**MDWG MINUTES**
June 11, 2020

**SOUTHWEST POWER POOL**
MODEL DEVELOPMENT WORKING GROUP MEETING

**June 11, 2020 9:00 am – 12:00 pm (CDT)**
**Conference Call**

# SUMMARY OF MOTIONS AND ACTION ITEMS

Action Items:

1. SPP Staff to determine the appropriate level of stakeholder review for models, especially models whose data is altered from original member submissions.
2. SPP Staff to review if year 9 – 11 model can be combined to reduce models.
3. SPP Staff to add owner number/name and a tab to the report card for letter of notice.

Motions:

4. Jason Shook motioned to adopt the agenda as modified. Jordan Lamb seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.
5. Andy Berg motioned to approve the schedule. Jeremy Harris seconded the motion. The motion passed unanimously.
6. Andy Berg motioned to approve the model selection. Jordan Lamb seconded the motion. The motion passed unanimously.
7. Jason shook motioned to approve the language to approve the rate a, b, c, to 1, 2, 3. Steve Hohman seconded the motion. The motion passed unanimously.
8. Reené Miranda motioned to approve the language to approve data coordination language as shown on the screen. Holli Krizek seconded the motion. The motion passed unanimously.

**MDWG MINUTES**
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# MINUTES

## AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

### AGENDA ITEM 1A & 1B – CALL TO ORDER AND ANTITRUST STATEMENT

SPP MDWG Interim Chair, Jerad Ethridge, called the meeting to order at 9:02 am with Quorum. SPP Staff Secetrary, Sunny Raheem, read the anti-trust statement to the group. Sunny reminded the group the meeting is in muted mode and will require users to press "*6" to unmute if someone would like to speak.

### AGENDA ITEM 1C & 1D – ATTENDANCE AND PROXIES

The following members attended or were represented by proxy:

| MDWG Member | Present | Proxy | Present | Company |
|---|---|---|---|---|
| Jerad Ethridge | YES | | | Oklahoma Gas & Electric, MDWG Interim Chair |
| Charles Aleman | YES | | | Golden Spread Electric Cooperative |
| Andrew Berg | YES | | | Missouri River Energy Services |
| Preston Blinsky | NO | | | Basin Electric Power Cooperative |
| John Boshears | YES | | | City Utilities of Springfield |
| Joe Fultz | YES | | | Grand River Dam Authority |
| Jeremy Harris | YES | | | KCP&L and Westar, Evergy Companies |
| Steve Hohman | YES | | | Omaha Public Power District |
| Holli Krizek | YES | | | Western Area Power Administration |
| Jordan Lamb | YES | | | East River Electric Power Cooperative |
| Reené Miranda | YES | | | Southwestern Public Service |
| Nate Morris | YES | | | Empire District Electric Company |
| Alex Mucha | YES | | | Oklahoma Municipal Power Authority |
| Scott Rainbolt | YES | | | American Electric Power |
| Scott Schichtl | NO | Josh Hesselbein | YES | Arkansas Electric Cooperative Corporation |
| Jason Shook | YES | | | GDS Associates |
| Liam Stringham | YES | | | Sunflower Electric Power Corporation |
| Sunny Raheem | YES | | | Southwest Power Pool, Inc., MDWG Secretary |

Additional Guests:

| Guests | Company |
|---|---|
| Josh Hesselbein | Arkansas Electric Cooperative Corporation |
| David Zhong, Martin Green | American Electric Power |
| Marcus Dethloff | Basin Electric Power Cooperative |
| Adam Mummert | Burns and McDonnell |
| Conner Sweet, Jerry Bradshaw, John Allen | City Utilities of Springfield |
| Tyler Baxter | Corn Belt Power Cooperative |
| Matthew Keenan | Enel Power |
| Pallab Datta, Ryan Baysinger | Evergy Companies |
| Diego Toledo | Grand River Dam Authority |
| Rebekah Kelman | Gridliance |
| Bryan Haslinger | ITC Transco |
| Calvin Coates | Kansas City Board of Public Utilities |
| John Payne | Kansas Electric Power Cooperative |
| Esun@les.com | Lincoln Electric System |
| Ryan Benton | Midwest Energy |
| Dustin Betz | Nebraska Public Power District |
| Mark Mallard | Northwestern |
| Daryl Huslig, attersj@oge.com | Oklahoma Gas and Electric |
| Paul Vovk | Omaha Public Power District |
| Audrey White, Becca McCann, Casey Cathey, David Duhart, Eddie Watson, Hugh Benfer, Kimberly Woods, Lottie Richardson, Mason Favazza, Michael Odom, Moses Rotich, Shahrokh Akhlaghi, Shannon Mickens, Zach Sabey | Southwest Power Pool, Inc. |
| Dave Sargent, Scott Mijin | Southwest Power Administration |
| Aravind Chellappa, Frank Favela | Southwestern Public Service |
| Eli Nyambegera, Tanner New | Sunflower Electric Cooperative |
| Hummad Malhi, Joe Williams, Josh Turner | Western Farmers Electric Cooperative |
| Brianna Haug, Chris Colson, Gayle Nansel | Western Area Power Administration |

