the Interconnection Request exceed twenty percent (20%) of the total Network Upgrade cost assigned to such Interconnection Request in the revised System Impact Study. Transmission Provider shall refund such excess amounts to the Interconnection Customer as soon as practicable.

5.3.5 Withdrawal from DPP Phase II

If MISO does not receive written confirmation from the IC regarding whether it intends to proceed to the DPP III or to withdraw its IR during the IC Decision Point II, MISO will deem the IR as withdrawn and refund the IC's DPP II Milestone (M3) and any remaining study deposits pursuant to Section 7.6 of the GIP. After the IC enters the DPP III, the DPP II (M3) Milestone payment becomes one hundred percent (100%) non-refundable, pursuant to Section 7.6.2 of the GIP.

5.3.6 Initial Interconnection Facilities Study

The first portion of the Interconnection Facilities Study will begin the first day of DPP II. This portion will focus on identifying cost estimates and the time required to construct the Interconnection Facilities. MISO shall use reasonable efforts to complete this portion of the Interconnection Facilities Study within ninety (90) Calendar Days.

5.4. Definitive Planning Phase III

The DPP III will start the next Business Day after the IC Decision Point II window expires. Phase III is designed to provide ICs a final, detailed analysis of their Interconnection Project's impact on the reliability of the Transmission System after incorporating updated generation assumptions due to potential withdrawal of IRs during DPP II and will be approximately sixty (60) Calendar Days in length. MISO will perform an update to the Model Building and Review results done in DPP II, scheduled for six (6) Business Days. Following this, MISO will conduct a final SIS, scheduled for fifty (50) Calendar Days. MISO will perform an update to the Phase II model to incorporate any withdrawals and reduction to the ER/NR sizes of the projects allowed at Decision Point 2 and this is scheduled to take six (6) Business Day upon which MISO will post the Final SIS model. The day after the final model posting, MISO will begin the Final SIS during the Phase

III study period, scheduled to last for fifty (50) Calendar Days. Upon completion of the Final SIS, MISO will then conduct any necessary Network Upgrade Facilities Studies (NU FaS) identified in the Final SIS. NU FaS studies can take up to ninety (90) Calendar Days to complete.

5.4.1. Model Updates and Final Interconnection System Impact Study

Prior to starting the final Interconnection SIS, MISO will update the study models built during Phase II by removing all the IRs that did not proceed to the DPP III. MISO will distribute the study models to the IC and the TO for final review. Any comments or corrections from the TO or IC to the revised study models must be submitted to MISO within six (6) Calendar Days after receipt of the revised study models. Should the TO or the IC fail to provide feedback on the revised study models within seven (7) Calendar Days after receipt of the revised study models, MISO shall deem the models acceptable. After this point, the final SIS can begin. Section 6.1 provides details of the SIS methodologies and deliverables.

5.4.2. Delays to Phase III Final Interconnection System Impact Study Timeline

At the request of the IC, or at any time MISO determines that it will not meet the required time frame for completing the final Interconnection SIS, MISO shall notify the IC regarding:

i. The schedule status of the final Interconnection SIS
ii. An estimated completion date and an explanation of the reasons why additional time is required.
iii. A revised cost estimate of study deposits with an explanation of the reasons why the cost estimates were revised. If required, the IC must provide an additional deposit equal to the difference between the initial and revised cost estimate within thirty (30) Calendar Days of MISO's notice. Failure of the IC to provide this additional deposit will result in withdrawal of the IR pursuant to Section 3.6 of the GIP.

5.4.3. Final Interconnection Facilities Study

The second portion of the Interconnection Facilities Study shall start after the final Interconnection SIS is complete. This study will estimate the cost and time required to build necessary Network Upgrades that are identified in the final Interconnection SIS in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facilities to the Transmission or Distribution System, as applicable, as well as that equipment, to the extent known and available in accordance with Section 3.5 of the GIP. MISO shall use reasonable efforts to complete this portion of the Interconnection Facilities Study within ninety (90) Calendar Days.

5.4.4 Delays to the Phase III Final Interconnection Facilities Study Timeline

At the request of the IC, or at any time MISO determines that it will not meet the required time frame for completing the final Interconnection Facilities Study, MISO shall notify the IC as to the schedule status of the Interconnection Facilities Study. If MISO is unable to complete the Interconnection Facilities Study and issue a draft GIA appendices and, as applicable, associated draft appendices for the related Facility Construction Agreement (FCA(s)) and/or Multi Party Facility Construction Agreement(s) (MPFCA(s)), along with supporting documentation, within the time required, it shall notify the IC and provide an estimated completion date and an explanation of the reasons why additional time is required. If MISO is unable to complete the Interconnection Facilities Study with the study deposit provided by the IC, MISO shall notify the IC and provide a revised cost estimate with an explanation of the reasons why. The IC shall provide an additional deposit equal to the difference between the initial and revised cost estimate within fifteen (15) Calendar Days of MISO's notice. Failure of the IC to provide this additional deposit will result in the withdrawal of the IR pursuant to Section 3.6 of the GIP.

5.4.5. Facilities Studies

The IC and TO may, within fifteen (15) Calendar Days after receipt of the draft Interconnection Facilities report, which information will be incorporated into the GIA appendices, and, as applicable, associated draft appendices for the related FCA(s) and/or MPFCA(s) and supporting documentation, provide written comments to be included in the final Interconnection Facilities report. As described above, MISO shall issue the final Interconnection Facility Study within ten (10) Calendar Days of receiving the IC's comments or promptly upon receiving the IC's statement that it will not provide comments. MISO may reasonably extend the fifteen (15) Calendar Days period upon notice to the IC if the IC's comments require MISO to perform additional analysis or make other significant revisions prior to the issuance of the final Interconnection Facilities Study report. Upon request, MISO shall provide the IC with supporting documentation, work papers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements provided in Section 13.1 of the GIP.

Within ten (10) Business Days of providing the draft Interconnection Facilities Study report and supporting documentation to the IC, MISO and the IC may meet to discuss the results of the Interconnection Facilities Study.

5.4.6. Interconnection Study Restudy

If MISO determines restudy is required because one of the contingencies in Article 11.3.1 of the GIA has occurred, or at MISO's discretion, MISO will reevaluate the need for the Common Use Upgrade and/or Shared Network Upgrade, and if still required, reallocate the cost and responsibility for any Common Use Upgrade and/or Shared Network Upgrade, without a restudy when possible, or with a restudy if MISO deems it necessary in order to ensure reliability of the Transmission System.

If a restudy of any Interconnection Study is required because an IR withdraws or is deemed to have withdrawn prior to all GIAs, FCAs, and/or MPFCAs, as applicable, for each respective DPP cycle have been executed or filed unexecuted with the FERC, MISO shall provide notice of a restudy as necessary. MISO will include in the notice of restudy a preliminary analysis supporting the need for an Interconnection Study restudy, an explanation of why an Interconnection Study restudy is required, and a good faith estimate of the cost to perform the Interconnection Study restudy. The Interconnection Study restudy will be performed according to the GIP and the BPMs in effect at the time the notice is given by MISO. The IC shall notify MISO within five (5) Business Days whether the IC wishes to proceed with the Interconnection Study restudy or withdraw its IR. MISO will deem a failure to notify MISO to proceed to perform the Interconnection Study restudy as the ICs withdrawal of its IR in accordance with Section 3.6 of the GIP. MISO will use reasonable efforts to complete the Interconnection Study restudy within sixty (60) Calendar Days from the date of notice. MISO may perform the Interconnection Study restudy of Network Upgrades common to more than one IR as a Group Study.

Definitive Planning Phase Processes and Methodologies

6.1. Generator Interconnection System Impact Study

A SIS will be conducted which will include thermal analysis, short circuit analysis, transient and voltage stability analysis. The SIS will provide a list of facilities (including Interconnection Facilities, Network Upgrades, Distribution Upgrades, Generator Upgrades, Common Use Upgrades, Shared Network Upgrades, and, if such upgrades have been determined, upgrades on Affected Systems) that are required as a result of the IR. The study may also include system protection, and loss analyses depending on the recommendation from the ad hoc group. SIS results will include a preliminary indication of the planning level estimate of cost and length of time that would be necessary to implement any Network Upgrades identified in the analysis. The Network Upgrades may be identified to accommodate a group of generators together, wherever applicable.

6.1.1. Steady State Analysis

The Steady State Analysis will include the evaluation of system performance under both normal and contingency conditions for all new generation IRs, including energy storage devices, in accordance with Reliability TPL Standards. The Steady State Analysis will generally include the following analyses:

i. Thermal analysis
ii. Voltage analysis
iii. PF requirement analysis
iv. Prior outage analysis

For IRs related to energy storage devices, MISO will evaluate the plant for an entire range of operation by testing the plant as a generator and a load.

6.1.1.1 Thermal analysis

Steady State Thermal analysis will be performed by adhering to all applicable standards as discussed below in Section 6.1.1.1.2. A new ad hoc study group will be formed and chaired by MISO for each study. MISO will determine, with input from the ad hoc group, the monitored element and contingency lists and other study assumptions. Based on the recommendations and input received from the ad hoc group, facilities in the Affected Systems that could potentially be impacted by the interconnection are monitored. For any identified significantly affected facility, the study will determine transmission upgrades and/or transmission alternatives required to mitigate the constraints for full power output. Development of solutions for identified transmission issues will consider transmission upgrades, including Storage As Transmission-Only Asset (SATOA), and transmission alternatives like planned generation re-dispatch, reconfiguration, load shed, or Remedial Action Scheme (RAS) on a comparable basis consistent with Attachment FF and Section 4.3.1.2 of the Transmission Planning BPM (BPM-020).

The study case will undergo a DC screen to identify monitored element and contingency pairs which are significantly loaded (e.g., ninety percent (90%) or more). The loadings will be recorded for the bench case and study cases and DFs will be calculated by using the Monitored Sensitivity function in PSS MUST. All monitored elements and contingency pairs which are overloaded (worst case loading) in the study case using AC analysis and which meets the criteria in Section 6.1.1.1.6 will be reported.

To mitigate a constraint, MISO will check the MTEP appendices and discuss with the impacted TO(s) to determine if there already exists a planned project which will alleviate the constraint. A Long Range Transmission Planning (LRTP) project included in an approved Multi-Value Project (MVP) Portfolio can only replace a previously identified Network Upgrade as constraint mitigation if that LRTP project is the same facility as the identified upgrade (i.e., same connecting substations at identical voltage); this is to avoid a full model build and restudy that would be required by including the MVP Portfolio.

If there is no such planned or proposed project, MISO will work with the impacted TO(s) and ICs to identify a solution consistent with baseline planning solution development described in Sections 4.3.1.2 and 4.3.1.3 of BPM-020, subject to the concurrence of MISO, the TO(s) and ICs. If a project(s) resolves the constraint, and that project(s) is approved by the Board within (1) calendar year of the GIA execution or execution of an amendment thereof, then the IC will not be responsible for upgrade(s) that would resolve the constraint, but the MTEP project will be included as a GIA contingent facility. If that project(s) is not approved within one (1) calendar year of the GIA execution or execution of an amendment thereof, the IC will be responsible for those transmission upgrade(s).

6.1.1.1.1 Bench Case Development

- The bench case (pre-project case) will be created by considering the most recent MTEP 5 year out LBA dispatch case as the base starting case. Any approved projects (in MTEP Appendix A) and projects recommended by MISO for Board approval (e.g., recommended short-term Transmission Plan defined in BPM-020) will be included in the Base Cases. Additionally, the most recent portfolio of Long Range Transmission Planning projects will be included in the bench case of the next DPP cycle following Board approval if Board approval is granted within 30 Calendar Days following Application Deadline.

- The higher queued generators (without a GIA) added to the starting case and dispatched at their expected output level as per fuel type as shown in Table 6-1 such that higher queued generators in MISO North (Classic) are sunk into MISO North (Classic) and generators in MISO South are sunk into MISO South[8] and generators in Affected System are sunk into the same area or subregion, if applicable, as they are modeled by the host RTO such as the existing generation is scaled down by the amount of MW of the higher priority queued generator(s) added. The study cycle generators and associated interconnection facilities are added to the bench case, but the study generators are not dispatched in the bench case. Units that have had GIAs signed after MTEP model development, but prior to study kickoff will be dispatched utilizing the same methodology as higher queued generators.

6.1.1.1.2 Study Case Development

- The study case (post-project case) will be created by starting with the bench case, but then dispatching the study generator(s) at their expected output level described in

[8] After dispatching generators per fuel type, the total generation in MISO North (Classic) and MISO South and the Affected System shall be equal to total generation in the respective region as seen in the starting MTEP case. This ensures that the total load & losses in a region are being served by total generation in the respective region and thereby implicitly respecting the N-S constraint/transfer limit.

Table 0-1 and then scaling down the non-study cycle generation in MISO North or MISO South or Affected System(s) by the amount of study cycle MW added.

Table 0-1 Dispatch per Fuel Type for Study and Higher Queued Generators (without a GIA)

Fuel Type under Study and Higher Queued	Summer Peak Dispatched as % of Interconnection Service	Shoulder Peak Dispatched as % of Interconnection Service
Combined Cycle	**100%**	**50%**
Combustion Turbine	**100%**	**0%**
Diesel Engines	**100%**	**0%**
Hydro	**100%**	**100%**
Nuclear	**100%**	**100%**
Storage[9]	**100%[10]**	**- 100%, 0% [9,10]**
Steam – Coal	**100%**	**100%**
Oil	**100%**	**0%**
Waste Heat	**100%**	**100%**
Wind	**15.6%[11]**	**100%**
Solar	**100%**	**0%[12]**
Hybrid Facility[13] (Any combination of the above fuel types except Battery which can be assumed up to 100% dispatchable in both Summer Peak and Shoulder Peak)	**Battery up to 100% Last Fuel Dispatched Other Fuels based on above dispatch assumptions of each fuel type with any adjustment based on requested interconnection Service[14]**	**Battery Up to 100% Last Fuel Dispatched Other Fuels based on above dispatch assumptions of each fuel type with any adjustment based on requested interconnection Service[15]**

[9] Storage requests that indicate the need to charge from the grid will be studied at their maximum charging capability. Transmission Service is required to charge from the Transmission System; the GIA does not grant Transmission Service. In order to obtain any type of Transmission Service for charging from the Transmission System, the IC will have to seek service as a Transmission Customer.

[10] For cycles before the DPP 2022 cycle, Storage dispatch in the shoulder peak case will continue to use the previous value of +/-100%

[11] Dispatch level for wind resources will be aligned with wind capacity credit used in the MTEP summer peak case. It was 15.6% in 2017 MTEP summer peak case. This value is subject to change based on the wind capacity credit which is calculated annually.

[12] For cycles before the DPP 2019 cycle, Solar dispatch in the shoulder case will continue to use the previous value of 50%

[13] A hybrid facility is a Generating Facility that utilizes more than one fuel source to inject power on to the Transmission System. This Generating Facility can be any combination of the fuel types in Table 6-1. For e.g., Solar + Storage, Wind + Storage, Solar + Wind, CC + Solar, Solar + Wind + Storage etc. This is inclusive of Surplus, Replacement, and Generator expansion requests that incorporate additional fuels. Batteries are last fuel dispatched in a hybrid configuration limited by either the Battery installed capacity or requested service level in both Peak and Shoulder Peak Cases.

[14] See Examples in Appendix E

[15] See Examples in Appendix E

Any other seasonal model with appropriate load and generation dispatch level, if required to adequately assess the system reliability in the region, may replace one or more of the cases listed above.

Table 6-1 above describes the fuel type dispatch levels for individual fuel type in summer peak and shoulder peak models for the DPP studies. The following assumptions will be used, as applicable, for hybrid facilities[16]:

i. The fuel type dispatch levels of Table 6-1 will be used for each corresponding fuel type in hybrid facilities except that, if the total Generating Facility output per fuel type dispatch in both summer peak and shoulder peak steady state models is below the total Interconnection Service requested, then the Generating Facility will be dispatched in such a way that total requested Interconnection Service is studied in at least one of the study models. The study model with the highest generation output after doing fuel type dispatch will be chosen to study the full requested Interconnection Service.
ii. For steady state models, generators will be reduced proportionally if the dispatched MW per fuel type dispatch is greater than Interconnection Service requested.
iii. For stability analysis, Section 6.1.2 of this BPM will be followed to determine the scenarios to be studied. By default, the generators will be reduced proportionally if the dispatched MW is greater than the Interconnection Service requested, and all generators will be online even at a reduced output. Generally, only discharging mode of storage will be studied in the stability analysis as the stability and control model are the same regardless of direction of real power flow[17]. Additional scenarios for stability analysis may be studied based on technologies used, if necessary.
iv. Short circuit analysis will be conducted with all units connected for the installed MVA (irrespective of MW service requested).
v. The Interconnection Customer can specify whether they plan to charge the storage devices from the Transmission System in the Generator Interconnection (GI) application (Appendix 1 to Attachment X). If the IC specifies that they will not charge from the Transmission System, then this will be documented in the GIA. For this type of request, the “charging” mode of storage will not be studied in the DPP studies[18].

[16] Appendix E of this BPM includes a few possible dispatch scenarios for hybrid facilities. In reality, there are many possible combinations of hybrid facility, which may or may not be captured in Appendix E. Therefore, based on engineering judgement, MISO may include other scenarios to assess the impact of the hybrid facility to the Transmission System, if necessary.
[17] This is applicable to hybrid facility with storage and standalone storage requests.
[18] This is applicable to hybrid facility with storage and standalone storage requests.

vi. The dispatch assumptions for hybrid facility will be applicable for all generators behind the same Point of Interconnection irrespective of a single hybrid application or separate GI applications for the same owner.

6.1.1.1.3 Generation to Include

The SIS bench and study case will include the following queued generation projects, including energy storage devices, in the region:

i. All projects with a GIA.
ii. All projects that have a DPP Queue Position and their associated Network Upgrades.
iii. All queued projects on the Affected System (in the Generator Interconnection queue of the other Transmission or Distribution Providers) will be modeled per MISO and Affected System joint agreements.

Generators requesting Retirement or Suspension under MISO Attachment Y process are notified about their approval by a letter from MISO upon completion of the necessary studies. Such generators will be treated as follows:

i. Generators under study will be modeled available for dispatch up to their interconnection service level.
ii. Generators with approved Attachment Y Notices that have not waived their interconnection rights (i.e., suspended) will be modeled offline for three (3) years beginning on their start date and be available for dispatch after the three (3) years based on the information provided by the Generator Owners through the Attachment Y Notice.
iii. Generators with approved Attachment Y Notices that have waived their interconnection rights (i.e., retired) will be modeled offline beginning on their Attachment Y start date and remain offline indefinitely based on the information provided by the Generator Owners through the Attachment Y Notice.
iv. Generators designated as SSRs will be modeled available for dispatch up to their interconnection service level until the latest in-service date of system improvements necessary to ensure system reliability as listed in the Attachment Y study report.

6.1.1.1.4 Applicable Reliability Criteria

FAC-002-2 standard requires a reliability impact assessment of new or materially modified generating facility, on the transmission system, to be undertaken and results coordinated with TOs, Load Serving Entities, Transmission Providers other Affected Systems. To ensure compliance with NERC reliability standard FAC-002-2, all applicable Regional, sub-regional, Power Pool and individual system local transmission planning criteria will be used to ensure that the assessment includes steady state, short circuit, and dynamic studies as necessary to evaluate system performance under both normal and contingency conditions[19] in accordance with reliability TPL standards.

All applicable NERC TPL and FAC standards can be referenced at the following link: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf

6.1.1.1.5 Cascading Outage Conditions

Based on the ad hoc group's recommendation, select events may be studied to identify potential cascading outage conditions. After taking appropriate NERC/ERO/Regional action, including the controlled reduction of generation, load and curtailing firm transfers, if the transmission facility is still overloaded, then additional upgrades may be required to alleviate the condition (Refer to section 6.1.1.1.2 for details pertaining to applicable reliability criteria).

6.1.1.1.6 Prior Outage Conditions

Based on the ad hoc group's recommendation, and in compliance with 6.1.1.1.2, contingency analysis in the local area will be performed for selected prior outage conditions. The purpose of this review is to identify operating restrictions or additional Network Upgrades to prevent unreliable operating conditions under prior outage conditions. In the event that a RAS or an operating plan in accordance with local planning criteria cannot be developed to prevent cascading uncontrolled outages, either a permanent reduction in generation (i.e., a relay scheme that trips the synchronizing breaker past a certain MW level) or a Network Upgrade may be identified.

The output of this study will be an appendix to the Interconnection SIS report. Also, the results of this study may be included in the operating sections of the appendices to the Interconnection and Operating Agreement.

6.1.1.1.7 Permissible Software Tools

Siemens PTI's PSS/E and PSS MUST software for power system studies will be used to perform the studies. MISO will use in-house software tools in conjunction with PSS/E and PSS MUST to

[19] The System Impact Study includes only select contingencies, based on inputs from the ad-hoc study group, for which system adjustments are permitted as per the TPL standards.

generate and post-process the study results. MISO may consider using other industry accepted power system analysis software tools with similar capabilities.

6.1.1.1.8 Criteria Used to Determine Constraints

In order to obtain any type of Interconnection Service, all generators, including energy storage devices, must mitigate injection constraints identified in the study. A constraint is identified as an injection constraint if:

i. The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system intact condition, or

ii. If LRTP projects are included in the study cases in MISO sub-regions, 6.1.1.1.8 iia and/or 6.1.1.1.8 iib constraint criteria shall be applicable.

   a. The generator has a larger than ten percent (10%) sensitivity factor on the overloaded less than 345 KV MISO Midwest facilities under post contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system intact condition.

   b. The generator has a larger than ten percent (10%) sensitivity factor on the overloaded less than 345 KV MISO South facilities under post contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system intact condition.

iii. The overloaded facility or the overload-causing contingency is at generator’s outlet, or

iv. The MW impact due to the generator is greater than or equal to twenty percent (20%) of the applicable rating (normal or emergency) of the overloaded facility, or

v. For any other constrained facility, where none of the Study Generators meet one of the above criteria in i, ii or iii, however, the cumulative MW impact of the group of study generators is greater than twenty percent (20%) of the rating of the facility, then only those study generators whose individual MW impact is greater than five percent (5%) of the rating of the facility and has DF greater than five percent (5%) (*i.e.*, power transfer distribution factor (PTDF) or outage transfer distribution factor (OTDF)) will be responsible for mitigating the cumulative MW impact constraint, or

vi. Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems’ criteria.

vii. Any other applicable TO FERC filed Local Planning Criteria.

Further, the Generating Facilities, including energy storage devices, requesting NRIS must mitigate constraints under system intact and single contingency conditions, by using the deliverability algorithm, if the generator impact (incremental flow caused by the generator) is equal to or greater than five percent (5%) of the net injected power into the grid.

