MPC Transmission Planning BPM

October 5, 2017

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I. Purpose

The purpose of this document is to describe the transmission planning process and study methodology, as well as prescribed mitigations used for MPC Planning Studies including but not limited to: Annual TPL Assessments, Interconnection Studies, and Transmission Service studies. Additionally, it sets a clear, prescriptive, and transparent process by which MPC's system can be consistently studied, and projects or operating solutions can be consistently implemented to robustly, reliably, and economically minimize the probability of reliability concerns. This includes meeting coordination provisions in Attachment K of the MPC tariff.

II. Definitions

Capitalized terms and acronyms that are not otherwise defined in this document shall have the respective meanings set forth in the Minnkota Tariff[1], the NERC Glossary of Terms[2], or the meaning commonly understood within the electric utility industry.

III.General Provisions

A. Coordination

MPC notifies, coordinates, and cooperates with its Planning Coordinator, neighboring Planning Coordinators, Transmission Planners, Transmission Owners, and/or Transmission Service Providers as necessary through review of study assumptions, system performance, alternatives considered, and coordinated recommendations.

MPC will seek regional coordination of studies evaluating major system changes through an ad hoc study group comprised of relevant regional entities. Specific generation interconnection and transmission service study coordination procedures with MISO and Manitoba Hydro (MH) are documented in the MH-MPC-MISO GIR and TSR Coordination Procedure. An ad hoc study group will not be required for certain studies, such as short term TSRs, very small generation, load additions, etc. MPC will use the following procedures when utilizing an ad hoc study group:

- Participation in the ad hoc study group will be initiated by sending an invitation to relevant neighboring entities. Entities that indicate their interest in participating in the ad hoc study group by the date specified in the invitation will be included in the ad hoc study group.
- The ad hoc study group will have the opportunity to review and comment on the draft study scope, the selection of cases, the models, and a draft report.

[1] Minnkota Power Cooperative, Inc. (2015, January 1). *Open Access Transmission Tariff.*
[2] North American Electric Reliability Corporation. (2015, May 19). *Glossary of Terms Used in NERC Reliability Standards.*

- MPC shall make good faith efforts to resolve disputes that may arise concerning the study method or study conclusions.

B. Posting and Retention

Study results and models will generally be retained for a minimum of three years. This retention timeframe may be adjusted depending on compliance requirements and the purpose of the study.

GIR and TSR study reports, with CEII information removed, will be posted on Minnkota's public website[3] and/or on the Minnkota OASIS page[4].

C. Study Methodology

1. Analysis

At a minimum, the following studies must be considered: a steady-state analysis, a transient stability analysis, a voltage stability analysis, and a short circuit analysis. It may be determined that some of these studies are not necessary, or that additional studies are required.

a) Steady State Analysis

The purpose of steady-state analysis is to determine whether the system will meet steady state thermal limits and voltage criteria during both system intact and post-contingent conditions. Steady state performance will be examined by simulating NERC TPL standard events.

b) Transient Stability Analysis

The purpose of the transient stability analysis is to determine whether the system will meet transient stability criteria following a system disturbance.

c) Voltage Stability Analysis

The purpose of the voltage stability analysis is to ensure that the system has adequate margin to maintain system voltages. Two types of voltage stability analysis are performed: PV and QV. For both, a few local outages (based on engineering judgment and limiting conditions) will be selected in addition to the system intact case.

PV analysis determines the maximum real power transfer levels which can be achieved before voltage instability and/or voltage criteria violation occurs for system intact and critical contingency case conditions. The goal of the QV curve analysis is to determine the reactive power margin that exists before area voltages fall outside criteria and/or the system becomes unstable for both system intact and contingencies.

[3] Minnkota Power Cooperative, Inc. Retrieved from Minnkota Power Cooperative Web site
[4] Open Access Technology International, Inc. (n.d.). *Minnkota OASIS Page*.

d) Short Circuit Analysis

The purpose of the short-circuit analysis is to determine the fault current levels on the system. Three-phase and single-line-to-ground faults will be simulated and the fault currents determined.

Short circuit strength at one or more buses may be reviewed if applicable. The lowest maximum fault current interrupting capability rating of equipment at the bus will be used as the study limit. If this limit is violated, a more detailed review of the topology and the maximum fault current interrupting capability of individual equipment will be performed.

2. Modeling

a) Load

Load forecasts of MPC load are based on MPC's Load Forecasting Methodology[5]. Load forecasts for other load serving entities are drawn from the regional model building process; however, they may be updated if necessary.

At a minimum, a peak load model (summer or winter) will be analyzed. Additional load models will also be analyzed if determined to be necessary. In most conditions, a winter peak, a summer peak, and a summer off-peak load model with high transfer should be analyzed. To the extent possible, loading on systems external to the MPC system should be modeled with load levels similar to the load levels modeled on the MPC system.

Off-Peak load will generally be modeled at 70% of peak. Light load models may also be used, and these will generally have load that is down to 40% of system peak. The 40% figure has been determined through historical load analysis of the MPC system.

b) Years

At a minimum, a near-term model and an out-year model will be analyzed. Additional years may be included in the main analysis or in a sensitivity, as is deemed appropriate by engineering judgment.

Typically, the near-term model covers a 1 or 2 year out timeframe, while an out-year model covers a 5 or 10 year out timeframe. Generation and transmission projects with a relatively high degree of certainty, but which are expected to be in service beyond the timeframe of the model, may be included in the model as is deemed appropriate by engineering judgment.

c) Generation Dispatch

Changes to generation will generally be dispatched to other generation on an economic and probabilistic basis considering historical dispatch for each applicable load level. A

[5] Minnkota Power Cooperative, Inc. *Load Forecasting Methodology.*

generation-to-load dispatch may be used if determined to be realistic and more conservative than a generator-to-generator dispatch.

In the annual TPL assessment, only firm transfers (including firm generation-to-load), will be modeled.

As a rule of thumb, baseload generation will be set to a "cruise" (normal operation) level, wind generation will be dispatched at 40% nameplate, and peaking generation will only be online in peak cases. Dispatches for less prevalent technologies, such as solar and storage, will be determined on a case-by-case basis.

d) Facility Outages

Known outages (six months or longer) and outages of equipment that have a replacement lead time of 1 year will be modeled in a sensitivity. Results from this sensitivity will be for informational purposes only. This will not be required for studies evaluating long term system changes.

e) System Performance Criteria and Equipment Ratings

System performance is evaluated in accordance with MPC's criteria and equipment ratings as defined in the MPC Planning Criteria. The models incorporate facility ratings and dynamic modeling assumptions that have been submitted by transmission owners through regional model-building efforts. System voltage criteria is monitored through input files and/or base case data. For the purposes of this document, applicable facility rating or applicable system performance criteria shall mean the continuous rating for system intact conditions and the emergency rating for post-contingency conditions.

In addition, interconnection studies are performed in accordance with facility connection requirements. MPC's connection requirements are documented in MPC Generation & Transmission & End Use Interconnection Requirements[6].

Criteria for non-MPC facilities will be applied based on the appropriate entity's planning criteria.

f) Facility Loading

Pre- and post-contingent loading of facilities will be calculated based on MVA at the actual voltage.

g) Events/Contingencies

For steady state, a comprehensive list of NERC Category P0 through P7 events will be run. In the case of MPC equipment, P4 events (fault plus breaker fail) are considered identical to P2 events (internal breaker fault). Multiple events that effectively simulate identical steady state responses will not be modeled; only one of these events will be run.

[6] Minnkota Power Cooperative, Inc. *MPC Generation & Transmission & End Use Interconnection Requirements.*

For dynamic stability, a reduced set of P0 through P7 events that simulate the worst system responses will be run. The events are reduced for the sake of time efficiency. Running a comprehensive set of TPL events in stability is not feasible for ongoing study processes. This event set will be chosen based on engineering judgment.

"Extreme events" may also be run for either steady state or dynamic stability analysis, based on engineering judgment.

h) System Adjustments

System adjustments may include automatic or manual actions, such as switching of equipment or re-dispatch of generation. Most of these actions are permissible as long as it's reasonable to assume that the action can be implemented within 30 minutes. System adjustments refer to actions taken after the first contingency in P3 and P6 events, as well as a P1 through P7 event. They are implemented as a way of reaching continuous/normal ratings before they take effect.

Re-dispatch of generation must adhere to the following:

- All generation utilized in the re-dispatch must have a generation distribution factor on the monitored facility of at least 3%.
- Only dispatchable generation may be increased. Any generation type may be reduced according to the unit's operating limitations.
- No more than 1,000 MW of generation shall be adjusted in the re-dispatch.