**MDWG MINUTES**
June 11, 2020

## AGENDA ITEM 1E – AGENDA REVIEW

Jerad Ethridge introduced the recent changes to the presenter of agenda item one. Jerad and Sunny Raheem proposed swapping agenda item three and seven around to accommodate presenters with conflicting meetings. Jerad asked the group if they had any additional modifications to the agenda. The group did not voice any additional modifications.

**Motion: Jason Shook motioned to adopt the agenda as modified. Jordan Lamb seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**

Material: JUN11_Attach1 - 1e. MDWG Meeting Agenda 20200611-redlined.docx

Jerad asked the group for any comments about the delivery of meeting materials. The group did not voice any concerns. Sunny mentioned staff did run into a glitch for posting and posted slightly late.

## AGENDA ITEM 2 – REVIEW OF PAST ACTION ITEMS

Sunny Raheem presented the red font updates to the action items. Sunny thanked Moses Rotich for updating the action item lists and for helping with the background materials. Sunny asked the group if they had any action items, in particular, they wanted to discuss at this time. The group did not voice any additional concerns.

## AGENDA ITEM 3 – RELIABLITY STANDARDS

Shannon Mickens presented a recap of NERC SPIDERWG Conference Call topics, subgroup updates, and discussions. Shannon provided an overview of reliability guidelines under development with SPIDERWG or its subgroup. Shannon provided an update on the recent Arkansas Public Service Commission Workshop and FERC Order – NERC's five (5) year assessments.

Chris Colson mentioned that the MDWG manual task force and Dynamic Load Task Force (DLTF) have been discussing Distributed Energy Resources (DER). Chris commented that with the approval of SPP Revision Request (RR) 372 (Evaluation of Energy Storage Resources for Interconnection Service), MOPC could help with DER gaining more traction soon.

## AGENDA ITEM 4 – 2021 MDWG / 2022 ITP ACTIVITIES

### AGENDA ITEM 4A – SCHEDULE (APPROVAL ITEM*)

Moses Rotich presented the updated 2021 series MDWG model build schedule to the group. Moses mentioned that the group had reviewed the schedule in detail at the last MDWG meeting and staff updated the schedule based on feedback received including a schedule legend. The group reviewed the schedule and made some cosmetic updates for consistency purposes. Jerad Ethridge mentioned that the approach by staff to discuss the schedule in a prior meeting before seeking approval seems to work well compared to past efforts. Moses mentioned that the schedule pdf, excel, and outlook calendar will be posted at the same time and all modeling contacts will be notified. Moses then thanked Kimberly Woods for her assistance in schedule development.

**Motion: Andy Berg motioned to approve the schedule. Jeremy Harris seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**

Material: JUN11_Attach2 - 4a. Draft_2021 MDWG-2022 ITP Powerflow and Short Circuit Model Build Schedule_Updated.xlsx

### AGENDA ITEM 4B – MODEL SELECTION (APPROVAL ITEM*)

Michael Odom presented the overview for the 2021 series MDWG / 2022 ITP model set. Evergy asked about the plan for model reduction since the total number of models seemed to be similar to the previous year. SPS asked if there was a task for staff to align the year one definition. Sunny Raheem mentioned that staff attempted to align year one a few years ago and ran into some compliance concerns around the SPP TPL assessment. Sunny mentioned that staff will be looking at it again. Sunny then mentioned that staff has been doing a review of the models built in the past five years and noted the total number of models have reduced but new standards and tariff processes requiring new models offset some reduction. Sunny mentioned that staff would like to bring the model reduction effort as an agenda item for the July MDWG meeting. Jerad then mentioned that the group should consider treating the model reduction and the current 2021 series MDWG model selection separately because model reduction will require a detailed work plan and approach including coordination with TWG and ESWG. Reené Miranda commented that members are continually building several models and having to perform checks on models that might have altered inputs from the original data submission. Reené cited the review of market powerflow model loads. Chris Colson supported Reené's comments about aligning year one and concerns about model reduction.