Mitigations for a NERC TPL multiple contingency events will be determined in accordance with reliability criteria identified in 6.1.1.1.2. Engineering judgment may be used for special cases.

6.1.1.1.9 Deliverability Analysis

For the purpose of Deliverability Analysis, impacts of higher queued or pre-existing requests for ERIS will not be considered unless they have a confirmed firm transmission service reservation associated with the generator. In that case, only the level of firm transmission service will be modeled in the Base Case when studying a lower queued project for deliverability. NRIS will be evaluated at one hundred percent (100%) of the requested capability of the IR, including those for energy storage devices. NRIS will be granted for the amount for which a generator commits to build the Network Upgrades, up to the requested capability of the IR, as identified through the deliverability analysis. The IC must choose the NRIS level prior to the completion of IC Decision Point II. Once the IC chooses a NRIS MW level, that MW amount will be used in the Final SIS in DPP Phase III.

The methodology for deliverability analysis can be found in Appendix C of this BPM.

6.1.1.1.10 Network Upgrade Cost Allocation

6.1.1.1.10.1 Thermal Network Upgrade Cost Allocation

The Network Upgrades cost for a set of projects (one or more sub-groups or entire group with identified Network Upgrades) will be allocated based on the MW impact from each project on the constrained facilities in the Study Case. The highest MW impact for each individual project on the constraint will be used in the calculation. All thermal constraints will be identified and a DF from each project, including energy storage devices, on each constraint will be obtained. Finally, the cost will be allocated based on the pro rata share of the MW impact on all constraints from each project, including energy storage devices where MW impact = DF * Gen Output of the project in the model where the constraint occurs. If the Network Upgrade alleviates multiple constrained facilities the cost is allocated based off the sum of the highest MW contribution on all of the constrained elements for the DPP project under contingency. If a project doesn't violate DPP reliability criteria for a constrained element, their MW impact = 0 for calculation purposes.

Table 6-2 provides a simple example of the cost allocation methodology described in this section.

Table 0-1 Example of Thermal Project Cost Allocation

Constraint	Mitigation	MW Impact Project 1	MW Impact Project 2
Overload of Line A	New Line X ($50M)	6	3
Overload of Line D	New Line X ($50M)	12	15
Overload of Line H	New Line X ($50M)	4	0
Total MW Impact	New Line X ($50M)	22	18
Cost Allocation		=(22/40*50) = $27.5M	=(18/40)*50 = $22.5M

Note that the allocation is applicable to the Network Upgrade cost only; each project will be responsible for the cost of Interconnection Facilities required to connect to the Transmission System. In order to save time and effort a more simplistic approach can be used for the purpose of cost allocation as long as the new method is acceptable to all parties and does not delay the study process.

6.1.1.1.10.2 Voltage Network Upgrade Cost Allocation

Cost allocation of voltage constraint driven Network Upgrades will be determined by the pro rata share of the voltage impact each project has on the most constrained bus under the most constraining contingency. The voltage impact of each project will be calculated by locking all voltage regulating equipment in the model and then backing out each project one at a time to identify each project's impact to the constraint. In severe instances of voltage collapse where projects cannot be backed out one at a time, they will be added one at a time to determine their impact to the constraint.

Table 6-3 provides a simple example of the cost allocation methodology described in this section.

Table 0-3 Example of Voltage Project Cost Allocation Methodology

Project	Contingent Voltage with all DPP Projects	Δ Voltage with DPP Project removed	New Voltage	Type	Cost Allocation %
Gen A		0.01	0.76	Harmer	33.33%
Gen B	0.75	0.02	0.77	Harmer	66.67%
Gen C		-0.01	0.74	Helper	0.00%
Total		0.03			100.00%

6.1.1.1.10.3 Transient Stability Network Upgrade Cost Allocation

Transient stability driven Network Upgrades will be cost allocated based on the pro rata share of the total MW request of all the projects causing instability. The project(s) causing instability will be determined by backing out each project one at a time to identify each project's impact to the constraint.

6.1.1.1.10.4 Complex Cost Allocation

As the number and types of constraints increases, mitigating the constraints individually may result in higher overall costs. In instances when mitigation(s) resolve multiple types of constraints (such as thermal + voltage or thermal + voltage + transient stability) the cost is allocated based off the ratio share of the total cost of the independent mitigation types in order to equitably allocate the cost to all parties contributing to constraints. In summary, only the lowest cost mitigation option will be constructed, but for cost allocation purposes the independent mitigations are required.

Table 6-4-1 and 6-4-2 provides an Example of Complex Cost Allocation

Table 0-4-1 Example of Independent Project Cost

Constraint	Independent Mitigation	Cost (M$)	Project
Branch U Overload	**Rebuild Branch U**	**$30M**	**Gen A**
Branch V Overload	**Rebuild Branch V**	**$25M**	**Gen B**
Bus Y Low Voltage	**Capacitor Bank**	**$1M**	**Gen C**
Gen D – Transient Instability	**Build New Line Bus S to Bus T**	**$204M**	**Gen D**
	Total Cost	$260M	

Table 0-4-2 Example of Complex Cost Allocation Methodology

Constraint	Best Fit Solution	Cost (M$)	Project
Branch U Overload	**Build New Line Bus S to Bus T**	**((30/260)*204) = $23.54M**	**Gen A**
Branch V Overload		**((25/260)*204) = $19.62M**	**Gen B**
Bus Y Low Voltage		**((1/260)*204) = $0.78M**	**Gen C**
Gen D – Transient Instability		**((204/260)*204) = $160.06M**	**Gen D**
	Total Cost	$204M	

6.1.1.1.10.5 Generator Interconnection Backbone Network Upgrade

In some instances, initial system conditions are so severe that the DPP model isn't in a usable state until Network Upgrades are added. GI Backbone Network Upgrades are the upgrades that are necessary in order to obtain a usable DPP model. Transmission Line GI Backbone Network Upgrades are cost allocated per the pro rata share of MW contribution of DPP projects on the constraints being alleviated by the GI Backbone Upgrades. Capacitor Bank and SVC GI Backbone Network Upgrades are cost allocated based off of the voltage change at the most constrained bus when each project is removed one at a time. In severe instances where projects cannot be backed out one at a time, they will be added one at a time to determine their impact to the constraint.

Table 6-5-1 and 6-5-2 provides an Example of GI Backbone Network Upgrade

Table 0-5-1 Example of GI Backbone Network Upgrade Constraint Identification

Constraint	Upgrade	MW Impact Project A	MW Impact Project B	MW Impact Project C	Total MW Impact
Overload of Line A-B	**New Line 1 ($100M)**	**5**	**10**	**0**	**15**
Overload of Line D-E	**New Line 2 ($200M)**	**10**	**20**	**5**	**35**
Low Voltage Bus G	**Cap Banks ($5M)**	**.01**	**.005**	**-.02 (helper)**	**.015**

Table 0-5-2 Example of GI Backbone Network Upgrade Cost Allocation Methodology

Upgrade	Cost Allocation Project A	Cost Allocation Project B	Cost Allocation Project C
New Line 1 ($100M)	**(5/15) * 100M = $33.33M**	**(10/15) * 100M = $66.67M**	**0**
New Line 2 ($200M)	**(10/35) * 200M = $57.14M**	**(20/35) * 200M = $114.29M**	**(5/35) * 200M = $28.57M**
Cap Banks ($5M)	**(.01/.015) * 5M = $3.33M**	**(.005/.015) * 5M = $1.67M**	**0**

6.1.1.1.11 Shared Network Upgrade Cost Allocation Eligibility

The Shared Network Upgrades are the Network Upgrades funded by an IC that are or will be in-service prior to the Commercial Operation date submitted by the IR under study, or are otherwise far enough along that it is not practical to bring the IR under study into an MPFCA for the upgrade.

As part of the SIS MISO will review the proposed configuration of the study generators, including energy storage devices, and perform a test, if required, to determine their eligibility for cost sharing. The set of Shared Network Upgrades included in the test will be all GIP facilities in-service for a period of less than five (5) years, and costs greater than or equal to $10 million.

If a generator meets any of the following two criteria, it will share the cost of the Shared Network Upgrade without any further tests:

i. The generator connects to the Shared Network Upgrades
ii. The generator connects to a substation where the Shared Network Upgrade(s) terminates.

For all other generators that do not meet the above criteria, further analysis will be performed to measure their use of and benefit from the Network Upgrades previously identified and funded by other generators. The intent of the test is to determine if the new generators under study are benefiting from a Network Upgrade previously identified for a different generator and should share in the cost of that Network Upgrade.

A power flow analysis will be performed to calculate the impacts of the study generators on the Shared Network Upgrades under system-intact conditions. The following two screening criteria will be used to make the decision.

i. If the impact of the IR on a generator funded Network Upgrade is greater than 5 MW AND is greater than one percent (1%) of the facility rating, the following additional screening will be performed.
ii. If the impact of the IR on a generator funded Network Upgrade is greater than five percent (5%) of the facility rating OR the power transfer distribution factor (PTDF) is greater than twenty percent (20%), the generator will share the cost of the Network Upgrade, now designated as a Shared Network Upgrade.

The flowchart in Figure 6-1 visually describes the whole methodology for determining the eligibility for cost sharing. The Shared Network Upgrades the new generator is responsible for will be listed in Appendix A of their GIA.

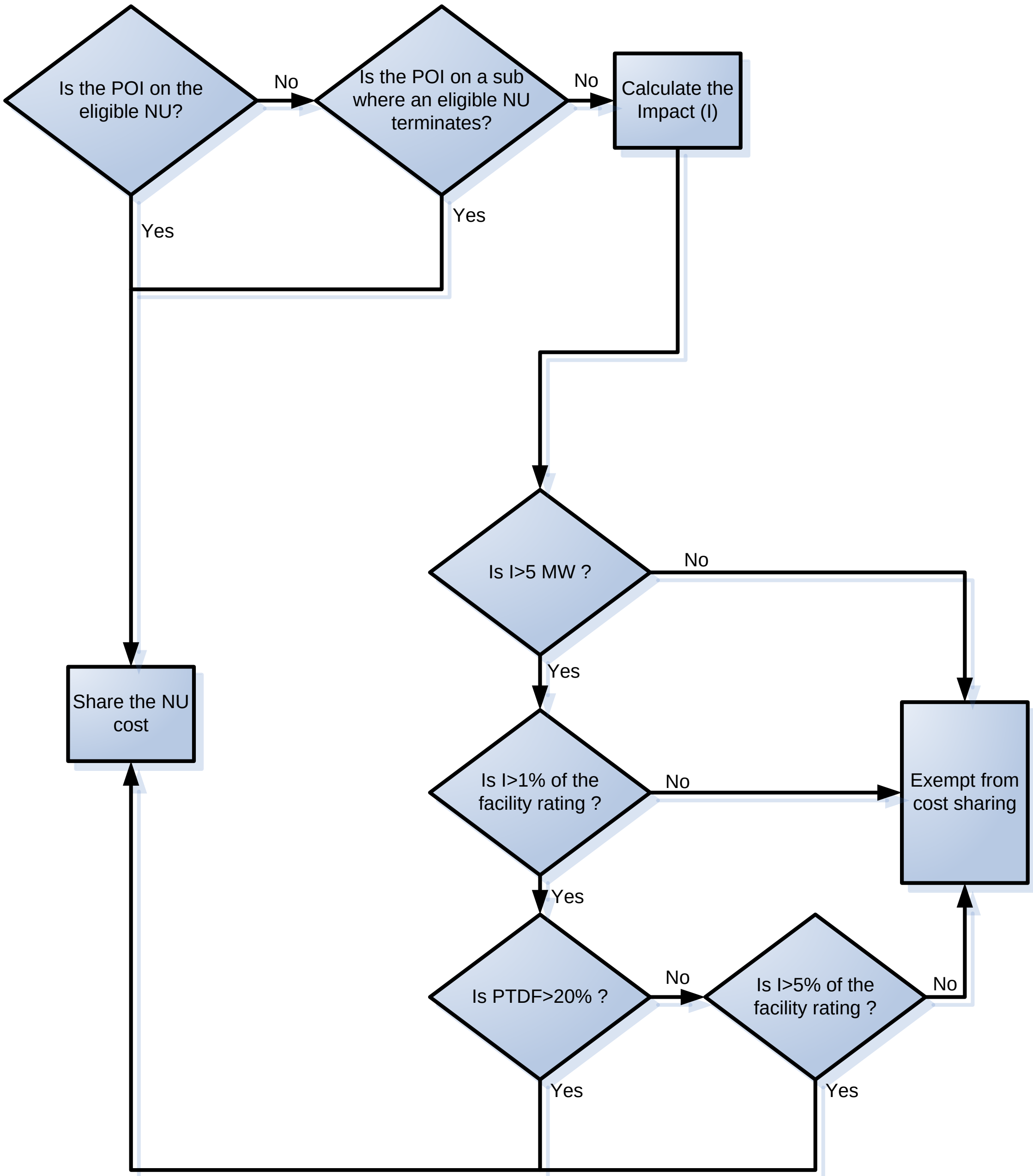

Figure 6-1 Flowchart describing the methodology to identify the Late Comer projects.

6.1.1.2. Steady State Voltage Analysis

Voltage analysis will be performed on the selected contingencies generated from the DC screen or contingencies deemed relevant to the analysis. Bus voltages outside of the defined limits (based on the LBA criteria) in the post case will be recorded and compared to the Base Case values. Bus voltages will be considered voltage constraints if, for a given contingency, the bus voltage is outside of the allowed voltage range for the post case and is at least 0.01 per unit worse than the Base Case voltage for the same contingency.

6.1.1.3. Power Factor Requirement and Low Voltage Ride Through Analysis for Wind Generation Plants

PF and Low Voltage Ride Through (LVRT) analysis will be performed to determine the requirements for a new Wind Generation Plant according to FERC Orders 661/661-A, FERC Order 827, and Appendix G of the pro forma GIA. MISO will use the following methodology in determining the final requirements as determined during the SIS.

i. To determine the PF requirements for a Wind Generation Plant, MISO will model each Wind Generation Plant under study at unity PF at the POI (no reactive capability). If voltage criteria violations at the POI exist, then MISO will enforce the criteria laid out in FERC Orders 661/661-A, thereby modeling the plant at the more stringent of 0.95 leading and lagging PF capability at the POI or the TOs' interconnection guidelines PF requirements. Should no voltage criteria violations exist, MISO will model the inherent capability of the Turbines at the POI using the best available IC supplied data, and proceed with the studies.
ii. For a new Generating Facility, MISO will request the IC to demonstrate compliance with the FERC Order 827 requirement. The associated modeling will be applied in the study model.
iii. A Wind Generation Plant must be able to remain online during select system disturbances. To test the LVRT capability of a Wind Generation Plant, MISO will evaluate the plants' performance for the following faults:
    a. Three phase faults with normal clearing
    b. Single Line to Ground faults with delayed clearing

If violations are found, the IC will be required to submit updated LVRT settings to ensure that the LVRT threshold is maintained at the POI. The Wind Generating Plant will be required to remain online for the specified time intervals.

6.1.2. Short Circuit and Stability Analysis

Short circuit analysis will generally include determining the fault current contribution from the new Generating Facility and its Network Upgrades under three-phase fault and single line to ground fault conditions. The study will identify any circuit breaker(s) that would need to be replaced to accommodate fault currents from the proposed Generating Facility.

The stability study will include the evaluation of the impact of the new Generating Facility on transient stability performance of the system by adhering to the reliability standards under 6.1.1.1.2. The stability study may also consider other scenarios to assess system transient stability in accordance with the local transmission planning criteria and Section 4.5 of this BPM.

Additionally, based on engineering judgement, MISO may include other scenarios to assess system transient stability when all generators in the same electrical area (local area) as the study generator(s) are at their full ERIS level. The IC will only be responsible for mitigating constraints which are caused by the study generators.

Example:

> The **base case** used for the stability study will be dispatched with all generators local to the study generator(s) to their full ERIS injection capacity.
>
> The **study case** will be created by adding the study generator(s) to the base case.
>
> The IC will only be responsible for constraints which appear in the study case but do not appear in the base case.

For wind turbine generators LVRT analysis would be done according to FERC Orders 661 and 661-A.

6.1.2.1. Base Case Assumptions

6.1.2.1.1 Load Levels

The Stability Study will be performed using a season and load level that traditionally represents the most limiting conditions for system stability in the region.

6.1.2.1.2 Generation to Include

Refer to Section 6.1.1.1.1.2.

For the short circuit analysis, queued generation will be added only in the area close to where the proposed generation is being added. Since the fault current contribution from a generator decays quickly the deeper you go into the system, the network changes electrically remote from the POI may be ignored for the purpose of short circuit analysis.

6.1.2.2. Applicable Reliability Criteria

Refer to Section 6.1.1.1.2.

6.1.2.3. Permissible Software Tools

Siemens PTI's PSS/E software for power system studies will be used to perform the studies. MISO may use the in-house software tools/scripts or regionally accepted software programs to generate the results with PSS/E and post-process them. MISO may consider using other industry accepted power system analysis software tools with similar capabilities.

For short circuit analysis, PSS/E, Aspen, CAPE, or any other industry accepted software tools with similar capabilities may be used.

6.1.2.4. Criteria Used to Determine Stability and Short Circuit Constraints

Stability Study

All conditions/disturbances leading to the Generating Facility or system instability in compliance with the applicable reliability standards in 6.1.1.1.2 will be documented as a constraint. If there is regional or TO's FERC filed planning criteria for transient period voltages or post transient voltage recovery, it will be monitored and, any violation caused by the proposed interconnection will be flagged as a constraint.

Short Circuit Study

All breakers over-dutied (underrated) after the addition of the proposed Generating Facility will be flagged.

6.1.2.5. Mitigation Used to Resolve Stability Constraints

MISO will coordinate and seek feedback from the ad-hoc group to identify and implement appropriate mitigation recommendations, for observed criteria violation in 0. This mitigation may include, but not limited to, the transmission reinforcement, faster breakers, new breakers, additional static or dynamic reactive support, an operating guide or RAS in accordance with local planning criteria depending on the type of disturbance causing the constraint.

6.1.3. Mitigation Verification

Sensitivity analyses will be performed by modeling Network Upgrades identified in all SIS analyses to verify that the recommended mitigation does not cause any new reliability violations. If it is determined that the coordinated and recommended mitigation plan causes further reliability violations on the transmission system, then the IC will be provided various alternatives as follows.

i. IC can agree to fund these additional upgrades and proceed to the Facilities phase of the GIP.
ii. IC can proceed with the alternative mitigation plan that does not cause reliability violations.

6.1.3.1. Storage Charging from the Grid

If a storage interconnection application indicates that it will charge from the grid, it will be modeled at its default maximum charging capability in the DPP Shoulder Peak charging case as shown in Table 6.1. For system constraints that appear only in the DPP Shoulder Peak charging case, limiting the battery charging rate(s) is an acceptable mitigation option. Any lower charging limit identified would be documented in the GIA as a control scheme requirement.

6.1.5. Customer Funded Optional Study

Any existing IC can request an optional study, as pursuant to Section 10 of the Attachment X of the MISO Tariff. The purpose of these technical studies is to provide additional information to the IC that is normally outside the scope of a typical SIS. MISO initially charges a sixty-thousand-dollar ($60,000) study deposit to perform such optional studies and then may request, if necessary, additional funds to complete the study.

6.1.5.1. Background

The Generation Interconnection SIS results identify reliability constraints that must have a mitigation plan prior to the execution of a GIA. Depending on the individual generator impact and the type of the requested interconnection service, there could be a situation where a reliability constraint is identified in the SIS report, but the IC is exempt from mitigating the constraint if its impact is below the threshold as identified in Section 6.1.1.1.6.

Therefore, despite not being responsible for paying for Network upgrades, identified in the SISs, an IC's generation facility can get curtailed in Real Time for the same constraint under varying operating environments. Therefore, to evaluate potential options to reduce Real Time congestion and curtailment for their respective generating facilities, ICs can request an Optional Interconnection Study by providing a detailed scope.

Since Optional Interconnection Studies are outside the scope of regular SISs and are performed out of regular interconnection study cycles, the results of any such analysis are non-binding.

6.1.5.2. Network Upgrade Funding and Facilities Studies:

If the IC(s) decide to fund the network upgrades, to mitigate the identified constraints identified in the Optional Interconnection Study, MISO will then facilitate the coordination with applicable TO. With applicable agreements between IC and TO(s) in place, MISO will include these network upgrades within its MISO Transmission Expansion Plan (MTEP) as "Other – MP Funded" project. MISO will work with applicable TOs to conduct a Facility Study. Facility Study timelines and cost would be consistent with Section 6.2 of this BPM.

6.1.5.3. MISO Sub-Regional Planning Meetings

Where a Market Participant (MP) requests and funds a Facility Study, MISO staff will notify all stakeholders at its upcoming applicable Sub Regional Planning Meeting. Further, when necessary FCAs are in place, MISO staff will notify all stakeholders at a subsequent SPM and include in MTEP as "Other - MP Funded" project.

6.1.5.4. Availability of ARRs

ICs can request MISO Auction Revenue Rights (ARRs) associated with funded transmission expansions. This will be handled by the Financial Transmission Rights (FTR) group consistent with BPM-004.

6.1.5.5 Shared Network Upgrade Cost Allocation Treatment:

Pursuant to Section III(A)(2)(a) of Attachment FF, a MP or a group of MPs are allowed assume cost responsibility to fund a network Upgrade on the Transmission System. However, any upgrade that is funded by the IC that was not identified as a required Network upgrade, during the Generation Interconnection Study process, will not qualify for the Shared Network Upgrade treatment as noted in Section 6.1.1.1.9.

6.1.6. External Network Resource Interconnection Service Study

This product gives Generating Facilities external to MISO the ability to procure NRIS under the MISO Tariff as long as it meets certain conditions.

To be eligible for study, the Generating Facility must have a signed Interconnection Agreement with the interconnecting Transmission Provider or be in commercial operation at the time of the request. Additionally, the Application Fee (D1), DPP Study Funding deposit (D2) and the DPP Entry (M2) Milestone deposit are required at the time of application for an external NRIS study request. Upon the receipt of a valid application, the request will be placed in the next applicable DPP cycle.

Deliverability studies will be processed in the same manner as any other Generating Facility requesting NRIS under MISO's tariff. MISO will perform all applicable ERIS reliability analysis as outlined in Section 6.1.1.1.2 to ensure system reliability for the injection from the Generating Facility external to MISO. In conjunction, a deliverability study will also be performed as outlined in Section 6.1.1.1.6.

The qualifying NRIS amounts will be memorialized through a MISO Service Agreement that will be filed at FERC. If any conditional service is granted, such service will be subjected to the annual interim studies outlined in Section 6.6. Generating Facilities requesting external NRIS must also procure firm Transmission Service to the MISO border through the host interconnecting Transmission Provider prior to the execution of a Service Agreement and such firm Transmission Service should be maintained for the duration of the Service Agreement.

