October 11, 2019

During the Commission's Working Session on August 28, 2019, there were several discussions which included general questions regarding the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) Generation Interconnection Procedures (GIP), and more specific comments and questions regarding projects receiving ERIS (Energy Resource Interconnection Service) and their impact on the future upgrade costs allocated to local Transmission Owners (TOs) and their customers.

This document attempts to address these questions and comments by providing a high-level overview of the MISO and SPP GIP and Transmission Expansion Planning (TEP) processes along with a more detailed discussion of ERIS and cost allocations.

This document was prepared by the technical staff at Power System Engineering, Inc. (PSE) as requested by Ruso Wind Partners, LLC. PSE is a full-service consulting firm which has been providing services to utilities and industrial clients since 1974. The technical staff that prepared this overview has experience working with MISO and SPP since their inceptions.

137 **PU-19-28** Filed: 10/11/2019 Pages: 16
Late-filed Exhibit 51(a) - PSE Memorandum

Ruso Wind Partners, LLC

1 Generation Interconnection Process Overview

The MISO and SPP GIP are conceptually similar but differ in key details. Both were initially based on the FERC pro-forma tariff, but they have evolved over time to meet the needs of each organization as they respond to an unprecedented level of new generation interconnection requests.

After FERC Orders No. 888 and 889, Generation Interconnection (GI) projects in MISO or SPP (and all Independent System Operators (ISOs)/Regional Transmission Organization (RTOs)) do not directly pay for their use of the existing Bulk Electric System (BES) when they build their projects. Rather, FERC has deemed them to be responsible for the costs of any upgrades that are required for their interconnection. Thus, a key part of the GIP is to identify what upgrades (if any) need to be made to the BES in order to allow the proposed GI projects being studied to safely and reliably connect to the grid and generate under specified system conditions. To accomplish this, these studies evaluate system performance including the new generation under a variety of conditions to ensure that it stays within a specific set of criteria.

If these criteria are violated – for example, if power flow on a line or transformer exceeds its thermal rating, or the voltage becomes unstable – the study process identifies the GI project(s) that contributed to the violations, and utilizes criteria based on the type of service desired to determine how the costs of mitigating the problem are to be allocated. Projects assigned these mitigation costs are then provided the opportunity to accept these costs and move forward to interconnection, change their service type or project size to avoid contributing to certain violations, or withdraw their project's application for interconnection.

MISO and SPP both utilize group studies to process interconnection requests received as of a certain date. These studies are coordinated between MISO and SPP, as well as other neighboring ISO/RTO/TOs, in order to establish a "queue priority" for each study group. This queue priority is used to evaluate interconnection service requests, determine GI Projects contributing to criteria violations, and identify cost responsibility for required network upgrades.

Additional details of the MISO and SPP GIP are provided later in this document.

Once a project has successfully completed the GIP, executed a Generator Interconnection Agreement (GIA), and begins injecting power on the system, the RTOs will monitor the system and dispatch the project based on the levels of ERIS and/or NRIS granted and system availability.

2 ERIS vs NRIS

SPP and MISO both offer the option of applying for Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS) when they submit their GI application. GI projects can request ERIS, NRIS, or a combination of both types of service. The GI project will be studied under the requirements and criteria of each type of service requested in the application. At various points during the MISO DPP or SPP DISIS three-phase study processes, GI projects are allowed to decrease the MW requested or change some or all of the requested NRIS to ERIS, but cannot add MW or change ERIS to NRIS. As described in the GIP Overviews below, the GI project is responsible for mitigating any criteria violations they cause or contribute to which the study identifies for the applicable service type requested.

The MISO tariff defines ERIS as follows:

> *"Energy Resource Interconnection Service (ER Interconnection Service) shall mean an Interconnection Service that allows Interconnection Customer to connect its Generating Facility to the Transmission System or Distribution System, as applicable, to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service does not convey transmission service."*

The ERIS definition in the SPP Tariff is similar:

> *"Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service."*

The MISO tariff defines NRIS as follows:

> *"Network Resource Interconnection Service (NR Interconnection Service) shall mean an Interconnection Service that allows Interconnection Customer to integrate its Generating Facility with the Transmission System in the same manner as for any Generating Facility being designated as a Network Resource. Network Resource Interconnection Service does not convey transmission service. Network Resource Interconnection Service shall include any network resource interconnection service established under an agreement with, or the tariff of, a Transmission Owner prior to integration into MISO, that is determined to be deliverable through the integration deliverability study process."*

The NRIS definition in the SPP tariff is similar:

> *"Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource.*

> *Network Resource Interconnection Service in and of itself does not convey transmission service."*

The NRIS definitions mention "Network Resource", which is defined in the MISO tariff as follows:

> *"Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis."*

The Network Resource definition in the SPP tariff is similar:

> *"Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis."*

As defined, NRIS service allows the project to be integrated into the Transmission system as if it were a network resource, whereas ERIS service only allows the project to use the existing system capacity on an "as available" basis. During the GI study process, projects seeking NRIS are subject to more stringent criteria than projects seeking ERIS; projects seeking NRIS may be required to mitigate issues that a project seeking ERIS would not be required to mitigate. Although NRIS does not guarantee deliverability, NRIS projects are likely more deliverable than if they had received ERIS service and did not invest in the NRIS upgrades. The upgrades required for NRIS service will also include any ERIS upgrades identified during the study process.

Both MISO and SPP calculate a Distribution Factor ("DF") for each project on facilities requiring mitigation to help them allocate mitigation costs. In SPP, both ERIS and NRIS projects will share in mitigation costs for facilities identified as impacting the short-circuit/fault duty, under- or over-voltage violations, dynamic stability angular deviations, and/or having a 3% or higher DF on thermally overloaded transmission facilities for system intact conditions. For thermally overloaded transmission facilities under contingency, NRIS projects having a 3% or higher DF or ERIS projects having a 20% or higher DF will be assigned mitigation cost responsibility.

MISO uses a similar methodology, except that they utilize a 5% DF criteria for NRIS where SPP utilizes a 3% DF criteria. In addition, MISO also assigns mitigation cost responsibility to new generation projects when the overloaded facility or the overload-causing contingency is at the generator's outlet; when the MW impact due to the generator is greater than or equal to 20% of the applicable rating (normal or emergency) of the overloaded facility; or for any other constrained facility where none of the study generators meet one of the criteria, but the cumulative MW impact of the group of study generators is greater than 20% of the rating of the facility. In this last instance, only those study generators whose individual MW impact is greater than 5% of the rating of the facility and have a DF greater than 5% will be responsible for mitigating the cumulative MW impact constraint. Further, Generating Facilities (including energy storage devices) requesting NRIS in MISO or SPP must mitigate constraints identified in a deliverability analysis under system intact and single contingency conditions.

3 Transmission Expansion Planning Overview

As FERC-designated RTO's, MISO and SPP's responsibilities include working with their members, regulators and stakeholders to create regional transmission expansion plans which identify projects which are needed to economically and reliably support the future resource needs of their respective transmission systems while meeting the current local reliability and market efficiency requirements. This process also seeks to support federal and state energy policies by planning for access to a changing resource mix, including changes due to plant retirements.

These projects are summarized in each RTO's respective TEP. The cost allocations for the projects identified during this process are allocated in accordance with tariff provisions and are intended to be allocated in a manner roughly commensurate with the projected benefits of these projects.