Following any P1 through P7 event resulting in system conditions that exceed normal (continuous) limits, it is assumed that the system can be returned to within normal (continuous) limits using system adjustments. Exceeding emergency limits is never allowed.

i) Sensitivities

Sensitivity models may be analyzed if different scenarios exist that could reasonably have more severe results than the base models. These sensitivities could include, but are not limited to, variations such as system interchange, load distribution, and/or generator dispatch.

3. Significantly Affected Facilities

For studies associated with the granting of interconnection or transmission service, Minnkota identifies Significantly Affected Facilities (SAF). These are facilities which violate system performance criteria (see above) and experience non-trivial impacts. Screening will be performed at 90% for DC screens and 100% for AC screens.

Distributions Factors (DF) for determining SAFs will be calculated based on the flow MVA in a screening analysis using the following equation.

$$DF = \frac{\Delta_{MVA}}{MW_{Project}}$$

Where Δ_{MVA} is the change in MVA between the pre and post-project cases, and $MW_{Project}$ is the MW of the interconnecting project (generator or load).

The DF for studies that do not include generation or load projects, such as transmission interconnection studies, will have $MW_{Project}$ equal to the applicable seasonal rating (SOL) of the monitored facility or interface.

In all studies associated with granting of interconnection or transmission service, violations of the applicable system performance criteria will be captured and reported if they exceed the following thresholds:

- Thermal: DF greater than 3% AND an impact greater than 1 MVA
- Voltage: impact greater than 0.01 p.u. (applies to all types of voltage analysis)

New interconnection and transmission service studies will not flag post-contingent thermal and voltage performance which exceeds a facility's continuous rating but not the facility's emergency rating, as it is assumed that the post-contingent corrective action would be to curtail the new service.

Minnkota requires mitigation for any violations of the applicable system performance criteria and maximum impact criteria. Minnkota's maximum impact criteria are specific to the type of system change being evaluated and are further defined in subsequent sections. For non-Minnkota transmission, Minnkota will use reasonable efforts to apply maximum impact criteria as defined by the applicable party.

D. Mitigation

Mitigation may be accomplished by constructing new facilities or upgrading existing facilities. Depending on what is being evaluated, alternative mitigations (such as operating guides, Remedial Action Schemes (RAS), automatic load shedding, and dynamic ratings) may also be permissible. In all cases, the mitigation must result in acceptable system performance according to the NERC TPL standards and the MPC Planning Criteria. For facilities belonging to other Transmission Owners or covered by other Transmission Service Providers, the policy of the appropriate entity will be used in determining mitigation options.

Requirements for use of alternative mitigation options on MPC facilities are provided below. MPC permits certain types of mitigation on an interim basis only. Interim mitigations are allowed for up to 5 years to allow time for permanent upgrades to be completed. Mitigation by operating guide or RAS is only allowed on an interim basis unless otherwise noted in this section. Mitigation by dynamic ratings or automatic load shedding is allowed on a permanent basis unless otherwise noted in this section.

1. **Remedial Action Scheme (RAS)**

   RAS's may not be used to mitigate system intact conditions. Firm delivery will not be granted if the source generator relies on RAS mitigation for TPL event types which do not allow interruption of firm transmission service.

   RAS must be designed in accordance with applicable NERC PRC standards.

   Existing RAS will continue to be allowed on a permanent basis if the original intention of their installation was on a permanent basis. For each RAS already placed in service on October 1st, 2015 on the MPC System, periodic reviews will be performed to ensure that the RAS is deactivated by MPC if and when the conditions requiring its use no longer exist, or when system improvements necessary to remove the RAS are in service.

2. **Operating Guides**

   When an operating guide is used for mitigation, generation curtailment or other system adjustments must be managed in such a way that steady state conditions do not violate the continuous ratings. Additionally, system conditions must be maintained such that the next contingency will not result in violation of applicable emergency ratings. Operating guides may only be used to the extent that RC tools are capable of monitoring the system for the applicable contingency and mitigating against it. The operating guide is also subject to the RC's commitment toward implementing the measures that are required.

   When an operating guide is used for mitigation of generation interconnection impacts on an interim basis, it must include language that requires curtailment or redispatch before constraint binding occurs in the congestion management process.

   An operating guide may be used to mitigate risk of thermal overload, low voltage (including voltage collapse) or dynamic instability. Mitigation by operating guide will involve management of system conditions so that post-contingent performance is stable and an adequate security margin exists.

   Operating guides are allowed on a permanent basis only if they are being used to apply dynamic ratings.

3. **Dynamic Ratings**

   Dynamic ratings may be allowed as permanent mitigation (including Interconnection and transmission service request mitigations) on facilities as per the MPC Facility Ratings Methodology.

4. **Automatic Load-Shedding**

   Automatic load-shedding may be used to mitigate risk of low voltages (including voltage collapse). The response must be proven to be sufficiently fast to meet the margin requirements of the appropriate MPC criteria, as demonstrated by relevant studies and careful application of engineering judgment.

An intentional delay is allowed before tripping of load in order to coordinate with protective relays, so as to prevent tripping of load during a fault. A delay of up to 5 seconds before tripping of load is assumed to be instantaneous.

Automatic load-shedding must follow applicable NERC requirements. Automatic load shedding is not an acceptable mitigation for impacts caused by interconnection, or for granting of firm delivery.

E. Corrective Action Plans (CAPs)

When it is determined that mitigation is required on a MPC facility, a Corrective Action Plan (CAP) will be developed to describe mitigation options as detailed below:

- Documentation of the system deficiency and the associated action(s) needed to achieve the required system performance
- Documentation of studies identifying the system deficiency
- Documentation of alternatives considered
- Required In-service date
- Estimated lead time
- Schedule of implementation

A standalone CAP will typically not be created for studies associated with granting of interconnection or transmission service. Instead, this information will be documented through the relevant System Impact Study and Facilities Study.

IV. Evaluations of Interconnection Requests

Interconnection studies shall follow the same methodology and mitigations as described above, with the exceptions noted in this section.

MPC interconnection studies will evaluate system performance of new facilities in accordance with the MPC interconnection procedure documents, including End Use Interconnection Procedures[7], Transmission Interconnection Procedures[8], and Large Generator Interconnection Procedures[9].

A. Coordination

MPC uses the ad hoc coordination and confirmation of participation approach for interconnection studies as described in MPC Generation, Transmission, and End Use Interconnection Requirements.

Specific procedures for coordination of generation interconnection studies with MH and MISO are defined in the MH-MPC-MISO GIR and TSR Coordination and Notification Procedure.

[7] Minnkota Power Cooperative, Inc. *MPC End Use Interconnection Procedures.*
[8] Minnkota Power Cooperative, Inc. *MPC Transmission Interconnection Procedures.*
[9] Minnkota Power Cooperative, Inc. *MPC Large Generator Interconnection Procedures.*

B. Posting & Retention

Interconnection studies will be retained for the life of the applicable generator, or ten years at a minimum. Non-generation interconnection studies will be retained for a minimum of five years.

C. Methodology

1. Analysis

Default study types for new interconnections are provided in MPC's interconnection procedure documents. The following sections provide additional details and/or types of analysis required for particular interconnection types.

a) Steady State Analysis

For generation cluster studies, the following methodology will be used.

A post-project case (post case) will be created by adding the study generators and associated interconnection facilities to the base case. The study generators shall be turned on and dispatched as described in the Generation Dispatch section below. The post case will undergo a contingency screen to identify monitored element and contingency pairs which are significantly loaded (including system intact violations of continuous facility ratings). The loadings will be recorded for the post and Base Cases and distribution factors will be calculated by using the Monitored Sensitivity function in PSS MUST. Filtering will also be used to identify significantly loaded facilities which are impacted by 20% or more of their applicable facility rating or which have a monitored element or contingency adjacent to a study generator's POI.

b) Short Circuit Ratio

MPC will apply appropriate short circuit ratio (SCR) limits on generator interconnections which involve power electronics. A minimum SCR threshold of 3.0 for all WTG types will be used to determine if a manufacturer analysis (such as an EMTP study) is required for a WTG interconnection. Alternatively, if a manufacturer has a design minimum SCR threshold that value shall be used.

A calculated SCR above or below the aforementioned limit is not an absolute indication of stability; therefore, mitigation of operational instability will be required following interconnection. This mitigation will likely be relegated to control changes.

For more detail on SCR, see *MPC Generation and Transmission and End Use Interconnection Requirements.*

c) Power Factor Requirements for Non-synchronous Generation

For a non-synchronous generator, MPC will estimate the need for the Interconnection Customer to provide reactive power capability in addition to the dynamic capability provided by the generator/inverter in order to meet the requirements established in

MPC Generation and Transmission and End Use Interconnection Requirements[10]. Additional reactive support needs identified in this analysis will be included in the study models. The following methodology will be used to establish reactive power requirements.