6.2. Facility Study

The Facility Study will determine the cost and time estimate to construct the Network Upgrades and TO's Interconnection Facilities necessary to physically and electrically interconnect the proposed Generating Facility to the Transmission System.

The Facilities Study will be broken down into two stages, the Interconnection Facility facilities study and Network Upgrade facilities study. The Interconnection Facility facilities study will be done in parallel with the DPP Phase II SIS and the Network Upgrade facilities study will be done after the DPP III SIS is complete. The combination of the two facilities studies will determine the cost and construction schedule of identified Network Upgrades and Interconnection Facilities for each project in the DPP.

6.2.1. Study Objectives

For facility improvements determined from the SIS and based on the official POI:

i. Design and specification of facility improvements in accordance with Good Utility Practice and applicable planning and design criteria. These criteria must be consistently applied to all existing and proposed generation projects in an LBA.
ii. Development of detailed cost estimates that include equipment, engineering, procurement, and construction costs according to the level of accuracy possible based on the proposed in-service date of the projects.
iii. Identification of the electrical switching configuration of the connection equipment, including, but not limited to the transformer, switchgear, meters, and other station equipment.
iv. Identification of the nature and estimated cost of any TO's Interconnection Facilities and Network Upgrades, System Protection Facilities and Distribution Upgrades on the Transmission System and Affected Systems necessary to accomplish the interconnection.
v. An estimate of the time required to construct facilities and required phasing of improvements, if any.
vi. Preparation of the draft Appendices to the Interconnection Agreement/Facilities Construction Agreement with completed exhibits

Generally, the TOs with facilities needing upgrades identified in the SIS will determine the construction and cost estimate of those upgrades and/or Interconnection Facilities. Cost estimates will be determined to a +/- twenty percent (20%) margin if the lead time to the in-service date for the required facilities does not exceed eighteen (18) months. For studies requiring cost estimates for longer lead items, a good faith estimate will be developed. To the extent the IC requests a cost estimate with a smaller margin of error, and the TO can reasonably obtain that estimate without holding up other projects in the DPP, then the estimate will be within the negotiated margin.

6.2.2. Scope of Upgrades

The Facilities Study will clearly describe, and list various upgrades required to interconnect the proposed Generating Facility. The report should include the following Exhibits to include in Appendix A of the GIA:

i. Exhibit A1: (IC provides to Consultant) IC Generating Facility and IC constructed Interconnection Facilities. This would include IC Single Line or Elementary One-line

Diagram(s) and system Maps depicting and identifying the POI, meter point(s), metering and relaying CT arrangements, the Ownership demarcation(s).

ii. Exhibit A2: (Consultant develops) TO single line or Elementary One-line Diagram(s) and system Maps depicting and identifying the POI, meter point(s), metering and relaying CT arrangements relative to the Interconnection, the Ownership demarcation(s), the TO Interconnection Facilities, Network Upgrades, Stand-Alone Network Upgrades, System Protection Upgrades and Affected System Upgrades.

iii. Exhibit A3: (Consultant develops) a Site Plan and/or General Arrangement drawing showing the entire interconnection substation complete with all transmission line structures impacted by the new substation. This drawing will be based on and developed from the IC provided certified site survey drawing.

iv. Exhibit A4: (Consultant develops) a basic Plan and Profile drawing showing the required line tap work associated with the interconnection sub or switching station. This drawing will be based on and developed from the IC provided certified site survey drawing.

v. Exhibit A5: (Consultant develops) a categorized list or tabulation of TO Interconnection Facilities, non-Stand-Alone Network Upgrades, Stand-Alone Network Upgrades, System Protection Upgrades and Affected System Upgrades to be constructed by the TO.

vi. Exhibit A6: (Consultant develops) a categorized detailed cost breakdown of facilities identified in Exhibit A5 as by TO, by major component (e.g., transformer, line terminal, breaker, etc.) and by subcomponent (e.g., lightning arrester, disconnect switches, protection equipment, communication equipment, monitoring and alarm equipment, metering facilities, grounding, special controls, or equipment needed to meet stability or short circuit criteria, etc.) Similarly, each transmission line should be subcategorized by ROW acquisition needs (new/existing and major/minor) and the major and minor components.

6.2.3. Cost of Upgrades

The Facilities Study will provide a breakdown of various components of Network Upgrades and Interconnection Facilities required to interconnect the proposed Generating Facility. The report should include the following Exhibits to include in Appendix A of the GIA:

i. Exhibit A7: (Consultant develops) a categorized tabulation of TO Interconnection Facilities, Non-Stand-Alone Network Upgrades, Stand-Alone Network Upgrades, System Protection Upgrades to be constructed by the IC.

ii. Exhibit A8: (Consultant develops) a categorized detailed cost breakdown of facilities identified in Exhibit A7 as by the IC by major component (e.g., line terminal, etc.) and by subcomponent (e.g., breaker, lightning arrester, disconnect switches, protection equipment etc.).

iii. Exhibit A9: (Consultant develops) Total categorized cost estimate for TO Interconnection Facilities and Network Upgrades (Stand-Alone and non-Stand-Alone) including a list or tabulation of Interconnection Network Upgrades (Stand-Alone and non-Stand Alone) that are subject to the Attachment FF treatment. There is no refund for radial facilities from network to the Generating Facility.

6.2.4. Conditions to GIA (Appendix A10)

The Facilities Study report identifies the cost and schedule of Network Upgrades that are identified for Interconnection projects. In addition to these upgrades, MISO may identify other conditions which may include other higher or similarly queued IRs, other MTEP assumptions embedded in the study case, Distribution Upgrades, or System Protection Upgrades for higher or similarly queued projects.

i. Exhibit A10: MISO will perform analysis on the GI study case and monitor upcoming MTEP upgrades that are not yet in service based on the following Criteria:
   a. DF ≥ 5% AND
   b. MW Impact ≥ 5 MW, AND
   c. MW Impact ≥ 1% of the Facility Rating

All Network Upgrades identified in the SIS, required to mitigate Voltage and Stability related issues, will be included in the Appendix 10 to the GIA.

Upcoming MTEP projects applicable to study GI project(s), proposed for voltage & stability purpose, will be listed.

6.2.5. Facility Study Exhibits for the GIA

The Facilities Study report will include the following exhibits to describe the Milestones, Construction and Coordination Schedule for the proposed interconnection. These exhibits will be included in the Appendix B of the GIA:

i. Exhibit A11 (IC provides): A list of key projects and regulatory activities that must be met by the IC after receipt of the final GIA for the project to maintain its queue position or mutually agreeable in-service schedule. The IC must provide evidence of continued

Site Control for Generating Facilities; Site Control for Interconnection Facilities and Network Upgrades after execution of the GIA (Section 7.2.2 of the GIP) The IC must also provide evidence that one or more of the following items are in development within one hundred eighty (180) Calendar Days of receiving the final GIA: 1) contract for the supply or transportation of fuel to the Generating Facility; 2) contract for the supply of cooling water to the Generating Facility; 3) contract for engineering services, construction services, or generating equipment; 4) contract for the sale of electric energy or capacity from the Generating Facility; or 5) application for state and local air, water, land or federal nuclear permits and that the application is proceeding per regulations.

ii. Exhibit A12 (Consultant develops): Construction and Coordination Schedule of the Generating Facility, IC Interconnection Facilities, the TO Interconnection Facilities, Network Upgrades (subcategorized by non-Stand-Alone and Stand-Alone Network Upgrades) identifying long lead items, outage issues and expected critical path coordination items. Identify activity start dates, duration of activity and expected completion dates for all major components.
   - Identify Progress Payments
   - Identify start-up and test responsibilities.
   - Identify TO permitting process.
   - Identify issues including right-of-way acquisition for new transmission lines or substations.

iii. Exhibit A13 – (Consultant Develops) List of affected TO activities and schedules necessary to obtain regulatory approval for facilities to be provided by affected TO(s).

6.2.6. Interconnection and Operating Guidelines

The study report should include any “project specific” guidelines or requirements for the interconnection and/or operation of the Facility that go beyond the generic and universal requirement of “Good Utility Practice.” These requirements/guidelines may include topics such as System Protection Facilities, communication requirements, metering requirement(s), grounding requirements, transmission line and substation connection configurations, unit stability requirements, equipment ratings, short circuit requirements, synchronizing requirements, generation and operation control requirements, data provisions, energization inspection and testing requirements (if applicable), the unique requirements (if any), of the TO to which the facility will be physically interconnected, switching and tagging, data reporting requirements, training, capacity determination and verification (including Ancillary Services and certification), emergency operations, including system restoration and black start arrangements, identified must-run conditions, provision of Ancillary Services, specific transmission requirements of nuclear units to abide by all NRC requirements and regulations, stability requirements, including generation short circuit ratio considerations, limitations of operations in support of emergency response, maintenance and testing, and any other specific requirements not listed above.

All such Interconnection and Operating Guidelines must be included in Appendix C to the GIA.

6.2.6.1 Interconnection Agreement Appendices Populated

The Facilities Study report must include the Exhibits A1 through A13 of the GIA populated in draft format. These exhibits must go through legal review by the TO prior to publishing the report. Having these draft GIA exhibits in the Facilities Study report will provide a good starting point for the development of the GIA and will make the GIA review process smoother and less time consuming.

6.2.7. Submittal of IA for Appendix Review

MISO recommends early negotiation requests after Decision Point II and issuance of the draft Phase II Interconnection Facilities Study under Attachment X, Section 11.1 to allow ample time for negotiations. Except when IC requests early or delayed negotiation or, when further Facilities Studies are required (FCA/MPFCA), MISO will tender to the IC and TO a draft GIA and, as applicable, draft FCA(s) and/or MPFCA(s), together with draft appendices completed to the extent practicable, within five (5) Business Days after issuance of the applicable first portion of the Interconnection Facilities Study report and final System Impact Study report: Negotiation Meeting: The purpose of this meeting will be to discuss the Appendices to the GIA/FCA/MPFCA. MISO will provide these documents for review at least five (5) Business days prior to the date comments are due. The participants are expected to review the technical information in the draft appendices to the GIA/FCA/MPFCA and provide any comments to MISO at least two (2) Business Days prior to the meeting. If required, additional negotiations will be handled primarily outside of a formal meeting. Follow Up Meeting: If requested, MISO will host an additional formal meeting to discuss any remaining details requiring person to person communications.

Five (5) Business Days after the start of negotiations, the IC shall provide:

i. Its initial payment option pursuant to Article 11.5 of the GIA, and
ii. IC's desired, In-Service Date, Initial Synchronization Date, and Commercial Operation Date, if different from the dates in the Facility Study Report.

These dates will be used to complete the cash flow payments and Milestones in Appendix B of the GIA.

6.2.8. Submittal of GIA/FCA for Execution / Filing Unexecuted

Compliant with Attachment X, Section 11.3, MISO will circulate the final GIA and FCA (if applicable) to all parties for execution. If there is a deviation in pro-forma Agreement, the GIA/FCA will be filed with FERC after execution by all parties. Otherwise, the MISO will maintain the executed agreement and notify FERC via its next Electric Quarterly Report (EQR). If the GIA negotiations result in an impasse, MISO will file the Agreement unexecuted with FERC no later than ten (10) Business Days from the date of party(ies) declaring an impasse.

6.2.9. Provisional Generator Interconnection Agreement

IC can request a PGIA for a project for a limited operation of the plant at any time through IC Decision Point II, or if the schedule becomes delayed by more than sixty (60) Calendar Days between Decision Point II and the end of the Facilities Studies. An IC must meet all of the following conditions before a PGIA will be offered:

i. All planning studies identifying system impacts and mitigations have been completed in accordance with NERC and applicable regional reliability criteria through a Provisional Interconnection Study
ii. Project has met all Milestones in the process (i.e., D1, D2, M1, M2, M3, and M4. The M3 and M4 deposits will be eight thousand dollars ($8,000) per MW of the IR if not already calculated)
iii. Facility Study has been completed for the required Interconnection Facilities for the project or if there are existing Interconnection Facilities that can be used for the project without any modifications.
iv. IC agrees to install equipment or protective devices that would disconnect the Generating Facility in the event the output of the Generating Facility exceeds the operational limit described in the PGIA.
v. IC agrees to assume all risks and liability associated with the changes in the Interconnection Agreement including but not limited to the change in output limit and additional costs for Network Upgrades

Under the PGIA, the maximum permissible output of the Generating Facility will be determined based on the incremental transfer capability available at the POI to the MISO footprint. Such limit will be identified on the Base Cases used for Available Flowgate Capacity (AFC) calculations under Attachment C of the MISO OATT. Analysis to identify the operational limit for provisional GIA will be performed after IC meets all process Milestones for the project. The operational limit for the Generating Facility under provisional GIA will be reviewed and updated as required on a planning year quarterly basis.

6.2.9.1. Provisional Interconnection Agreement Limit Methodology

The MISO methodology for calculating operating limits for all generators requesting interconnection service by executing a PGIA uses a two-pronged approach as follows:

i. A MUST DC transfer analysis will calculate DFs of all generators that have greater than 20% (OTDF) and a 5% (PTDF) impacts on all constraints.
ii. These DFs will be used to calculate the operating limits, in addition to other constraints as demonstrated in the examples that follow, by utilizing Microsoft Excel Solver optimization tool. Examples are shown in Section 6.2.9.1.3.

except that a constraint should not be considered as a limit if the LODF (Line Outage Distribution Factor) value between the overloaded element and the unfinished contingent facility from GIA Exhibit A10 is less than 20%. This LODF screening does not apply if the overloaded element in this analysis, or the unfinished contingent facility, is directly connected at the generator's POI.

In order to implement this methodology, there are several inputs and assumptions that must be addressed that are outlined below.

6.2.9.1.1 PSSE Base Case Assumptions

i. MISO will use a seasonal near-term MTEP model and adjusted to match the study horizon. The adjustments will be strictly limited to the dispatch of QOL units to the Annual ERIS level and the change in generation will be offset based on their merit order within the same LBA. Transmission and generation outages lasting ≥ 60% of the study quarter will be included only in the binding quarter. Approved retirements and suspensions will be modeled offline.
ii. No changes will be made to the load pattern in the case.
iii. No changes will be made to any other generator dispatch.
iv. No changes will be made to the case topology.

6.2.9.1.2 Input Files and Analysis Assumptions

i. MISO will use N-1 Contingencies to evaluate the DFs for each unit on all constraints.
ii. MISO will use monitored files for all facilities above 34 kV.
iii. MISO will use the most current available generator information and use the Pmax and Pmin based on the generator limits provided.

6.2.9.1.3 Generator Output Optimization Equations

The main concept behind this technique is to optimize the summation of Initial Flow of each constraint and the individual MW impact of each PIA generator on that constraint, such that the optimized flow on the monitored element is less than or equal to the Emergency rating of the line under the key contingencies being studied. Also, while optimizing the flow on constrained facilities, the generator limits are used as constraints such that the generation output is maximized for each optimized constrained flow. In other words, the desired solution would try to maximize the output of each unit such that the flow on the constrained element will be equal to or less than the rating of the monitored element.

EQUATION SETUP WITH CONSTANTS AND VARIABLES

Y1 = Unit 1
Y2 = Unit 2
C1 = Total flow on Monitored element of Constraint 1
C2 = Total flow on Monitored element of Constraint 2
C3 = Total flow on Monitored element of Constraint 3
C4 = Total flow on Monitored element of Constraint 4
Cn = Total flow on Monitored element of Constraint n
Ygen1 = Output of Unit 1
Ygen2 = Output of Unit 2
Ymax1 = Maximum Output of Unit 1
Ymax2 = Maximum Output of Unit 2
Ymin1 = Minimum Output of Unit 1 (Set to Zero for analysis)
Ymin2 = Minimum Output of Unit 2 (Set to Zero for analysis)
α 1 = Initial MW Flow on Monitored Element of Constraint 1
α 2 = Initial MW Flow on Monitored Element of Constraint 2
α 3 = Initial MW Flow on Monitored Element of Constraint 3
α 4 = Initial MW Flow on Monitored Element of Constraint 4
α n = Initial MW Flow on Monitored Element of Constraint n
β 1,1 = DF of Unit 1 on constraint 1
β 1,2 = DF of Unit 1 on constraint 2
β 1, n = DF of Unit 1 on constraint n
β 2,1 = DF of Unit 2 on constraint 1
β 2,2 = DF of Unit 2 on constraint 2
β 2,n = DF of Unit 2 on constraint n
β k,1 = DF of Unit k on constraint 1
β k,n = DF of Unit k on constraint n

If we try to calculate the total constraint flow on Monitored Element of Constraint **C1** with two units **Y1** and **Y2**, then the equation is as follows:

$$C1 = \alpha 1 + Ygen1 * \beta 1,1 + Ygen2 * \beta 2,1 + Ygenk * \beta k,1$$

If instead of using two units **(Y1 and Y2)**, we used **k** units (all the units with provisional and conditional GIAs) then the above equation would change to the following equation and capture the DFs of all units **(Y1 to Yk)** on Constraint **C1** as follows:

$$C1 = \alpha 1 + Ygen1 * \beta 1,1 + Ygen2 * \beta 2,1 \ldots\ldots + Ygenk * \beta k,1$$

Similarly, we can extend the same concept for all constraints as follows:

$$C2 = \alpha 2 + Ygen1 * \beta 1,2 + Ygen2 * \beta 2,2 \ldots\ldots + Ygenk * \beta k,2$$
$$C3 = \alpha 3 + Ygen1 * \beta 1,3 + Ygen2 * \beta 2,3 \ldots\ldots + Ygenk * \beta k,3$$
$$C4 = \alpha 4 + Ygen1 * \beta 1,4 + Ygen2 * \beta 2,4 \ldots\ldots + Ygenk * \beta k,4$$

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.
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$$Cn = \alpha n + Ygen1 * \beta 1,n + Ygen2 * \beta 2,n \ldots\ldots + Ygenk * \beta k,n$$

6.2.9.1.4 Optimization Technique using EXCEL SOLVER

The optimization process needs two sets of critical data:

a. The DFs for each unit for all constraints that are obtained from the results of a MUST First Contingency Incremental Transfer Capability DC transfer analysis. Therefore, the MUST output will provide **β 1,1, β 2,1** etc. values.
b. The Pmax and Pmin for each generator that has signed a provisional or conditional GIA. From equations above, we will need **Ymax1, Ymin1** etc.

Once the data from 6.2.9.1.4.a and 6.2.9.1.4.b is obtained, then the Excel Solver tool will be used to calculate the operating limits with the following set of constraints:

Maximize the output of all Units **Y1- Yn** such that the constrained flows for **C1** to **Cn** are optimized to the rating of the line. In other words, The Excel Solver will solve and come up with the optimized value for all Unit outputs within the following constraints:

Maximize **Σ Ygen (1 to k)** within the following constrained parameter values:

Ymax1>=Ygen1>Ymin1
Ymax2>=Ygen2>Ymin2
Ymaxk>=Ygenk>Ymink
AND

Optimize **C1** = Rating of the monitored element of **C1**
Optimize **C2** = Rating of the monitored element of **C2**
Optimize **Cn** = Rating of the monitored element of **Cn**

6.2.9.1.5 Frequency of these studies

MISO will perform this analysis every planning year quarter and post the results on MISO OASIS under the following link:

http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_report_Page_for_TIAs.mht

6.2.9.2. Microsoft Excel Help Files Solver Description

Further description of the Excel Solver function can be found at the following link:

https://support.office.com/en-au/article/An-introduction-to-optimization-with-the-Excel-Solver-tool-1f178a70-8e8d-41c8-8a16-44a97ce99f60

6.2.10. Use of Multi Party Facility Construction Agreement (MPFCA)

A MPFCA will be developed in the event multiple IRs share the responsibility for a common Network Upgrade or System Protection Facility on the TO's Transmission System ("Common Use Upgrade" or "CUU"). A separate MPFCA will be developed for a CUU on each TOs' Transmission System. A CUU may consist of multiple Network Upgrades and/or System Protection Facilities.

The Network Upgrades and System Protection Facilities required solely for a single IR on the direct-connect TO's Transmission System will continue to be included in the GIA for that IR. Further, any Network Upgrades or System Protection Facilities that are not a CUU on the

Transmission System of a TO which is not a party to the GIA will continue to be included in the FCA.

The IC's GIA will include in Appendix A and Appendix B the facilities that are required under separate FCA(s) and/or MPFCA(s) and corresponding Milestones that must be completed prior to commencement of service under the GIA.

ICs with IR that require a CUU will be held responsible to execute and provide irrevocable security for their respective shares of a MPFCA (or in the case of an unexecuted MPFCA, provide irrevocable security after acceptance of the unexecuted MPFCA by FERC) in the event that:

i. A constraint is identified in the DPP SIS, that meets the criteria to require mitigation, and
ii. One or more of the following:
    a. More than one IR contributes to that constraint, and/or
    b. Other IR(s) contribute to a different constraint(s) requiring mitigation before commencement of their Interconnection Service, and where:
        i. The constraint(s) is resolved by the same upgrade (i.e., CUU); and
        ii. The CUU is determined to be the most prudent upgrade to resolve the constraint(s) to such a level that the CUU enables the interconnection of multiple IRs.

6.2.11. Refunds of Definitive Planning Phase Milestones (M2, M3, M4) – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is on or after January 22, 2024

ICs are eligible to receive forty percent (40%) refund of the DPP Entry Milestone (M2) only when the IR is withdrawn or deemed withdrawn prior to the end of IC Decision Point I. If the IR is withdrawn any time after the IC Decision Point I, then the DPP Entry Milestone (M2) becomes one hundred percent (100%) at risk and will be used to fund Study Cost and Network Upgrades pursuant to Section 7.8 and 7.6.2.1.1 of Attachment X of the GIP.

ICs are eligible to receive one hundred percent (100%) refund of the DPP II Milestone (M3) only when the IR is withdrawn or deemed withdrawn before the end of IC Decision Point II. If the IR is withdrawn any time after the ID Decision Point II, then the DPP II Milestone (M3) becomes at risk and will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

ICs are not eligible to receive any portion of the DPP II Milestone (M4) if the IC decides to withdraw its IR any time after entering the DPP III. The DPP II Milestone (M4) will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

Milestone payments will be refunded in the event the IC withdraws because the total Network Upgrade cost estimates in the DPP Phase II SIS increased by more than fifty percent (50%) and more than ten thousand dollars ($10,000) per MW over the DPP Phase I SIS as a result of MISO, Affected System or TO error

Milestone payments will be refunded in the event the IC withdraws because the total Network Upgrade cost estimates in the DPP Phase III SIS increased by more than thirty-five percent (35%) and more than ten thousand dollars ($10,000) per MW over the DPP Phase II SIS as a result of MISO, Affected System or TO error.