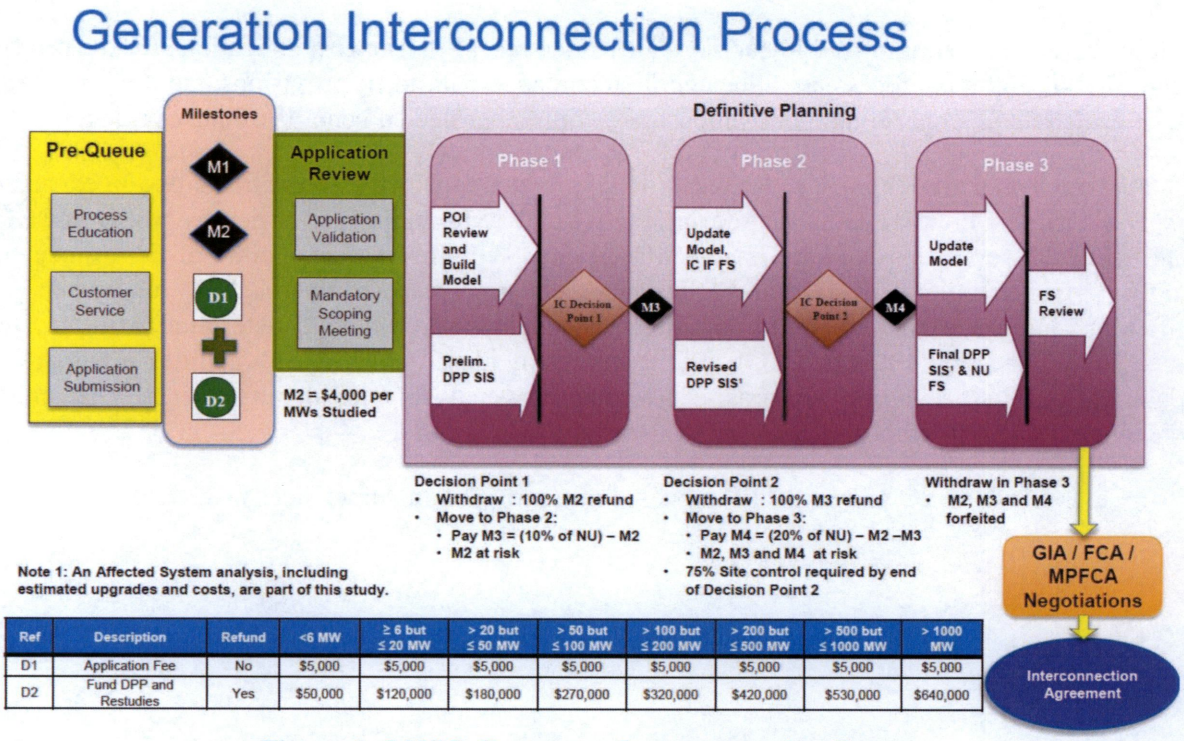
The GI and Transmission Service Request (TSR) projects included in these transmission expansion plans are those which are identified during the GI and TSR studies performed by MISO and SPP. The reliability upgrades included in the MTEP and STEP results are identified during separate analyses; while similar to the GIA and TSR analyses in many respects, the reliability analysis utilizes different model assumptions, time horizons, and evaluation criteria to determine which system upgrades will be required. Thus, a GI or TSR study may identify overloaded facilities which are not identified during a reliability analysis, and a reliability analysis may identify overloaded facilities which are not identified during a GI or TSR study.

Overviews of the MISO and SPP TEP processes are provided in Appendices C & D.

Appendix A: MISO GIP Overview

The MISO GIP was designed to provide generators with reliable, non-discriminatory access to the bulk electric transmission system.

MISO has divided the GIP into three parts: Pre-Queue, Application Review, and Definitive Planning. The diagram in Figure 1 illustrates MISO's process:



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 1: MISO Generator Interconnection Process

A.1 Pre-Queue

The Pre-Queue portion of the process (yellow) is dedicated to educating the prospective Interconnection Customers (ICs) as to the nuances of the MISO GIP and culminates in the submission of the interconnection application, the study deposit, and the related Technical and Non-Technical Milestones.

The *Interconnection Application* provides the detailed technical data and information regarding the proposed GI project. The required information includes the size and location of the proposed project, the type of generation, the type of service requested, the technical details of the generator(s) and the interconnection, the proposed interconnection schedule, site control information, and evidence of site control for the project.

MISO offers two interconnection service options: *Energy Resource Interconnection Service (ERIS)* and *Network Resource Interconnection Service (NRIS)*. ERIS allows the IC to connect its Generating Facility to the Transmission System or Distribution System, as applicable, to be eligible to deliver

the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission System on an as available basis. NRIS allows the IC to integrate its Generating Facility with the Transmission System in the same manner as for any Generating Facility being designated as a Network Resource. Neither type of service guarantees deliverability, but projects requesting NRIS are evaluated against a more stringent criteria and, everything else being equal, are more likely to be deliverable.

Two *Study Deposits* are required for each application submitted. The *D1 Deposit* is a non- refundable $5,000 Application Fee; the *D2 Deposit* funds the DPP study and any required restudies and is based on the size (in MW) of the proposed project as shown at the bottom of the above process diagram.

The *Technical Milestones* required with the application include the following and are referred to by MISO as the *M1 Milestone Requirements*.

- Definitive Step-up Transformer Data to Point-of-Interconnection (POI)
- Definitive Generation Output (MW)
- Definitive One-Line Diagram
- Type 3 and 4 Inverter Based Short Circuit Data
- Definitive POI
- Definitive Steady-State Models and Standard/Generic Library Stability Models
- Definitive Impedance from Collective Substation to POI

The *Non-Technical Milestones* required with the application include the following:

- Complete and Valid Application
- Proof of 75% site control or $100k deposit (dedicated refundable deposit)
- Site Control Affidavit attesting that the IC has a minimum of 75% Site Control

MISO also has an *M2 Milestone*, which is currently a payment of $4,000/MW due with the Application in the form of cash or an irrevocable letter of credit.