Jerad brought the discussion back to the agenda topic for the 2021 series MDWG models. Jeremy Harris suggested an alternate approach to potentially adding the unique ITP models as part of the MDWG model set for review purposes in lieu of reviewing both sets of models. The group discussed if the model reduction effort should be addressed at the dispatch focus group level.

**Action Item: SPP Staff to determine the appropriate level of stakeholder review for models, especially models whose data is altered from original member submissions.**

**Action Item: SPP Staff to review if year 9 – 11 model can be combined to reduce models.**

**Motion: Andy Berg motioned to approve the model selection. Jordan Lamb seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**

Material: JUN11_Attach3 - 4b. 2021 MDWG & 2022 ITP Model Selection.pptx

## AGENDA ITEM 5 – BREAK

The group took a five-minute break.

## AGENDA ITEM 6 – 2020 MDWG / 2021 TPL DYNAMIC MODEL BUILD UPDATE

Shahrokh Akhlaghi provided a quick update on the status of the 2020 MDWG / 2021 TPL dynamic models. Shahrokh mentioned that staff is slightly behind schedule but is working to make up ground on the effort.

## AGENDA ITEM 7 – 2020 MDWG / 2021 ITP SHORT CIRCUIT MODEL BUILD UPDATE

Michael Odom provided an update on the status of the 2020 MDWG / 2021 ITP short circuit models. Jerad asked Michael to describe the SERC and MEC data inclusions. Michael mentioned that staff would work on updating the MDWG and ITP short circuit models over the next few weeks.

## AGENDA ITEM 8 – SPP REORGANIZATION UPDATE

Casey Cathey presented the potential transition of the MDWG to an advisory group (MDAG) to the TWG based on VATF recommendations for reducing the number of working groups. Casey mentioned that SPP MOPC will discuss the recommendations at the July MOPC. Casey provided an overview of the potential transition of the MDWG and coordination with the TWG. The group asked about the voting structure as an advisory group. Staff mentioned that the voting structure would be less formal than required by Robert’s Rule but should encourage others that have modeling responsibilities in active participation. Additional updates to be provided after July MOPC.

## AGENDA ITEM 9 – MDWG REPORT CARD REVISION

Kimberly Woods presented the MDWG report card revisions to the group. Kimberly highlighted the goal of the effort. The group discussed if owner numbers and name can be added to the report card. The group discussed the process for adding new owner numbers. Staff will add in the owner numbers/name based on the feedback. Moses Rotich mentioned SPP plans to ask MMWG for additional owner numbers at the July MMWG meeting. Moses reminded the group if MDWG members would like to request owner numbers they should reach out to him to coordinate.

## AGENDA ITEM 10 – MDWG MANUAL LANGUAGE (APPROVAL ITEM)

Michael Odom presented the MDWG manual language for rate a, b, c and updates to be in accordance with the new PSSE version 34 fields. The group discussed the intent of the manual language change. Michael mentioned that it is to be consistent with the PSSE version 34 rating fields and not a changing of what rate a, b, and c represent.

**Jason shook motioned to approve the language to approve the rate a, b, c, to 1, 2, 3. Steve Hohman seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**

Michael presented the updated data coordination language to the group. Chris Colson provided additional clarification comments on the intent of the language. Jerad Ethridge mentioned that the language allows alternative notification to be provided instead of the letter of notice.

**Reené Miranda motioned to approve the language to approve data coordination language as shown on the screen. Holli Krizek seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**

**Action Item: SPP Staff to add owner number/name and a tab to the report card for letter of notice.**

Material: JUN11_Attach4 - 9. SPP Model Development Procedure Manual 2020 v4.0 June 11 2020_Pending.docx

## AGENDA ITEM 11 – SUMMARY OF ACTION ITEMS

1. SPP Staff to determine the appropriate level of stakeholder review for models, especially models whose data is altered from original member submissions.

2. SPP Staff to review if year 9 – 11 model can be combined to reduce models.

3. SPP Staff to add owner number/name and a tab to the report card for letter of notice.

## AGENDA ITEM 12 – DISCUSSION OF FUTURE MEETINGS

Jerad Ethridge outlined the future MDWG, MDWG workshop, MDWG focus groups, and MDWG manual task force meetings.

## AGENDA ITEM 7 – ADJOURN (APPROVAL ITEM)

Jerad Ethridge adjourned the meeting at 12:16 pm (CDT).