Milestone payments less any Automatic Withdrawal Penalty amounts applied pursuant to Section 7.6.2.1.1 of the Attachment X, will also be refunded in the event the IC withdraws and the total Network Upgrade cost estimates in the Facilities Study increased by more than thirty-five percent (35%) and more than ten thousand dollars ($10,000) per MW over the Network Upgrade cost estimates in the DPP Phase III Interconnection SIS.

Milestone payments less any Automatic Withdrawal Penalty amounts applied pursuant to Section 7.6.2.1.1 of the Attachment X, will also be refunded in the event the IC withdraws within the later of five (5) Business Days or at the end of an IC Decision Point, if applicable, of results indicating designated increases in estimated upgrade costs across the following intervals:

1. DPP Phase I to DPP Phase II
    a. An increase in the combined MISO Network Upgrade costs from Phase I to Phase II of at least fifty percent (50%) and more than ten thousand dollars ($10,000) per MW from the preliminary SIS to the Revised SIS; or
2. DPP Phase II to DPP Phase III
    a. An increase in combined MISO Network Upgrade and Affected Systems costs from Phase II to Phase III of at least thirty-five percent (35%) and more than fifteen thousand dollars ($15,000) per MW from the Revised SIS to any Final SIS.

Refunds of Definitive Planning Phase Milestones (M2, M3, M4) – for the Interconnection Requests for which the application deadline to enter the Definitive Planning Phase is before January 22, 2024

ICs are eligible to receive forty percent (50%) refund of the DPP Entry Milestone (M2) only when the IR is withdrawn or deemed withdrawn prior to the end of IC Decision Point I. If the IR is withdrawn any time after the IC Decision Point I, then the DPP Entry Milestone (M2) becomes one hundred percent (100%) at risk and will be used to fund Study Cost pursuant to Section 7.8 of Attachment X of the GIP.

ICs are eligible to receive one hundred percent (100%) refund of the DPP II Milestone (M3) only when the IR is withdrawn or deemed withdrawn before the end of IC Decision Point II. If the IR is withdrawn any time after the ID Decision Point II, then the DPP II Milestone (M3) becomes at risk and will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

ICs are not eligible to receive any portion of the DPP II Milestone (M4) if the IC decides to withdraw its IR any time after entering the DPP III. The DPP II Milestone (M4) will be used to fund Network Upgrades pursuant to Section 7.8 of Attachment X of the GIP.

Milestone payments will be refunded in the event the IC withdraws because the total Network Upgrade cost estimates in the DPP Phase III SIS increased by more than twenty five percent (25%) and more than ten thousand dollars ($10,000) per MW over the DPP Phase II SIS as a result of MISO, Affected System or TO error.

Milestone payments will also be refunded in the event the IC withdraws and the total Network Upgrade cost estimates in the Facilities Study increased by more than twenty five percent (25%) and more than ten thousand dollars ($10,000) per MW over the Network Upgrade cost estimates in the DPP Phase III Interconnection SIS.

Milestone payments will also be refunded in the event the IC withdraws within the later of five (5) Business Days or at the end of an IC Decision Point, if applicable, of results indicating designated increases in estimated upgrade costs across the following intervals:

1. DPP Phase I to DPP Phase II

a. An increase in the MISO Network Upgrade costs from Phase I to Phase II of at least fifty percent (50%) and more than ten thousand dollars ($10,000) per MW from the preliminary SIS to the Revised SIS;

b. Affected System upgrade costs on transmission systems other than the MISO Transmission System of more than ten thousand dollars ($10,000) per MW.

2. DPP Phase II to DPP Phase III
   a. An increase in MISO Network Upgrade costs from Phase II to Phase III of at least thirty-five percent (35%) and more than fifteen thousand dollars ($15,000) per MW from the Revised SIS to any Final SIS;

   b. An increase in Affected System upgrade costs on transmission systems other than the MISO Transmission System of forty percent (40%) and more than fifteen thousand dollars ($15,000) per MW

3. DPP Phase I to DPP Phase III
   a. An increase in MISO Network Upgrade costs of fifty percent (50%) and more than twenty thousand dollars ($20,000) per MW from the Preliminary SIS to any DPP Phase III SIS.

6.3. Coordination of studies between PJM and MISO

In accordance with Section 9.3.3 of the MISO-PJM Joint Operating Agreement ("JOA"), MISO and PJM shall conduct Interconnection Studies, as necessary, to determine the impacts of IRs on each other's transmission system, which will be treated as an Affected System. This joint coordination of Interconnection Studies will be in addition to the existing Interconnection Studies that MISO and PJM already perform to evaluate the impacts of their respective queues on their own transmission system and will be subject to the guidelines laid out in the MISO-PJM JOA.

The Transmission reinforcement and the study criteria used in the Coordinated Interconnection Studies will honor and incorporate provisions as outlined in the PJM and MISO Business Practices Manuals and their respective Tariffs.

When MISO and PJM perform any Coordinated Interconnection Study, the PJM and PJM TO study and reinforcement criteria will apply to PJM transmission facilities and the MISO and MISO TO study and reinforcement criteria will apply to MISO transmission facilities. For all tie lines between MISO and PJM, the reinforcement criteria and cost allocation rules of the region that identified the constraint criteria violation will be applied.

Coordination timing, as prescribed below, shall be based on the current MISO and PJM study cycles, and will be adjusted if there are changes to the study cycle timelines in the future.

6.3.1. Study of PJM Interconnection Request Impacts on MISO Transmission

During the course of its interconnection feasibility studies, PJM shall monitor the MISO transmission system and provide to MISO the draft results of the potential impacts to the MISO transmission system. This monitoring will include an examination of the potential for projects to impact the MISO system by determining whether the project under study has a ≥ 3 percent distribution factor on MISO facilities that operate below 500 kV or ≥ 10 percent distribution factor on MISO facilities that operate at or above 500 kV under system intact conditions.

Following the completion of the PJM Feasibility Study and after the execution of the PJM SIS Agreement by the customer, PJM shall forward to MISO, at a minimum of twice per year (March 15 and September 15), information necessary for MISO and the MISO TOs to study the impact of the PJM IRs on the MISO transmission system.

MISO and the MISO TOs shall study the impact of the PJM Interconnection on the MISO transmission system and provide draft results to PJM by:

- February 1 for PJM IRs provided to MISO on or before September 15 of the previous year,
- August 1 for PJM IRs provided to MISO on or before March 15 of the same year.

During the course of MISO's affected system interconnection study for PJM interconnection requests, MISO shall apply Energy Resource Interconnection Service (ERIS) criteria to all of PJM's interconnection request(s). These impacts will be studied using methodology and criteria specified in Section 0 of the MISO BPM and may include thermal analysis and other analysis as necessary. These impacts identified by MISO shall include a description of the required system reinforcement(s), an estimated planning level cost and construction schedule estimates of the system reinforcement(s). The results received from MISO, including any required transmission system reinforcements, shall be included in the PJM System Impact Study or Facilities Study report consistent with the PJM OATT. At times PJM may identify to MISO the need to perform studies associated with an IR other than the times identified above. MISO shall endeavor to study these requests at the earliest time that is feasible, but not later than the times as specified above (commencing after March 15 and September 15).

In the event of project withdrawals in the PJM queue, MISO may perform additional reliability analysis during the PJM Facilities Study phase and revise the affected system study results that were provided during the PJM SIS phase.

If MISO identifies required Network Upgrades on the MISO transmission system, due to a PJM IR, the PJM IC(s) shall be required to follow all provisions, delineated under Attachment X of the MISO tariff, related to Facilities Study funding and appropriate Network Upgrade FCA.

Cost allocation for required Network Upgrades on the MISO transmission system, for PJM Interconnection projects, shall be governed by and subject to MISO Tariff and BPMs.

6.3.2. Study of MISO Interconnection Request Impacts on PJM Transmission

After each MISO DPP cycle application deadline and at least thirty (30) days prior to the commencement of the DPP Phase I of the DPP for such cycle, MISO shall perform screening analysis on all Interconnection Requests in such study cycle to monitor for impacts to the PJM transmission system and provide to PJM the draft results of the potential impacts to the PJM transmission system. This monitoring will include an examination of the potential projects to impact the PJM system through determination if the project under study has a ≥3 percent distribution factor or ≥ 5 MW impact or ≥ 1 percent of facility rating on any PJM facilities under normal and contingency conditions.

No later than five (5) Business Days after the commencement of the MISO DPP Phase I study, MISO shall forward to PJM information necessary for PJM and the PJM TOs to study the impact on the PJM transmission system of the MISO Interconnection Request(s) in such cycle that entered DPP Phase I. PJM and the PJM TOs may study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide any available preliminary results to MISO within 100 days following commencement of DPP Phase I.

Prior to commencing the MISO DPP Phase II study, MISO shall forward to PJM the latest available information necessary for PJM and the PJM TOs to study the impact on the PJM transmission system of the MISO Interconnection Request(s) included in such study. PJM and the PJM TOs shall study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide the study results to MISO no later than 30 days prior to the completion of DPP Phase II.

Prior to commencing the MISO DPP Phase III study, MISO shall forward to PJM the latest available information necessary for PJM and the PJM TOs to study the impact on the PJM transmission system of the MISO Interconnection Request(s). PJM and the PJM TOs may study the impact of the MISO Interconnection Request(s) on the PJM transmission system and provide the study results to MISO no later than 30 days prior to the completion of DPP Phase III.

During the course of PJM's affected interconnection study for MISO interconnection projects, PJM shall model all MISO interconnection projects that have requested Network Resource Interconnection Service (NRIS) under the MISO OATT as a Capacity Resource under the PJM OATT and all MISO interconnection projects that have requested ERIS under the MISO OATT as an Energy Resource under the PJM OATT. All projects will be modeled and studied using the criteria and methodology described in PJM Manual 14B.
These impacts identified by PJM shall include a description of the required reinforcements on PJM's transmission system, an estimated planning level cost and construction schedule estimates of the system reinforcement. The results received from PJM, including any required transmission system reinforcements, shall be included in the MISO System Impact Study report. At times MISO may identify to PJM the need to perform studies associated with an Interconnection other than the times identified above. PJM shall endeavor to study these requests at the earliest time that is feasible.

If PJM identifies required Network Upgrades on the PJM transmission system, due to a MISO R, then the MISO IC(s) shall be required to follow all provisions delineated under the PJM Tariff related to Facilities Study funding and appropriate Network Upgrade FCA obligations.

Cost allocation for Network Upgrades necessary on the PJM transmission system due to MISO Interconnection projects shall be governed by and subject to the PJM Tariff and related Manuals.

6.3.3. Coordination of Projects with Provisional/Conditional GIAs

If a generation interconnection project is conditional upon Network Upgrades on the Affected System and comes in service prior to those Network Upgrades being completed, that project's output will be subject to limitations in accordance with the applicable tariff of the Affected System.

6.3.4. Coordination of Studies between SPP and MISO

In accordance with Section 9.4 of the MISO-SPP Joint Operating Agreement ("JOA"), MISO and SPP shall conduct Interconnection Studies, as necessary, to determine the impacts of IRs on each other's transmission system which will be treated as an affected system. This joint coordination of Interconnection Studies will be in addition to the existing Interconnection Studies that SPP and MISO already perform to evaluate the impacts of their respective queues on their own transmission system and will be subject to the guidelines laid out in the MISO-SPP JOA.

The transmission reinforcement and the study criteria used in the coordinated interconnection studies will honor and incorporate provisions as outlined in the SPP and MISO Business Practices Manuals, study procedures, and their respective Tariffs.

When MISO and SPP perform any coordinated interconnection study, the SPP and SPP TO study and reinforcement criteria will apply to SPP transmission facilities and the MISO and MISO TO study and reinforcement criteria will apply to MISO transmission facilities. For all tie lines, the most limiting conditions identified by either Party will be used to determine the need for and scope of the required upgrade. The reinforcement criteria and cost allocation of the Party that identified constraint will apply to the tie line.

When MISO performs a study on a SPP IR, that request's output will be dispatched into the SPP footprint. When SPP performs a study on a MISO IR, that request's output will be dispatched into the MISO footprint.

Coordination timing, as prescribed below, shall be based on the current MISO and SPP study cycles and will be adjusted if there are changes to the study cycle timelines in the future.

6.4.1. Study of SPP Interconnection Request Impacts on MISO Transmission

During the course of its Definitive Interconnection System Impact Study (DISIS), SPP shall monitor all facilities with nominal voltage 100 kV and higher of those MISO TOs that are immediately adjacent to SPP facilities ("First Tier Area"). Thermal loading of facilities within First Tier Areas that exceed the normal rating during system-intact conditions or that exceed the emergency rating during contingency conditions shall be identified. Voltages of facilities within First Tier Areas that are outside the range of 0.95 to 1.05 per unit during system-intact conditions or 0.90 to 1.05 per unit during contingency conditions shall be identified. SPP shall provide to MISO the results of the potential impacts to the MISO transmission system.

- No later than 5 Business days after the commencement of Phase One and Phase Two of the SPP DISIS, the Interconnection Facilities Study, or any restudy, SPP shall forward to MISO the information necessary for MISO and the MISO TOs to study the impact on the MISO transmission system of the SPP interconnection request(s). MISO and the MISO TOs shall study the impact(s) of the SPP interconnection request(s) on the MISO transmission system and provide the results to SPP by the later of: (1) 30 days following study commencement; or (2) 15 days prior to the scheduled completion of the SPP DISIS or any restudy, as applicable.

These impacts will be studied using methodology and criteria specified in Section 6.1 of this BPM and may include thermal analysis and other analysis as necessary. These impacts identified by MISO shall include a description of the required system reinforcements, an estimated planning level cost and construction schedule estimates of the system reinforcement. At times SPP may identify to MISO the need to perform studies associated with an IR other than at the times identified above. MISO shall endeavor to study these requests at the earliest time that is feasible, but not later than the times as specified above.

If MISO identifies required Network Upgrades on the MISO transmission system, due to an SPP IR, the SPP IC(s) shall be required to follow all provisions, delineated under Attachment X of the MISO tariff, related to Facilities Study funding in accordance with Section 6.2 of this BPM and the appropriate Network Upgrade FCA. The SPP IC will be required to fund this Facility Study.

Cost allocation for required Network Upgrades on the MISO transmission system, for SPP Interconnection projects, shall be governed by and subject to MISO Tariff and Manuals.

6.4.2. Study of MISO Interconnection Request Impacts on SPP Transmission

During the course of its Definitive Planning Phase (DPP) studies, MISO shall monitor the SPP transmission system and provide to SPP the results of the potential impacts to the SPP transmission system. This monitoring will include an examination of the potential projects to impact the SPP system through determination if the project under study has ≥ 3% distribution factor or ≥ 5MW impact or ≥1% of facility rating on any SPP facilities under normal and contingency conditions.

- No later than 5 Business Days after the commencement of the MISO DPP Phase I study, MISO shall forward to SPP the information necessary for SPP and the SPP TOs to study the impact on the SPP transmission system of the MISO interconnection request(s). SPP and the SPP TOs may begin studying the impact of the MISO interconnection request(s) on the SPP transmission system.

- No later than 5 Business Days after the commencement of the MISO DPP Phase II study, MISO shall forward to SPP the information necessary for SPP and the SPP TOs to study the impact on the SPP transmission system of the MISO interconnection request(s). SPP and the SPP TOs shall study the impact(s) of the MISO interconnection request(s) on the SPP transmission system and provide the results to MISO within 30 days following the commencement of DPP Phase II.

- No later than 5 Business Days after the commencement of the MISO DPP Phase III study or any restudy, MISO shall forward to SPP the information necessary for SPP and the SPP TOs to study the impact on the SPP transmission system of the MISO interconnection request(s). SPP and the SPP TOs shall study the impact(s) of the MISO interconnection request(s) on the SPP transmission system and provide the results to MISO within 30 days following the commencement of DPP Phase III or any restudy, as applicable.

These impacts identified by SPP shall include a description of the required reinforcements on SPP's transmission system, and an estimated planning level cost. At times MISO may identify to SPP the need to perform studies associated with an IR other than at the times identified above. SPP shall study these requests no later than the times specified above.

If SPP identifies required Network Upgrades on the SPP transmission system, due to a MISO IR, then the MISO IC(s) shall be required to enter into an Interconnection Facilities Study Agreement for Affected System Generators. The MISO IC will be required to fund this study. Following the completion of the Interconnection Facilities Study, the MISO IC(s) may be required to enter into an Affected Systems' Facilities Construction Agreement with the Affected SPP TO and SPP. Funding by the MISO IC for the Interconnection Studies and Network Upgrades shall be consistent with funding practices by SPP ICs under Attachment V of the SPP OATT for Interconnection Studies and Network Upgrades. Cost allocation for Network Upgrades necessary on the SPP transmission system due to MISO IRs shall be consistent SPP IC cost allocation for Network Upgrades subject to the SPP Tariff and related Manuals.

6.4.3. Coordination of Projects with Provisional/Conditional GIAs

If a generation interconnection project is conditional upon Network Upgrades on the Affected System and comes in service prior to those Network Upgrades being completed, that project's output will be subject to limitations in accordance with that respective RTO's tariff.

6.4.3.1. Limitations on SPP Generators with Impacts on the MISO System

SPP Generation Interconnection Projects that come into service prior to completion of required Network Upgrades on the MISO transmission system will be subject to the MISO Annual ERIS and Quarterly Operating Limit processes, as outlined in Section 6.6 of this BPM and the MISO Tariff in Attachment X Section 11.5, until required Network Upgrades on the MISO transmission have been completed. MISO will coordinate project output limitations with SPP on a quarterly basis, and MISO will provide SPP with the list of conditions that will be added to SPP IC's Interconnection Service agreement.

6.4.3.2. Limitations on MISO Generators with Impacts on the SPP System

MISO Generation Interconnection projects that come into service prior to completion of required Network Upgrades on the SPP transmission system will be subject to the MISO Annual ERIS and Quarterly Operating Limit processes, with input from SPP's Affected System study process. . SPP will coordinate thermal constraints and associated limits with MISO on a quarterly basis or more often as events occur, and SPP will provide MISO the list of conditions that will be added to MISO Generator Interconnection Agreement.

6.4.3.3. Limitations on PJM Generators with Impacts on the MISO System

PJM Generation Interconnection Projects that come into service prior to completion of required Network Upgrades on the MISO transmission system will be subject to the MISO Quarterly Operating Limit process, as outlined in the MISO Tariff in Attachment X Section 11.5 and in the MISO Transmission Access Planning Provisional Interconnection Agreement Limit Methodology whitepaper, until required Network Upgrades on the MISO transmission system have been completed. MISO will coordinate project output limitations with PJM on a quarterly basis, and MISO will provide PJM with the list of conditions that will be added to PJM IC's Interconnection Service agreement.

6.4.3.4. Limitations on MISO Generators with Impacts on the PJM System

MISO Generation Interconnection projects that come into service prior to completion of required Network Upgrades on the PJM transmission system will be subject to PJM's yearly process until required Network Upgrades on the PJM transmission system have been completed. PJM updates the output limits on all Interconnection Service agreements on a yearly basis, at a minimum, to account for changing transmission and generation assumptions. Any significant changes to the assumptions of the study may be reviewed on a more frequent basis. PJM will coordinate project output limitations with MISO on a yearly basis, and PJM will provide MISO with the list of conditions that will be added to MISO Generator Interconnection Agreement.

6.5 Coordination of Studies between Manitoba Hydro (MH), Minnkota Power Cooperative (MPC), and MISO

6.5.1. Application of Governing Agreements

Governing Agreement for MPC and MISO Coordination

This coordination procedure is established between MPC and MISO pursuant to sections 9.1 and 14.1 of the MISO-MPC Coordination Agreement.

Governing Agreement for MH and MISO Coordination

This coordination procedure is established between MH and MISO pursuant to section 5.4 of the MISO-MH Coordination Agreement.

Governing Agreement for MPC and MH Coordination

This coordination procedure is established between MPC and MH pursuant to sections 9.011, 9.02, and 9.022 of the Interconnection, Facilities and Coordinating Agreement respecting Ridgeway-Shannon 230 kV Interconnection.

Purpose

The purpose of this coordination procedure is to coordinate Generation IRs and Long-Term Firm Transmission Service Requests where one of the three parties may be an Affected System. Each party will implement this procedure through Tariff and/or Business Practices under each party's respective tariff(s).

Definitions

- **Affected System**: a non-Host TSP whose transmission system may be reasonably expected to experience a non-trivial loading impact due to a TSR or GIR on a Host TSP's transmission system.
- **Affected System Upgrades**: upgrades required to the Confirmed Affected System transmission system to accommodate the Host TSP GIR or TSR. The need for the Affected System Upgrade will be identified in the impact study and further defined in the Affected System facilities study.
- **Business Practices**: a (set of) document(s) that implement certain obligations of the respective party and its tariff customer.
- **Confirmed Affected System**: An Affected System that has been confirmed through either the Host TSP or the Affected System impact analysis that the Affected System has an impacted facility due to a TSR or GIR on a Host TSP's transmission system as shown in the Host TSP impact study report
- **Generation Interconnection Request or GIR**: a request to interconnect or modify generation under the respective TSP's policies and procedures (MISO's tariff Attachment X (Generator Interconnection Procedures (GIP)), MPC's Large Generator Interconnection Procedures (LGIP) or Small Generator Interconnection Procedures (SGIP), or MH's Open Access Interconnection Tariff (OAIT))
- **Generator Interconnection Agreement or GIA**: an agreement documenting the terms of interconnection service between a TSP and its customer.
- **Host TSP**: MH, MPC, or MISO that receives the GIR or TSR
- **Impact Study Agreement**: the agreements under each party's respective policies and procedures to evaluate the impact of the TSR or GIR
- **Long Term Firm Transmission Service Request (TSR)**: a request for long term firm transmission service across the TSP's transmission system under the respective party's tariff (MISO's tariff, MPC's Open Access Transmission Tariff (OATT), or MH's OATT)
- **MISO Definitive Planning Phase or DPP**: the final impact study phase for MISO GIRs as defined by the Business Practices under MISO's Tariff.
- **MISO M2 Milestone**: the MISO DPP entry milestone as defined by the Business Practices under MISO's Tariff.
- **Neighboring TSP(s)**: MH, MPC, and/or MISO that does not receive the GIR or TSR. General reference to any or all of the parties to this coordination language.
- **Network Upgrade**: upgrade required on the Host TSP transmission system to accommodate the GIR or TSR as defined by the parties' respective tariffs, policies, or procedures.
- **POR/POD**: Point of Receipt/Point of Delivery as defined by each party's respective tariffs.

- **Remedial Action Scheme**: as defined by NERC standards.

Transmission Service Provider or TSP – as defined by NERC standards.

Scope

This section defines the GIRs and TSRs that are deemed in scope for this procedure. A GIR or TSR that is deemed in scope will be subject to the coordination procedures below. If the GIR or TSR is not deemed in scope, it is not subject to the coordination procedures below.