The completed Generation Interconnection application, D1 and D2 deposits, and M1 and M2 milestone requirements need to be accepted by MISO at least forty-five (45) Calendar Days prior to the start of the next DPP study cycle.

A.2 Application Review

Once an IC submits an application package to MISO, MISO completes an Application Review as shown in Figure 2:

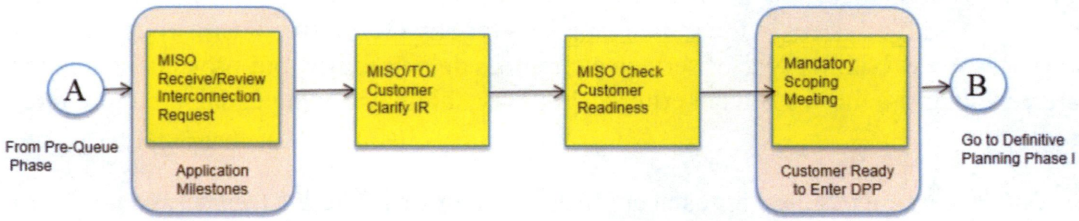


Figure 2: MISO Application Review Process

During this step in the process, MISO reviews the application for completeness, verifies the information provided, and clarifies any ambiguities with the customer. If there are any deficiencies in the application, MISO notifies the IC. Any deficiencies need to be resolved at least forty-five (45) Calendar Days prior to the start of the next DPP study cycle in order to participate in that cycle. Once the application is complete, the D1 and D2 Deposits have been received, and the M1 and M2 Milestone requirements have been met, the Interconnection Application is considered valid, and the project's interconnection Queue Date is established.

The likely affected TOs are sent a copy of the Interconnection Request application for review and are invited to participate with the IC in a Mandatory Scoping Meeting to review the project and application materials.

A.3 Definitive Planning

The *Definitive Planning Phase (DPP)* is where the project will be studied to determine the requirements for interconnection. MISO performs a three phase (DPP 1, DPP 2, and DPP 3) group study for six separate geographic areas (Central, East-ATC, East-ITC, East-UP, South, and West) within the MISO footprint.

The DPP study will identify the Direct Interconnection Costs (DICs) and any Network Upgrades (NUs) required for interconnection, as well as determine which of the Network Upgrade Costs (NUCs) will be allocated to each project in the study group. For successful projects, the DPP culminates in the execution of the Generation Interconnection Agreement (GIA). This process is estimated to take 505 days; restudies, if required, may extend this timeline. The diagram in Figure 3 describes the DPP study process

