GENERATOR INTERCONNECTION MANUAL
(DISIS MANUAL)

By Generator Interconnection Department

Published January 2023

Version 1.8
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REVISION HISTORY

<table>
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<td>12/2019</td>
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<td>DISIS Manual</td>
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<td>Model Acquisition Process &amp; Location</td>
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<td>GI</td>
<td>1.2</td>
<td>Outdated Information Removed/GIS Dispatch Map Updated</td>
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| 4/2021  | GI     | 1.3     | ERIS Removed from NR Dispatch (DIS1701 P2 & Forward)
Model Reduction
DISIS Report Guide
DISIS FAQs
TPL-001-4 Contingency Guide
Solve Parameters and Generator Outage Exception |
| 4/2021  | GI     | 1.3.1   | Stability Dispatch Revision |
| 8/2021  | GI     | 1.4     | Updated Study Schedule Status page link
Updated REGIONAL GROUPINGS from 16 groups to 5 Regions
Updated Dispatch table |
| 12/2021 | GI     | 1.5     | Update Contact Info |
| 4/2022  | GI     | 1.6     | Review of all sections and modifications to reflect current practice and to prepare for conversion to SPP Business Practice. |
| 10/2022 | GI     | 1.7     | Clarified fuel-based dispatch, incorporated language from Business Practices 7250, 7300, 7350, and 7400, reorganized sections and made updates throughout per GI Manual Task Force under Transmission Working Group. |
| 1/2023  | GI     | 1.8     | Corrected Short-Circuit Model reference section in Section 4.3.3.2. Changed from section 4.2.1 (Powerflow Model Development) to 4.3.1.1 (Stability Model Set). |
1 INTRODUCTION

This business practice is a companion to SPP’s Generator Interconnection Procedures (GIP) in Attachment V of the SPP OATT. It provides additional detail and specifications describing how SPP administers the provisions in the SPP OATT related to interconnection service. To the extent that there is a conflict between the OATT and this business practice, the OATT controls.

Generator Interconnection (GI) study reports and other current information regarding study status, model requests, submissions and inquiries are available through SPP’s Generator Interconnection portal on SPP.org (https://www.spp.org/engineering/generator-interconnection/).
2 DEFINITIONS

Unless noted otherwise, capitalized terms used in this document have the definitions given in the [SPP Open Access Transmission Tariff](#). The following additional definitions are referenced in this document:

**Current-Queue Request** – An Interconnection Request being evaluated in the current study

**Group** - The interconnection requests are grouped into five (5) active regions based on geographical and electrical impacts; reference the geographical map in Error! Reference source not found.

**Legacy** – prior to the time SPP began providing Interconnection Service under its OATT

**MW_{VER}** – Maximum power output (MW) of an ITP Generator or requested capacity of a Prior-Queued Request or Current-Study Request

**MW Amount** - The capacity amount (megawatt) evaluated for each request

**N-n** – Transmission system with all circuits closed except \( n \) circuits

**ITP Generator** – A generator that has been incorporated into the Integrated Transmission Planning (ITP) base reliability model set during the ITP model development process

**Prior-Queued Request** – An Interconnection Request that has neither been withdrawn nor terminated, that has a higher queue priority (was entered in an earlier DISIS Queue Cluster Window) than Current-Queue Requests and is not an ITP Generator

**System-Intact** – N-0, Transmission system with all circuits intact

**SCR_{POI}** – Short-circuit ratio at the Point of Interconnection (POI)

**SCMVA_{POI}** – Short-circuit MVA at the POI

**Transfer Distribution Factor (TDF)** – The impact of an interchange transaction or power injection at a bus on a given flowgate; the measure of responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one area to another expressed in as a percentage (up to 100%) of the change in power transfer

**Upgrade ID** - The identification number that SPP utilizes for each upgrade
3 ORGANIZATIONAL GROUP SUPPORT

The Generation Interconnection User Forum (GIUF) shares information and gathers feedback related to SPP’s GI studies. The GIUF relies on the collective knowledge of interested GI customers and stakeholders to assist in developing recommendations to improve SPP’s GI services.

The Transmission Working Group (TWG) develops and oversees regional and interregional transmission planning processes, including generator interconnection and long-term transmission service study processes. The TWG reviews proposed transmission interconnections and coordinates transmission planning activities to develop SPP’s Integrated Transmission Plan and Transmission Expansion Plan. The TWG is primarily responsible to approve GI Business Practices via SPP’s Revision Request process, especially as it relates to system reliability. SPP’s Regional Tariff Working Group (RTWG) is secondarily responsible to approve GI Business Practices via SPP’s Revision Request process.

The GI Manual Task Force (GIMTF) is responsible for reviewing and updating SPP’s GI Study Manual (this document). The GIMTF will review the GI Study Manual language and processes and will propose new language and changes to the current manual to facilitate effective and efficient GI studies pursuant to the direction of the Transmission Working Group (TWG). The GIMTF will make a recommendation to the TWG of its findings.
Definitive Interconnection System Impact Studies (DISIS) identify the steady-state violations, transient instabilities and short-circuit impacts associated with connecting generation to the transmission system. The DISIS identifies required Transmission Owner (TO) Interconnection Facilities, Network Upgrades and other Direct Assignment Facilities needed to connect at each specific Point of Interconnection (POI).

**DISIS Three-Phase Diagram**

**DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDIES (DISIS)**

DISIS Phase 1 consist of steady-state analysis and short-circuit ratio calculation.

DISIS Phase 2 consist of steady-state analysis, stability dynamic analysis and short-circuit analysis.

After each phase of study, a final report is posted with requests and upgrades. The following day after final posting, a decision point window opens for 15-business days for requests to proceed or withdrawal.

The three-phase process incentivizes withdrawals as soon as possible in the process in order to avoid multiple restudies. Additionally, the backlog mitigation plan accelerates the study process.
4.1 DISIS METHODOLOGY

Steady-state, transient stability and short-circuit analyses are conducted to study the impacts of the Interconnection Requests submitted in each Queue Cluster Window.

Interconnection Requests may be studied for one or both types of interconnection service: Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS). Note that all NRIS requests will also be studied for ERIS throughout each phase of the study process. Transmission constraints are identified based on all of the clustered generation interconnection requests being dispatched at the same time. Neither NRIS nor ERIS guarantees transmission service or deliverability pursuant to Part II or Part III of the SPP OATT. Transmission service must be requested and studied through the same process as any other Designated Resource wanting to deliver energy to a specified point (Point-to-Point Transmission Service) or to a specified Network Load (Network Integrated Transmission Service). Base Plan funding determinations for Base Plan Upgrades are subject to limits stated in Attachments Z2 and J of the SPP OATT. Upgrades required to attain either NRIS or ERIS are not eligible for Base Plan funding.

Once interconnection is complete, there is no difference between SPP Operations’ treatment of NRIS and ERIS generating facilities.

4.1.1 ERIS Summary

- **Energy Resource Interconnection Service** allows Interconnection Customers (ICs) to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility’s output using the existing firm or non-firm capacity of the Transmission System on an “as available” basis.

- In all ERIS scenarios, dispatch uses the entire SPP footprint as a sink based on the load ratio share methodology.

- Transmission Distribution Factor (TDF) is calculated for each generation interconnection request individually by sinking to the same generators used as a sink when dispatching the ERIS cases.

- **All NRIS requests are included in ERIS analysis and are evaluated as ERIS requests as ERIS service is a required level of service in order to obtain NRIS service.**

4.1.2 NRIS Summary

- **Transmission Provider** must conduct the necessary studies and the Transmission Owner construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as Network Resources. Network Resource Interconnection Service allows Interconnection Customer’s Generating Facility to be designated as a Network Resource (NR), up to the Generating Facility’s full output, on the same basis as
existing Network Resources interconnected to Transmission Provider’s Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

- **ERIS requests are not included in NRIS dispatch unless they have approved transmission service recognized in the ITP dispatch** (this change was approved by TWG 2022).

- **In the NR Summer & Winter scenarios:**
  - Dispatch is spread to the entire SPP footprint based on the load ratio share.
  - TDF is calculated for each generation interconnection request individually by sinking the resource to the interconnection control area (interconnection control area/Transmission Owner)

- **In the NR Light scenarios:**
  - Dispatch is spread to the group (01NR, 02NR, 03NR, 04NR or 05NR) in which the request is located based on the load ratio share in that group.
  - TDF is calculated for each generation interconnection request individually by sinking the resource to the interconnection control area (interconnection control area/Transmission Owner)

- **Note requests may elect to convert from NRIS to ERIS during Decision Point 1 (DP1), which is contingent upon a modification election. After DP1, NRIS service election cannot be converted to ERIS.**

DISIS studies are performed using a three-phase study approach. Studies are divided into phases to provide more transparency on the status of requests and to reduce the overall time for a request to go through the study process and acquire a Generator Interconnection Agreement.