A synchronous condenser with infinite capacity will be modeled at the Point of Interconnection (POI). Power factor measurements are taken at the high-side of the generator substation. Three tests will be performed, as follows:

1. Set the Generating Facility to its maximum real power output and maximum dynamic reactive power injection capability. Set the synchronous condenser at the POI to control voltage at the POI to MPC's minimum post-contingent voltage criteria. Measure the power factor. If necessary, add switched capacitors to achieve reactive power injection in accordance with MPC's power factor criteria.
2. Set the Generating Facility to its maximum real power output and maximum dynamic reactive power absorption capability. Set the synchronous condenser at the POI to control voltage at the POI to MPC's maximum post-contingent voltage criteria. Measure the power factor. If necessary, add switched inductors to achieve reactive power absorption in accordance with MPC's power factor criteria.
3. Set the Generating Facility to zero real power output and corresponding maximum dynamic reactive power absorption capability. Set the synchronous condenser at the POI to control voltage at the POI to MPC's maximum post-contingent voltage criteria. Note any reactive power injection from the high-side of the generator substation toward the Transmission System. If necessary, add switched inductors to eliminate all reactive power injection in accordance with MPC's power factor criteria.

If necessary, reactive devices will be modeled in steps based on MPC's instantaneous voltage change criteria as found in the *MPC Generation and Transmission and End Use Interconnection Requirements*. The change in voltage will be measured with the WTGs off-line and switched devices locked.

Interconnection facilities, such as collector systems and wind turbine transformer equivalents, are commonly modeled based on generic assumptions in Interconnection Studies. Interconnection Customer should confirm sizing of reactive devices based on actual interconnection facility designs when they are known to ensure that the Generating Facility meets the requirements of the *MPC Generation and Transmission*

[10] Per FERC Order 827, switched inductors and capacitors may only be used to compensate for reactive power charging and consumption from the collector system and the transformer at the generator substation.

and End Use Interconnection Requirements and the generator's interconnection agreement[11].

d) No-Load Analysis

The purpose of the no-load analysis is to quantify the reactive power exchange of a wind farm's lead line with the grid when there is no wind (and consequently no real power generation). Engineering judgment will be used to determine whether no-load analysis is required based on the strength of the bus at the POI and the length and voltage of the generator's lead line. Models for no-load analysis will be created from the summer off-peak case by disconnecting local wind machines (but not their collector systems or power factor correction equipment) and taking other actions based on engineering judgment.

Following P0 or P1 events, the system must be able to be restored to continuous voltage criteria using reasonable system adjustments that can be implemented for the duration of a long term outage. Opening transmission elements or reducing other generation is not permissible. If system performance criteria is violated in the study case and voltage cannot be restored to normal voltage criteria, the wind farm developer will be required to provide mitigation (reactor, wind turbine upgrade, etc.) in addition to meeting the power factor requirements set forth above.

No-load analysis may also be performed as determined to be necessary by engineering judgment in situations not involving wind turbines.

e) Net Zero Generation Interconnection

Net Zero generation interconnection is defined as a generator interconnecting at a location where generation already exists and not increasing the combined maximum power output at that location.

In the case of a net zero generation interconnection, steady state thermal analysis will not be required. If the net zero generator is able to demonstrate comparable reactive support as the original system topology (prior to the net zero generator interconnection), steady state voltage analysis and voltage stability analysis will also not be required.

2. Modeling

a) Load

The following tables document which load models will be selected for interconnection analysis depending on the type of interconnection and analysis being performed.

[11] FERC Order 827 has defined standard power factor requirement language for inclusion in interconnection agreements for non-synchronous generation.

Table: Default Load Selection by Study Type

Analysis Type	Summer Peak	Winter Peak	Summer Off-Peak High Transfer	Light Load
Steady State	X	X	X	X (if required)
Transient Stability			X	
Voltage Stability (generation only)	X	X	X	
Short Circuit/SCR	Short circuit model			
No-load (wind only)				X

Table: Load Selection by Interconnection Type

Interconnection Type	Summer Peak	Winter Peak	Summer Off-Peak High Transfer	Light Load
Baseload Generation	X	X	X	
Peaking Generation	X	X	X	
Wind Generation	X	X	X	X (no-load)
Solar Generation	X		X	
Energy Storage (near generation)	X (inject)	X (inject)	X (inject)	X (absorb, no-load)
Energy Storage (near load)	X (absorb)	X (absorb)	X (absorb)	X (inject)
Transmission	X	X	X	X (no-load)
Load	X	X		

b) Years

Out-year models will be required for interconnection analysis.

Near term models will only be included in the main analysis or in a sensitivity as is deemed appropriate by engineering judgment, as near term model may produce results which are valid for a relatively short period of time with respect to the planning horizon. Mitigation options for constraints that only appear in the near term models will be reviewed on a case-by-case basis.

c) Generation Dispatch

Generation interconnection studies will evaluate the generator under study at its requested capacity for all load levels required by the table above, with the following exceptions:

- For any generation interconnecting to a transmission or distribution facility which is primarily a load serving facility, the winter peak case may be replaced with a light load case for steady state analysis. The light load case

will primarily be used to identify maximum reverse loading on transmission and distribution facilities which were traditionally load serving.

- Energy storage devices will be modeled at their maximum injection or absorption levels as defined in the table above, unless otherwise qualified in this document or determined to be reasonable by engineering judgment.
- If an energy storage device is not seeking to provide capacity, reserve, or other services which require it to be available for either full injection or full absorption at any time, certain load models may not be necessary.

Regional generation will be dispatched in a stressed, yet credible dispatch. Emphasis will be placed on maximizing generation which is electrically close and, in the case of renewable generation, geographically close (with the following exceptions). Modifications to the case selection and dispatch procedures above are permissible based on engineering judgment, and in some cases, those modifications may lead to more stressed system conditions.

- Local baseload units will be set to URGE in high export cases and cruise in peak cases.
- Renewable generation which is in the region but not close to the project will be modeled at reduced levels, typically being set to 40% in summer off-peak high export models and to 20% in peak models.
- When studying a peaking unit, other peaking units will be turned on and renewable generation will be turned off in the summer off-peak case. This will typically result in the case not being a high transfer case.
- When studying non-peaking units, peaking units will be turned off in summer off-peak and light load cases.

Sinks for generation dispatch adjustments, including the generator under study, will generally be to the RTO footprint in which the generator resides. Generators close to the project under study may be excluded from regional scaling to ensure all local generation is maximized.

For transmission interconnection studies involving larger networked transmission Facilities, studies will, at a minimum, demonstrate two scenarios with high transfer across the new Facility in either direction. Not all load models may be required.

d) Sensitivities

In the event that MPC is aware of substantial differences in system flow bias near the point of interconnection between the study model and actual system flows, MPC will consider running an additional sensitivity analysis to confirm that the injection constraints cover the actual anticipated flows accurately.

e) Events/Contingencies

For generation interconnection, mitigation will be required for all TPL category P0-P7 events, unless system adjustments are permitted as an initial condition (P3 and P6). If system adjustments are allowed, it is assumed that the generator under study may be reduced to mitigate its impact on any constraints.

For transmission and end-use interconnection, mitigation will be required for all TPL category P0-P7 events.

f) Interconnection Queue Coordination

MPC grants priority based on interconnection queue request date.

MPC will coordinate with the interconnection queues of neighboring TP's as follows.

(i) MISO:

Queue coordination is coordinated per the MH-MPC-MISO GIR and TSR Coordination and Notification Procedure, which is attached to this BPM.

(ii) MH:

Queue coordination is coordinated per the MH-MPC-MISO GIR and TSR Coordination and Notification Procedure, which is attached to this BPM.

(iii) Southwest Power Pool (SPP):

MPC coordinates with SPP on a case-by-case basis.

(iv) Square Butte Electric Cooperative:

MPC coordinates with the Square Butte Generation Interconnection Queue based on interconnection queue request date.

Interconnection re-studies may be required if projects proceed out-of-queue with respect to other entries in MPC's queue, or with respect to neighboring Transmission Service Provider queues. Re-studies will not be initiated due to minor changes in transmission configuration, facility ratings, or load levels (although these changes may be included if a re-study is otherwise required).

D. Maximum Impact Criteria and Cost Allocation

MPC requires mitigation of impacts which exceed the applicable system performance criteria and which exceed the applicable maximum impact criteria. For non-Minnkota transmission, Minnkota will use reasonable efforts to apply maximum impact criteria as defined by the applicable party.

MPC will seek to optimize cost shared transmission solutions to the mutual benefit of all parties.