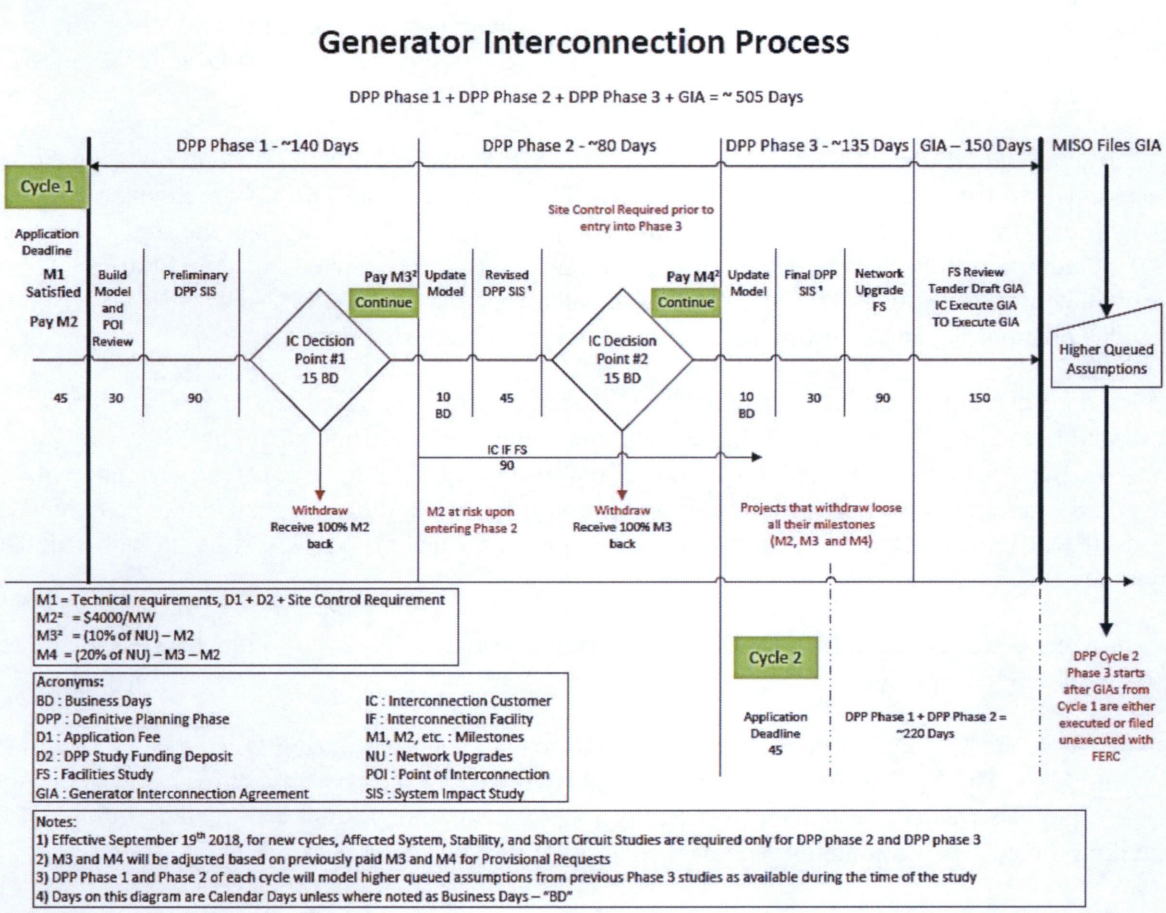


Figure 3: MISO GIP Process

The DPP study starts with a *DPP Kick-off Call* where the project parameters and study approach are reviewed and confirmed.

The DPP Study is broken into three phases. Generally speaking, the results of each phase are evaluated against the study criteria, and the projects are assigned cost responsibility for fixing any criteria violations arising from their interconnection which are required to be mitigated, as described above.

DPP Phase 1 (DPP1) is a ~140 day process which starts with a 30 day *Model Build* and *POI Review*. During the POI Review, the IC has 10 business Days to review the study model, verify that the project parameters are modeled correctly, and request changes and/or submit comments. The IC is required to submit an A-10 Model Review Form in order to continue in the study process.

The next step in DPP1 is the *Preliminary System Impact Study (SIS).* This study is a Steady-State Thermal Analysis which is completed within 90 calendar days and provides planning level estimates for network upgrades, including TO NUs at the POI.

Decision Point 1 comes at the end of DPP1. IC's need to decide if, based on the Preliminary SIS results, they want to move forward into DPP2 and make the M3 Milestone payment ((10% of NUCs)

– M2) or withdraw and have 100% of their M2 Milestone payment refunded. Also, the project size (MW) can be reduced up to 100% at Decision Point 1. Moving forward into DPP2 places the M2 Milestone payment at risk.

The projects which decide to move forward into *DPP Phase 2 (DPP2)* are entering an ~80 day process which also starts with a model review. The focal point of DPP2 is a Revised SIS (~45 calendar days) which updates the Steady-State Thermal Analysis for changes in the study group, and also includes Stability Analysis, Short Circuit Analysis, and Affected System Studies. The IC Interconnection Facilities Study (~90 calendar days) also starts during DPP2. The DPP2 Revised SIS provides planning level cost estimates for the NUs identified during the study.

Decision Point 2 comes at the end of DPP2. IC's need to decide if, based on the Revised SIS results, they want to move forward to DPP Phase 3 and make the M4 Milestone payment ((20% of NUCs) – M2 – M3) or withdraw and receive a 100% refund of the M3 Milestone payment. Evidence of 75% site control is required before moving forward in to DPP3. Also, the project size may be reduced by up to 10% at Decision Point 2. Moving forward into DPP3 places the M2, M3, and M4 Milestone payments at risk.

The projects which proceed into *DPP Phase 3 (DPP3)* are entering a ~ 135 day process which also starts with a model review.

Results from the IC Interconnection Facilities Study which started during DPP2 become available early in DPP3. The Final SIS (~30 calendar days) for the surviving projects, Affected System Study (ASA), and the related NUs Facilities Study (~90 calendar days) are completed during DPP3, including the cost allocations for each participating project.

Projects that withdraw during DPP3 place their M2, M3, and M4 Milestone payments at risk.

The DPP concludes with a GIA. The DPP process timeline includes ~150 days for the GIA to be drafted, negotiated, and executed.

A.4 Affected Systems Studies

MISO and their neighboring RTO/ISO/TOs coordinate their GI studies on an on-going basis to determine the impacts of Interconnection Requests on each other's transmission system. These studies are coordinated in queue priority order for each study group.