**4.1.3 Sub-Regional Groups**

The Non-Legacy ITP Generators, Prior-Queued requests and Current-Study Requests are aggregated or clustered into sub-regional groups based on electrical impacts as generally shown in Error! Reference source not found.. Generally, POIs are used as the reference point for determining location. Each request is assigned to only one group. For interconnection requests connecting between sub-regional groups, SPP will define the group by factors including, but not limited to electrical impacts, historical POI, and consistency with prior electrical impacts. Dependent on the type of service request (e.g. ERIS vs NRIS, Conventional vs Renewable), the DISIS studies will evaluate the request using a generation dispatch process involving either the entire SPP region or these sub-regional groupings or both the SPP region and the sub-regional groupings. When using the sub-regional groups, each sub-regional group’s clustered Current-Study Requests are dispatched and evaluated independent from other sub-regional groups in determining potential constraints. Constraint mitigation is coordinated
between the sub-regional groups for any potential commonly identified constraints amongst the groups.

Figure 1: Approximate Location of Current Regional Cluster Groups
4.2 STEADY-STATE ANALYSIS

The DISIS steady-state analysis involves development of powerflow models, identification of non-convergent conditions, voltage constraints, thermal constraints and cost allocation. The process generally uses the same procedures used for the ITP base reliability analysis including a common model set and contingency set, with exceptions as described in the following sections.

Steady-State analysis is performed for DISIS Phase 1 and Phase 2 and as applicable for any subsequent restudy.

4.2.1 Model Development

The ITP base reliability powerflow models serve as the starting point for all interconnection studies requiring steady-state powerflow analysis. Reference ITP Manual location. *ITP Model Development Set Excerpt (Base Reliability only, DISIS does not use Year 10)*

<table>
<thead>
<tr>
<th>Description</th>
<th>Year 2</th>
<th>Year 5</th>
<th>Year 10</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Reliability</td>
<td>Summer</td>
<td>Summer</td>
<td>Summer</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td>Winter</td>
<td>Light Load</td>
<td>Light Load</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Non-coincident Peak (3)</td>
<td>Non-coincident Peak (3)</td>
<td>Non-coincident Peak (3)</td>
<td></td>
</tr>
</tbody>
</table>

The DISIS steady-state analysis uses the following years and seasons from the ITP model set:

- Year 2
  - Summer Peak
- Year 5
  - Light Load
  - Summer Peak
  - Winter Peak

The ITP powerflow models are modified as follows to create a base model set from which the DISIS study models can be created. Updates are made to reflect changes that have occurred subsequent to the publishing of the ITP models:

- Model corrections expected to have an impact on the DISIS study results;
- Newly-confirmed long-term transmission service reservations, including delivery point additions (Attachment AQ), and associated network upgrades;
- Network upgrades approved pursuant to Attachment O processes such as ITP reliability, economic, Public Policy, Sponsored Upgrades, Delivery Point Addition, high-priority, etc.;
- Generators, both internal and external to SPP, that have been studied in the interconnection process but are not modeled in the ITP cases (Prior-Queued Requests), including associated network upgrades; and
- Generators associated with Current-Queue Requests.
Neither Prior-Queued Requests nor Current-Queue Requests are dispatched when developing the BASE models. ITP Generator dispatch in the BASE model may be modified in accordance with ITP Manual and ITP model build procedures to reflect new transmission service reservations, load additions and error corrections. ITP upgrades that are added to the model will be included in the seasonal cases in which they are expected to be in-service based on projected in-service dates. Each Generating Facility is represented in the powerflow models as an equivalent generator dispatched at the applicable percentage of the requested service amount with rated power factor capability. The facility modeling includes representation of equivalent generator step-up (GSU) and main power transformer(s) with impedance data provided in the interconnection request application. Collector system(s) and transmission lead line(s) shorter than 20 miles are represented as zero-impedance branches. Longer lead lines are explicitly represented.

### BASE Models to Prior-Queued Models and Current-Queued Models Diagram

SPP will post BASE Models, PQ Models and CQ Models\(^\text{1}\) and open an IC/TO comment period. ICs and TOs are requested to review only their CQ requests and specific location topology. Detailed example from above ITP Base Reliability:

<table>
<thead>
<tr>
<th>DESCRIPTION</th>
<th>YEAR 2</th>
<th>YEAR 5</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>BASE</td>
<td>- Summer</td>
<td>- Summer</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Winter</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Light Load</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Maximum Count: 4 BASE + 31 PQ + 31 CQ = 66 models
<table>
<thead>
<tr>
<th>SERVICE TYPE</th>
<th>DISPATCH SCENARIO</th>
<th>YEAR 2</th>
<th>YEAR 5</th>
<th>PQ MODELS</th>
<th>CQ MODELS</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERIS</td>
<td>HVER</td>
<td>- Summer, 5 groups</td>
<td>- Summer, 5 groups</td>
<td>20</td>
<td>20</td>
<td>40</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Winter, 5 groups</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Light Load, 5 groups</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LVER</td>
<td></td>
<td>- Summer, SPP Region</td>
<td>- Summer, SPP Region</td>
<td>3</td>
<td>3</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Winter, SPP Region</td>
<td></td>
<td></td>
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<tr>
<td>NRIS</td>
<td>NR</td>
<td>- Summer, SPP Region</td>
<td>- Summer, SPP Region</td>
<td>8</td>
<td>8</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Winter, SPP Region</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Light Load, 5 groups</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>TOTAL</td>
<td></td>
<td></td>
<td></td>
<td>31</td>
<td>31</td>
<td>62</td>
</tr>
</tbody>
</table>

4.2.1.1 GENERATOR DISPATCH

The BASE model is modified to create the Prior-Queued model (PQ model) set by dispatching Prior-Queued Requests according to the dispatch description in the following sections.

The base model is modified to create the Current-Queued model (CQ model) set by dispatching both Prior-Queued Requests and Current-Queue Requests according to the dispatch description in the following sections.

**ITP Legacy and Non-Legacy Generation + Prior-Queued, and Current-Queued Differences Diagram**

Legacy ITP generation was online prior to GI queue and represents generation prior to 2001. Non-Legacy ITP generation have been studied by a GI process and have reached commercial operation. These units are in the ITP base reliability models. Prior-Queued (PQ) generation has been studied by GI, but has not yet reached commercial operation and is not represented in ITP base reliability models. Current-Queue (CQ) requests are active in the current study being performed. DISIS will treat these types differently according to the dispatch table below.
To simulate and analyze the variety of generation and service types included in a DISIS cluster, three dispatch scenarios are developed for both the prior-queued and current-queued case model sets.

- High-Variable Energy Resource (HVER) cases reflect scenarios in which Variable Energy Resources\(^2\) are generating at high levels and conventional resources are at relatively low levels. HVER scenarios are developed for summer peak, winter peak, and light load seasons and are used to evaluate both ERIS-only and NRIS requests.

- Low-Variable Energy Resource (LVER) cases reflect scenarios in which Variable Energy Resources are generating at low levels and conventional resources are at relatively high levels. LVER scenarios are developed for summer and winter peak seasons only and are used to evaluate both ERIS-only and NRIS requests.

- Network Resource (NR) cases reflect scenarios in which NRIS generator output is maximized and ERIS-only generator output is minimized. NR scenarios are developed for summer peak, winter peak, and light load seasons and are used to evaluate only NRIS requests.

Cases reflective of the HVER, LVER, and NR scenarios are developed when resources in those categories are in the current DISIS. For example, if the current DISIS only includes HVER and NR requests, cases with LVER scenarios are not developed, but HVER and NR scenarios are developed.

Note that Area Interchanges are adjusted to account for transactions inferred by the Fuel Based Dispatch and sinking methodologies as described in the following sections. Regional net interchanges are held constant, however.

4.2.1.1.1 SOURCE GENERATION

The percentages in Table 1 define the dispatch levels applied to Prior-Queued Requests and Current-Queue Requests in the Prior Queued and Current-Queued models with the exception noted below. The percentages in the tables are applied to the requested interconnection service amount, not to the nameplate rating.

Both ERIS-only and NRIS requests are dispatched in the HVER and LVER scenarios. NRIS requests are evaluated as ERIS requests in the HVER and LVER Scenarios. Only NRIS requests or Non-Legacy ITP ERIS generators with transmission service reservations are dispatched in the NR scenarios. Where a single Interconnection Request consists of multiple components of different fuel types, commonly known as a hybrid request, each component is dispatched individually

\(^2\) See OATT Attachment AE, Section 1.1: Variable Energy Resource - A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the Facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.
according to its fuel type. If the resulting dispatch would exceed the requested capacity for the Interconnection Request, the dispatch will be scaled down on a pro-rata basis (of calculated values) to honor requested capacity.