Respectfully Submitted,

Sunny Raheem

Secretary

Attachments

Material: JUN11_Attach1 - 1e. MDWG Meeting Agenda 20200611-redlined.docx

Material: JUN11_Attach2 - 4a. Draft_2021 MDWG-2022 ITP Powerflow and Short Circuit Model Build Schedule_Updated.xlsx

Material: JUN11_Attach3 - 4b. 2021 MDWG & 2022 ITP Model Selection.pptx

Material: JUN11_Attach4 - 9. SPP Model Development Procedure Manual 2020 v4.0 June 11 2020_Pending.docx

SPP Southwest Power Pool

**SOUTHWEST POWER POOL, INC.**

**MODEL DEVELOPMENT WORKING GROUP MEETING**

**June 11, 2020**

**Conference Call**

**9:00 a.m. – 12:00 p.m. (CDT)**

# AGENDA

1. Administrative Items........................................................................................Jerad Ethridge (10 mins)
    a. Call to Order
    b. Antitrust Statement
    c. Attendance
    d. Proxies
    e. Agenda Review (***Approval Item***)
        i. Acknowledgement of discuss meeting materials
2. Review of Past Action Items ..................................................................... Sunny Raheem (5 mins)
3. Reliability Standards Update ........................................................... Shannon Mickens (25 mins)
4. 2021 MDWG / 2022 ITP Activities:
    a. Schedule (***Approval Item****) ............................... Moses Rotich/David Duhart (20 mins)
    b. Model Selection (***Approval Item****) .......................................... Michael Odom (20 mins)
5. Break.............................................................................................................................. (5 mins)
6. 2020 MDWG / 2021 TPL Dynamic Model Build Update ...................Shahrokh Akhlaghi (10 mins)
7. 2020 MDWG / 2021 ITP Short Circuit Model Build Update ...................... Michael Odom (5 mins)
8. SPP Reorganization Update......................................................................Casey Cathey (30 mins)
9. Model Build Report Card Revision ........................................................ Kimberly Woods (10 mins)
10. MDWG Manual Language (***Approval Item***) ............................................Michael Odom (30 mins)
11. Summary of Action Items ............................................................................ Sunny Raheem (5 mins)
12. Discussion of Future Meetings ...................................................................Jerad Ethridge (10 mins)
    a. <u>MDWG</u>:
        i. July 9, 2020 Conference Call (9:00AM – 12:00PM)
        ii. August 13, 2020 Conference Call (9:00AM – 12:00PM)

iii. GO Education Session Conference Call June 17, 2020 (1:00PM – 4:00PM)

iv. Workshop Tentatively Schedule for August 18 – 19 (8:30AM – 4:00PM) at SPP Campus/WebEx

b. Manual Task Force:

i. June 18, 2020 (10:00AM-12:00PM)

ii. July 2, 2020 (10:00AM-12:00PM)

c. Focus Groups Meetings:

i. Power Flow:

1. June 15, 2020 (9:30AM – 11:30AM)

2. June 29, 2020 (9:30AM – 11:30AM)

ii. Short Circuit:

1. August 11, 2020 (9:00AM – 11:00AM)

2. November, 17, 2020 (9:00AM – 11:00AM)

iii. Dynamics:

1. July 22, 2020 (10:00AM – 12:00PM)

2. October 21, 2020 (10:00AM – 12:00PM)

iv. Generation Dispatch:

1. June 26, 2020 (2:00PM – 4:00PM)

13. Adjourn.......................................................................................................... All