A.5 Future Changes

It is anticipated that the MISO GIP will continue to evolve to accommodate the high levels of generation interconnection requests and in response to emerging technologies such as battery storage and Distributed Energy Resources (DER). State and federal renewable energy mandates and new FERC Orders will also have an impact in shaping future policy. Thus, the policy summaries provided above represent a "snapshot" of the policies in place as of this writing.

Appendix B: SPP GIP Overview

SPP describes their GIP as "a progressive cluster-study methodology affording participants several windows of opportunity throughout the calendar year to submit their generation interconnection requests for validation and study".

FERC approved SPP's transition to a three-phase progressive study methodology on July 1, 2019. This new process is conceptually similar to the three-phase MISO GIP process, with some differences. SPP summarized this new process as shown in Figure 4:

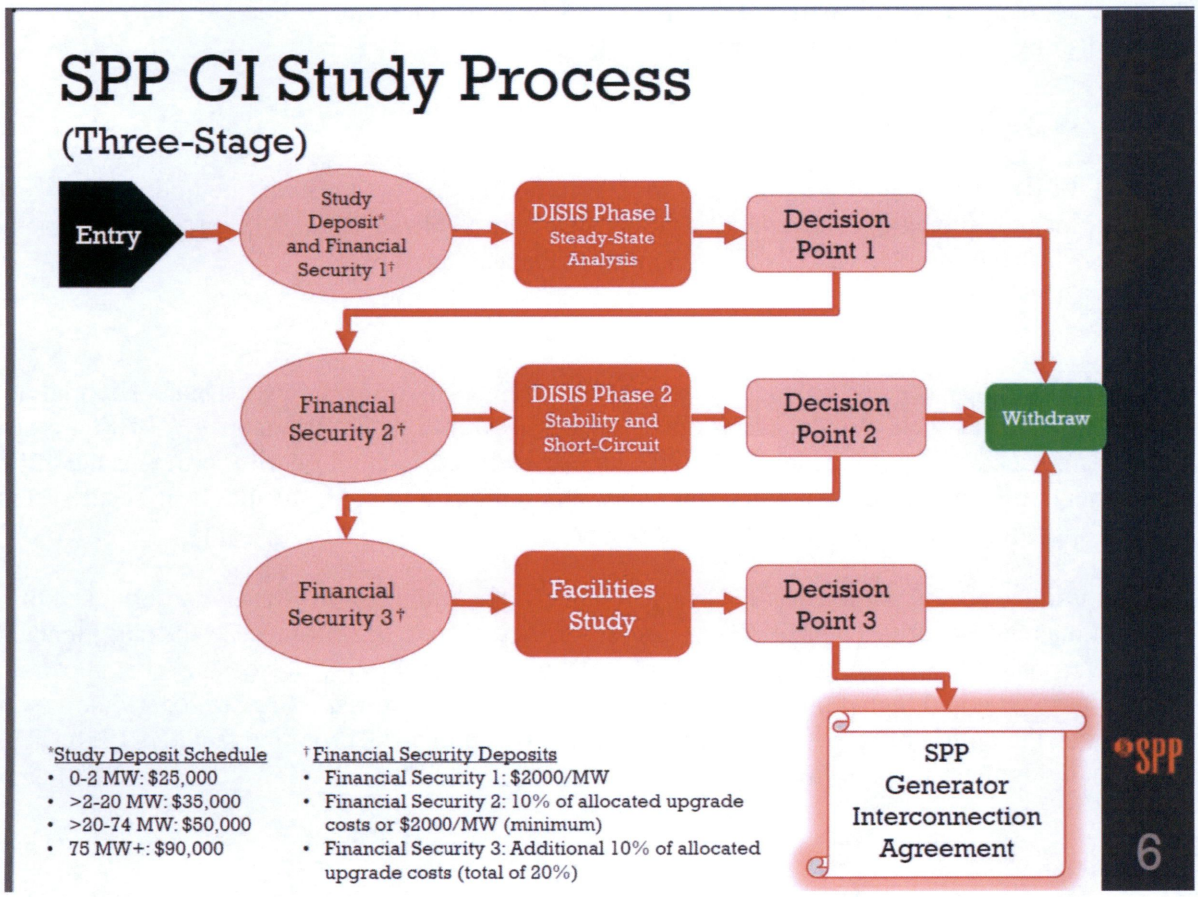


Figure 4: SPP GI Study Process

Initial estimates are that this process will take approximately 485 calendar days from the beginning of the Definitive Interconnection System Impact Study (DISIS) Phase 1 through GIA execution.