The dispatch levels in Table 1 have been approved by the Transmission Working Group (TWG). The TWG periodically reviews these dispatch levels and can recommend and approve changes as needed according to the Revision Request process.

DISIS Model Diagram (from bottom up)

**See ITP Manual Section 2.1 BASE RELIABILITY MODEL OVERVIEW describes the generation inclusion and dispatch**

**Non-Legacy ITP Generator with POIs equivalent to Current-Queued Request**

- Prior-Queued: requests that are queued higher than the current study but not included in ITP Base Reliability Model Generation Resources
- Current-Queued generation: requests that are currently under evaluation

---

3 See minutes of the February 28-March 1, 2022 TWG meeting
Table 1: Fuel-Based Dispatch (FBD) Tables for Steady-State

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>In-Group</th>
<th></th>
<th>Out-Group</th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Summer Peak</td>
<td>Winter Peak</td>
<td>Light Load</td>
<td>Summer Peak</td>
<td>Winter Peak</td>
</tr>
<tr>
<td></td>
<td>PQ</td>
<td>CQ</td>
<td>PQ</td>
<td>CQ</td>
<td>PQ</td>
</tr>
<tr>
<td>HVER Scenario</td>
<td>NC</td>
<td>0%</td>
<td>NC</td>
<td>0%</td>
<td>NC</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Diesel Engine</td>
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<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Hydro</td>
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</tr>
<tr>
<td>Nuclear</td>
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<td>100%</td>
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<td>100%</td>
</tr>
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<td>Storage</td>
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<td>0%</td>
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<td>0%</td>
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<tr>
<td>Coal</td>
<td>0%</td>
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<td>Oil</td>
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<td>Waste Heat</td>
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<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
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<tr>
<td>Wind</td>
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<td>100%</td>
<td>45%</td>
<td>100%</td>
<td>75%</td>
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<tr>
<td>Solar</td>
<td>40%</td>
<td>100%</td>
<td>10%</td>
<td>100%</td>
<td>0%</td>
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<tr>
<td>Hybrid</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
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LVER Scenario

<table>
<thead>
<tr>
<th>Fuel Type</th>
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<th>Out-Group</th>
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<tbody>
<tr>
<td></td>
<td>Summer Peak</td>
<td>Winter Peak</td>
<td>Light Load</td>
<td>Summer Peak</td>
<td>Winter Peak</td>
</tr>
<tr>
<td></td>
<td>PQ</td>
<td>CQ</td>
<td>PQ</td>
<td>CQ</td>
<td>PQ</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>N/A</td>
</tr>
<tr>
<td>Combustion Turbine</td>
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<td>100%</td>
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<td>Hydro</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>N/A</td>
</tr>
<tr>
<td>Nuclear</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>N/A</td>
</tr>
<tr>
<td>Storage</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>N/A</td>
</tr>
<tr>
<td>Coal</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>N/A</td>
</tr>
<tr>
<td>Oil</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>N/A</td>
</tr>
<tr>
<td>Waste Heat</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>N/A</td>
</tr>
<tr>
<td>Wind</td>
<td>20%</td>
<td>20%</td>
<td>20%</td>
<td>20%</td>
<td>N/A</td>
</tr>
<tr>
<td>Solar</td>
<td>40%</td>
<td>40%</td>
<td>10%</td>
<td>10%</td>
<td>N/A</td>
</tr>
<tr>
<td>Hybrid</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
</tr>
</tbody>
</table>

NR Scenario

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>In-Group</th>
<th></th>
<th>Out-Group</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Summer Peak</td>
<td>Winter Peak</td>
<td>Light Load</td>
<td>Summer Peak</td>
<td>Winter Peak</td>
</tr>
<tr>
<td></td>
<td>PQ</td>
<td>CQ</td>
<td>PQ</td>
<td>CQ</td>
<td>PQ</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Diesel Engine</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Hydro</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Storage</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Coal</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Oil</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Waste Heat</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Wind</td>
<td>20%</td>
<td>100%</td>
<td>20%</td>
<td>100%</td>
<td>60%</td>
</tr>
<tr>
<td>Solar</td>
<td>40%</td>
<td>100%</td>
<td>10%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Hybrid</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
<td>See Hybrid Example</td>
</tr>
</tbody>
</table>

Notes

- PQ = Prior-Queued Request
- CQ = Current-Queue Request
- NC = No Change in dispatch from BASE model
- N/A = Not Applicable for this scenario
- Percentages are based on the requested interconnection service amount in megawatts.
### Prior-Queued Hybrid Example (HVER Model)

<table>
<thead>
<tr>
<th>Hybrid Request #</th>
<th>Hybrid Request Capacity</th>
<th>Type</th>
<th>Installed Capacity (MW)</th>
<th>Summer Peak</th>
<th>Winter Peak</th>
<th>Light Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100 MW</td>
<td>Solar</td>
<td>50</td>
<td>40%*50MW = 20MW</td>
<td>10%*50MW = 5MW</td>
<td>0%*50MW = 0MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wind</td>
<td>100</td>
<td>40%*100MW = 40MW</td>
<td>45%*100MW = 45MW</td>
<td>75%*100MW = 75MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>150</td>
<td>60MW</td>
<td>50MW</td>
<td>75MW</td>
</tr>
<tr>
<td>2</td>
<td>190 MW</td>
<td>Storage</td>
<td>100</td>
<td>0%*100MW = 0MW</td>
<td>0%*100MW = 0MW</td>
<td>0%*100MW = 0MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wind</td>
<td>200</td>
<td>40%*200MW = 80MW</td>
<td>45%*200MW = 90MW</td>
<td>75%*200MW = 150MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>300</td>
<td>80MW</td>
<td>90MW</td>
<td>150MW</td>
</tr>
</tbody>
</table>

If requested Hybrid capacity is exceeded by calculated values, dispatch will be scaled down on a pro rata basis (of calculated values) to honor requested capacity.

Example assumes hybrid is in-group, but not at a current study gen’s electrically equivalent POI.

### Current-Queue Hybrid Example (HVER Model)

<table>
<thead>
<tr>
<th>Hybrid Request #</th>
<th>Hybrid Request Capacity</th>
<th>Type</th>
<th>Installed Capacity (MW)</th>
<th>Summer Peak</th>
<th>Winter Peak</th>
<th>Light Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>100 MW</td>
<td>Solar</td>
<td>50</td>
<td>100%*50MW = 50MW → 33MW</td>
<td>100%*50MW = 50MW → 33MW</td>
<td>0%*50MW = 0MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wind</td>
<td>100</td>
<td>100%*100MW = 100MW → 67MW</td>
<td>100%*100MW = 100MW → 67MW</td>
<td>100%*100MW = 100MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>150</td>
<td>150MW → 100MW</td>
<td>150MW → 100MW</td>
<td>100 MW</td>
</tr>
<tr>
<td>2</td>
<td>190 MW</td>
<td>Storage</td>
<td>100</td>
<td>100%*100MW = 100MW → 63MW</td>
<td>100%*100MW = 100MW → 63MW</td>
<td>0%*100MW = 0MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Wind</td>
<td>200</td>
<td>100%*200MW = 200MW → 127MW</td>
<td>100%*200MW = 200MW → 127MW</td>
<td>100%*200MW = 200MW</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>300</td>
<td>300MW → 190MW</td>
<td>300MW → 190MW</td>
<td>200MW → 190MW</td>
</tr>
</tbody>
</table>

If requested Hybrid capacity is exceeded by calculated values, dispatch will be scaled down on a pro rata basis (of calculated values) to honor requested capacity.

Example assumes hybrid is in-group.

If the POIs of a non-Legacy ITP Generator or Prior-Queued Request and a proposed POI of a Current-Queue Request are located:

1. At the same substation and at the same nominal voltage level,
2. On the same branch\(^4\) or on a collection of in-series two-terminal branches and associated buses and facilities\(^5\), or

3. On radial branches and associated facilities

The non-Legacy ITP Generator or Prior Queued Request will be treated as Electrically Equivalent and dispatched at the In-Group Current-Queue Request amount. If the proposed POIs for any requests change between phases of study, and the change in POI is not deemed a Material Modification, then dispatch will be changed accordingly in the subsequent phases.