Large Generator Interconnections

A GIR is deemed in scope for this coordination procedure as follows:

i. All MISO North GIR for MISO
ii. All GIR for MPC
iii. All GIR for MH

For any GIR that falls within this scope, the Neighboring TSPs will be considered Affected Systems.

MISO North refers generally to the northern part of MISO, which is subject to change as members join or leave MISO. The red section in the picture[20] below captures the in-scope area for MISO at the time the agreement was executed.

[20] From MTEP 2014 - https://www.misoenergy.org/planning/transmission-studies-and-reports/#nt=%2Freport-study-analysistype%3AMTEP%2Fmtepdoctype%3AMTEP%20Report%2Fmtepreportyear%3APrevious%20MTEP%20Reports&t=10&p=0&s=FileName&sd=desc

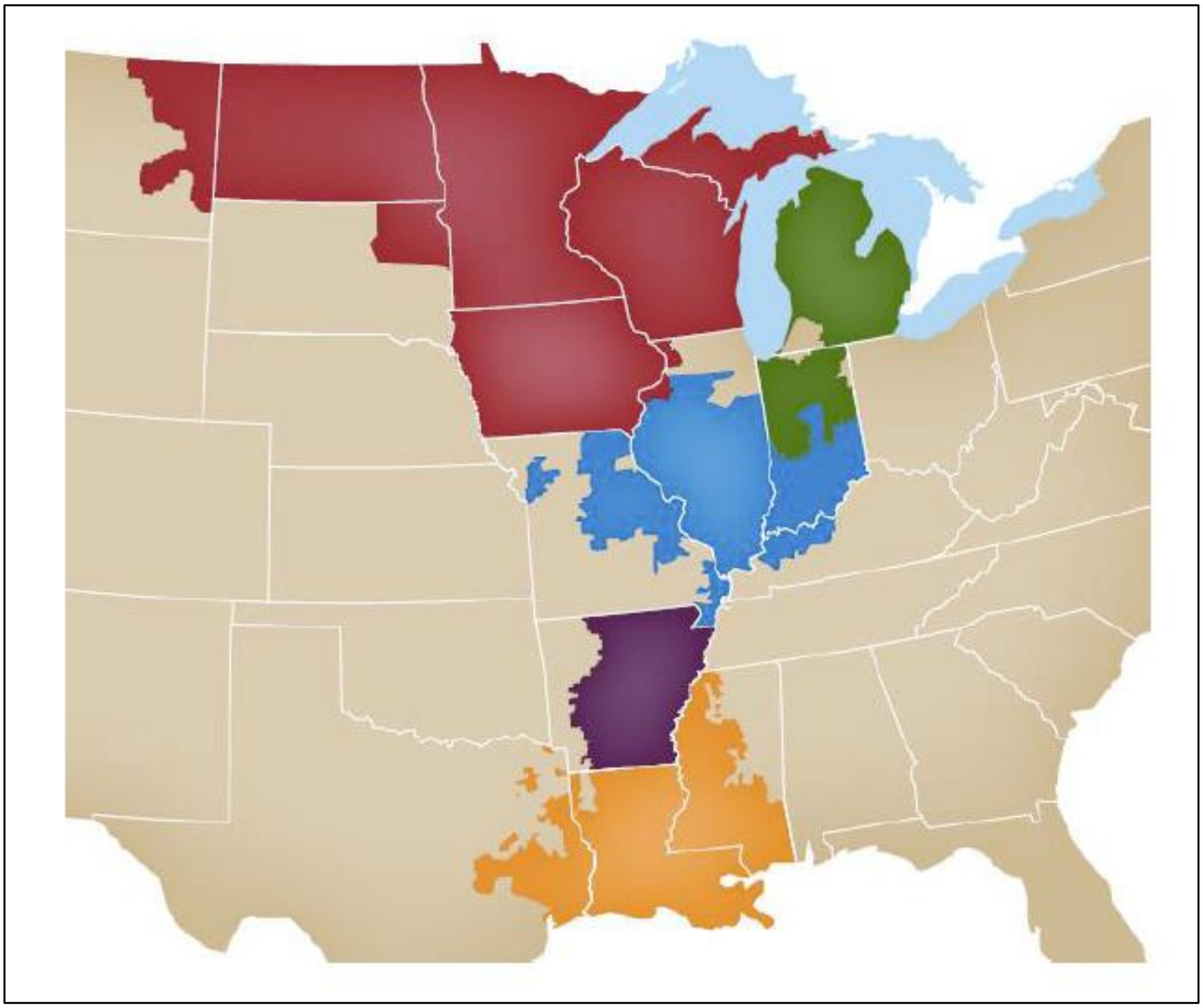


Figure 0**-2 MISO Planning Regions**

Small Generator Interconnections

If it is determined by the Host TSP that a GIR is potentially eligible for accelerated processing under the Host TSP's interconnection procedures due to its small size, the GIR will be deemed in scope for this coordination procedure as follows:

- All GIR for MISO interconnecting in the following LBAs: GRE, MDU, MP, NSP, OTP
- All GIR for MPC

MH does not differentiate between small generator and large generator interconnections and therefore does not offer accelerated processing for small generator interconnections.

Procedure

Generation Interconnection Requests

MISO, MH, and MPC have agreed to the following process by which Generator IR studies are conducted to determine the impacts of Generator IRs on each other's transmission systems. Coordination with Affected Systems is required by the parties' respective policies and procedures. This joint coordination of Generator IR studies serves to clarify the process by which that coordination is conducted for MISO, MH, and MPC.

Process diagrams are included to provide clarity. If a conflict arises between the process diagram and the text in this procedure, the text shall rule.

6.5.5.1.1 Queue Priority and Cost Allocation

For the purposes of performing impact studies, all parties will model higher queued and concurrently queued projects. Position in the queue is determined by:

- The date that a valid GIR is received under the MH tariff.
  - For a group study conducted under the MH OAIT, the queue position of the group relative to MISO and MPC projects will be the date that the last valid GIR in the group study was received by MH.
- The date that a valid GIR is received under the MPC LGIP or SGIP
  - For a cluster study conducted under the MPC LGIP, the queue position of the cluster relative to MISO and MH projects will be the date that the last valid GIR in the cluster was received by MPC.
- The MISO M2 Milestone payment submission deadline per the MISO tariff.

MISO projects will not in any event be considered to have equal queue priority to an MH or MPC project, due to the fact that the MISO (M2) Milestone deadline is at a specific point in time. An MH or MPC Impact Study Agreement that is signed on the MISO (M2) Milestone deadline will have higher queue priority than the MISO project. An MH or MPC Impact Study Agreement that is signed the day after the MISO (M2) Milestone deadline will have lower queue priority than the MISO project.

MPC and MH projects will have the same queue priority if the Impact Study Agreements are signed on the same day. In this case, they will be treated as concurrent projects for cost allocation on common Network Upgrades and Affected System Upgrades.

Projects with a completed impact study or a GIA that was executed prior to the implementation of this jointly coordinated language between MH, MPC, and MISO will be treated as higher queued generators in future interconnection studies.

The highest queued project (or group of projects in a group study) driving the need for an upgrade shall pay for the upgrades required to mitigate its impact on the transmission system, consistent with cost causation principles, unless the parties agree on another cost allocation that results in a more desirable outcome for the customers. The Neighboring TSP will provide cost of upgrades required on its system to the Host TSP for cost allocation amongst the generator interconnection projects using Host TSP's cost allocation methodology. In the case of concurrent MH and MPC projects, if projects are deemed to require the same upgrade, costs will be allocated pro rata based on each project's respective impact on the constrained element unless otherwise agreed to by MH and MPC.

6.5.5.1.2 Notice

The Host TSP will provide notice of GIRs identified in section 0 to the Neighboring TSPs:

- When a valid GIR is received by MPC;
- When a valid GIR is received by MH; and
- When the MISO M2 Milestone deadline has passed for MISO.

The Host TSP will send an email with details of the associated GIR project so that the Neighboring TSP can begin including the project in their models. The Host TSP will include the Neighboring TSPs in the ad-hoc study group for a Host TSP GIR impact study.

The Host TSP will also provide a similar notice to the Neighboring TSPs following a qualified change or withdrawal of a GIR identified in section 6.5.4.

6.5.5.1.3 Impact Study Obligations

The Host TSP will monitor impacts on the Neighboring TSP's transmission systems in all Host TSP impact studies and provide the results to the Neighboring TSP's.

Results and any associated mitigations on the Host TSP's transmission system will be provided at the earliest possible date to allow for the Neighboring TSPs to consider the impacts identified on their own transmission systems.

When the Host TSP performs the impact study, the Host TSP will use reasonable efforts to monitor the affected system and:

- The MISO and the MISO TO study and reinforcement criteria will apply to the monitoring of MISO transmission facilities;
- The MPC study and reinforcement criteria will apply to the monitoring of MPC transmission facilities; and
- The MH study and reinforcement criteria will apply to the monitoring of MH transmission facilities.

These potential impacts will be included in the Host TSP impact study report. The Host TSP will provide the Affected Systems the opportunity to validate the impacts on their transmission systems and identify mitigations.

Additionally, the Neighboring TSP's can each choose to study the impacts of the Host TSP GIR on their own transmission systems and send results to the Host TSP for inclusion in the final impact study report. The Host TSP will provide the necessary information and models so that Neighboring TSP's can perform these impact studies. The Host TSP will allow the Neighboring TSP the same amount of time to complete affected system studies as the Host TSP has scheduled for its own study. The Host TSP may request results slightly in advance of its own deadline in order to incorporate the Neighboring TSP's results into its own report. The Host TSP will allow the Neighboring TSP's extra time if requested and if the additional delay does not hinder timely completion of the Host TSP's impact study.

If the Affected System's policies allow for the sharing of study models, an IC can apply to obtain the study models from the Affected System by executing the required confidentiality agreements.

The Host TSP shall include in the Host TSP impact study report the impacts on the Affected System based on Affected System criteria. Any changes to the Affected System Criteria shall not be enforceable once the Affected System study has started. These impacts shall include:

- The minimum amount of interconnection service that can be granted without Affected System Upgrades,
- A description of the required system reinforcements,
- A planning level cost estimate, and
- Preliminary estimate of the in-service date of the system reinforcement.

The Host TSP will promptly share impact study reports with the Affected Systems upon completion.

6.5.5.1.4 Mitigating Host TSP GIR Impacts on the Confirmed Affected System's Transmission System

If the impact study confirms a constraint to interconnection service on an Affected System's transmission system, the Host TSP will require the customer to contact the Confirmed Affected System and make arrangements with the Confirmed Affected System to identify and construct facilities for mitigation of impacts. For required Affected System Upgrades on the Confirmed Affected System due to a Host TSP GIR, the Host TSP will require the IC(s) to follow all provisions delineated under the Affected System policies, procedures, and Business Practices. Required arrangements include but are not limited to signing the facilities study agreement and signing the Confirmed Affected System upgrades agreement to construct the mitigations identified in the Confirmed Affected System facilities study.

The Host TSP and Confirmed Affected System will promptly share facility study reports with each other upon completion.

If generation interconnection projects are granted interconnection service by the Host TSP prior to completion of required Affected System Upgrades on the Confirmed Affected System, commercial operation shall be limited up to the amount at which there are no transmission constraints identified by the studies on the Confirmed Affected System(s) transmission system. The study to determine limitation is coordinated between the Host TSP and the Confirmed Affected System TSP. If one exists, the Affected System will provide operating limitation policies to the IC upon request.

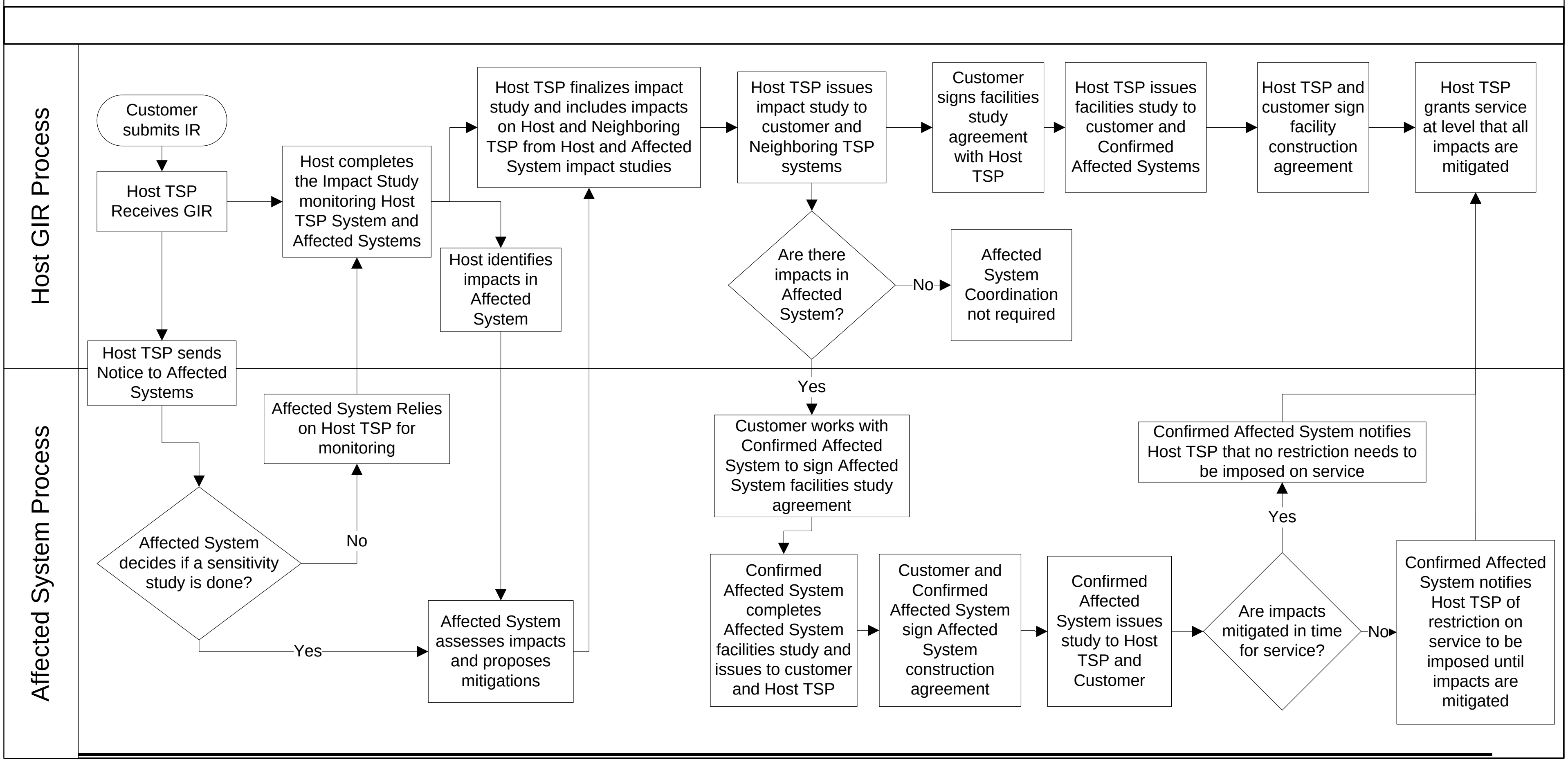
6.5.5.1.5 Special Provisions for Accelerated Processing

For generators that are eligible for accelerated processing and are deemed to be in scope for this coordination procedure, the parties agree to the following special provisions:

- Notice will be provided to the Neighboring TSPs upon receipt of a valid GIR.
- The Host TSP will inform the Neighboring TSPs of their study schedule deadlines and request that the Neighboring TSPs use good faith efforts to accommodate the Host TSP's accelerated schedule if the Neighboring TSP performs an Affected System study.
- In the event that a Neighboring TSP is not able to complete an Affected System study in time to meet the Host TSP's study schedule, the Host TSP will continue in accordance with its posted procedures, making reasonable efforts to accommodate a late submission by the Neighboring TSP.

If a GIR that was potentially eligible for accelerated processing is later required to complete the standard interconnection process, the normal provisions of the agreement will apply.

GIR Coordination – Affected System



6.5.5.2 Compensation for Affected System Analysis (Applicable to MPC and MISO Only)

The IC will be responsible for the costs incurred by the Neighboring TSP for performing affected system analysis associated with SISs with the help of engineering consultants. A Host TSP will reimburse the Neighboring TSP using IC's study deposit funds upon receipt of an invoice from the Neighboring TSP. Only the direct costs of the engineering consultants will be included in the invoice.

6.6 Annual ERIS Evaluation and Annual Interim Deliverability Study

6.6.1 Scope

For all permanent GIAs with conditions and Provisional GIAs, an Annual ERIS evaluation will be performed which will identify the maximum level of injection available for the next Resource Adequacy Planning Year. Further, for all permanent GIAs with conditional ERIS that will eventually convert to ERIS and NRIS, an Annual Interim Deliverability analysis will be performed which will identify the maximum level of conditional NRIS available for the next Resource Adequacy Planning Year, up to the level of eventual NRIS. If a project has explicit conditions associated with MTEP Appendix A projects, listed in their existing GIA, the Annual ERIS and Annual Interim Deliverability Studies will be applicable from the time of their Commercial Operation Date until those explicit conditions are met.

6.6.2. Eligibility and Timing of Studies

The Annual ERIS and Annual Interim Deliverability study for the next Planning Year will be completed by October 31st of every calendar year. The results of the Annual Interim Deliverability Study for the next immediate planning year will be documented in the MISO Interconnection Service Workbook.

The Annual ERIS and Annual Interim Deliverability Analysis for the next Planning Year will include only those projects with Generator Interconnection Agreements that have been executed by April 15th of the study calendar year. In addition, all generators that are subject to the Annual studies must be online during the Planning Year being analyzed.

6.6.3. Annual ERIS Evaluation

The maximum amount of injection available for the studies generator will be identified for the next Planning Year.

6.6.3.1. Methodology

The Annual ERIS evaluation would include the following suite of reliability analyses that will be carried out on both the Summer Peak and Shoulder Peak cases:

i. Thermal Analysis,
ii. Steady State Voltage Analysis,
iii. Transient Stability Analysis (to be completed if stability constraints were identified in the DPP studies and the mitigation projects are not yet in place)

The constraint criteria for the above analyses will be consistent with the Generator SIS criteria as laid out in Sections 6.1.1.1.6, 6.1.1.2 and 6.1.2.4. This study will not identify any Network Upgrades on the Transmission System. The injection limit from this analysis will be determined on a pro rata basis based on the nameplate of the generators under evaluation. . A constraint should not be considered as a limit if the LODF (Line Outage Distribution Factor) between the overloaded element and the unfinished contingent facility from the project's GIA Exhibit A10 is less than 20%. This LODF screening does not apply if the overloaded element in this analysis, or the unfinished contingent facility, is directly connected at the generator's POI.

6.6.3.2. Base Case Assumptions

The Summer Peak and Shoulder Peak Base Cases for the Annual Interim ERIS evaluation will be reflective of the Generation and Transmission System expected to be in-service at the start of the Planning Year. The individual cases for the following two years will be reflective of the Transmission and Generation that is expected to be in service at the start of those individual Planning Years.

6.6.3.3. Load Levels and Generation Dispatch

The Summer Peak and Shoulder Peak case Load Levels and Generation Dispatch will be consistent with Load Level and Dispatch assumptions used for the respective MTEP Cases as per Section 3.3 of MISO Transmission Planning BPM 020. The Generator IRs under consideration for Annual Interim ERIS evaluation would be dispatched consistent with the existing Section6.1.1.1.1.1.

6.6.4. Annual Interim Deliverability Study

The maximum amount of conditional NRIS available, for the next Planning Year, will be identified. In addition, the Annual conditional NRIS value will be capped at the lower of a) Annual ERIS value or b) Annual Interim Deliverability study NRIS value.

6.6.4.1 Methodology

The Interim Deliverability Study will follow the MISO deliverability methodology as documented in Appendix C of this BPM.

The Interim Deliverability Analysis will be performed on the Summer Peak Case used for the Annual ERIS evaluation analysis. A constraint should not be considered as a limit if the LODF (Line Outage Distribution Factor) between the overloaded element and the unfinished contingent facility from the project's GIA Exhibit A10 is less than 20%. This LODF screening does not apply if the overloaded element in this analysis, or the unfinished contingent facility, is directly connected at the generator's POI.

6.6.5. Exit from Annual ERIS and Annual Interim Deliverability Studies

Any Interconnection Project with explicit conditionality associated with MTEP Appendix A projects, listed in their existing GIA based on the A10 process (Section 6.2.4), will exit the Annual ERIS and Annual Interim Deliverability Studies when those explicit conditions have been met and when the obligations to direct assigned upgrades to the GI project(s) have been met. For purposes of this section, the following situations shall not prevent the exit from the Annual ERIS and Annual Interim Deliverability Studies if the affected Transmission Owner(s) and MISO do not see a reliability issue after a review:

1) Incomplete conditions associated with the A10 process which have the MTEP classification of "Other" and which have in-service dates delayed for five (5) years or longer from their initially proposed in-service dates in MTEP
2) Incomplete conditions associated with the A10 process which have been cancelled and not replaced in the MTEP process, or if replaced but the replacement project is not to fix an overload issue contributed by the generator according to the A10 study threshold criteria.

6.6.6. Annual ERIS Studies and QOL Coordination

The amount of ERIS injection that clears the Annual ERIS evaluation for the next Planning Year will not be subject to the Quarterly Operating Limits (QOL) studies for all 4 quarters of that year. Any ERIS injection that does not clear the Annual ERIS evaluation for the next Planning Year will be included in the QOL studies for all 4 quarters of that year. The customer may choose not to be included in the QOL studies if they wish to be limited by the Annual ERIS evaluation results for all 4 quarters of that year.

6.7. Modification of Existing Generating Facilities

6.7.1. Generating Facility Modification Process

Generating Facility Modification shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of the equipment at the Existing Generating Facility. If a planned modification to an Existing Generating Facility (with unsuspended interconnection rights) is expected by the IC (or generator owner) to have material (adverse) impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, or ii) dynamic system stability and response, or iii) short-circuit capability limit; the IC shall submit a request in writing to MISO for a Generating Facility Modification prior to performing any permanent[21] modification[22,23] to an Existing Generating Facility. The request shall be in the form of a letter describing the planned changes to the Existing Generating Facility and all relevant data and analysis. The request shall be submitted to MISO at the following address:

Director, Resource Utilization
MISO
720 West City Center Drive
Carmel, IN 46032

Generating Facility maintenance that requires replacement of components with newer comparable components to ensure continued or enhanced reliable operation of the Generating Facility will generally be considered to have *de minimis* impact on the transmission system. It is the IC's responsibility to support any determination that the planned modification is not expected to result in degradation of transmission system reliability. The evidence to support this engineering judgment may be an assessment that is performed by the IC, TO, or a third party.