To enter the SPP GI process, an applicant needs to submit a completed Application and Study Agreement, Technical Data for the proposed project, Evidence of Site Control, the Study Deposit, and a Financial Security Deposit of $2,000/MW. Similar to MISO, SPP offers both ERIS and NRIS as interconnection options.

The SPP DISIS projects are studied in groups called "clusters"; the 2020 - 2022 cluster schedules are provided in Table 1.

Table 1: Transitional Definitive System Impact Cluster Study Open Window Schedule

Cluster Study Group	Open Season (11 Months)	DISIS Review Period (1 Month)
DISIS-2020-001	May 25, 2019 – April 30, 2020	May 1, 2020 – May 31, 2020
DISIS-2021-001	May 31, 2020 – April 30, 2021	May 1, 2021 – May 31, 2021
DISIS-2022-001	May 31, 2021 – April 30, 2022	May 1, 2022 – May 31, 2022

Once the application is validated and accepted, SPP will assign a queue number and provide the requested study agreement for signature.

B.1 Definitive Interconnection System Impact Study (DISIS)

As noted, FERC approved SPP's transition to a three-phase progressive study methodology on July 1, 2019. This new process is conceptually similar to the three-phase MISO DPP process, with some differences. The study stages and decision points are discussed below.

Stage 1

The Stage One study lasts 90 calendar days and provides results for the Steady-State Thermal and Voltage Analysis as well as calculating the Short-Circuit Ratio. Cost Estimates (+/-30%) are also provided for each new upgrade identified during these analyses. In addition, SPP provides the Initial Interconnection Facilities and Network Upgrades required along with any available affected system impacts, upgrades, and estimated cost results.

Decision Point 1 occurs at the end of Stage 1. Projects that withdraw will receive a refund of their Stage 1 Financial Security Deposit (FS1); projects that continue on to Stage 2 will pay Financial Security Deposit 2 (FS2) (the greater of $2,000/MW or 10% of SPP upgrade costs x cost allocation factor 2 less FS1), and their Financial Security Deposit 1 will be at risk. Projects continuing on to Stage 2 have the option of reducing the MW requested by up to 50%, dropping from NRIS to ERIS, and/or changing their Turbine/Inverter.

Stage 2

The Stage Two study lasts 120 calendar days and provides results for the Dynamic and Transient Stability Analysis and the Short-Circuit Analysis, as well as refreshed results for the Stage 1 Steady-State Thermal and Voltage Analysis as needed. Cost Estimates (+/-30%) are also provided for each new upgrade identified during these analyses. In addition, SPP provides any available affected system impacts, upgrades, and estimated costs results.

Decision Point 2 occurs at the end of Stage 2. Projects that withdraw will receive a refund of their Stage 2 Financial Security Deposit; their Stage 1 Financial Security is also refundable if costs exceed the "penalty-free" threshold. Projects that continue on to Stage 3 will pay Financial Security Deposit 3 (20% of SPP upgrade costs less FS1 and FS2), and their Financial Security Deposits 1 and 2 will

be at risk. Projects continuing on to Stage 3 have the option of reducing the MW requested by to 10%.

Stage 3

The Stage Three study lasts 135 calendar days and provides refreshed results for the earlier studies as needed, as well as Facilities Study-level Cost Estimates (+/-20%) for each new upgrade allocated to a request in the study and Construction Lead Time Estimates. In addition, SPP provides any available affected system impacts, upgrades, and estimated costs results.

Decision Point 3 occurs at the end of Stage 3. Projects that withdraw will receive a refund of their Stage 3 Financial Security Deposit; their Stages 1 and 2 Financial Security are also refundable if costs exceed the "penalty-free" threshold. Projects that continue on will provide comments on the Stage 3 report and begin GIA negotiations with the TO. Their Financial Security Deposits 1, 2, and 3 will be at risk. Projects continuing on to Stage 3 have the option of reducing the MW requested by to 10%.

Penalty-Free Withdrawal

If estimated costs increase significantly between stages, the customer can withdraw without risking financial security. The threshold for penalty-free withdrawal is an increase of 25% or greater, and $10,000/MW or greater between Stages 1 and 2, or an increase of 35% or greater, and $15,000/MW or greater between Stages 2 and 3 (including any Stage 3 revision). Known affected-system upgrade costs are included for purposes of determining if these penalty-free withdrawal provisions apply.