4.2.1.1.2 SINK GENERATION

In order to maintain gen-load balance within each planning region and maintain seams interchanges, generators not enforced to specific dispatch levels in the Fuel Based Dispatch (FBD) process (non-PQ and non-CQ generators) are eligible to be adjusted (sink units). Units labeled as must run as identified in the ITP Base Reliability and Economic dispatch methodologies, including but not limited to hydroelectric, cogeneration facilities, landfill gas and nuclear units, are excluded from consideration for sinking generation. The following chart represents steady-state sink order:

---

**Fuel Based Dispatch Percentages applied to PQ and CQ**

[Diagram showing sink order]

In the ERIS scenarios, SPP generation imbalances due to FBD are offset by reducing the dispatch of sink generators as defined above based on the load-ratio share (LRS) of the Transmission Owner powerflow modeling control areas\(^6\).

\[
\text{Control Area LRS} \% = \frac{\text{Control Area Load}}{\text{SPP Total Load}}
\]

---

\(^4\) Define branch as includes lines and transformers between two buses.

\(^5\) Where this case crosses group boundaries then the Current-Queue request will be evaluated in the group identified for Non-Legacy ITP Generators and Prior-Queued requests based on electrical impacts.

\(^6\) Transmission Owner power flow modeling areas are defined in Appendix V of the Eastern Interconnection Reliability Assessment Group’s Multiregional Modeling Working Group Procedural Manual ([https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/](https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/))
Control Area MW to sink = Control Area LRS % x Total SPP MW Imbalance

Units included in the sink definition within each Control Area are scaled on a proportional basis while enforcing machine minimum limits. If insufficient generation exists in the sink for a given Control Area, the remaining imbalance assigned to that Control Area is redistributed to the remaining SPP areas.

\[
\text{New Control Area LRS \%} = \frac{\text{Control Area Load}}{\text{SPP Total Load} - \text{Deficient Control Area Load}}
\]

This process continues until the SPP imbalance is corrected or until there is no available generation left in the SPP region sink system. If an imbalance remains due to insufficient sink capacity, the process is repeated by enlarging the sink definition progressively as described below until the SPP system is balanced:

1. The Current-Queue Requests out-of-group will be reduced from the fuel-based dispatch levels in Table 1 on a pro rata basis.
2. Prior-Queued Requests in-group will be reduced from the fuel-based dispatch levels on a pro-rata basis excluding the fuel-based dispatch Electrically Equivalent exception cases as defined above.
3. Prior-Queued Requests in-group designated as Electrically Equivalent will be reduced from the fuel-based dispatch levels on a pro-rata basis.

If the above options are not sufficient to correct the imbalance, further reductions will be determined on a case-by-case basis and may include reducing Current-Queued requests from the fuel-based dispatch levels on a pro-rata basis, turning off ITP generators, and reducing generation external to SPP.

In the NRIS light load scenarios, SPP generation imbalances due to FBD are offset by reducing the dispatch of sink units by method of a Group LRS instead of by a regional LRS.

\[
\text{Control Area LRS \%} = \frac{\text{Control Area Load}}{\text{Group Total Load}}
\]

Control Area MW to sink = Control Area LRS \% x Total Group MW Imbalance

In the NRIS summer peak and winter peak scenarios, generation imbalances are handled by the same method used as the ERIS analysis.

For non-SPP regions (both ERIS and NRIS scenarios), a proportional, uniform scaling across all sink units in each region is used to offset the regional imbalance. If insufficient generation is available in sink system, the same process is used as defined above to enlarge the sink definition until the imbalance is corrected.
4.2.2 Contingency Analysis

After the study models are developed, SPP performs a contingency analysis on the Current-Queued model set to identify potential non-convergent conditions, voltage constraints and thermal constraints. The ITP contingency, subsystem, and monitored element files are used as the base auxiliary files. These auxiliary files are updated to include sink subsystem(s) used when calculating TDFs for each CQ request, consistent with the dispatch process sink system (ERIS). For NRIS TDF impact analysis, sink systems consist of local Control Areas. Lastly, subsystem files include a system to be used to account for generation and/or load imbalances introduced by contingencies to prevent the system swing from accounting for these imbalances.

Consistent with the ITP, contingencies evaluated for DISIS include those events listed in North American Electric Reliability Corporation (NERC) standard TPL-001-4 Table 1 that do not permit loss of non-consequential load or interruption of firm transmission service. P3 events (loss of a generator followed by a second contingency event) are not evaluated for interconnection service because the standard permits the adjustment of generation prior to the second event, which for interconnection studies would result in duplication of a P1 (single contingency) event. The ITP contingencies may be modified as needed to reflect topology changes introduced by the addition of generating facilities and upgrades.

Network constraints are found by performing AC contingency calculation (ACCC) analysis.

The following solution parameters are used for both the initial development of the study models as well as the contingency analysis:

- Fixed Slope Decoupled Newton-Raphson
- Tap Adjustment – Stepping
- Switch Shunt Adjustments – Enable All
- Adjust Phase Shift
- Adjust DC Taps
- VAR Limits – Apply Immediately

For the study model build, area interchange control is enabled via tie lines and loads. For contingency analysis, the following table details the area interchange option based on the event type.
Table 2: Area Interchange Settings

<table>
<thead>
<tr>
<th>EVENT TYPE</th>
<th>AREA INTERCHANGE CONTROL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model Build/System Intact</td>
<td>Enabled (Tie Lines and Loads)</td>
</tr>
<tr>
<td>Generator</td>
<td>Disabled(^7)</td>
</tr>
<tr>
<td>Transmission Circuit</td>
<td>Disabled</td>
</tr>
<tr>
<td>Transformer</td>
<td>Disabled</td>
</tr>
<tr>
<td>Shunt Device</td>
<td>Disabled</td>
</tr>
<tr>
<td>Loss of Multiple Elements (Excluding Generator)</td>
<td>Disabled</td>
</tr>
<tr>
<td>Loss of Multiple Elements (Including Generator)</td>
<td>Disabled(^8)</td>
</tr>
</tbody>
</table>

4.2.2.1 NON-CONVERGED CONDITIONS

Identification of non-convergence is a process to ensure identified issues are not associated with tool limitations or methods, but rather are true system deficiencies. A first pass analysis is used to identify an initial list of contingencies that may result in a non-converged or blown-up state. These contingencies are further tested to attempt to reach a converged state. Examples of further tests include, but is not limited to:

- Ensuring toggling reactive devices or transformer taps are preventing a converged state. This can be done programmatically by limiting the number of devices allowed to adjust at a given time or manually checked by locking devices.
- Testing the contingency in multiple tools/software to see if a different solution engine yields a converged state.
- Relaxing some solution parameters that may be causing numerical instability.
- Reviewing reactive devices for locked devices that may be contributing to convergence issues or prevented from offering system support.
- Reviewing Interconnection Projects for data errors or improper modeling causing solution problems.

\(^7\) See minutes of TWG meeting Feb. 28 – Mar. 1, 2022: SPP Reserve Group (all generation excluding Wind, Solar, and Hydro) is dispatched to make up for generation outage

\(^8\) SPP Reserve Group (all generation excluding Wind, Solar, and Hydro) is dispatched to make up for generation outage.
Following the iterative review of problematic contingencies, remaining non-converged contingencies are determined to be attributable to the Current-Queue. Appropriate transmission support will be identified to mitigate the constraint(s).

Upgrades required to mitigate non-converged conditions will be assigned to every Current-Queue request having a Power Transfer Distribution Factor (PTDF) impact of at least 3% on the contingent element monitored in the direction of system intact MW flow causing non-convergence.

4.2.2.2 THERMAL OVERLOADS

Every element in the SPP planning models has a normal (Rate A) and emergency (Rate B) rating. Thermal overloads are identified when the flow across a monitored element exceeds either its normal rating under System-Intact conditions or its emergency rating under contingency conditions. Thermal overloads are identified using the Current-Queue (CQ) model set which incorporates a cluster generation dispatch for all CQ requests as described in section 4.2.1.1.2.

Upon identifying thermal overloads, then each individual Current-Queue Request’s impact on those thermal overloads is determined using a separate Transfer Distribution Factor (TDF) analysis as described below.

Upgrades required to mitigate constraints identified in the ERIS scenarios will be assigned to every Current-Queue Request meeting any of the following criteria:

- TDF impact on each overloaded facility is calculated for each CQ request using the individual generator facility as the source and sinking that resource to the same generators used as a sink when dispatching the ERIS cases.
- At least 3% TDF impact where the constraint is identified under System-Intact conditions,
- At least 20% TDF impact where the constraint is identified under contingency conditions,
- At least 5% TDF impact where the constraint is identified under contingency conditions where the sum of all Current-Queue Requests having a TDF impact on the constrained element of at least 5% equals at least 20% of the constrained element’s emergency rating

Upgrades required to mitigate constraints identified in the NR scenarios will be assigned to every NRIS Current-Queue Request meeting any of the following:

- TDF impact on each overloaded facility is calculated for each CQ request using the individual generator facility as the source and sinking that resource to the interconnection control area (interconnection control area/Transmission Owner)
- At least 3% TDF impact, where the constraint is identified under System-Intact conditions,
- At least 3% TDF impact, where the constraint is identified under contingency conditions
4.2.2.3 VOLTAGE VIOLATIONS

After all non-converged contingency and thermal overload mitigations are determined, any remaining voltage violations are checked to determine applicability to the Current-Queue. The following voltage performance guidelines are used in accordance with the Transmission Owner local area planning criteria.9

SPP voltage criteria10 is applicable to all SPP facilities 69 kV and greater in the absence of more stringent criteria.