1. Single Interconnection

MPC's maximum impact criteria for interconnection evaluations are defined as SAFs which meet the following criteria:

- Thermal
  - The new facility has a larger than twenty percent (20%) distribution factor on the overloaded facilities under post contingent condition or five percent (5%) distribution factor under system intact condition, or
  - The overloaded facility or the overload-causing contingency is at the new facility's outlet (POI for a generator or load, either terminal for transmission), or
  - The megawatt impact due to the new facility is greater than or equal to twenty percent (20%) of the applicable facility rating of the overloaded facility
- Voltage
  - The voltage change due to the new facility is greater than 0.01 p.u. of the nominal system voltage

2. Generation Cluster

a) Facility Upgrade

A generator in a group study will participate in mitigating an upgrade if it meets any of the maximum impact criteria defined for individual projects in Section IV.D.1 above. Additionally:

- For any constrained facility, where the cumulative megawatt impact of the group of study generators is greater than 20% of the rating of the facility, then all study generators whose individual megawatt impact is greater than 5% of the rating of the facility in the direction of flow on the facility will be responsible for mitigating the cumulative megawatt impact constraint.
- For any constrained facility, where the cumulative voltage impact of the group of study generators is greater than 0.01 p.u. of the nominal system voltage, then all study generators whose individual voltage impact is greater than 0.003 p.u. of the nominal system voltage will be responsible for mitigating the cumulative voltage impact constraint.

Costs will be allocated using a pro rata share of the MW or voltage impact of each impacting generator. In other words, a generator's portion of the cost of an upgrade will be determined by the incremental MW or voltage impact of that project relative to the MW or voltage impacts of the other projects in the group which are also responsible for mitigating the same facility.

b) New Transmission Facility

If new transmission is identified as an alternative to facility upgrades, cost allocation and cost responsibility will be determined according to the following principles.

Cost allocation for new transmission facilities (transmission lines and transformers) will be determined based on the study generator's avoided cost of Interconnection Facilities, Network Upgrades, and Affected System Upgrades (based on cost estimates provided in ISIS) relative to the avoided cost of other study generators in the cluster. Avoided costs for Network Upgrades and Affected System Upgrades will be calculated according to the facility upgrade cost allocation provisions in Section IV.D.2.a).

Clarifications and Special Circumstances

The following list provides exceptions and clarifications to the general principle of cost allocation based on avoided cost for new transmission alternatives.

- New substations and/or substation terminal equipment associated with the new transmission line will be considered part of the new transmission line for purposes of cost allocation, except as noted below.
- Reactive devices which are built as part of a new transmission facility (e.g. a line-connected reactor) will be considered part of that new transmission facility for purposes of cost allocation. Reactive devices which are required for mitigation of voltage violations will be allocated costs consistent with the Facility Upgrade methodology in Section IV.D.2.a) above.
- If new transmission is proposed as an alternative to facility upgrades and results in additional mitigation requirements, the responsibility for the additional mitigation requirements will be shared in the same ratio as the new transmission facility.
- If a new parallel transmission facility is required because it is not feasible to uprate an existing facility, the total avoided cost will include both the cost for the new parallel transmission facility, and any reduced mitigation costs on other facilities due to the elimination of that line as a single contingency.
    - Example: A transmission line is overloaded and it is determined that building a new parallel transmission line is the only feasible mitigation. The cost of the new transmission line is $20M. Cost allocation based on MW impact is determined to be $15M for Generator A and $5M for Generator B. The line was also the critical contingency for a different circuit which required a $5M upgrade. The cost allocation for that upgrade was solely to Generator A. The cost of the new transmission line would be allocated as follows: Generator A had an avoided cost of $15M + $5M. Generator B had an avoided cost of $5M. Therefore, Generator A and Generator B would pay 80% and 20% of the new line cost, respectively.
- If a new substation serves as both a study generator's POI and a terminal for a new transmission facility, the Interconnection Customer who uses that

substation for its POI will pay the full cost of the minimum substation required for interconnection (typically a three breaker ring bus for a line tap). Substation expansions (e.g. adding a fourth breaker to the ring bus) for termination of the new networked transmission facility will be cost shared in the same manner as the new transmission facility that requires that substation expansion.

- If a study generator's proposed lead line is networked as a system upgrade to benefit multiple study generators, the lead line will be cost shared according to the same methodology presented for new transmission facilities. The lead line will be counted as an avoided cost for the study generator who would have built the line for its interconnection facilities.
    - Example: Generator A proposes to build a 10 mile lead line to reach its POI at a cost of $10M. The study reveals that extending the lead line 5 miles from the generator to another point on the transmission system would cost $5M and relieve Generator A and Generator B of $3M and $4M of upgrades, respectively. The following calculations would apply:
        - Generator A's percentage allocation of the lead line will be ($10M + $3M) / ($10M + $3M + $4M) = 76%
        - Generator B's percentage allocation of the lead line will be ($4M) / ($10M + $3M + $4M) = 24%
        - Generator A's percentage allocation of the new 5 mile line will be $3M / ($3M + $4M) = 43%
        - Generator B's percentage allocation of the new 5 mile line will be $4M / ($3M + $4M) = 57%
        - The total cost in this example is reduced from $17M to $15M. Generator A's cost dropped from $13M to $9.75M, while Generator B's cost increased from $4M to $5.25M. To ensure mutual benefit, the $1.25M cost increase to Generator B would be shifted to Generator A. This ensures that Generator B would not be harmed. Generator A still benefits from a reduction in cost of $2M and also receives support from Generator B for the alternative project.

3. Affected System Analysis

When performing affected system analysis to determine impacts of neighboring providers' queued generation interconnection requests on the MPC system, MPC will apply its standard generation interconnection impact criteria for ERIS requests. MPC will apply its standard transmission service impact criteria for NRIS requests, in recognition of the similarity (and in some cases identical treatment) between NRIS and firm delivery service.

V. Evaluations of Long-term Transmission Service Requests

Delivery studies shall follow the general procedures and mitigations as described in the general section, and any exceptions are noted in this section.

MPC delivery studies will evaluate the impact of new Transmission Service Requests (TSRs) on system performance in accordance with the MPC Open Access Transmission Tariff [12](OATT).

A. Coordination

Specific procedures for coordination of delivery studies with MH and MISO are defined in the MH-MPC-MISO GIR and TSR Coordination and Notification Procedure.

B. Posting & Retention

Transmission service study reports will be retained for a minimum of five years after the date of issue. If service is granted, the associated report will be retained until the sooner of a) five years after the service period ends, or b) five years after the study is superseded by another study.

C. Methodology

1. General System Impact Analysis

The impact of long-term TSRs on the transmission system will be evaluated using conventional steady state analysis as described elsewhere in this document. More specific information can be found in the Modeling section below. Steady state analysis is usually sufficient to determine system impacts of a TSR because the TSR is usually associated with a resource for which an interconnection system impact study has already been done. However, other types of analysis, such as voltage stability analysis or dynamic stability analysis, will be done for the TSR system impact study if determined to be necessary based on engineering judgment.

2. Flowgate Impact Analysis

For long-term TSRs, Flowgate impact analysis will consist of an online and/or an off-line analysis, depending on the start date, stop date, and duration of the TSR. The online and off-line analyses are used to determine if the proposed projects will adversely impact regionally constrained interfaces (PTDF and OTDF Flowgates).

Online analysis is performed by the OASIS Automation Tool[13]. All long-term Transmission Service requests which are active within 18 months of the queue date are evaluated using the OASIS Automation Tool to ensure that there is enough capacity available during the 18 month AFC window. While evaluating TSRs using the OASIS automation tool, MPC uses the queue date of the TSR as the first day for the AFC verification for the next 18 months.

[12] Minnkota Power Cooperative, Inc. *Open Access Transmission Tariff.*
[13] The results from the OASIS Automation Tool are housed on the webTrans system.

Off-line analysis is done by monitoring of regional Flowgates in the general TSR system impact analysis to cover the planning horizon beyond 18 months. Monitoring is accomplished through the use of a PSS®MUST monitored element data file which contains Flowgate definitions and ratings. The definitions include monitored elements (including multiple elements per Flowgate where applicable) and, for OTDF Flowgates, the contingent elements. The ratings have been adjusted to include TRM and CBM. Specific information regarding the off-line studies can be found in the Modeling section below.

MPC staff will select one or both types of network analysis as follows:

1. If the start date and the end date of the TSR are within the next 18 months of the queued date, then the OASIS Automation tool results are sufficient to either accept or refuse a TSR, unless MPC planning staff believes that further analysis is required and an off-line analysis is warranted.
2. If the start and end date of the TSR are beyond 18 months of the queued date, then MPC does not use the OASIS Automation tool results. In such scenarios, MPC will rely on the off-line analysis only.
3. If the start date of the TSR is within the next 18 months of the queued date and the end date is beyond the next 18 months of the queued date, MPC uses the OASIS Automation tool and off-line analysis.
4. If the OASIS Automation tool indicates that one or more Flowgate AFCs will be exceeded by the requested transmission service then MPC will take appropriate action depending on the term of the requested transmission service. MPC will grant service up to the maximum level that does not exceed the AFC on any Flowgate.
    a. If the start date and the end date of the TSR is within the next 18 months of the queued date, then MPC will use the OASIS Automation tool results exclusively in determining how much transmission service can be granted.
    b. If the start date of the TSR is within the next 18 months and the end date is beyond the next 18 months, then MPC will use the OASIS Automation tool to determine how much transmission service can be granted during the 18-month period. The off-line analysis is required to assess system availability beyond 18 months.