B.2 Affected Systems Studies

SPP and their neighboring RTO/ISO/TOs coordinate their GI studies on an on-going basis to determine the impacts of Interconnection Requests on each other's transmission system. These studies are coordinated in queue priority order for each study group.

B.3 DISIS Cluster Study and Posting Schedule

SPP continues to work through unprecedented volumes of Generator Interconnection Requests, including new requests, Cluster Restudies, Modification Requests and Restudies, Facilities Studies and Generator Interconnection Agreements. This has caused significant study delays. The estimated study schedule as of September 8, 2019 is provided in Table 2.

Table 2: SPP DISIS Estimated Posting Dates

GI Cluster	DISIS Phase 1	DISIS Phase 2	Facility Study
Legacy Cluster DISIS-2016-002-1 Groups 4,7,8,9,15,16			12/23/2019
DISIS-2017-001	04/14/2020	09/01/2020	02/04/2021
DISIS-2017-002	01/27/2021	06/17/2021	11/20/2021
DISIS-2018-001	11/13/2021	04/02/2022	09/04/2022
DISIS-2018-002	09/18/2022	11/08/2022	04/13/2023
DISIS-2019-001	04/02/2023	08/22/2023	01/25/2024

B.4 Future Changes

It is anticipated that the SPP GIP will continue to evolve to accommodate the high levels of generation interconnection requests and in response to emerging technologies such as battery storage and Distributed Energy Resources (DER). State and federal renewable energy mandates and new FERC Orders will also have an impact in shaping future policy. Thus, the policy summaries provided above represent a "snapshot" of the policies in place as of this writing.

Appendix C: MISO TEP Process Overview

The MISO Transmission Expansion Plan (MTEP) includes several broad categories of projects which MISO describes as follows:

Generation Interconnection Projects (GIP) are associated with the interconnection of new generation or the capacity increase of existing generation. Costs are primarily paid for by the interconnection customers.

Baseline Reliability Projects (BRP) are Network Upgrades identified in the base case as required to ensure that the Transmission System is in compliance with applicable Electric Reliability Organization reliability standards and the reliability standards adopted by Regional Reliability Organizations and applicable within the Transmission Provider Region. Baseline Reliability Project costs are allocated to the local Transmission Pricing Zone(s) and recovered through Attachment O by the Transmission Owner(s) developing the projects.

Market Efficiency Projects (MEP) meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as Market Efficiency Projects based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater. Costs are distributed to benefiting pricing zones, in accordance with Attachment FF of the Tariff.

Targeted Market Efficiency Projects (TMEP) are designed to alleviate historical market-to-market congestion between MISO and PJM Interconnection while meeting certain cost and construction requirements. The costs of Targeted Market Efficiency Projects are allocated first between MISO and PJM Interconnection by the ratio of each RTO's Day-Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO share of costs for the project is then allocated to beneficiaries using historical nodal load congestion contribution data.

Multi-Value Projects (MVP) meet Attachment FF requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.

Other Projects may be included in MTEP but do not quality as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects.

Transmission Delivery Service Projects (TDSP) are required to satisfy a transmission service request. The costs of these upgrades are identified during the TDSP study and are generally assigned to the requestor.

Market Participant Funded Projects (MPFP) are defined as Network Upgrades fully funded by one or more market participants but owned and operated by an incumbent Transmission Owner.

The 2019 MTEP proposes 472 upgrades at an estimated cost of $3.8 billion.

Appendix D: SPP TEP Process Overview

The SPP Transmission Expansion Plan (STEP) includes similar broad categories of projects. SPP describes the 2019 SPP STEP as a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. Projects in the 2019 STEP include upgrades required to satisfy requests for Transmission Service, which would be funded by the requestor; upgrades required to satisfy requests for Generator Interconnection Service, which would also be funded by the requestor; approved projects from the Integrated Transmission Planning (ITP) 20-Year,10- Year and Near-Term Assessments, which include economic, public policy, operational, and reliability needs assessments; approved Balanced Portfolio Upgrades; approved High Priority Upgrades; endorsed Sponsored Upgrades, which would be funded by the sponsor; and approved Interregional Projects.

The costs of STEP upgrades which are not funded by the requestor or sponsor as noted above are allocated to the SPP footprint, allocated between the SPP footprint and the local zone, or allocated to the local zone based on their voltage. This is often referred to this as the "Highway/Byway" cost allocation methodology.

Table 3: Hyway/Byway Cost Allocation Methodology

Voltage	Region Pays	Local Zone Pays
300 kV and above	100%	0%
above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

The 2019 STEP consists of 568 upgrades with a total estimated cost of $5.2 billion.