Per Unit voltages must change by at least 2% from the Prior-Queued models to the Current-Queued models to be assigned to the current cluster. For constraints meeting this criteria, requests having at least 3% PTDF on the contingent element monitored in the direction of system intact MW flow causing voltage constraints will be assigned responsibility for mitigating the voltage issue(s). For system intact voltage constraints, PTDFs of at least 3% on the line with largest system intact MW flow into the bus experiencing the voltage constraint is used to assign responsibility.

4.2.2.4 FIRST-TIER EXTERNAL AREAS FACILITIES 115 KV AND GREATER

Consistent with the ITP, first-tier areas will be monitored to identify potential reliability needs. SPP coordinates the contingency definitions and monitoring criteria with the external area.11

4.2.3 Solution Process and Methodology

When conducting constraint analysis, solutions and/or mitigations are used to resolve the identified issues. During the mitigation analysis, upgrades that have been identified are added to the models in sequential order as shown in Error! Reference source not found. below. This is done as a holistic approach to use common, previously identified mitigations to aid in the mitigation of constraints that are identified later in the analysis process.

Table 3: Solution Set Implementation

<table>
<thead>
<tr>
<th>Service Type</th>
<th>Scenario</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERIS</td>
<td>S0</td>
<td>No upgrades (except for temporary reactive elements as described below)</td>
</tr>
<tr>
<td></td>
<td>S1</td>
<td>ERIS upgrades mitigating non-converged contingencies</td>
</tr>
</tbody>
</table>

---

9 See each Transmission Owner’s local area planning criteria posted on SPP OASIS http://www.oasis.oati.com/ (requires certificate to access)
10 See SPP Planning Criteria Section 5.4
11 See SPP ITP Manual Section 4.2.4
For S0, the powerflow cases may be in a severely stressed condition and require system support to be able to solve and achieve a stable state. To that end, temporary reactive elements may be added to the model to reach this state. These elements are only added in the event that existing reactive equipment is insufficient. A list of these temporary reactive devices is provided with the study models.

For the S1 portion of the mitigation process, solutions are used to solve non-converged constraints and, if applicable, remove temporary reactive elements. Temporary reactive devices may also be deemed appropriate solutions to non-convergence and be used as mitigations and will be assigned and cost allocated accordingly.

During the process of constraint analysis, multiple alternate solutions are determined through the process, but only one is chosen as the final solution. The final solution set is first and foremost reliable. All constraints both System-Intact and N-n are to be resolved for system reliability to be considered achieved. Next, the least-cost solution is chosen. Minimization of cost is considered not on an individual request basis, but for the cluster as a whole. Solutions are subject to change based on feedback from the respective Transmission Owner (limiting equipment ratings, feasibility, etc.). Lastly, solutions may mitigate system issues spanning multiple groups within SPP. All projects assigned to constraints mitigated by these solutions will be assigned cost responsibility.

During the DISIS, S0 and S3 are represented in model sets (both for ERIS and NRIS) and are posted for IC and TO review.

<table>
<thead>
<tr>
<th></th>
<th>S2</th>
<th>S3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NRIS</strong></td>
<td>ERIS upgrades mitigating non-converged contingencies and thermal violations</td>
<td>ERIS upgrades mitigating non-converged contingencies, thermal and voltage violations</td>
</tr>
<tr>
<td><strong>S0</strong></td>
<td>All ERIS upgrades (addition of temporary reactive elements as described below)</td>
<td></td>
</tr>
<tr>
<td><strong>S1</strong></td>
<td>All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies</td>
<td>All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies and thermal violations</td>
</tr>
<tr>
<td><strong>S2</strong></td>
<td>All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies and thermal violations</td>
<td>All ERIS upgrades + NRIS upgrades mitigating non-converged contingencies, thermal and voltage violations</td>
</tr>
</tbody>
</table>
4.3 STABILITY AND SHORT-CIRCUIT ANALYSIS

Short-circuit ratio calculation is performed during DISIS Phase 1. Stability and Short-Circuit analysis is performed during DISIS Phase 2.

4.3.1 Modeling

4.3.1.1 STABILITY MODEL SET

The SPP Model Development Advisory Group (MDAG) dynamic stability models serve as the starting point for all studies requiring dynamic analysis. Reference SPP Model Development Procedure Manual location.

The DISIS stability analysis uses the following years and seasons from the MDAG/TPL model set:

- Year 5 Summer Peak.
- Year 5 Winter Peak.

SPP will post BASE, PQ, and CQ models along with the Phase 2 draft report.

<table>
<thead>
<tr>
<th>DESCRIPTION</th>
<th>YEAR 5</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>BASE</td>
<td>Summer, Winter</td>
<td>2</td>
</tr>
<tr>
<td>PQ, CQ</td>
<td>Summer, Winter</td>
<td>4</td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td>6</td>
</tr>
</tbody>
</table>

4.3.1.2 SHORT CIRCUIT MODEL SET

The Year 5 Summer Peak Stability model is used for short-circuit analysis.

4.3.1.3 GENERATING FACILITY AND INTERCONNECTION FACILITIES

Each Generating Facility is represented in the dynamic stability models as an equivalent generator dispatched at the applicable percentage of the requested service amount. The facility modeling includes representation of equivalent GSU and main power transformer(s), with impedance data and power factor capability provided in the interconnection request. Equivalent collector system(s) and transmission lead line(s) impedances are also explicitly modeled for dynamic stability analysis. Dynamic stability models provided by interconnection customers are
assumed to properly represent their facilities. Model tuning for interconnection facilities is not performed during the GI process.

4.3.1.4 STABILITY MODEL DISPATCH

4.3.1.4.1 SOURCE GENERATION

The percentages in Error! Reference source not found. define the dispatch levels applied to non-Legacy MDAG generators\textsuperscript{12}, Prior-Queued Requests and Current-Queue Requests in the Prior-Queued and Current-Queue models with the exception noted below. The dispatch levels in the table are applied to the requested interconnection service amount, not to the nameplate rating.

Generators are dispatched the same regardless of ERIS or NRIS request type. Where a single Interconnection Request consists of multiple components of different fuel types, commonly known as a hybrid request, each component is dispatched individually according to its fuel type. If the resulting dispatch would exceed the requested capacity for the Interconnection Request, the dispatch will be scaled down on a pro-rata basis (of calculated values) to honor requested capacity.

The dispatch levels in Error! Reference source not found. have been approved by the TWG. The TWG periodically reviews these dispatch levels and can recommend and approve changes as needed according to the Revision Request process.

\textit{DISIS Model Diagram (from bottom up)}

\begin{center}
\begin{tikzpicture}
\fill[red!30] (0,0) rectangle (4,4);
\node at (2,2) {+ Current-Queue Generation};
\fill[green!30] (0,2) rectangle (4,2.5);
\node at (2,2.25) {+ PRIOR-QUEUED + Non-Legacy MDAG Firm and Non-Firm Variable Generation Not Dispatched in MDAG};
\fill[blue!30] (0,0) rectangle (4,2);
\node at (2,1) {Legacy and Non-Legacy MDAG Generation};
\node at (2,3.5) {DISIS MODEL};
\node at (5,3) {CQ Model (post-transfer case)};
\node at (5,2.5) {PQ Model (pre-transfer case)};
\node at (5,2) {MDAG/Base Case Model};
\end{tikzpicture}
\end{center}

\textsuperscript{12} Non-Legacy MDAG generators are firm and non-firm Variable Energy Resources (e.g. Solar and Wind) not dispatched in the MDAG model consistent with the SPP Model Development Procedure Manual. Non-Variable Energy Resources are assumed to have been considered for dispatch as needed in the MDAG model consistent with the SPP Model Development Procedure Manual; these resources will follow the Fuel Based Dispatch Table for Stability on a limited case-by-case basis.
*See MDAG Modeling Process for Generator Parameters, Modeling of Conventional Generation PGEN, Modeling of Battery Resources PGEN, Modeling of Wind/Solar Renewable Resources PGEN sections describe the generation inclusion and dispatch