3. Modeling

The following details apply to the general analysis (as well as off-line flowgate impact analysis if required) for a long term TSR study. Models are consistent with regional transmission planning processes. Specifically, the models are taken from the MISO Transmission Expansion Planning process.

a) Load

Load representing a summer peak case will be the primary case used due to reduced summer ratings.

Subject to engineering judgment, load representing a winter peak or summer off-peak case may also be used. Winter peak will typically be added when evaluating TSRs to serve native load on the MPC system. Summer off-peak will typically be used when evaluating through and out TSRs which sink outside the MPC transmission system.

b) Years

A near term and an out-year case will be selected for summer peak evaluation. Only out-year cases will be used for load profiles other than summer peak. The near term case may be omitted, subject to engineering judgment, if there are no significant topology changes anticipated prior to the out-year time frame.

c) Generation Dispatch

The sink for TSRs requesting Network Integration Transmission Service will be selected from other dispatchable NITS resources on the MPC transmission system.

Point-To-Point service evaluation is dispatched to resources in the specific sink area identified in the TSR. Sink area resources are selected so as to approximate an economic dispatch. Economic dispatch is based on knowledge of the resources, such as merit order lists or age and fuel type. In the absence of sufficient knowledge to select specific resources, all generation in the area is reduced pro rata.

Prior queued TSRs which produce parallel flows (primarily based on the TSR's source) will be included in the study models. Resources will be dispatched in a manner consistent with transmission planning processes, as evidenced in models from the MISO Transmission Expansion Planning process. Minnkota and 3rd party resources which have firm service arrangements and which are within the bounds of, or directly adjacent to, the MPC transmission system will be specifically reviewed to ensure that the dispatch includes all firm transfers in the prevailing flow direction of the TSR under study. MPC footprint generation will be dispatched at maximum firm cruise levels in off-peak cases to reflect service both to MPC load and to the MISO market.

d) Events/Contingencies

At a minimum, TPL category P0-P5 events will be run as part of the standard steady state analysis. Mitigation is not required for violations stemming from TPL contingencies that allow Interruption of Firm Transmission Service.

Additionally, Flowgate impacts will be monitored by inclusion of regional Flowgates in the monitored element file. Flowgate definitions will include the monitored element, contingency, and Flowgate rating (TFC – TRM).

e) System Adjustments

If a violation results from a P3 contingency, system adjustments will be permitted as follows: generation from the BA/LBA of the outaged generator will be turned up to cover the loss of resource. If sufficient capacity is not available from the BA/LBA, the

associated RTO's contingency reserve group will be utilized to cover the remainder. Curtailment of firm service from another unit is not permitted as a system adjustment in order to grant firm service to a new unit.

f) Losses

Incremental losses due to the TSR are made up by maintaining area interchange, using the area swing buses designated in the benchmark planning models. To accomplish this, first the actual net area interchange is checked in the benchmark models, then the desired net area interchange of each area is set equal to the actual net area interchange value, and then the models are solved with area interchange control enabled. In the post-TSR models, the desired net interchange of the source area is incremented by the TSR amount, the desired net interchange of the sink area is decremented by the TSR amount, and the models are solved with area interchange control enabled.

4. On-the-Path/ Off-the-Path Evaluations for Off-line Studies

Transmission system constraints, which include Flowgates, will be treated according to the following On-the-Path/Off-the-Path evaluation technique during off-line studies for transmission service: constraints on the transmission service path outside the Minnkota footprint are ignored, and constraints off the transmission service path are honored. If a request sources and sinks within the Minnkota footprint, both Minnkota and non-Minnkota constraints are honored. If a request sources in the Minnkota footprint and sinks outside the Minnkota footprint, constrained facilities owned by the sink/POD are ignored assuming that the customer will have to submit a request on the sink/POD entity's OASIS and that entity will be responsible for evaluation on facilities owned by it. Constraints on facilities that are not owned by Minnkota or the sink/POD entity are honored as third party limits since a request will not be submitted on that entity's OASIS. Similar logic is used when a request sources outside the Minnkota foot print and sinks inside the Minnkota footprint. The On-the-path/Off-the-path logic is honored for AFC only. For ASTFC, all Flowgates are honored irrespective of whether the Flowgate is On-the-Path or Off-the-Path.

For example, consider a TSR from Minnkota to SPP. The TSR is for a Minnkota owned source and the non-Minnkota sink is under the SPP Tariff. In this case, constraints on facilities that are under the SPP Tariff are ignored while evaluating this request, since the customer will have to submit a request on the SPP OASIS to complete the transmission service path. However, constraints on facilities owned by MISO are honored as third party limits for this request since the customer is not required to submit a request on the MISO OASIS. However, in the above example, if both SPP and MISO Flowgates show up as constraints for ASTFC, they are honored.

D. Maximum Impact Criteria

MPC requires mitigation of impacts which exceed the applicable system performance criteria and which exceed the applicable maximum impact criteria.

MPC's maximum impact criteria for transmission service evaluations are defined as follows:

- Thermal
  - PTDF greater than 5%
  - OTDF greater than 3%
- Voltage
  - The pre-project to post-project voltage change is greater than 0.01 p.u. of the nominal system voltage

For non-Minnkota transmission, Minnkota will use reasonable efforts to apply maximum impact criteria as defined by the applicable party.

MPC allows firm service to be granted when post-contingent loading is below the emergency rating. Post-contingent loading above the continuous rating will be reported in studies, but firm service can be granted as long as normal congestion mitigation procedures can be expected to relieve the overload.

If interconnection constraints exist for the source associated with new firm delivery service, the following limitations will be applied:

- Firm delivery service will not be limited by interconnection constraints caused by contingencies for which interruption of Firm Transmission Service is allowed
- For constraints caused by contingencies for which interruption of Firm Transmission Service is not allowed:
  - Firm delivery service will not be granted if mitigation for the interconnection constraint is accomplished by an operating guide or RAS
  - Firm delivery service will be limited to the MW amount at which there is no violation in the interconnection SIS
  - Firm delivery service will not be limited for mitigation by dynamic rating if there is reasonable assurance that the dynamic rating will be available any time the energy associated with the TSR is being delivered

VI. Revisions

Author	Description	Date
Will Lovelace	Original	10/1/15
Will Lovelace, Aaron Vander Vorst	Modified SCR language, added MH-MPC-MISO GIR and TSR Coordination and Notification Procedure	4/15/2016
Aaron Vander Vorst	Modified maximum impact criteria to remove engineering judgement and align with MISO criteria	5/31/2016
Aaron Vander Vorst	Expanded group study procedures, updated for FERC Order 827, updated SAF criteria and model year requirements	7/29/2016
Tim Bartel	Added Affected System analysis language for generator interconnections, modified near-term case requirements in TSR SIS modeling	5/11/2017
Tim Bartel	Minor revision to ad hoc process language in III.A. Other miscellaneous cleanup.	8/8/2017
Tim Bartel	Clarifications to the methodology in Section V (Evaluations of Long-Term TSRs). Use of flowgate monitor file, choice of sink based on economic dispatch, dispatch assumptions for existing firm service, and use of interchange control to cover losses due to the TSR.	10/5/2017

VII. References

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VIII. Attachment A

MH-MPC-MISO GIR and TSR Coordination and Notification Procedure

See attached document.

1. Application and Governing Agreements:

This coordination procedure applies to Manitoba Hydro (MH), Minnkota Power Cooperative (MPC), and the Midcontinent Independent System Operator (MISO). This procedure is effective as of the date this procedure is signed.

1.1 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.

1.2 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.

1.3 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.

2. Purpose:

The purpose of this coordination procedure is to coordinate Generation Interconnection Requests 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 Business Practices under each party's respective tariff(s).

3. 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.