For on-going generator maintenance, where the replacement components are comparable and impacts are expected to be *de minimis*, there is no need for the submission of information to MISO for determination of material (adverse) impacts. In cases where replacement components are not comparable, MISO will determine if the change is a Qualitied Change.

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[21] Temporary modifications do not require changes to the GIA. Temporary modifications made while waiting on the comparable part to be delivered and modifications made as a result of equipment failure to support continued reliability may not be "comparable." However, such modifications do not require changes to the GIA, as they are a part of an owner's routine maintenance and/or equipment failure processes and are not subject to MISO review.

[22] Any modification that may result in an increase in net injection above the existing Interconnection Service will require a new Interconnection Request to be submitted to MISO prior to an increase in actual injection at the POI.

[23] Generating Facility modification for complete fuel conversion that does not involve complete tear down of an existing Generating Facility will be eligible for generator modification process.

A determination of whether a planned change has a *de minimis* impact on the transmission system shall be made using good engineering judgment and shall be based on the decision made or opinion rendered by a qualified engineer. In making this determination, the qualified engineer shall take into account all available data and rely on his or her experience with the generation technology and transmission system and knowledge of NERC standards. Additionally, the IC may request a meeting with MISO and the TO prior to submitting a request for Generating Facility Modification evaluation to discuss the planned change and any need for additional studies.

If the IC is certain that the planned change to the Existing Generating Facility would constitute a Qualified Change, the IC can enter the DPP cycle in MISO's Generator Interconnection queue by submitting a new IR.

6.7.1.1. Milestones

A deposit is not required if the IC submits engineering studies supporting a determination that the planned change is not a Qualified Change. However, a fee may be required at a later date to reflect the cost of review, or a study deposit may be collected if the analysis submitted by the IC is incomplete or does not demonstrate that the planned change is not Qualified Change.

6.7.1.2. Evaluation of Generating Facility Modification

Requests submitted to MISO must evaluate any change in operating characteristics of the Existing Generating Facility that is different than what was studied in the interconnection process or reflected in its interconnection agreement. The IC must submit its studies/analyses that are performed by a qualified subject matter expert to MISO for consideration in its review. Like-for-Like (or comparable) replacements and refurbishments of existing equipment are not Qualified Changes, and MISO's evaluation of these equipment is not required unless the IC anticipates that such changes may have material impact on the Transmission System, per the criteria defined in Section 6.7.4 of this BPM.

MISO will respond to the IC within 30 days and provide the path for the IC to amend their GIA, as necessary, or to submit a new IR.

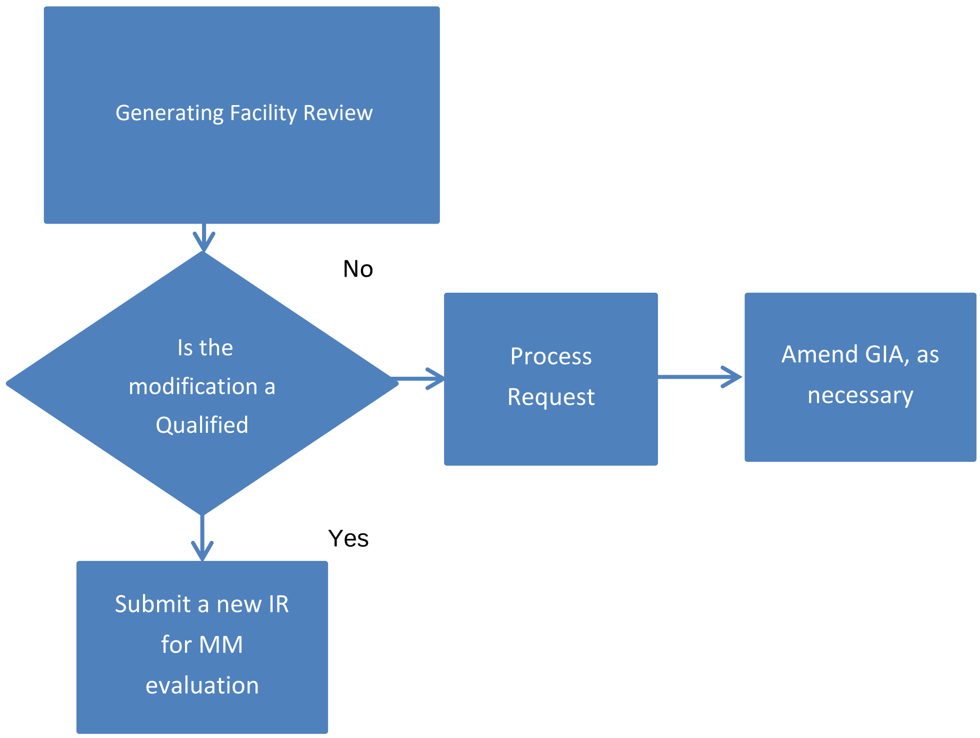

Figure 6-3 Flowchart describing Generating Facility Modification evaluation and Qualified Change determination.

6.7.2. Generating Facility Replacement Process

Generating Facility Replacement process (pursuant to Section 3.7 of Attachment X to MISO Tariff) can be used if an IC is planning to replace one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection (i.e., same voltage level at the interconnecting substation) as the Existing Generating Facility.

To initiate the Generating Facility Replacement process, an IC can submit an Interconnection Request (Appendix 1 to Attachment X) to MISO accompanied by a study deposit in the amount of $60,000. The request can be submitted at any time if it meets all the requirements as described in Section 3.7 of Attachment X to MISO Tariff. Once the complete application is received, MISO will assign a queue number for the replacement request and will post them publicly on MISO's Generator Interconnection queue webpage.

If the existing generating unit has a shared legacy GIA with other generating units that are not part of the replacement request, the IC shall request MISO to convert existing shared legacy GIA to current pro forma GIA, representing the shared generators, prior to submitting the replacement request. As part of a Generator Replacement request, IC may request to split a shared legacy GIA to multiple GIAs.

6.7.2.1 Evaluation Process for Generating Facility Replacement Requests

Generating Facility Replacement evaluation will consist of two studies: (i) Replacement Impact Study, and (ii) Reliability Assessment Study.

Replacement Impact Study

Replacement Impact study is an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of the Transmission System when compared to the Existing Generating Facility. This study will use the models from the latest DPP cycle for which the DPP Phase 3 System Impact Study is completed. These models will correspond to the MISO region applicable to the replacement request and will include the Network Upgrades from the corresponding DPP study. The dispatch assumptions for the study are detailed in Table 6-1. This study will utilize Material Modification evaluation criteria as set forth in Section 6.7.4 of this BPM. If MISO determines that the replacement request is not a Qualified Change, the IC can move forward with the requested replacement provided that Reliability Assessment Study also shows no reliability concerns or that mitigations will be in place for the issues identified. The replacement unit shall meet FERC Order 827, FERC Order 661/661-A, and FERC Order 842 requirements, as applicable.

Table 6-1: Dispatch Assumptions for Replacement Impact Study

	Benchmark Case	Study Case
Retiring Unit	ON	OFF
Replacement Unit	OFF	ON

- Dispatch of the Retiring Unit and Replacement Unit is by fuel type as set forth in Section 6.1.1.1.2 of this BPM.
- For those replacement requests where the Interconnection Service (IS) requested for the Replacement Unit is less than that of the Retiring Unit, the Retiring Unit and Replacement Unit is dispatched by fuel type and in accordance with the IS requested in the replacement request.

Reliability Assessment Study

Reliability Assessment Study is an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of Transmission System during the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility. The Reliability Assessment Study assumptions will be similar to Attachment Y (Suspension/Retirement) study as set forth in Section 6.2 of MISO BPM-020. In no case will the existing unit be eligible as a System Support Resource (SSR) through the Generating Facility Replacement process. The study year of the base model will reflect the date of cessation of operation of Existing Generating Facility. The dispatch assumptions for the study are detailed in Table 6-2. The Existing Generating Facility shall be responsible for mitigating any reliability violation identified in the Reliability Assessment Study and may not cease operations until all mitigations are implemented or are in service. Mitigation for this interim period may, as applicable, include: (i) redispatch/reconfiguration through operator instruction; and (ii) remedial action scheme or any other operating steps depending upon the type of reliability violation identified. If there are no reliability concerns or if all identified reliability concerns will have mitigations in place, the IC can move forward with the requested replacement provided that Replacement Impact Study also shows no material adverse impact (not a Qualified Change).

Table 6-2: Dispatch Assumptions for Reliability Assessment Study

	Benchmark Case	Study Case
Retiring Unit	**ON**	**OFF**
Replacement Unit	**OFF**	**OFF**

Reliability Assessment Study will not be performed: (1) if there is no gap period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility, or (2) if the Existing Generating Facility is in Forced Outage or has an approved Attachment Y suspension per MISO Tariff.

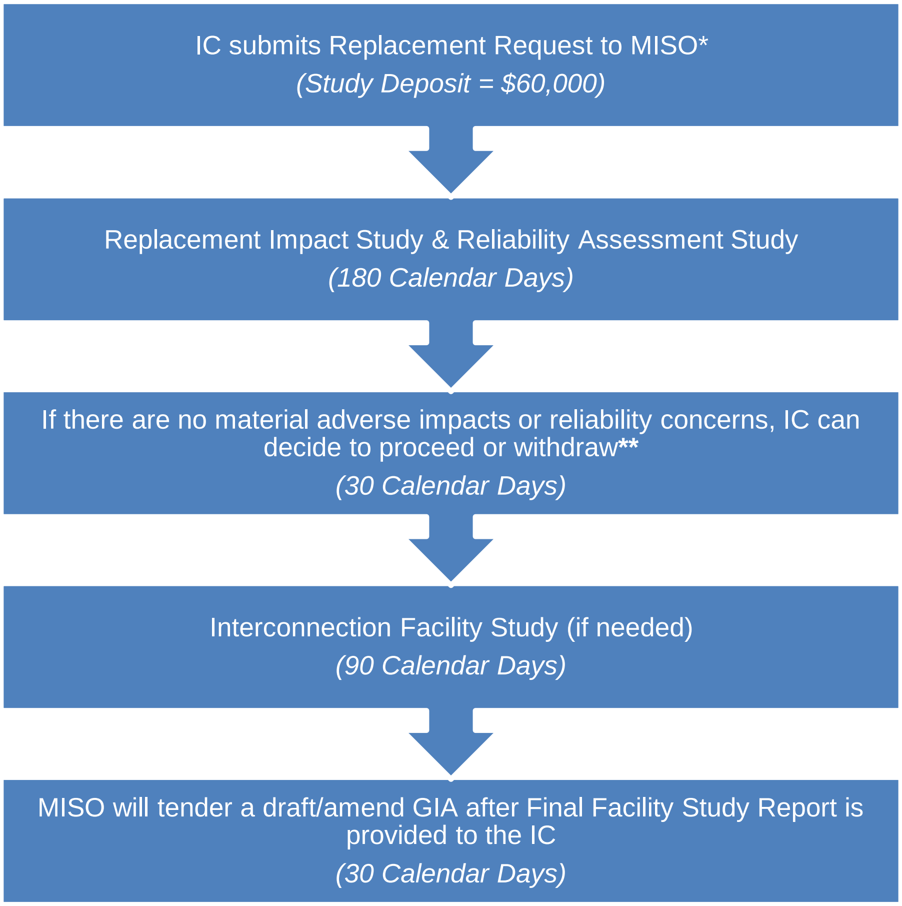

Figure 6-4 Flow Diagram describing Generating Facility Replacement Process

*Request will be evaluated in the order they are received

** If the Replacement Impact Study identifies material adverse impacts and/or the Reliability Assessment Study identifies reliability concerns that cannot be mitigated, the Generating Facility Replacement process cannot be utilized. To continue with the replacement, the IC will need to submit a new Interconnection Request to the Interconnection Queue, follow the 3-phase DPP process for the replacement unit, and submit an Attachment Y request for retirement of the Existing Generating Facility, as appropriate. Alternatively, the IC can withdraw the replacement request.

6.7.3. Surplus Interconnection Service

Surplus Interconnection Service (pursuant to Attachment X to MISO Tariff) shall mean any Interconnection Service that is derived from the unneeded portion of Interconnection Service established in a GIA or in agreement with, or under the tariff of, a Transmission Owner prior to integration into MISO, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection would remain the same.

To request for Surplus Interconnection Service, an IC can submit an Interconnection Request (Appendix 1 to Attachment X) to MISO accompanied by a study deposit in the amount of $60,000. The request can be submitted at any time if it meets all the requirements described in Attachment X to MISO Tariff. As part of the Interconnection Request, the IC must notify MISO whether the sole operation of the Surplus Interconnection Service Generating Facility at the Point of Interconnection should also be included as a part of Interconnection Study for the Surplus Interconnection Service. Such studies will identify whether the Surplus Interconnection Service Generating Facility can be solely and reliably operated after the retirement of the Existing Generating Facility, if applicable. If this scenario shows no material adverse impact in the Interconnection Study, then this can be used to satisfy one of the requirements for continuation of Surplus Interconnection Service after retirement or cessation of commercial operation of an Existing Generating Facility for a limited period not to exceed one (1) year (Section 3.3.1.3 of Attachment X to MISO Tariff). Once the complete application is received, MISO will assign a Surplus Interconnection Service request number for the Surplus Interconnection Request and will post them publicly on MISO’s Generator Interconnection queue webpage.

The Interconnection Study for Surplus Interconnection Service consists of reactive power, short circuit/fault duty, and stability analyses. If MISO is unable to verify that the Existing Generating Facility was previously studied for the granted level of Interconnection Service, MISO may perform steady state analyses to demonstrate reliable operation of the Surplus Interconnection. For identified applicable studies, MISO will utilize Qualified Change evaluation criteria as set forth in Section 6.7.4 of this BPM. The study will use the models from the latest DPP cycle for which the DPP Phase 3 System Impact Study is completed. These models will correspond to the MISO region applicable to the Surplus Interconnection Request and will include the Network Upgrades from the corresponding DPP study. The study will use fuel type dispatch assumptions as set forth in Section 6.1.1.1.2 of this BPM, as applicable[24]. If MISO determines that the Surplus Interconnection Service proposed in the Surplus Interconnection Request would not result in material adverse impact on the Transmission System and/or Affected Systems, as compared to the impacts that are created by the Existing Generating Facility without the inclusion of the proposed Surplus Interconnection Service, the IC can move forward with the requested Surplus Interconnection Service.

IC submits Surplus Interconnection Request to MISO*
(Study Deposit = $60,000)

↓

Within 30 Calendar Days, MISO will commence Interconnection Study for Surplus Interconnection Service
(90 Calendar Days)

↓

If there are no material adverse impacts, IC can decide to proceed or withdraw**
(30 Calendar Days)

↓

Interconnection Facility Study (if needed)
(90 Calendar Days)

↓

MISO will tender a draft GIA after Final Facility Study Report is provided to the IC
(30 Calendar Days)

Figure 6-5 Flow Diagram Describing Surplus Interconnection Process

* Request will be evaluated in the order they are received

[24] Default fuel type dispatch assumptions may change depending on the application and agreement, details to be finalized during the study scope preparation.

** If the Interconnection Study for Surplus Interconnection Service identifies material adverse impacts on the Transmission System and/or Affected System, the IC shall proceed through Definitive Planning Phase cycle similar to a request for interconnection of a new Generating Facility. Alternatively, the IC can withdraw the Surplus Interconnection Request.

6.7.4. Qualified Change Evaluation Criteria

For Generator Facility Modification evaluation, MISO may perform steady-state (thermal/voltage), reactive power, short circuit/fault duty, and stability analyses, as necessary, using the applicable reliability criteria consistent with DPP study as set forth in Section 6.1.1.1.4 of this BPM to ensure that required reliability conditions are studied. The type of contingencies used for this evaluation will be consistent with DPP study as set forth in Section 6.1 of this BPM. Upon receipt of the Qualified Change evaluation from the IC, MISO will notify the impacted TO(s) and will coordinate with the impacted TO(s) during the study process.

The following criteria will be used to determine whether the change to an Existing Generating Facility is a Qualified Change:

- Any change in expected output of the Generating Facility that is higher than what was studied in the interconnection process unless a control scheme is employed to limit the injection at the POI to ERIS limit.
- An increase in short circuit current that degrades transmission system reliability.
- Angular stability performance and dynamic response that degrades transmission system reliability.
- Violation of steady-state thermal or voltage limits caused by the planned change utilizing the DPP criteria as set forth in Sections 6.1.1.1.8 and 6.1.1.2 of this BPM.

Post – GIA Phase

The following sections describe various activities in project development after the Generator Interconnection Agreement is executed.

Initial Payment

The IC is required to pay the initial payment of either 1) twenty percent (20%) of the total cost of Network Upgrades, TO Interconnection Facilities, TO's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades identified in the GIA if the Generator In-service date is within five (5) years of executing the GIA; or 2) ten percent (10%) if it is beyond five (5) years; or 3) the total cost of Network Upgrades, TO Interconnection Facilities, TO's System Protection Facilities, Distribution Upgrades and/or Generator Upgrades in the form of security. The initial payment shall be provided to TO by the IC within the later of a) forty-five (45) Calendar Days of the execution of the GIA by all Parties, or b) forty-five (45) Calendar Days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by the IC, or c) forty-five (45) Calendar Days of the filing if the GIA is filed unexecuted and the initial payment is not being protested by the IC. If the IC made its Milestone payments in the form of cash and the IC elects a cash initial payment, then MISO shall transfer those funds to the TO on the IC's behalf.

Limited Operation

If any of the TO's Interconnection Facilities, Network Upgrades, or TO's System Protection Facilities, Distribution Upgrades or Generator Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of IC, perform operating studies on a timely basis to determine the extent to which the Generating Facility and the IC's Interconnection Facilities may operate prior to the completion of the TO's Interconnection Facilities, Network Upgrades, TO's System Protection Facilities, Distribution Upgrades or Generator Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and the GIA. The maximum permissible output of the Generating Facility will be updated on a quarterly basis if the Network Upgrades necessary for the interconnection of the Generating Facility pursuant to the GIA are not in service within six (6) months following the Commercial Operation Date of the Generating Facility as specified in Appendix B of the GIA. These quarterly studies will be performed using the same methodology set forth Section 6.2.9 of this BPM for Provisional GIAs. These quarterly updates will end when all Network Upgrades necessary for the interconnection of the Generating Facility pursuant to this GIA are in service.

7.1. Suspension

After the execution of the Interconnection Agreement, the IC is expected to meet the Milestones and construction schedule as established in the Interconnection Agreement. In certain conditions, IC has the option to suspend the construction of the Network Upgrades and Interconnection Facilities based on narrowly defined criteria. The following rules and conditions will govern the suspension of a project in the post-IA phase.

- Permitted only for Force Majeure reasons: “Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party’s control. A Force Majeure event does not include an act of negligence or intentional wrongdoing by the Party claiming Force Majeure.”
- When coming out of suspension with only partial construction resulting in reduced project capacity, recovery eligibility is reduced on a pro-rata basis relative to the new size of the project.
- Will require an up-front payment equivalent to greater of Network Upgrade costs or $5 million.
- Suspended IRs may be revisited periodically to ensure IC is working toward coming out of suspension.

When emerging from suspension, the IC must provide written notice to MISO noting the date as of which the request is no longer suspended along with notice of any changes to the Interconnection Facilities and/or Generating Facility as compared to the description in the Interconnection Agreement, or the studies performed in support of the Interconnection Agreement. MISO will restudy the project coming out of suspension with the transmission assumptions that exist on the day it receives such notice. MISO will require a reasonable study deposit to perform such studies. Failure to provide the needed data and deposit at the time of notice may lead to the IC being declared in Breach of Agreement.

7.2. Construction

The project construction will take place according to the construction schedule established in the Generator Interconnection Agreement. In the event, a project goes into suspension the required Network Upgrades and TO Interconnection Facilities will be constructed on the schedule described in the appendices to the GIA, except for the following reasons:

i. Construction is stopped by a Governmental Authority.
ii. Network Upgrades are not needed for another project; or
iii. MISO or the TO determines that a Force Majeure event prevents construction.

The IC will closely coordinate the various construction activities with the TO to make sure the appropriate design standards are followed and technical specifications of the IC constructed facilities match with that of the TO constructed facilities.

7.3. Interconnection Customer delays

Interconnection Customer requests to amend GIA milestones are addressed under the terms of the effective GIA. Article 30.10 of the *pro forma* GIA requires the consent of all Parties in order to amend the terms of the GIA. Therefore, to the extent that the effective GIA does not otherwise prohibit or preclude the Interconnection Customer's request to amend GIA milestones, consent of MISO and the Transmission Owner are required before the Interconnection Customer's proposed amendment may be pursued.

In order to ensure consistent treatment and efficient review of such requests, MISO requires that the requesting Interconnection Customer satisfy the following criteria to provide MISO with complete information upon which to determine whether its consent to amendment will be provided pursuant to GIA Article 30.10. These criteria are as follows:

- (1) Interconnection Customer to provide a written statement from a Company Officer or authorized agent describing circumstances that require the milestone change;
- (2) Interconnection Customer and Transmission Owner agree on specific milestone changes in writing and in advance of submitting request to MISO;
- (3) Interconnection Customer demonstrates an absence of any significant potential for harm to other queued projects. Factors that may be considered: whether changes specifically affect Network Upgrades, aside from those at the POI; whether proposed change would satisfy a Qualified Change standard (see

Qualified Change definition in Attachment X of the MISO Tariff for additional details); whether POI is shared by any downstream projects (i.e., no dependencies); whether the particular project is appearing in MTEP models; whether Network Upgrades or affected system upgrades are assigned to the project.

7.4. Testing

The IC or the designated MP will notify MISO with a test plan in advance of conducting the tests for the Generating unit(s). The notification should be provided by completing the Pre-commercial Generation Test Notification form located in Appendix D of this BPM and submitting it to MISO Real Time Operations at least five (5) Business Days prior to the first testing date. The MISO Operations will work with the Asset Owner/MP and approve a schedule to conduct the tests. The testing process will also be coordinated with Transmission Operators.

7.5. Registration of Asset with MISO

The Market Registration BPM describes the details of Asset Registration.

7.6. Inclusion in Network Model

The Network and Commercial Model BPM describes the steps required to submit the information to include a generator in Network Model.

7.7. Commercial Operation

The IC must provide notification to the MISO after the project achieves Commercial Operation. Such notification is provided in the form of Appendix E to the GIA and must be received by MISO within thirty (30) days of Commercial Operation date in order to initiate any refund. The notification should also include as built modeling data of the plant. Attachment A of the application can be used to provide such data. MISO will settle the project account and provide a final invoice to the IC within thirty (30) days of receiving the Appendix E to GIA.

Distributed Energy Resource Affected System Study

8.1 Definitions

Distributed Energy Resource (DER): Any source of electric power located on the distribution system.[25]

DER Affected Systems Study (DER AFS): The MISO process to evaluate Transmission System impacts from DER interconnection requests.