**Non-Legacy MDAG Generator with POIs equivalent to Current-Queued Request

- Prior-Queued: requests that are queued higher than the current study not included in MDAG Base Model Generation Resources
- Current-Queue: requests that are currently under evaluation

**Table 4: Fuel Based Dispatch Table for Stability**

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>In-Group</th>
<th></th>
<th></th>
<th>Out-Group</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Summer Peak</td>
<td>Winter Peak</td>
<td>Summer Peak</td>
<td>Winter Peak</td>
<td>Summer Peak</td>
<td>Winter Peak</td>
</tr>
<tr>
<td></td>
<td>NL &amp; PQ</td>
<td>CQ</td>
<td>NL &amp; PQ</td>
<td>CQ</td>
<td>NL &amp; PQ</td>
<td>CQ</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Diesel Engine</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
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<tr>
<td>Hydro</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Storage</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Coal</td>
<td>100%</td>
<td>100%</td>
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<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Oil</td>
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<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Waste Heat</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>NC</td>
<td>0%</td>
</tr>
<tr>
<td>Wind</td>
<td>40%</td>
<td>100%</td>
<td>45%</td>
<td>100%</td>
<td>NC</td>
<td>20%</td>
</tr>
<tr>
<td>Solar</td>
<td>40%</td>
<td>100%</td>
<td>10%</td>
<td>100%</td>
<td>NC</td>
<td>40%</td>
</tr>
</tbody>
</table>

Hybrid See Hybrid Example

**Notes**
- NL = non-Legacy MDAG generator
- PQ = Prior-Queued Request
- CQ = Current-Queue Request
- NC = No Change in dispatch from MDAG model
- Percentages are based on the requested interconnection service amount in megawatts.

If the proposed POIs of a non-Legacy MDAG generator or Prior-Queued Request and a Current-Queue Request are located:

1. At the same substation and at the same nominal voltage level,
2. On the same branch or on a collection of in-series two-terminal branches and associated buses and facilities
   13, or
3. On radial branches and associated facilities

The non-Legacy MDAG generator or Prior-Queued Request will be dispatched at the In-Group Current-Queue Request amount. If the proposed POIs for any requests change between phases of study, then dispatch will be changed accordingly in the subsequent phases.

---

13 Where this case crosses group boundaries then the Current-Queue request will be evaluated in the closest group by impedance.
4.3.1.4.2 SINK GENERATION

In order to maintain gen-load balance within each planning region, the generation dispatched in the Source Generation section displaces MDAG Generation not included in the source. The following chart represents stability sink order:

The additional generation is offset by reducing the dispatch of Pre-Existing Generators across the entire SPP footprint excluding in-group Variable Energy Resources. Certain Resource types such as nuclear, hydro, etc. are excluded from the sink generation.

If minimum generation limits are reached when reducing MDAG generators, the following prioritized generation adjustments will be modeled as needed.

1. The current study requests out-of-group will be reduced from the percentages in Table 4: Fuel Based Dispatch Table for Stability on a pro rata basis.

2. Non-Legacy MDAG generators and Prior-Queued Requests in-group will be reduced from the fuel-based dispatch percentages on a pro-rata basis excluding the fuel-based dispatch exception cases above.

Additional reductions will be determined on a case-by-case basis and may include reducing non-Legacy MDAG generators and Prior-Queued Request in-group from the fuel-based dispatch percentages on pro-rata basis meeting exception cases above, reducing Current-Queue Requests from the fuel-based dispatch percentages on pro-rata basis, turning off MDAG generators, and reducing generation external to SPP.
4.3.2 Stability Analysis

4.3.2.1 STABILITY FAULT EVENTS

For all stability models developed, a transient stability analysis will be performed to determine generator unit response due to fault events on the system.

For the stability analysis, unstable conditions will be addressed for transmission reinforcement for contingencies specified in the dynamic stability assessment for TPL-001-4 contingencies equivalent to P0, P1, P2.1-2.3, P4, and P5 as identified by SPP and the Transmission Owners. Higher depth contingencies (P6-P7) will be evaluated as necessary for the location of the generation for mitigations. Unsuccessful reclosing will be evaluated for the faulted loss of elements, excluding transformers, for a P1 and P6 event.

The transient stability analysis will evaluate:

- System stability in response to fault events
- Compliance of Current-Queued Requests and Prior-Queued Requests with FERC Order 661-A
- Adherence to the SPP Disturbance Performance Requirements
- Post event voltage recovery within the SPP voltage criteria

Fault events will include P1 events involving each network circuit segment connected within three levels of each Current-Study Request’s POI as well as P4 and P6 events involving each network circuit connected within two levels of each Current-Study Request’s POI. A network circuit is comprised of each segment of sectionalized single (or double) circuits from substations or buses to accommodate generation and radial load. Each level includes all substations on the remote end of all network circuits. (i.e., 0 levels away from a line tap POI includes substations with at least 3 connected circuits on either end of the tapped circuit) Additionally, P1, P4, and P6 events on relevant regional or tie line facilities applicable to the study group will be evaluated. Each event should remove from service all elements that are expected to automatically disconnect for each event.

4.3.2.2 MITIGATIONS

Mitigation of stability issues, not also observed as a steady-state issue, will evaluate reduced fault duration and removal of reclose from the fault definition. Actual equipment settings and capabilities may provide reduced clearing times.

Evaluation of reduced clearing times and removal of reclose may be used to identify and determine whether mitigation is provided by existing equipment and settings or may be provided by a Network Upgrade to fault interrupting equipment (i.e., breakers and relays).

\[\text{SPP reserves the right to include/exclude additional contingencies regardless of their level away from the request’s point of interconnection.}\]
4.3.3 Short-Circuit Analysis

4.3.3.1 DISIS PHASE 1 SHORT-CIRCUIT RATIO CALCULATION

SPP calculates the short-circuit ratio using this formula and reports the results in DISIS Phase 1:

\[ \text{SCR}_{POI} = \frac{\text{SCMV}_{POI}}{\text{MW}_{VER}} \]

4.3.3.2 DISIS PHASE 2 SHORT-CIRCUIT FAULT CURRENT CALCULATION

Because sequence data in stability models is not comprehensive, SPP calculates three-phase fault currents for each bus using the models described in section 4.3.1.1 of this Business Practice. Transmission Owners review the results and may identify preliminary issues to SPP along with preliminary upgrades for inclusion in the report. The short circuit analysis assumes that all upgrades identified in the powerflow analysis are in-service unless otherwise noted in the individual group short-circuit results.

Preliminary results are refined in the Interconnection Facilities Study with any additional required upgrades and cost assignment identified at that time.

DISIS Phase 2 also includes a short-circuit ratio and critical clearing time screening as described in the OATT.

4.4 LIMITED OPERATION

As defined in the GIP Section 8.4.3, Limited Operation is a quantification of the amount of interconnection capacity available to the Interconnection Customer without system overloads, voltage violations, instabilities or breaker over-duty prior to the in-service date of all identified upgrades. Limited Operation amounts are calculated for each request during the DISIS and are listed in the report.
### 4.5 COST ALLOCATION

In accordance with GIP Section 4.2.2, cost allocation of Network Upgrades for Current-Study Requests that are wind are determined using the light load model. Cost allocation of Network Upgrades of all other Current-Study Request generator types is determined using the summer peak model.

<table>
<thead>
<tr>
<th>UNIT TYPE</th>
<th>CASE USED</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>5-year Light Load</td>
</tr>
<tr>
<td>Non-Wind</td>
<td>5-year Summer Peak</td>
</tr>
</tbody>
</table>

For transmission circuit upgrades, an analysis is performed to determine the System-Intact TDF, also known as a Power Transfer Distribution Factor (PTDF) that each Current-Study Request had on each new upgrade. The PTDF is calculated on the group specific light load or summer peak model in which the project resides. The impact each Current-Study Request had on each upgrade project is weighted by the size of each request. In this case, the size of the request is the interconnection service amount MWs being requested for interconnection service (in other words queue value). Finally, the costs allocated to each Current-Study Request for a particular upgrade are then determined by allocating the portion of each request’s impact over the impact of all affecting requests. The PTDF calculation uses the same source and sink methodology utilized in the Contingency Analysis sections 4.2.2.2, 4.2.2.3, and 4.2.2.4. Individual generator impacts are determined, rather than using cluster-based impacts. For upgrades mitigating constraints in multiple groups, all generators assigned to those constraints will share in the cost. Consistent with the above methodologies, the group and scenario specific to each unit will be used to calculate the PTDF and subsequent MW impact.