Generator Interconnection Agreement or GIA – an agreement documenting the terms of interconnection service between a TSP and its customer

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 MH's Open Access Interconnection Tariff (OAIT))

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

Remedial Action Scheme – as defined by NERC standards

POR/POD – Point of Receipt/Point of Delivery as defined by each party's respective tariffs

Transmission Service Provider or TSP – as defined by NERC standards

4. Scope:

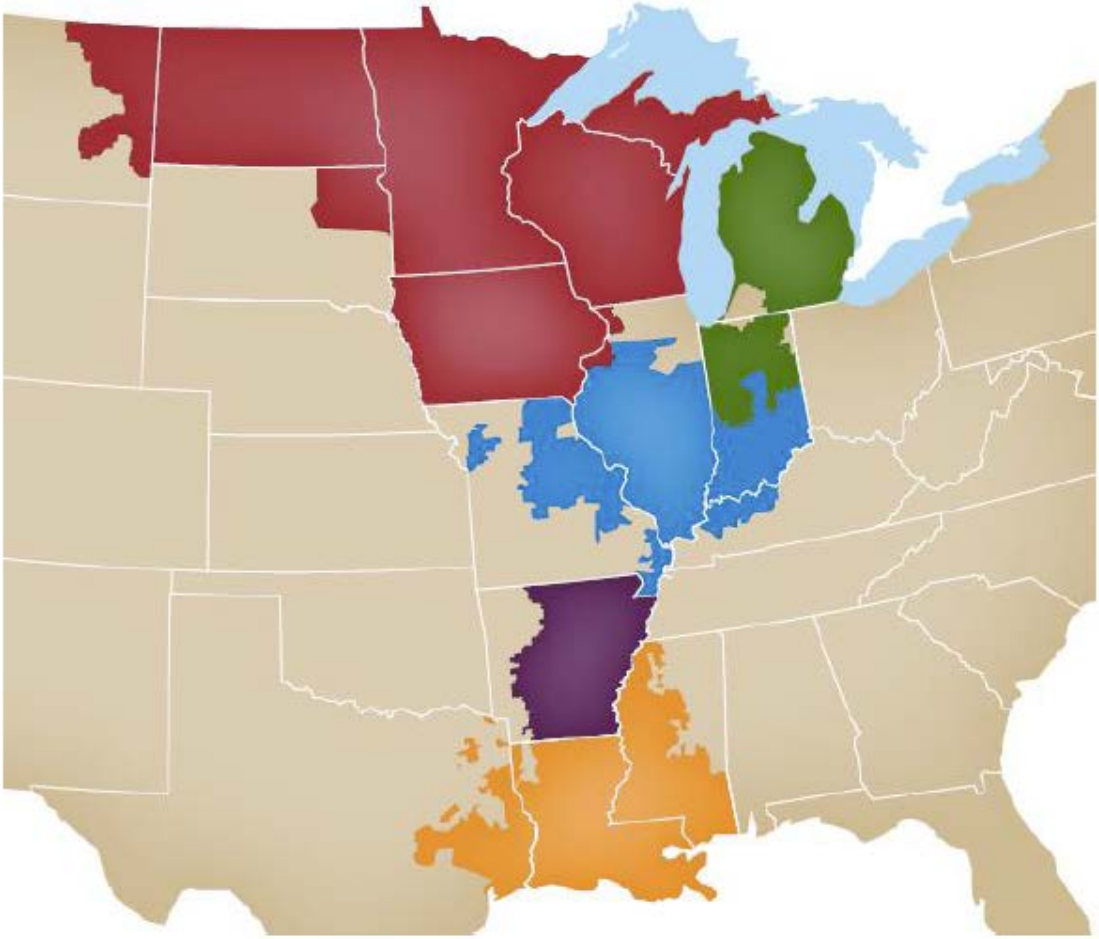
A GIR is deemed in scope for this coordination procedure as follows:

- All MISO North GIR for MISO

- All GIR for MPC
- 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[1] below captures the in-scope area for MISO at the time the agreement was executed.



A TSR is deemed within scope for this agreement as follows:

- MH will be considered an Affected System for TSRs requested under the MPC or MISO tariffs if the TSR has a POR or a POD from the following list:

[1] From MTEP 2014 - https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP14/MTEP14%20Book%201%20-%20Transmission%20Studies.pdf

    - ALTE, ALTW, CE, DPC, GRE, LES, MDU, MEC, MGE, MHEB, MP, MPC, MPW, NPPD, NSP, ONTW, OPPD, OTP, SMP, SPC, WAPA, WEC, WPS.
- MPC will be considered an Affected System for TSRs requested under the MH or MISO tariffs if the TSR has a POR or a POD from the following list:
    - GRE, MDU, MHEB, MP, MPC, NSP, ONTW, OTP, SPC, WAPA.
- MISO will be considered an Affected System for all TSRs requested under the MPC or MH tariff

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.

5. Procedure:

5.1 Generation Interconnection Requests:

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

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 the Impact Study Agreement is signed under the MH tariff
- The date that the Impact Study Agreement is signed under the MPC LGIP
- 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 a 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 date 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 date 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 the 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. 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.

5.1.2 Notice

The Host TSP will provide notice of GIRs identified in section 4 to the Neighboring TSPs:

- when a new Impact Study Agreement is signed for MPC;
- when a new Impact Study Agreement is signed for 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.

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 TSPs.

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 transmission owner 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 TSPs 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 TSPs can perform these impact studies. The Host TSP will allow the Neighboring TSP a minimum of two

months after the ad hoc kickoff call to complete their optional independent impact studies and provide information back to Host TSP regarding impact mitigations needed on their respective transmission systems. The Host TSP will allow the Neighboring TSPs 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 Interconnection Customer 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.

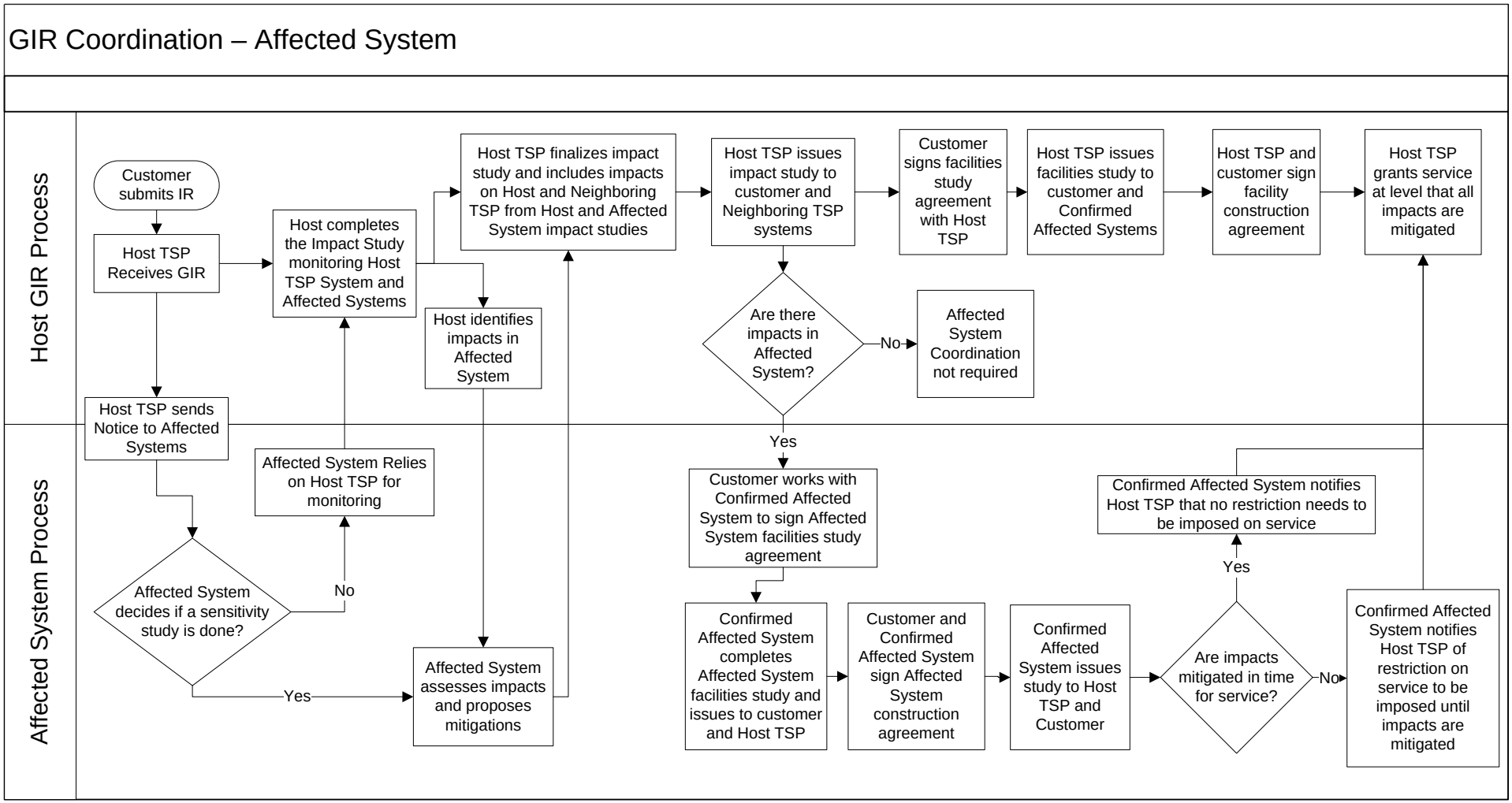
The Host TSP will promptly share impact study reports with the Affected Systems upon completion.