DER Customer: The person or entity requesting RERRA-jurisdictional interconnection.

DER Net Injection: The DER Substation net injection, which is calculated by taking the DER Substation generation (cumulative amount) minus applicable substation loading (peak or shoulder peak) as viewed at the high side of the distribution substation transformers.

DER Substation: Shorthand for the substation represented in MISO Transmission Expansion Planning (MTEP) models at which one or more DER will inject into the transmission grid. This is the most granular level that MISO reviews DER impacts.

Distribution System: All electric facilities owned by a Distribution Provider, as defined by the North American Electric Reliability Corporation (NERC), regardless of how such facilities are classified by the Distribution Provider that: (1) are connected to the Transmission System; (2) are not a part of the Transmission System, and (3) are not connected to the Transmission System solely through facilities under the control of another transmission provider.[26]

Electric Distribution Company (EDC): A company that distributes electricity to retail customers through distribution substations and/or lines owned by the company, as defined in MISO's tariff Module A.

Facilities Study: An engineering study conducted by the Transmission Provider or Independent Transmission Company in collaboration with the affected Transmission Owner(s) and Independent Transmission Company Participant(s) to determine the required modifications to the Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested Transmission Service. The Transmission Provider shall have the final determination and ultimate responsibility for any such studies. Facilities Studies for any transmission facilities not under the operational control of the Transmission Provider shall be performed by the Transmission Owner, or Independent

[25] NERC SPIDERWG Terms and Definitions Working Document. Last Updated: June 2020. Available at: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

[26] MISO, Re: Midcontinent Independent System Operator, Inc. Order No. 2222 Compliance Filing Docket No. ER22-___-000. Available at: https://cdn.misoenergy.org/2022-04-14%20Docket%20No.%20ER22-1640-000624051.pdf

Transmission Company, or any entity it designates to perform the studies, as defined in MISO's tariff Module A.

Network Upgrade: All or a portion of the modifications or additions to transmission related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all Users of such Transmission System, as defined in MISO's tariff Module A.

Transmission Owner: Each member of the Independent System Operator whose transmission facilities (in whole or in part) make up the Transmission Provider Transmission System, as defined in MISO's tariff Module A.

Relevant Electric Retail Regulatory Authority (RERRA): An entity that has jurisdiction over and establishes prices and/or policies for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

8.2 Scope

MISO's DER AFS processes pertain only to DER as defined by this document. This definition covers sources of power while excluding controllable load and energy efficiency, which are sometimes considered to be DER in other industry definitions (e.g., the Federal Energy Regulatory Commission (FERC)).[27] MISO's DER AFS is intended to evaluate the impacts of DER newly proposed for interconnection through the applicable EDC and RERRA process. DERs that have a pre-existing interconnection service agreement, according to the applicable EDC and RERRA processes, are not intended for inclusion in the impacts evaluation group[28] under MISO's DER AFS studies, consistent with the outcome of the Lake Substation example included in Appendix F. Should a conflict arise between RERRA interconnection timing requirements and MISO's DER AFS timing requirements within BPM-015, the RERRA interconnection requirements take precedent given the State-jurisdictional nature of DER interconnection.

Accounting for DER interconnection being a RERRA jurisdictional process, MISO's role in the electric system, and evolving wholesale market rules (e.g., FERC Order 2222), limitations exist

[27] NOPR, 157 FERC ¶ 61,121 at P 104; see supra Section IV.B. (Definitions of Distributed Energy Resource and Distributed Energy Resource Aggregation).

[28] In this context, the "impacts evaluation group" is intended to represent the DER that impacts would be evaluated and assigned to. However, all known DER needs to be included in the screening and analysis assumptions.

as to what is addressed through MISO's DER AFS proposal. MISO seeks to provide clarity on two key limitations:

- **RERRA-jurisdictional matters** — DER interconnection is a RERRA jurisdictional process. MISO understands that RERRAs can be different entities including state commissions, municipal governments, and cooperative boards. Further, RERRAs have independent laws and rulemaking processes over DER interconnection, resulting in different available information, processes, and outcomes.
- **Market Participation —** MISO's DER AFS does not confer transmission rights or allow access to wholesale markets without further action on behalf of a DER Customer. DER Customers may access the Energy and Ancillary services markets by registering as a MISO Market Participant[29] and by enrolling DER assets in market product for which the DER is eligible. By contrast, capacity market participation requires the DER customer to secure appropriate transmission rights, which can be done by procuring Network Resource Interconnection Service (NRIS) through MISO's Definitive Planning Phase generator interconnection process[30] or by obtaining Firm Transmission Service[31].

At a high level, the scope of this document and MISO's DER AFS proposals include three areas: (1) screening, (2) studies and reports, and (3) facilities studies and network upgrades (Figure 0-1). See Section 8.3 for a more detailed process view.

Figure 0-1 High-level overview of MISO's DER AFS proposal scope

8.3. Procedure

MISO is aware that some RERRAs define transmission studies and affected systems studies within RERRA-jurisdictional interconnection rules. MISO considers the MISO DER AFS to be a

[29] See MISO Tariff Module A for Market Participant definition. Available at: https://docs.misoenergy.org/legalcontent/Module_A_-_Common_Tariff_Provisions.pdf
[30] See MISO BPM-015 for DPP process. Available at: https://cdn.misoenergy.org/BPM%20015%20-%20Generation%20Interconnection49574.zip
[31] MISO, Long Term Transmission Service Requests webpage. Information available at: https://www.misoenergy.org/planning/transmission-planning/long-term-transmission-service-requests/

type of affected system studies and recognizes that other TO studies may be appropriate based on TO Local Planning Criteria and applicable RERRA rules.

The MISO DER AFS process starts with screening, carried out jointly by MISO and the TO, which leads to a DER AFS should screening results show violations in technical criteria found in Sections 8.3.1.2 and 8.3.1.3. MISO will conduct quarterly DER AFS cycles to efficiently manage the expected growing volume of DER in coming years.

MISO will issue a DER AFS report at the conclusion of the DER AFS, should one ultimately be performed, showing steady state analysis results for voltage and thermal impacts. The DER Customer, EDC, and TO will have an opportunity to share feedback on the draft study report, per Section 8.3.3. If study results indicate DER-caused impacts exceeding defined thresholds, indicative cost estimates for Network Upgrades will be provided in advance of kicking off a more detailed Facilities Study. Figure 0-2 illustrates key DER AFS milestones and timeframes.

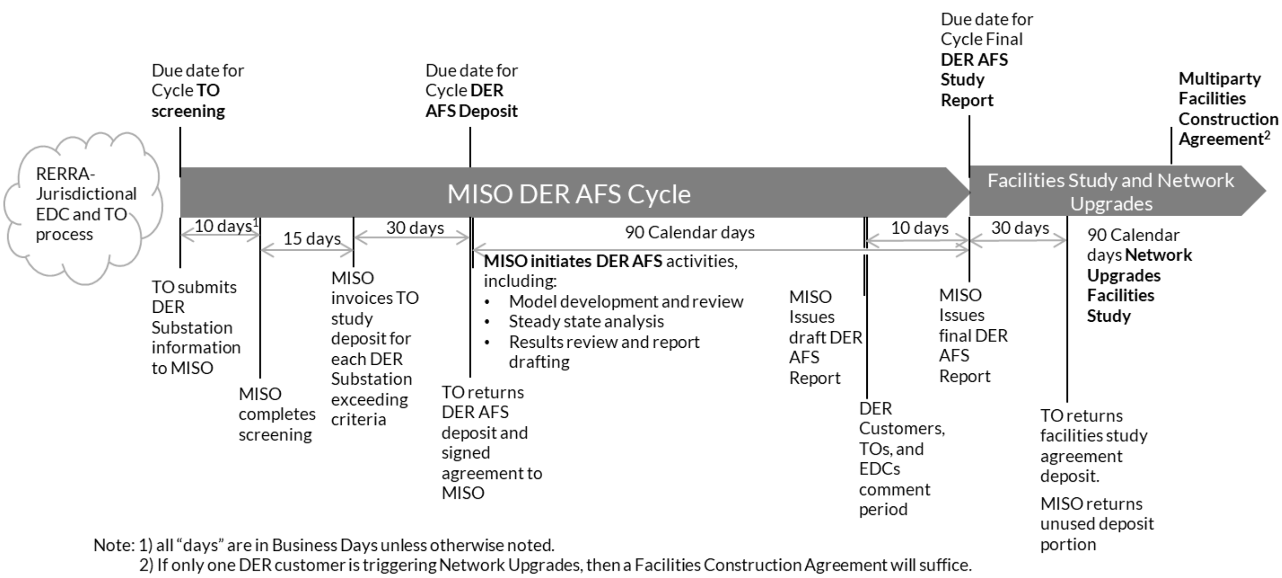

Figure 0-2 Illustration of DER AFS timeline view

8.3.1 Screening

8.3.1.1 Screening Assumptions

The TO and MISO shall assume full injection of all DER resources when applying DER screens. Full injection could mean the full DER nameplate or be a lesser value should operational capacity limitations be proposed. The TO, in concert with the EDC, determines the DER injection level submitted to MISO for screening.

The TO and MISO shall select summer peak and/or shoulder peak load conditions, drawing from MISO's fuel dispatch philosophy in Section 6.1.1.1.2 of this BPM for DPP studies. Table 0-1 shows an adaptation of summer peak and shoulder peak selection for DERs from Table 6-1. Should the DPP study fuel dispatch philosophy change, MISO will update the DER AFS screening approach to align with the DPP study dispatch assumptions. All DER in the study case is dispatched according to Table 8-1.

Table 0-1 DER AFS screening adaptation for summer peak and shoulder peak selection

DER Fuel Type for Screening	Summer Peak Dispatch	Shoulder Peak Dispatch
Solar	**100%**	**0%**
Storage	**100%**	**100%**
Wind	**100%**	**100%**
Hybrid[32]	**100%**	**100%**
Diesel Engines	**100%**	**0%**
Combustion Turbine	**100%**	**0%**
Waste Heat	**100%**	**100%**
Oil	**100%**	**0%**
Hydro	**100%**	**100%**

The load considered in the summer peak and shoulder peak conditions shall be consistent with the most current Load Serving Entity (LSE) information submitted for MTEP modeling.

[32] Hybrid Exception: a combination of only diesel, solar, combustion turbine, or oil would only be dispatched for summer peak. Otherwise, the full amount of DER is dispatched under both shoulder peak and summer peak conditions. As a simplifying assumption, the full hybrid capacity would be dispatched during each condition for screening. The dispatch allocation would be more granular for affected system studies, in accordance with BPM-15 practices.

Examples in Table 0-2 illustrate the application of the screening model selection concepts. The examples assume levels of DER Net Injection that would require screening.

Table 0-2 Example applications of DER screening model selection

5 MW solar only	Summer Peak
4 MW solar and 1 MW battery storage	Summer Peak and Shoulder Peak
10 MW hybrid (solar and combustion turbine)	Summer Peak
10 MW hybrid (solar, wind, and storage)	Summer Peak and Shoulder Peak

8.3.1.2 Transmission Owner Screening

When an EDC approaches a TO with information on potential DER Transmission System impacts, the TO shall perform a screen for DER Net Injections exceeding one megawatt (1 MW) using the screening assumptions outlined in Section 8.2.1.1. DER Net Injection screening shall use the applicable model(s) load and assume full injection of all DER at the DER Substation.

If TO screening of a DER Substation indicates DER Net Injections exceeding one megawatt (1 MW), the TO shall submit to MISO the information outlined in Section 8.3.2.3, categorized by the fuel types shown in Table 0-1. The information shall be submitted by the screening deadline milestone for consideration in the next DER AFS cycle.

Once a DER Substation has exceeded the Net Injection screening threshold, and a DER AFS completed showing no impacts, MISO will not perform an additional DER AFS on that substation until the DER Net Injection at the DER Substation goes up by one megawatt (1 MW) or greater. Similarly, if a DER AFS-identified Network Upgrade is completed at a DER Substation, MISO will not perform an additional DER AFS on that substation until the DER Net Injection at the DER Substation goes up by one megawatt (1 MW) or greater. Should an identified Network Upgrade not be funded, any incremental DER Net Injection will trigger another MISO DER AFS. An example of this process can be found in Appendix F.

8.3.1.3. MISO Screening

MISO will compile all DER Substation information submitted by TOs and perform screening to determine which DER Substations require DER AFS. MISO will use the same screening assumptions as the TO and outlined in Section 8.3.2.3.

MISO will identify DER Substations with DER Net Injection exceeding 5 MW and forward these DER Substations to the next quarterly DER AFS without additional screening.

For DER Substations in the 1-to-5 MW range, MISO will apply the 1%-line loading change screen and forward any DER Substations that exceed the threshold for DER AFS. The 1%-line loading change screen evaluates the net change (positive or negative) in loading on modeled lines using the DER screening assumptions outlined in Section 8.2.1.1.

Figure 0-3 shows a depiction of the overall screening process.

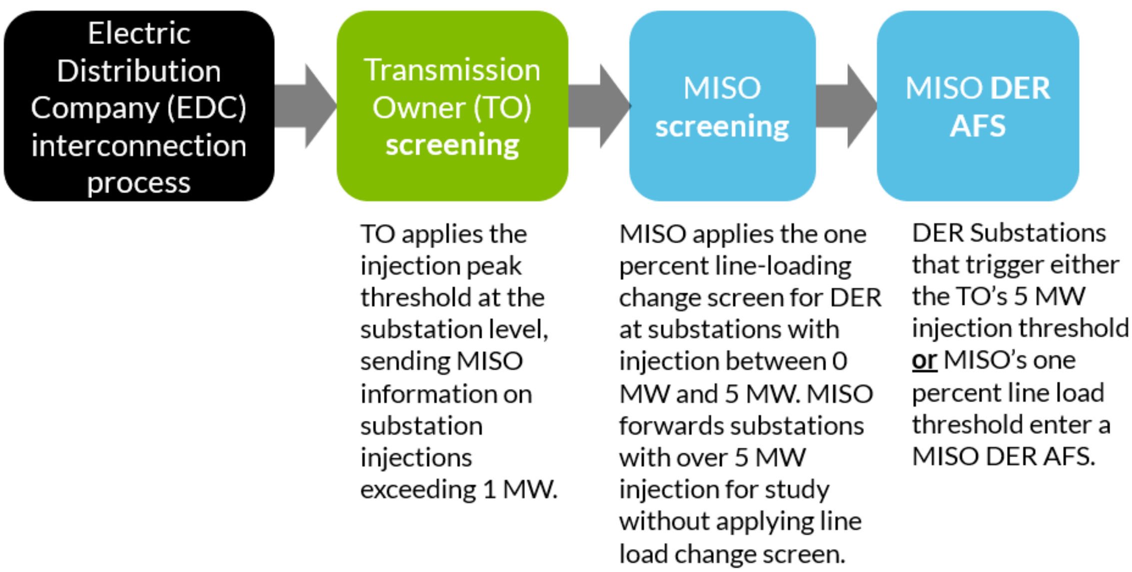

Figure 0-3 Summary of TO and MISO screening process and thresholds

After the TO requests MISO screening or study, MISO will perform line loading change screening, as applicable, within 10 business days of the TO screening deadline. For DER Substations that require a DER AFS, MISO will invoice TOs within 15 business days of screening completion. The TO may be reimbursed for any DER AFS Costs consistent with RERRA regulatory requirements and TO utility structures. The TO shall provide a DER AFS deposit, for $60,000 per DER Substation, to MISO within 30 business days of MISO invoice.

8.3.2. Study Process

If a DER AFS is needed, MISO will carry out DER AFS cycles with a quarterly cadence. If there are no requests for a DER AFS at the beginning of a quarterly cycle, a study cadence may be skipped. The DER AFS process shall be allocated 90 calendar days, with steps such as screening, agreements, and deposits occurring outside of the 90 calendar days. Figure 0-4 shows DER AFS process steps with respect to the 90 calendar days. Not shown in this figure are the screening steps leading up to the DER AFS agreements and deposit, as discussed in Sections 8.2.1.2 and 8.2.1.3.

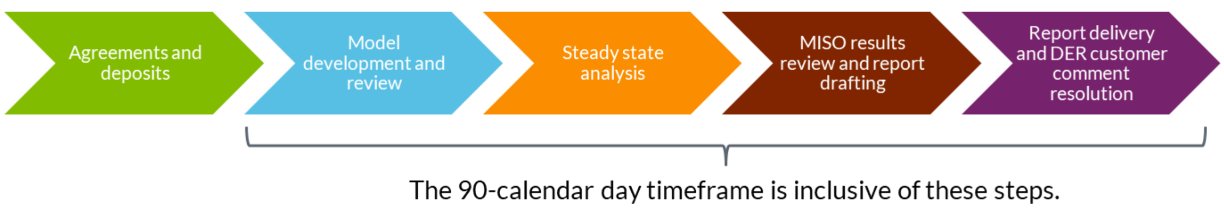

Figure 0-4 Overview of DER AFS process in relation to 90 calendar day study timeframe

8.3.2.1 Agreement

The TO and MISO will enter into a DER AFS Agreement that will outline the study scope, cost, and timing milestones as well as the responsibilities of each party.

8.3.2.2 Deposit Amount and Payment Methods

The TO shall provide a DER AFS deposit for $60,000 per DER Substation within the timeframes defined in this document. MISO shall track study expenses and refund any unused DER AFS deposit amount. While MISO anticipates the requested amount covers most DER AFS situations, there may be instances where MISO needs to request additional funding from the TO to complete the study. Consistent with other MISO Generator Interconnection practices, the interconnection customer is charged actual study costs. The TO may be reimbursed for any DER AFS Costs consistent with RERRA regulatory requirements (e.g., applicable tariff) and TO utility structures. MISO will reconcile study costs with deposits upon completion of each quarterly cycle. The deposit amount is independent of the number of DER requesting interconnection at a given DER Substation.

Automated Clearing House (ACH) payments and wire transfers are MISO's required methods for receiving deposits and refunding unused deposit portions.

8.3.2.3. Data Exchange

The DER information submitted to MISO for screening is sufficient for MISO to carry out the DER AFS. The minimum information required for each screening cycle includes: (1) Substation name and associated transmission bus number; (2) DER capacity, in megawatts, categorized by the fuel types found in BPM-015; (3) equivalent short circuit impedance by fuel type; and (4) reactive power control mode and settings by fuel type. The entity submitting information may choose to submit assumptions for equivalent short circuit impedance by fuel type and reactive power control mode and settings by fuel type to be used for all DER submitted by that entity until further notice of assumptions changes by that entity.

The DER information shall be submitted in IDEV or PSSE (*.raw) format, representing the aggregate DER connected and proposing interconnection at the transmission bus using the data record for generators. The DER information should include both newly proposed and existing DER.

DER being studied through DER AFS shall be submitted via email to DER-AFS@misoenergy.org.

8.3.2.4. Modeling Assumptions and Inputs

MISO selects the latest DPP Phase 3 model at the time a new DER AFS cycle is initiated. MISO selects peak and shoulder peak models based on Section 6.1.1.1.2 of this BPM.

MISO has a partial view of existing DER, which is included as negative load in the MTEP models when reported by members. Per section 8.3.2.3, DER AFS will model DER as a generator rather than a negative load. MISO will include all new DER information submitted for a given cycle but will not include previous cycle information unless submitted by the TO for the current DER AFS cycle or submitted as part of MISO's modeling business practices.

DER will be dispatched against local area generators as defined by the MTEP model "area number."

8.3.2.5. Voltage and Thermal Analysis and Constraint Criteria

MISO will perform thermal and voltage analysis that include each DER Substation qualifying for a DER AFS.

MISO shall use the same thermal analysis and constraints outlined in Sections 6.1.1.1 and 6.1.1.1.8 in this BPM, respectively. The deliverability analysis in Section 6.1.1.1.9 of this BPM is not included in the DER AFS study.

MISO will use the same voltage analysis and constraints outlined in Section 6.1.1.2 of this BPM, which references Local Balancing Authority criteria.

MISO plans to use PSSE and TARA to perform steady state powerflow analysis, aligned with the current business practice in Section 6.1.1.1.7 of this BPM.

8.3.3. Report

MISO will prepare two versions of the DER AFS report:

- A **Public version** of the draft DER AFS report will be posted on MISO's public-facing website for the TO, EDC, DER Customer(s), and other interested parties (e.g., RERRA) to view high-level results. This version will document any system impacts found along with indicative estimates for any Network Upgrades needed to mitigate the impacts.
- A **Confidential version** of the DER AFS report with Critical Energy/Electric Infrastructure Information[33] (CEII) will be available to the TO, EDC, and DER Customer(s), as appropriate, with restricted access.
    a. CEII version is only needed if network upgrades are required.
    b. Parties with access could view detailed study contingency and network upgrade information which would be shared with the EDCs as needed.

Since the DER AFS consider cumulative DER at the substation level, MISO does not attribute impacts to specific DER. The entity responsible for managing the RERRA-jurisdictional interconnection process (e.g., EDC) would be responsible for disaggregating the results, when relevant, to assign impacts and Facilities Study deposit funding.

[33] FERC, Critical Energy/Electric Infrastructure Information (CEII). Accessed 10/12/22. Information available at: https://www.ferc.gov/ceii

The DER AFS report will provide information needed to disaggregate DER Substation impact results. The thermal impacts can be disaggregated using simple linear impacts and cost assignment methodology, applying a dollars per kilowatt ($/kW) of DER capacity. Voltage impacts will be shown in a table, similar to MISO's SPP study Steady State Voltage Violations tables in Appendix B of the MISO-SPP study[34], to allow for impacts assignment. If cumulative impacts are 1% or greater, study report impacts are assigned per DER Substation based on voltage impact contributions.

If the DER AFS finds constraints, MISO will contact the TO to collaborate on mitigations and planning-level estimates before the DER AFS draft report is posted.

MISO will hold a 10-business day comment period for affected TOs, EDCs, RERRAs, and/or DER Customers to share comments. Affected parties are invited to send feedback to MISO via email with the unique DER Substation study identifier in the subject line. MISO will respond to all feedback prior to finalizing the study.

When impacts are identified that require a Facilities Study, the DER Substation has 10 business days from the time of study finalization to fund the Facilities Study deposit in order to remain active in that cycle of MISO's DER AFS process. Should the DER Substation not fund the Facilities Study deposit, the DER at the DER Substation may be submitted to the next DER AFS cycle.