For example, assume there are three Current-Study Requests: X, Y and Z, responsible for the costs of Upgrade 1. Given their respective PTDFs for the upgrade have been determined, the cost allocation for Current-Study Request X for Upgrade Project 1 is found by the following set of steps and formulas:

- **Determine an impact factor on a given project for all responsible GI requests:**
  - Request X Impact Factor on Upgrade 1 = PTDF (%)\(X\) * MW\(X\) = \(X1\)
  - Request Y Impact Factor on Upgrade 1 = PTDF (%)\(Y\) * MW\(Y\) = \(Y1\)
  - Request Z Impact Factor on Upgrade 1 = PTDF (%)\(Z\) * MW\(Z\) = \(Z1\)

- **Determine each request’s allocation of cost for that particular project:**
  - Request X’s Upgrade 1 Cost Allocation($) = \(\frac{\text{Network Upgrade 1 Cost } (\$) \times X1}{X1 + Y1 + Z1}\)
• Repeat previous for each responsible Current-Study Request for each project.

For substation specific upgrades, such as new reactive devices, reconfigurations, etc., PTDFs cannot be calculated on a bus or node basis. Therefore, the PTDFs are generally checked on either the worst-case contingent element in the direction of system intact flow or on all circuits connecting to the location where the upgrade is installed where the highest absolute value PTDF of all the circuits is used to calculate the MW impact for each interconnection request for solutions resolving system intact non-converged and voltage constraints. The process then proceeds in alignment with the transmission circuit allocation process.

The cost allocation of each necessary Network Upgrade is determined by the size of each request and its impact on the given upgrade. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades. Costs assigned to each Current-Study Request are listed in the report.

4.5.1 Cost Estimates

SPP requests feedback and cost estimates from TOs for all assigned upgrades in the DISIS. All cost information submitted by TOs are incorporated into the study for accuracy. In the event that SPP does not receive a cost estimate, SPP-developed cost estimates based on historical data will be utilized.

4.5.2 Incremental Long-Term Congestion Rights

The SPP OATT provides Incremental Long-Term Congestion Rights (ILTCR) as compensation for the cost of Network Upgrades allocated for interconnection service.\textsuperscript{15}

4.6 AFFECTED SYSTEMS COORDINATION

SPP maintains agreements with most neighboring Transmission Providers that define how impacts from Interconnection Requests are coordinated between systems. References and links to the individual agreements are listed in the

\textsuperscript{15} See SPP OATT Attachment J Section V (C). Generation Interconnection Related Network Upgrades
Reference Documents section of this business practice. SPP coordinates with other Transmission Providers on a case-by-case basis. For interconnection to facilities owned by SPP Transmission Owners and other facility owners that are within the SPP Region, see Section 0.
SPP as an Affected System in this document.

When a neighboring entity studies DISIS requests' impact to the neighboring system, according to JOAs found in the Appendix section, the neighboring entity provides their report to SPP by the end of Phase 2. Therefore, at the end of Phase 2 a request should have their SPP DISIS result report and any AFS result report, if applicable. In the event the neighboring entity study results are not available, SPP will communicate the delay and continue with the SPP DISIS process regardless of AFS delay.

4.7 DISIS REPORT

SPP will post a DISIS results report that provide Current-Queued requests information about models, constraints, upgrades, and costs associated with the upgrades. Upgrades can be contingent (meaning, relies on a previous upgrade at no cost unless the higher queued request(s) associated with that upgrade withdrawals) or current study (meaning, upgrades associated with constraints that require mitigation, but for the current requests under study). Interconnection costs for current requests are reported as well.

DISIS Reports are located under ‘Impact Studies’ on OASIS: https://opsportal.spp.org/Studies/Gen

SPP provides final study models along with the report that include the upgrade solutions and/or upgrade idevs.

4.8 FACILITY STUDY

Placeholder for Facility Study

4.9 RESTUDY/SENSITIVITY DUE TO WITHDRAWALS

Placeholder for Restudy/Sensitivity due to withdrawals

4.10 SPP AND STAKEHOLDER ACCOUNTABILITY

SPP and stakeholders will introduce steps to focus on accountability for timelines and milestones that consist of mechanisms designed to promote the timely exchanges of data, reviews, and approvals within the interconnection service study process.

4.10.1 Project Schedule

SPP will develop a project schedule for each cluster and successive study. This schedule will identify the timing, duration, and responsible parties for all data exchanges, reviews, and
approvals required to complete the DISIS assessment. SPP will coordinate with SPP stakeholders in the development of this schedule and provide stakeholder updates on a frequent basis.

This schedule will be maintained by SPP and regularly reviewed at appropriate SPP stakeholder meetings to keep affected parties informed of upcoming milestones to ensure the timely completion of the planning process.

4.10.2 Interconnection Customer and Transmission Owner Reviews

The GI Modeling Task Force\textsuperscript{16}, under GIUF recommendations, improve model accuracy, help solve models, provide transparency, incorporate TPL methodology, and adjust powerflow solutions parameters (Area Interchange and Non-convergence). In order to implement these, SPP and the GI Modeling Task Force recommended the following critical times for ICs and TOs review throughout the study process:

1. Submission and Scoping Calls – SPP, ICs and TOs
   a. ICs and TOs are expected to coordinate prior to application submission.
   b. SPP receives the interconnection application and schedules scoping calls with SPP, ICs and TOs to review the interconnection request.
   c. ICs are expected to review SPP’s GI Queue and ensure their application data, one-lines, DYRE files, etc. match each other at the time the request is submitted. There is a one-time cure period if deficiencies are identified.

2. Model Review – SPP, ICs and TOs
   a. SPP will post BASE, PQ, and CQ cases for review.
   b. TOs review ratings between latest planning model and GI study models and sign off for completing the model review process.
   c. ICs review of POI, configuration, topology, impedance and machine parameters/models for the interconnection requests and sign off for completing the model review process.
   d. Failure to provide appropriate feedback during the Model Review period could lead to upgrade assignments, which SPP may address in later phases of the study.

3. Draft Report Review – SPP, ICs and TOs
   a. SPP will post a draft report** and create a window where ICs can submit questions and feedback to SPP. SPP GI Planning needs to provide

\textsuperscript{16} GI Modeling Task Force Discussion/Update GIUF Meeting Materials January 2022
responses/feedback to submitted questions in a timely fashion*. SPP will post the TDF values in the report.

4. SPP will use the GIUF meetings or separate results calls to talk about the proposed solutions, explaining the constraints, contingencies, flows, thermal and voltage issues. However, this action is not intended to open a window for ICs and TOs to submit alternative mitigations to the constraints, as it would add an additional level of time and complexity to develop a final portfolio of projects for each cluster*.

*As the schedule permits

**The draft report is a courtesy to improve the DISIS process

In all instances, SPP’s Remedy Management System shall be utilized to submit feedback or questions to SPP.
5 INTERCONNECTION SERVICE FOR ENERGY STORAGE RESOURCES

This section describes procedures for processing and evaluating interconnection requests for energy storage resources (ESR) under SPP's Generator Interconnection Procedures (GIP).

5.1 APPLICABILITY

A request to interconnect an ESR to the SPP Transmission System shall be treated as an Interconnection Request under the GIP and does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery nor to receive electricity for the purpose of charging.

A request to add an ESR to an existing Generating Facility may be made either as a new request for Interconnection Service or as a new request for Surplus Interconnection Service.17

A request to modify an existing ESR that is prohibited from charging from the Transmission System so that it can charge from the Transmission System will be treated as a new request for the sole purpose of determining the reliability impact of charging from the Transmission System.

5.2 PROCESS

ESRs will be evaluated for reliability impacts to the SPP Transmission System in both discharging mode (as a generator) and charging mode (as a withdrawal). The evaluation of both modes of operation will be conducted as part of the applicable Interconnection Study under the GIP. The application for interconnection service will require the provision of information necessary to fully evaluate interconnection of ESR facilities.

5.3 DISCHARGE MODE

When evaluating the interconnection of an ESR as a generator, the ESR will be dispatched in the GI cluster study models in the following ways:

Steady-State Power Flow Analysis
Pursuant to the dispatch levels listed in Table 1.

Dynamic Simulation
In the same way as other non-storage resources.

17 Subsequent to the acceptance of SPP’s compliance filing under FERC Order 845
5.4 CHARGE MODE

The GI study process does not evaluate ESRs as load as that is assessed in a separate tariff process (Delivery Point Addition/Modification or Transmission Service). The GI study process may evaluate the interconnection facility upgrades required to connect. Evaluation of the ESR in charging mode will determine the Interconnection Facilities\(^\text{18}\) necessary to accommodate charging activity at the requested maximum rate of charge specified by the customer. The customer shall also specify the maximum rate of charge capability of the ESR. If the requested maximum rate of charge is less than the maximum rate of charge capability, the customer shall specify the monitoring and control equipment necessary to ensure that the device does not exceed the requested maximum rate of charge when charging from the Transmission System. The necessary control technologies and protection systems shall be established in Appendix C of the executed, or requested to be filed unexecuted, GIA or Interim GIA, as applicable.