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 interconnection customer(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 Interconnection Customer upon request.


GIR Coordination – Affected System
Host GIR Process
Affected System Process
Customer submits IR
Host TSP Receives GIR
Host TSP sends Notice to Affected Systems
Affected System decides if a sensitivity study is done?
No
Yes
Affected System Relies on Host TSP for monitoring
Host completes the Impact Study monitoring Host TSP System and Affected Systems
Host identifies impacts in Affected System
Affected System assesses impacts and proposes mitigations
Host TSP finalizes impact study and includes impacts on Host and Neighboring TSP from Host and Affected System impact studies
Host TSP issues impact study to customer and Neighboring TSP systems
Are there impacts in Affected System?
No
Affected System Coordination not required
Yes
Customer works with Confirmed Affected System to sign Affected System facilities study agreement
Confirmed Affected System completes Affected System facilities study and issues to customer and Host TSP
Customer and Confirmed Affected System sign Affected System construction agreement
Confirmed Affected System issues study to Host TSP and Customer
Are impacts mitigated in time for service?
Yes
No
Confirmed Affected System notifies Host TSP that no restriction needs to be imposed on service
Confirmed Affected System notifies Host TSP of restriction on service to be imposed until impacts are mitigated
Customer signs facilities study agreement with Host TSP
Host TSP issues facilities study to customer and Confirmed Affected Systems
Host TSP and customer sign facility construction agreement
Host TSP grants service at level that all impacts are mitigated

5.2 Transmission Service Requests:

MISO, MH, and MPC have agreed to the following process by which Long Term Firm Transmission Service Request studies are conducted to determine the impacts of TSRs on each other's transmission systems. Coordination with Affected Systems is required by the parties' respective tariffs. This joint coordination of TSR studies serves to clarify the process by which that coordination is conducted for MISO, MH, and MPC.

5.2.1 Notice

The Host TSP will provide notice of new TSRs which fall within the scope in section 4 to the Affected System(s) once the TSR customer has signed an impact study agreement. The Host TSP will send an email with details of the associated TSR so that the Neighboring TSP can begin including the TSR in their models. The Host TSP will include the Affected Systems in the ad-hoc study group for a Host TSP TSR impact study. This notice shall be provided regardless of whether the Affected System is also a Host TSP.

5.2.2 Impact Study Obligations

There are two coordination scenarios to consider for a TSR:

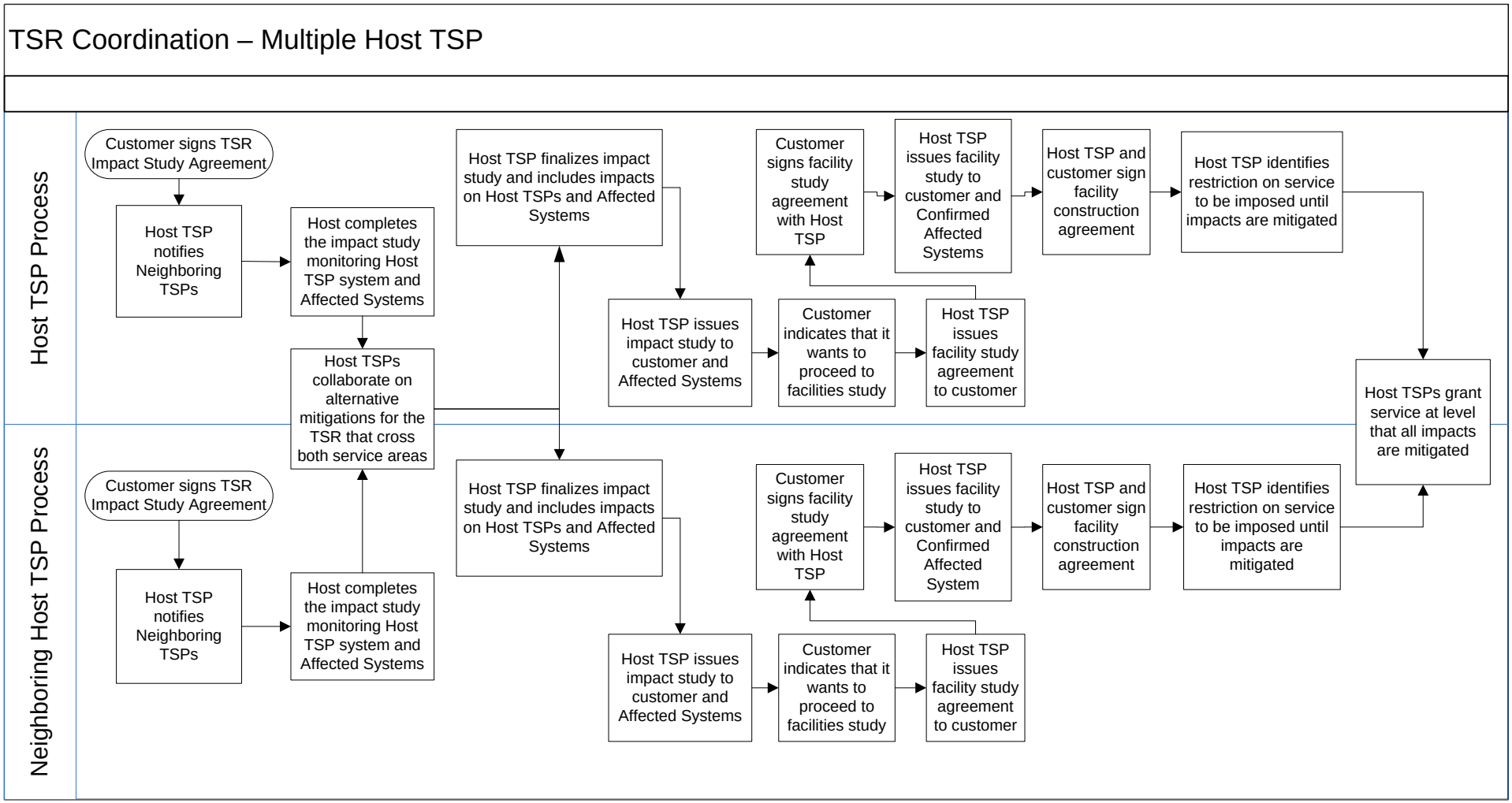
- when two or more of the parties are Host TSPs, and
- when only one of the parties is a Host TSP.

5.2.2.1 Process for a TSR that has more than one of the Neighboring TSPs as Host TSPs

The first scenario occurs when the transmission of energy from the source to the sink identified in a TSR is dependent on transmission service from two or more TSPs which are parties in this coordination procedure. In this scenario the study to evaluate the impact of the TSR on the Host TSP's transmission system will be completed by each Host TSP as per the Host TSP's tariff, Business Practices, and study methodology.

If one of the Neighboring TSPs is a non-Host TSP, the non-Host TSP will be deemed an Affected System by each Host TSP and all associated provisions related to Affected Systems coordination will apply, as stated in the second scenario below.

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.


TSR Coordination – Multiple Host TSP
Host TSP Process
Customer signs TSR Impact Study Agreement
Host TSP notifies Neighboring TSPs
Host completes the impact study monitoring Host TSP system and Affected Systems
Host TSPs collaborate on alternative mitigations for the TSR that cross both service areas
Host TSP finalizes impact study and includes impacts on Host TSPs and Affected Systems
Host TSP issues impact study to customer and Affected Systems
Customer indicates that it wants to proceed to facilities study
Host TSP issues facility study agreement to customer
Customer signs facility study agreement with Host TSP
Host TSP issues facility study to customer and Confirmed Affected Systems
Host TSP and customer sign facility construction agreement
Host TSP identifies restriction on service to be imposed until impacts are mitigated
Host TSPs grant service at level that all impacts are mitigated
Neighboring Host TSP Process
Customer signs TSR Impact Study Agreement
Host TSP notifies Neighboring TSPs
Host completes the impact study monitoring Host TSP system and Affected Systems
Host TSP finalizes impact study and includes impacts on Host TSPs and Affected Systems
Host TSP issues impact study to customer and Affected Systems
Customer indicates that it wants to proceed to facilities study
Host TSP issues facility study agreement to customer
Customer signs facility study agreement with Host TSP
Host TSP issues facility study to customer and Confirmed Affected System
Host TSP and customer sign facility construction agreement
Host TSP identifies restriction on service to be imposed until impacts are mitigated