8.3.4. Facilities Studies and Network Upgrades

The Facilities Study process is used to estimate cost and timeframes for constructing Network Upgrades. Details of the process are currently found in Sections 5.4.3 and 5.4.5 of this BPM. The Facilities Study will list the required upgrades and include a categorized detailed cost breakdown of identified facilities, consistent with Sections 6.2.2 and 6.2.3 of this BPM. Facilities Study cost is not included in the original DER AFS study deposit for MISO study. Therefore, if the MISO DER AFS study identifies violations and Network Upgrade mitigations, additional funding for Facilities Study will be required. The TO will have 30 business days to return the Facilities Study agreement and deposit after MISO issues the final DER AFS Report. After the

[34] MISO, Leidos, MISO Affected Systems Studies for SPP Projects Phase II April 2021. Available at: https://opsportal.spp.org/documents/studies/files/2017_Generation_Studies/FinalReport-MISO_AFS-2017-DISIS_v2.0.pdf

Facilities Study, a MISO MPFCA[35] is needed between MISO, the TO, and the relevant Funding Party or Parties (e.g., DER Customers). If there is only one DER Customer, then a MISO Facilities Construction Agreement[36] in Section 7.2 would be used in place of the MISO MPFCA.

MISO is not proposing a cost-sharing mechanism between the DPP and DER AFS process.

8.3.5. Tracking and Reporting Information

MISO will make reporting information to be publicly available and updated with each DER AFS cycle. The information made publicly available will be consistent with data confidentiality practices outline in Section 8.3.3. The following information will be reported for each DER Substation included in screening or study activities:

- Transmission Owner
- Total Connected DER
- Date of last MISO Screen
    a. 1% Screen (Pass/Fail)
    b. Net Injection (1 – 5 MW) Screen (Pass/Fail)
    c. Net Injection (greater than 5 MW) Screen (Pass/Fail)
- Ongoing AFS (Y/N)
- Total Pending DER in current DER AFS
- Number of completed DER AFS Studies
- Upgrades Identified (Y/N)

Non-binding Dispute Resolution

All disputes arising under section 13.5.2 of Attachment X are initially subject to the informal dispute resolution process described in 13.5.1 of Attachment X. All requests that proceed to Non-binding Dispute Resolution shall be initiated through the submission of a properly completed Request for Non-binding Dispute Resolution form (Appendix F hereto) to the [ginterconnection@misoenergy.org] email address. The Party initiating a dispute shall provide the following information at the time of dispute initiation:

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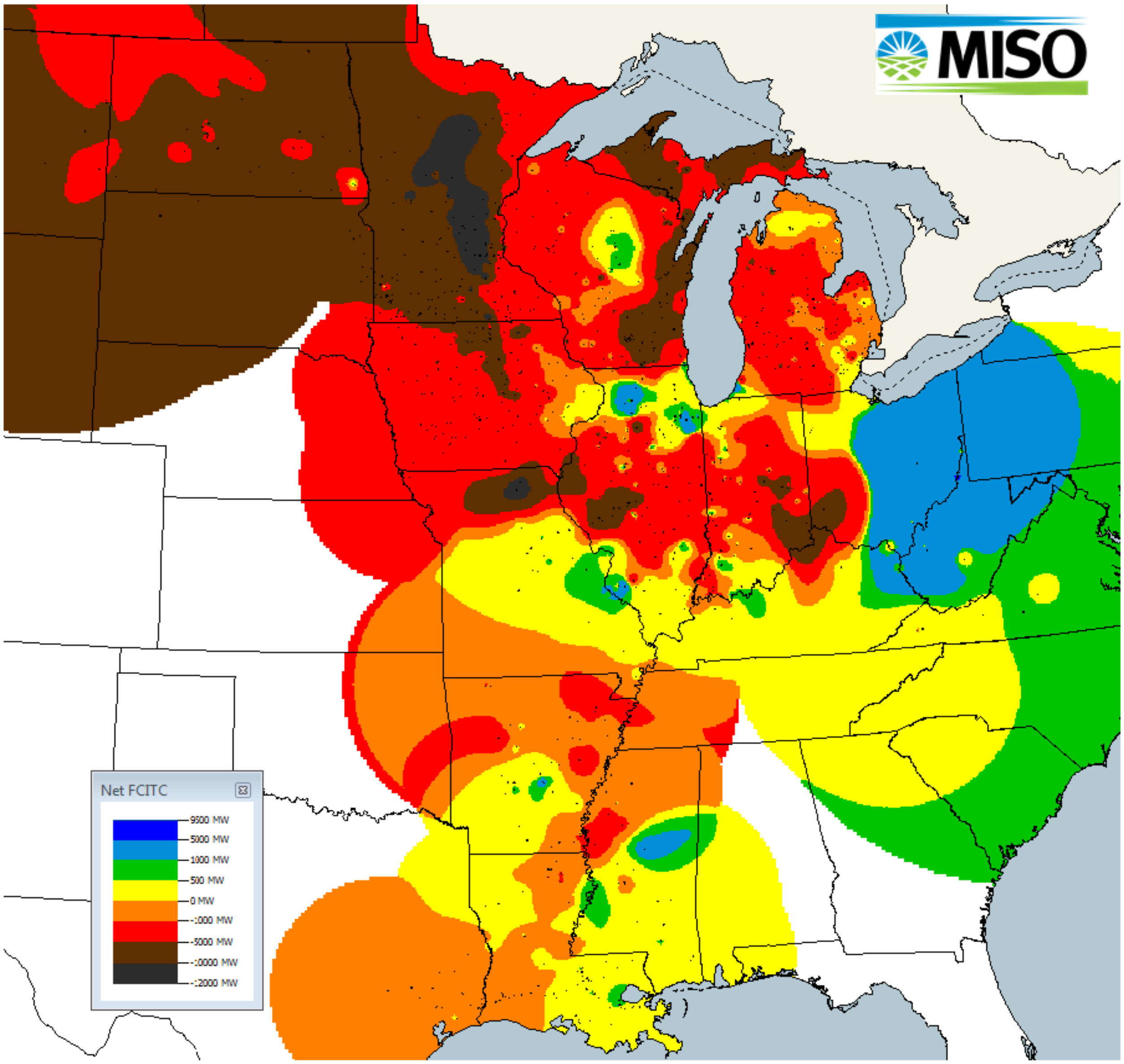
[35] MISO, Tariff Attachment X: Appendix 9, Multi-Party Facilities Construction Agreement. Available at: https://docs.misoenergy.org/legalcontent/Attachment_X-Appendix_9_-_Multi-Party_Facilities_Construction_Agreement_%28MPFCA%29.pdf

[36] MISO, Tariff Attachment X: Appendix 8, Facilities Construction Agreement. Available at: https://docs.misoenergy.org/legalcontent/Attachment_X-Appendix_8_-_Facilities_Construction_Agreement_%28FCA%29.pdf

- The identity of the party making the request;
- The identity of the party with whom the dispute is being raised;
- The identity, if known, of any other parties who may be impacted by the outcome of the dispute being raised;
- A summary of the factual information giving rise to the dispute, including steps taken to resolve the dispute;
- Citations to any authority governing the dispute (i.e., applicable sections of the Tariff, MISO Agreement, Business Practices Manuals and/or any other applicable authority);
- The desired outcome of the Non-binding dispute resolution process; and
- Contact information as specified in Appendix F.

Appendix A

Sample Contour Map



This is a sample contour map generated using August 2017 Definitive Planning Phase model for Central, MI, ATC and South regions and an August 2016 model for the West region. Estimated time through interconnection queue does not include construction time.

Appendix B

Generator Interconnection Ad Hoc Information Session Request Form

I. Interconnection Customer

Name: ________________________________
Title: ________________________________
Company Name: ________________________
Address: ________________________________
Phone No.________________________________
Email address ________________________

II. Project Details

Project Size (MW) ______________
No. of units/rating________________
Fuel type: _____________________
Desired ISD: ___________________
Anticipated date to enter the Queue_____________

III. Site

County: ______
State: ________
Area Transmission Owner(s) __________________
POI: ____
(If not identified, list all options that are being considered)
Distance from the nearest substation or transmission line_______________________
Available Connection Voltage(s) _____________________________
Site Control _________ (Yes/No)
ROW Required for Interconnection Facilities? _____________ (Yes/No)

IV. Specific Questions for the Transmission Provider/Transmission Owner (use a separate sheet, if required)

1.

2.

3.

4.

V. Information Session is requested by

Signature: ________________________________
Name (print or type):______________________________
Title: ________________________________
Company Name: ________________________
Address: ________________________________
Phone No.______________________________
Email address ________________________

This form can be faxed or mailed to the following address:

Midcontinent Independent System Operator, Inc.
Attn: Transmission Access Planning
720 West City Center Drive
Carmel, IN 46032
Fax 317-249-5358

Appendix C

MISO Generation Deliverability Study Method

i. Introduction

This document serves the purpose of providing the methodology to determine whether a generator can be certified as deliverable under the MISO Tariff as per.
(1) Attachment X (Generator Interconnection Process for NRIS), or
(2) Module E (Resource Adequacy Requirements).

A generator that is certified deliverable through MISO's deliverability study could be designated by Load within the MISO's Market footprint to satisfy its Resource Adequacy requirement as specified in Module E.

The generator deliverability study analyzes the ability of a group of generators to operate at their maximum capability without being constrained ("bottled up") by the electric transmission system. The test is performed in a 3-step process as outlined below.

Any new generator or existing non-Designated Network Resource (non-DNR) applying for NRIS under Attachment X of the MISO Tariff can be considered deliverable to the MISO aggregate load if it passes the deliverability study. The deliverability study was applied to existing generating resources prior to the start of MISO's Energy Market; as well, it has been and can be applied prior to integration of any new Balancing Authority into MISO.

The generation deliverability study is one piece of MISO's DPP cycle and is also included in the annual process for MTEP. MISO's deliverability study in DPP cycle determines the deliverability of study generators requesting NRIS and ensures that existing resources with NRIS remain deliverable, including units in suspension. The annual MTEP deliverability study ensures that the deliverability of all NRIS generators in MISO is maintained as future transmission is planned.

ii. Study Method

Step 1: Create Deliverability Model

Purpose of Step 1: Establish a power-flow model with MISO summer-peak load and interchange served by MISO resources with NRIS.

The deliverability model is developed from the ERIS study model used for the DPP cycle and region under study, with all prior-queued generators at their granted NRIS value and their associated network upgrades included. If there is any change in the network before the five (5) year horizon that may impact deliverability of the generators under study, those issues can be addressed during scoping and model review. As in ERIS models, Affected System units with queue priority are included. ERIS only generation is turned off and un-dispatched NRIS generation is turned on to at least pgen = 0, such that total generation in MISO classic and MISO South in the deliverability model is equal to total generation in MISO classic and MISO South in the Study model. For the Annual MTEP Deliverability Study, only NRIS generators with signed GIAs or PGIAs will be dispatched up to their granted levels. As such, all NRIS generators are turned on, and any ERIS generators are “turned off” and remain off in the model for analysis with the exception of Behind the Meter Generators (BTMG) which are left as-is. For the purpose of maintaining a conservative approach to a deliverability study, Behind the Meter Generator (BTMG) units are treated as NRIS generators and are left on in the model at their existing dispatch levels, even though they technically do not have MISO NRIS. ERIS generators with Firm Transmission Service are to be treated the same as NRIS generators.

For the DPP deliverability study, study generators for the cycle are ramped up to their requested NR levels by TARA Deliverability tool. The study generators requesting NRIS are adjusted automatically by TARA Deliverability tool which provides a more conservative approach to flowgate identification.

In the study model for the annual MTEP deliverability study, all NRIS generators are counted as study generators, and are dispatched according to LBA methodology to offset the ERIS generators being turned off.

The Deliverability case will include approved MTEP projects and those targeted for approval in the applicable MTEP cycle.

If a deliverability model is desired by stakeholders, MISO will provide it on a case-by-case basis.

Step 2: **Use PowerGEM TARA to capture potential deliverability constraints.**

Purpose of Step 2: Use TARA to find branch violations on monitored elements throughout the MISO system caused by study generators. This step returns a list of all violations, which can be refined using post-processing to find the worst-case violations for each monitored element.

TARA Input Files:

Power-flow file (.raw): The Deliverability case file created in Step 1.

Subsystem file (.sub): Includes the subsystems MISO_EX, MISO_IM, and any other subsystems required to support related Monitored Facility (.mon) files and Contingency (.con) files.

MISO_EX and MISO_IM both contain all areas located in the MISO market footprint. By including all of MISO as both the source and sink for the system, every generator's deliverability will be studied by TARA Deliverability tool against every other part of the MISO system when identifying study flowgates. (For the purposes of this Deliverability analysis, a "flowgate" is defined as a constrained mon-con pair. These flowgates do not necessarily follow any of the legacy flowgates in the MISO area used over the years.) The original interchange for areas in MISO and its neighbors is maintained during this redispatch by proportionally scaling generation in the MISO_EX area.

For DPP studies, study generators part of the DPP cycle under study are defined as part of the MISO_EX subsystem and treated separately from other NRIS generators within MISO by including them in the special STUDY block in the subsystem file. In the MTEP Deliverability Analysis, all NRIS generators in MISO_EX footprint are treated as study generators.

Monitor file (.mon): Include all transmission facilities under MISO's functional control as well as appropriate external transmission facilities of neighboring entities.

Contingency file (.con): For DPP studies, use the ERIS study contingency files corresponding to the study model that is previously reviewed by the Expansion Planning Group and TOs in the DPP ad-hoc study group. Contingency files for deliverability studies should only contain P1 and

P0 contingencies. Additionally, TARA automatically generates and tests N-1 contingencies (auto singles) of monitored elements in the MISO_EX and seams regions subsystem.

For the annual MTEP deliverability study, use the same contingency files corresponding to the 5 years out summer peak MTEP model as those used for annual MTEP reliability assessment.

TARA analysis:

Flowgate Screening: TARA Deliverability tool is able to automatically screen for flowgates by creating monitored element-contingency pairs with a DF greater than a prescribed value. Up to 8000 MW is transferred from MISO_EX to MISO_IM while keeping the MISO interchange at the same level. Through a trial-and-error method, MISO determined that an 8000 MW transfer cap is sufficient to reveal all credible overloads (this transfer parameter will be reviewed and revised if needed for any specific study). For the purposes of the deliverability study, all flowgates are identified for which at least one study generator has a DFAX greater than or equal to 5%, and the flowgate itself has a DC loading of greater than or equal to 70%.

Stressed Dispatch: For each flowgate created by TARA Deliverability tool, the top 30 generators contributing to the flowgate (i.e., the generators with the highest DFAX on the flowgate) have their output increased to their granted NRIS for existing/higher-queued generators or the requested NRIS for study generators. To compensate for the increase in system generation, generators in the rest of MISO_IM are uniformly scaled down.

Gen 342: 55%
Gen 103: 51%
…
Gen 159: 16%
…
Gen 677: 5.1%
…
Gen 921: -5.0%

Turned on at 100% capacity. Total number not to exceed 30.

Purpose: Make sure to turn up only reasonable amount of generation in the list/circle.

DF>5%

The purpose of this dispatch is to create a severe, yet credible, dispatch for each identified flowgate in the deliverability model.

If the DC-solution-method loading on the line is greater than 70%, the list of harmers is saved for AC verification.

Loading Adder: The impact of flows from large offline generators outside of the top 30 DF list are not captured in previous steps but can be non-negligible. To account for the impact of large NRIS generators that are outside of the Top 30 DFAX list, any NRIS generator whose DFAX is greater than 5% and whose MW impact (Pmax * DFAX) is greater than 20% of the line rating is turned on to its NRIS level as part of the stressed dispatch.

AC Verification: An AC power flow analysis is automatically performed by TARA Deliverability tool for all flowgates with a DC loading of greater than 70%. AC analysis confirms loading violations identified during DC analysis in order to appropriately account for the impact of reactive power loading, which can yield higher total line loadings.

For each flowgate, TARA calculates the shared generation deduction required for the study generators contributing to the flowgate's AC-solution-method violation. The shared deduction is the amount by which each study generator affecting a given flowgate must be scaled down in order to prevent loading violations on the flowgate. The deduction is proportionally taken from each study generator affecting a particular flowgate. If a particular monitored element becomes a flowgate under multiple contingency conditions, the contingency requiring the highest deduction is used.

Step 3: Results

If a study generator does not contribute more than 5% of the DFAX on any flowgate with a loading violation, it is considered fully deliverable, subject to any conditions to the GIA (Appendix A10). If a study generator does contribute to a flowgate with a loading violation, it is not considered fully deliverable without a network upgrade. The shared deduction is calculated by uniformly scaling down the study generators in the top 30 harmers until the flowgate is no longer overloaded.

For each study generator that is not fully deliverable, the flowgates for which it is in the top 30 list are ranked in order of the shared deductions. A study generator is considered deliverable up to a MW value where no overloads occur on any flowgate, as determined by the shared deduction, assuming all associated generator requests limit their NR request to the shared deduction value specified in the deliverability results.

All deliverability limiting constraints should be verified as a part of the Ad Hoc study group process.

Existing Operating guides are considered in deliverability study only if the guide does not involve the redispatch of existing NRIS generators, and it is an acceptable practice as per the applicable planning criteria.

For an IR under study, the IC can choose either to make the network upgrades to eliminate the constraint, or to proceed with ERIS instead of NRIS for the portion of their NRIS request that is not deliverable.

Appendix D

Pre-Commercial Generation Test Notification Form

The following form would need to be submitted to MISO Real Time Operations at least five **(5)** Business Days prior to the first date of testing.

Project Number:

Project Name:

Point of Interconnection:

Dispatcher Contact Information:

Date	Start Time (in EST)	End Time (in EST)	Expected MW Output	Expected MVAR Output (Only needed if beyond normal power factor)

Appendix E

Examples: Dispatch Assumptions for Hybrid Facility

Example: Generic Dispatch Assumptions for Hybrid Facility

Scenario	Existing Generator 1 (Wind, Solar, CC etc.)	Study Generator 2 (Wind, Solar, CC etc.)	Study Generator 3 (Wind, Solar, CC etc.)	Study Generator 4 (Storage)	Interconnection Service Requested	Steady State (Shoulder Peak)[37]	Steady State (Summer Peak)[38]	NRIS or Deliverability (Summer Peak)
1	0	50	100	0	120	MIN (fuel type dispatch of both study generators, 120)		MIN (max. MW output of both study generators, 120)
2	0	100	0	+/-50	120	Discharging: MIN (fuel type dispatch of both study generators, 120) Charging: – fuel type dispatch of storage (non-storage offline)		Discharging: MIN (max. MW output of both study generators, 120)
3	100	0	0	+/-50	120	Discharging: MIN (fuel type dispatch of existing gen. + fuel type dispatch of storage, 120) Charging: – fuel type dispatch of storage (non-storage offline)		Discharging: MIN (max. existing gen. MW + max. storage MW, 120)
4	0	100	0	+/-50	150	Discharging: Fuel type dispatch of both study generators Charging: – fuel type dispatch of storage (non-storage offline)		Discharging: Max. MW output of both study generators
5	0	50	100	0	150	Fuel type dispatch of both study generators		Max. MW output of both study generators

MIN (): Smallest of the two values.

[37] The dispatch assumptions in Section 6.1.1.1.2 (i) will be used, if applicable.
[38] The dispatch assumptions in Section 6.1.1.1.2 (i) will be used, if applicable.

Examples: Dispatch Assumptions for Hybrid Facility with Specific MW Values

Scenario	Wind	Solar	Storage	Interconnection Service Requested	Storage Mode	Steady State (Shoulder Peak)				Steady State (Summer Peak)				NRIS or Deliverability (Summer Peak)			
						Wind	Solar	Storage	Hybrid Output	Wind	Solar	Storage	Hybrid Output	Wind	Solar	Storage	Hybrid Output
1	100	50	0	120	Discharging	96	24	0	120	15.6	50	0	65.6	80	40	0	120
					Charging	N/A											
2	100	50	0	150	Discharging	100	50	0	150	15.6	50	0	65.6	100	50	0	150
					Charging	N/A											
3	100	0	50	120	Discharging	80	0	40	120	15.6	0	50	65.6	80	0	40	120
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			
4	100	0	50	150	Discharging	100	0	50	150	15.6	0	50	65.6	100	0	50	150
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			
5	0	100	50	120	Discharging	0	50	50	100	0	80	40	120	0	80	40	120
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			
6	0	100	50	150	Discharging	0	50	50	100	0	100	50	150	0	100	50	150
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			
7	100	100	50	220	Discharging	100	70	50	220	15.6	100	50	165.6	88	88	44	220
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			
8	100	100	50	250	Discharging	100	100	50	250	15.6	100	50	165.6	100	100	50	250
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			
9	0	0	50	50	Discharging	0	0	50	50	0	0	50	50	0	0	50	50
					Charging	0	0	-50	-50	0	0	-50	-50	N/A			

Appendix F

Example Screening of DER Substation After a DER AFS

1. “Lake Substation” has DER interconnection requests that equate to 5.5 MW of DER Net Injection onto transmission at summer peak and/or shoulder peak.
2. TO performs a 5 MW Net Injection screen and requests a MISO study.
3. MISO performs DER Affected Systems Study and determines no impacts.
4. An additional 0.5 MW of DER Net Injection is proposed at Lake Substation.
5. The TO considers the aggregate 6 MW of DER Net Injection with the new 1 MW screening dead band limit (currently set at 6.5 MW for Lake Substation) and determines no request for study is needed. Should the TO request a study, MISO would review records and respond that none is needed.
6. An additional 0.75 MW of DER is proposed at Lake Substation.
7. The TO applies the aggregate 6.75 MW of DER Net Injection against 6.5 MW dead band limit and requests a MISO study for new/incremental 1.25 MW of DER Net Injection with impacts assignment applicable to the 0.75 MW triggering a DER AFS.

Appendix G

REQUEST FOR NON-BINDING DISPUTE RESOLUTION
(Please forward to: ginterconnection@misoenergy.org)

Claimant Company Information:
Claimant Company Name: ______________________________
Business Address: ____________________________________
City: ______________ State: __________ Zip: _____________

Designated Contact for Non-Binding Dispute Resolution:
Full Name: ____________________ Title: _________________
Contact's Firm or Company Name: _________________________
Business Address: _____________________________________
City: ______________ State: __________ Zip: ______________
Telephone No.: (   ) _______ E-mail Address: ______________

Description of Dispute:

Name of Opposing Party or Parties: ____
____

Please attach to this form a detailed statement of facts explaining the nature of your dispute. Your explanation (in any format) should address:
(a) How has the dispute developed;
(b) What is causing the dispute;
(c) Who are the parties affected by the dispute;
(d) Does the dispute involve a single event or a series of repetitive events;
(e) What you have done to resolve the dispute;
(f) What is the desired outcome;
(g) Citation to any authority governing the dispute (i.e., applicable sections of the Tariff, MISO Transmission Owners Agreement, Business Practices Manuals and/or any other applicable authority);
(h) Whether a decision in this dispute affects matters subject to FERC's jurisdiction under either section 205 or 206 of the Federal Power Act; and
(i) Whether a decision in this dispute affects matters subject to the jurisdiction of any state authority.