Network Upgrades that may be required to support charging activity will be identified in the applicable Transmission Service study in accordance with Part II or Part III of the tariff. Charging activity conducted without obtaining the appropriate transmission service reservation is prohibited and would constitute a default of the GIA.

The evaluation of the impact of the ESR in charging mode may be waived if the application meets these requirements:

- The application for interconnection service stipulates that the Generating Facility cannot take energy from the Transmission System when operating in charging mode, by either Self-Dispatch or at the direction of SPP.
- The application for interconnection service includes a description of the monitoring and control equipment that will be used to ensure that the Generating Facility cannot take energy from the Transmission System when operating in charging mode.

Normal auxiliary load required solely for the operation of the ESR is exempted from this requirement.

\(^\text{18}\) As defined in Section 1 of the GIP, Interconnection Facilities include all facilities and equipment between the Generating Facility and the POI, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.
6 SPP AS AN AFFECTED SYSTEM

6.1 BASIC PRINCIPLES OF APPLICABILITY

As set forth in Section 2.1 of Attachment V to the SPP Open Access Transmission Tariff (OATT), the GIP apply to the processing of Interconnection Requests to the Transmission System that are subject to FERC jurisdiction. Any generator interconnecting to the Transmission System where such interconnection is subject to FERC jurisdiction must submit an Interconnection Request pursuant to Attachment V of the SPP OATT.

6.2 EXCEPTIONS TO APPLICABILITY

This guideline serves to clarify application of the GIP by providing examples of instances where the GIP would not apply.

Examples include, but are not limited to instances where:

1. The Generating Facility will be a Qualifying Facility (QF) where the QF’s total output will be sold to its host utility according to PURPA and subject to state jurisdiction.  

2. The Generating Facility will interconnect to a facility not already subject to the OATT at the time the request is submitted, whether or not it plans to make wholesale electric energy sales.

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19 Interconnection Customers claiming exemption from the GIP must provide documentation of Qualifying Facility FERC certification, substantiating state jurisdiction and documentation from the host that 100% of the output will be sold to the host utility at avoided cost. QFs intending to make third party sales are subject to FERC jurisdiction per Order 2003 and are appropriately studied as part of the GIP. See FERC Order No. 2003 at P 814 (“[T]he Commission has jurisdiction over a QF’s interconnection to a Transmission System if the QF’s owner sells any of the QF’s output to an entity other than the electric utility directly interconnected to the QF. . . This jurisdiction applies to a new QF that plans to sell its output to a third party, and to an existing QF interconnected to a Transmission System that historically sold its total output to an interconnected utility or on-site customer and now plans to sell output to a third party.”). See also FERC Order No. 2003 at P 813; FERC Order No. 2006-A at PP 100-102; PURPA 292.203.a (3); PURPA 292.303. No interconnection of a QF pursuant to the GIP affects or diminishes any substantive rights of the QF to assert non-FERC jurisdictional status at any time according to the requirements of the law.

20 See FERC Order No. 2006 at PP 5, 8; FERC Order No. 2003 at P 804; FERC Order No. 2003-A at P 710; FERC Order No. 2003-C at P 51. At the time an Interconnection Request is made to interconnect to a non-jurisdictional facility, the interconnection is not subject to the GIP. After a Generation Facility that makes
3. The Generating Facility will produce electric energy to be consumed only on the Interconnection Customer’s site.\textsuperscript{21}

4. The Generating Facility will be used to supply energy only to unbundled retail customers over local distribution facilities.\textsuperscript{22}

5. Generating Facility will not operate in sustained parallel with the Transmission System. For purposes of this exception, “sustained parallel” applies to any Generating Facility which operates in synchronous operation with the electrical power system for 100msec or more.

\section*{6.3 SYSTEM STUDIES FOR NON-JURISDICTIONAL FACILITIES}

Generator interconnections, not subject to the OATT, may still require studies to identify impacts on SPP’s or the directly-connected Transmission Owner’s transmission system. The Transmission Owner will notify SPP of interconnection requests of 5 MW or more that are submitted directly to the Transmission Owner because they fall under the exemptions in this business practice; or are otherwise required by the Transmission Owner’s processes to be studied pursuant to SPP’s study process. SPP and/or the Transmission Owner will evaluate each interconnection request not subject to OATT requirements and will make the final determination whether the interconnection study will be performed by SPP and/or by the Transmission Owner. In instances where further study is warranted, such studies will be performed by the Transmission Owner or SPP, at the direction of the Transmission Owner. Non-jurisdictional generator interconnection customers may be required to enter into the appropriate study agreements with SPP to facilitate an affected system study agreement. Additionally, requests for non-jurisdictional generator interconnections may be required to be coordinated with SPP in accordance with NERC standards.

Although such studies may be performed within SPP’s GIP for planning purposes, the non-jurisdictional generator interconnection customer will not be subject to the OATT.

In such instances, the following shall apply:

1. When notified, the Transmission Owner is responsible for conducting any required studies to determine if the request may impact the Transmission System.

\begin{flushright}
wholesale electric energy sales has been connected, the interconnection facility is now subject to an OATT for Interconnection Requests made after that time.
\textsuperscript{22} Unbundled retail service over local distribution facilities is not under FERC jurisdiction. See FERC Order No. 2006 at PP 7-8 and n.8.
\end{flushright}
2. Should the Transmission Owner determine that the generator interconnection may impact the Transmission System, the Transmission Owner shall notify SPP of such impacts and provide to SPP any system impact studies that detail such impacts.

3. As an impacted system, SPP will determine what additional studies will be required to coordinate the impacts, up to and including studying the impact in the Definitive Interconnection System Impact Studies. The Transmission Owner/distribution provider shall require as a condition of interconnection with the interconnection customer that all SPP required studies be completed. The Transmission Owner/distribution provider shall have the option to enter into the applicable Affected System study agreements and to be financially responsible for such studies, or as a condition of interconnection, to require the interconnection customer to submit a request to enter the Definitive Interconnection System Impact Study process or other SPP study process as applicable.²³

4. It shall remain the Transmission Owner’s responsibility to complete any generator interconnection agreements in accordance with the Transmission Owner’s generator interconnection procedures regarding the completion of Network Upgrades required on the Distribution System and on the Transmission Owner’s transmission system.

5. If SPP’s studies show that Network Upgrades are required on the Transmission System, the Transmission Owner/distribution provider shall have the option to enter into a facilities agreement with SPP or require, as a condition of interconnection, the interconnection customer to enter into a facilities agreement with SPP and any affected Transmission Owner(s)/distribution provider(s) to complete the Network Upgrades required on their Transmission System.

6. All Network Upgrades must be completed prior to operation of the Generating Facility, unless other mitigations have been approved by SPP until the Network Upgrades are completed.

²³ The Transmission Owner(s)/distribution provider(s) has the ability to pass-through the Interconnection Study costs to its customer.
Reference materials and links are available at the sites below:

- **SPP Open Access Transmission Tariff**[^24]
  - Generator Interconnection Procedures (Attachment V)
- **SPP Business Practices**[^25]
- **Seams Agreements**[^26]
  - Associated Electric Cooperatives, Inc.
  - California Independent System Operator Corporation
  - Electric Reliability Council of Texas
  - Midcontinent Independent System Operator, Inc.
  - Peak
  - Public Service Company of Colorado
  - Saskatchewan Power Corporation
  - Southwestern Power Administration
  - Tennessee Valley Authority
- **SPP Disturbance Performance Requirements**[^27]
- **SPP Quarterly Project Tracking Report**[^28]
- **Request Management System**[^29]
- **New Three Stage Interconnection Process**[^30]
- **ITP Manual location**[^31]
- **SPP Model Development Procedure Manual location**[^32]

[^25]: https://www.spp.org/spp-documents-filings/?id=18162
[^26]: https://www.spp.org/spp-documents-filings/?id=18378
[^28]: https://spp.org/spp-documents-filings/?id=18641
[^29]: https://spprms.issuetrak.com/login.asp
[^31]: https://www.spp.org/engineering/transmission-planning/
[^32]: https://spp.org/spp-documents-filings/?id=18607
# LIST OF ACRONYMS

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>DF</td>
<td>Distribution Factor</td>
</tr>
<tr>
<td>DP</td>
<td>Decision Point</td>
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<td>ESR</td>
<td>Energy Storage Resource</td>
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<td>EHV</td>
<td>Extra-High Voltage (300kV or higher)</td>
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<tr>
<td>FCITC</td>
<td>First Contingency Incremental Transfer Capability</td>
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<td>FERC</td>
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