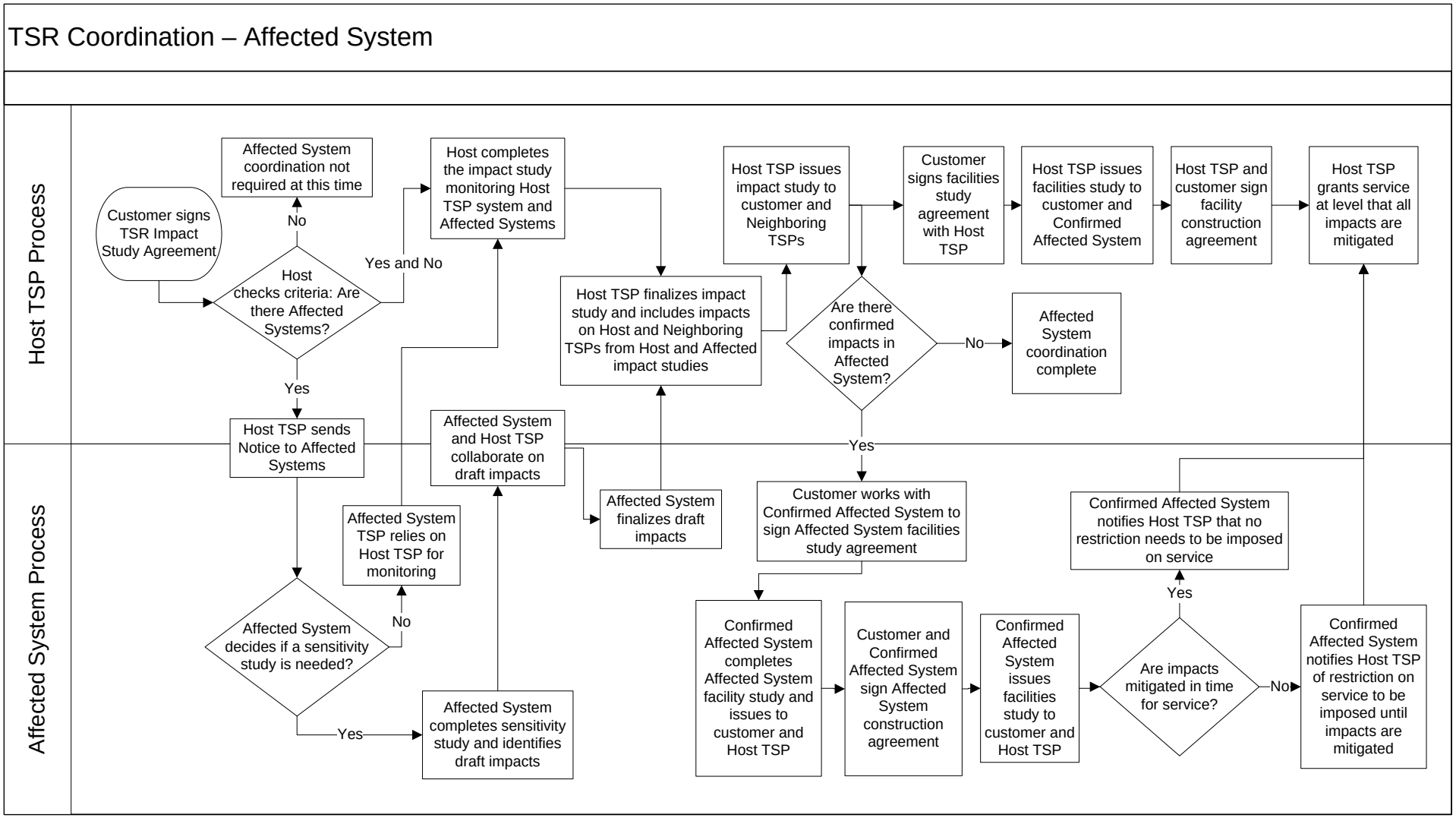
5.2.2.2 Process for Affected System Coordination

The second scenario occurs when the transmission of energy from the source to the sink identified in a TSR is dependent on transmission service from only one of the TSPs party to this coordination procedure. This scenario also covers treatment of a non-Host TSP when there is a TSR coordinated between two Host TSPs. If a Neighboring TSP is deemed an Affected System in accordance with section 4 Scope, the Host TSP will include the Affected System(s) in the coordinated study process by providing Affected Systems with an opportunity to perform a sensitivity impact study on their own transmission system to be included in the Host TSP's impact study report. The Host TSP shall forward to the Affected System(s) the information necessary for the Affected System(s) to study the impact of the TSR on their respective transmission systems.

The Host TSP will accept study results from the Affected System(s) regarding the impact of the TSR on the Affected System's transmission system until a date ten calendar days before the Host TSP's impact study is due to the TSR customer, provided that the Affected System will be allowed a minimum of 45 calendar days to complete their sensitivity study, unless otherwise agreed to. If the Host TSP determines that the study process is extended due to the complexity of the project, the same extension will be granted to the Affected System(s). Sensitivity studies conducted by Affected System(s) will use the methodology and criteria of the Affected System conducting the study.

The Affected System may either perform its own sensitivity study on the impact of the TSR on its transmission system for inclusion in the Host TSP's study report or may defer to the Host TSP's analysis for monitoring of its own transmission system. If the Affected System decides to perform its own sensitivity study, the time requirements for providing the results of the study to the Host TSP shall be as described above. If the Affected System's policies allow for the sharing of study models, a Customer can apply to obtain the study models from the Affected System by executing the required confidentiality agreements.

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.


TSR Coordination – Affected System
Host TSP Process
Affected System Process
Customer signs TSR Impact Study Agreement
Host checks criteria: Are there Affected Systems?
No
Affected System coordination not required at this time
Yes and No
Host completes the impact study monitoring Host TSP system and Affected Systems
Yes
Host TSP sends Notice to Affected Systems
Affected System and Host TSP collaborate on draft impacts
Affected System TSP relies on Host TSP for monitoring
Affected System decides if a sensitivity study is needed?
No
Yes
Affected System completes sensitivity study and identifies draft impacts
Affected System finalizes draft impacts
Host TSP finalizes impact study and includes impacts on Host and Neighboring TSPs from Host and Affected impact studies
Host TSP issues impact study to customer and Neighboring TSPs
Are there confirmed impacts in Affected System?
No
Affected System coordination complete
Customer signs facilities study agreement with Host TSP
Host TSP issues facilities study to customer and Confirmed Affected System
Host TSP and customer sign facility construction agreement
Host TSP grants service at level that all impacts are mitigated
Yes
Customer works with Confirmed Affected System to sign Affected System facilities study agreement
Confirmed Affected System completes Affected System facility study and issues to customer and Host TSP
Customer and Confirmed Affected System sign Affected System construction agreement
Confirmed Affected System issues facilities study to customer and Host TSP
Are impacts mitigated in time for service?
Yes
Confirmed Affected System notifies Host TSP that no restriction needs to be imposed on service
No
Confirmed Affected System notifies Host TSP of restriction on service to be imposed until impacts are mitigated

5.2.2.3 General Impact Study Obligations

During the course of the TSR impact study for both scenarios, the Host TSP will monitor the Affected Systems' transmission systems and provide the draft results of potential impacts to the Affected Systems. When the Host TSP performs the impact study, the Host TSP will use reasonable efforts to monitor the affected system and:

- the MISO transmission owner 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.

If available, the Affected System will provide service limitation policies to the Customer upon request.

Potential impacts on the Neighboring TSP's transmission systems will be included in the Host TSP's impact study report along with any information regarding the validity of the impacts. Each Host TSP will coordinate with its Neighboring TSPs to develop alternatives to mitigate identified impacts. The Host TSP will include the following details provided by the Confirmed Affected System(s) in the Host TSP's impact study report:

- the minimum amount of transmission service that can be granted without Affected System Upgrades,
- a preliminary description of the required Affected System Upgrades,
- an estimated planning level cost, and
- preliminary estimate of the in-service date of the system reinforcement

The Host TSP will refer the TSR customer to the Confirmed Affected System to begin the associated facilities study agreement process and construction of Affected System Upgrades for network reinforcements required on that transmission system.

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

5.2.3 Mitigating Host TSP TSR on the Confirmed Affected System's Transmission System

If the transmission customer proceeds to the facilities study stage with the Host TSP (or to a service agreement if no facilities studies are necessary), notice will be provided by the Host TSP to any Confirmed Affected Systems. The tariff and Business Practices of an Affected System will apply to the identification and construction of Affected System Upgrades and/or implementation of other mitigation measures to address impacts to the Confirmed Affected System identified in the impact study.

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

Transmission service will only be granted by the Host TSP up to the amount at which there are no transmission constraints identified by the studies on the transmission systems of the Confirmed Affected System(s). Partial transmission service may be granted if the Confirmed Affected System is not constrained at that level of service. The requested amount of transmission service can only be granted once all identified constraints on the system (MISO, MH, and MPC) have been mitigated.

If Confirmed Affected System(s) constraints are addressed through the use of alternative measures in lieu of constructing facilities, or as an interim measure while facilities are under construction, firm transmission service will not be granted beyond the amount permitted by the Confirmed Affected System's Business Practices.