***** The approval items denoted with "*" shall be jointly developed by PC, TP, and MDWG

| *Task Name* |
|---|
| **2021 MDWG/2022 ITP Series Model Build Schedule (Powerflow & Short Circuit) - PSS/E v34.7 - Model On Demand (MOD) v11 (MOD-032 East)**<br>**Note: The SPP MDWG Model Development Procedure Manual 2020 v4.0 will be utilized for this model build.** |
| **SPP Staff send out kick-off email** |
| **Pass 0: Powerflow (PF) & Short Circuit (SC) Data (Topology, Sequence Data & Initial Generator Retirements Updates)** |
| **Trial 1: SPP Staff Lock Down MOD and MOD/EDST** |
| **SPP Staff compiles MOD/EDST data and Review/Build Pass 0 - Trial 1 Solved Powerflow models** |
| ***SPP Staff Post Pass 0 - Trial 1 Models, DocuCode, and MOD-033-1 unacceptable differences for Data Submitter Review*** |
| **Data Submitters review Pass 0 - Trial 1 models and provide PF and SC data Updates through MOD and EDST** |
| **Data Submitter Updates- Topology, Sequence Data and Initial Generator Retirements Due** |
| **Trial 2: SPP Staff Lock Down MOD and MOD/EDST** |
| **SPP Staff compiles MOD/EDST data and Review/Build Pass 0 - Trial 2 Solved Powerflow Models** |
| ***SPP Staff Post Pass 0 - Trial 2 Models, DocuCode, and conflicting Generator Retirement List for Data Submitter Review*** |
| ***Pass 0 - Complete*** |
| **Pass 1 - Coordinate & Submit Load, Generation, Transaction, Topology and SC Data Updates** |
| **Data Submitters review Pass 0 - Trial 2 models and submit Load, Generation, Transaction, Topology and SC data updates through MOD and EDST for use in Pass 1 - Trial 1 Models** |
| **Data Submitter Updates (Load, Generation, Transaction, Topology & Sequence Data) Due** |
| **Trial 1: SPP Staff Lock Down MOD and MOD/EDST** |
| **SPP Staff compiles MOD/EDST data and Review/Build Pass 1 - Trial 1 Solved Powerflow Models** |
| **SPP Staff Review/Build Pass 1 - Trial 1 Short Circuit Models** |
| ***SPP Staff Post Pass 1 - Trial 1 PF and SC models, Report Card, Retirement List and DocuCode for Data Submitter Review*** |
| **Data Submitters review Pass 1 - Trial 1 Models and Submit PF and SC data updates through MOD and EDST for use in Pass 1 - Trial 2 Models** |
| **Data Submitter Updates (Load, Generation, Transaction, Topology & Sequence Data) Due** |
| **Trial 2: SPP Staff Lock Down MOD and EDST** |
| **SPP Staff compiles MOD/EDST data and Review/Build Pass 1 - Trial 2 Solved Powerflow Models** |
| **SPP incorporate 2020 AG1 Transmission Service updates into MOD/EDST** |
| **SPP Staff Review/Build Pass 1 - Trial 2 Short Circuit Models** |
| ***SPP Staff Post Pass 1 - Trial 2 PF and SC models and DocuCode for Data Submitter Review*** |

| |
|---|
| *Pass 1 - Complete* |
| **Pass 2 (Last Chance for Generator Additions , Retirements, Pmin & Pmax, Loads and Interchange)** |
| **Data Submitters review Pass 1 - Trial 2 models and submit PF and SC data updates through MOD and EDST for use in Pass 2 Models** |
| **Data Submitters-Final Submission of Generator Additions, Retirements, Pmin & Pmax, Loads, and Interchange Corrections through MOD and EDST** |
| **SPP Staff Lock Down MOD and MOD/EDST** |
| **SPP Staff compiles MOD/EDST data and Review/Build Pass 2 Solved Powerflow models (Merge with latest MMWG models)** |
| **SPP Staff Review/Build Pass 2 Short Circuit Models (Merge with latest SERC SC Models)** |
| ***SPP Staff Post Pass 2 PF and SC models and DocuCode for Data Submitter Review*** |
| ***Pass 2 - Complete*** |
| **FINAL PASS (Final Generation Dispatch, DocuCheck Issue Corrections, MOD-033 Feedback and Topology Updates)** |
| **MDWG Face-to-Face Meeting** |
| **Data Submitters Review Pass 2 Models; Submit PF and SC corrections through MOD and EDST for use in the Final Pass Models** |
| **Data Submitters-Final Submission of Generation Dispatch, Docucheck Corrections, MOD-033 Feedback and Topology data updates through MOD and EDST** |
| **SPP Staff Lock Down MOD and EDST -- FINAL** |
| **SPP Staff compiles MOD/EDST data and Review/Build Final Pass Solved Powerflow models** |
| **SPP Staff Review/Build Final Pass Short Circuit Models** |
| ***SPP Staff Post Final Pass PowerFlow and Short Circuit Models for Approval*** |
| **MDWG/TWG Review 2021 MDWG/2022 ITP Powerflow Models for Finalization** |
| **MDWG/TWG Review 2021 MDWG/2022 ITP Short Circuit Models for Finalization** |
| ***Finalization - MDWG Net Conference to Vote and Approve 2021 MDWG Powerflow Models as Final*** |
| ***Finalization - TWG to Vote and Approve 2022 ITP Powerflow Models as Initial-Final*** |
| ***Finalization - MDWG Net Conference  to Vote and Approve 2021 MDWG Short Circuit Models as Final*** |
| ***Finalization - TWG to Vote and Approve 2022 ITP Short Circuit Models as Initial-Final*** |
| |
| **2021 MDWG/2022 ITP Model Build Schedule Acronyms** |
| **SC = Short Circuit** |
| **PF = PowerFlow** |
| **EDST = Engineering Data Submission Tool** |
| **MOD = Model On Demand** |

| |
|---|
| **MDWG = Model Development Working Group** |
| **TWG = Transmission Working Group** |
| |

| Duration | Start | Finish |
|---|---|---|
| **185 days** | **Mon 7/6/20** | **Fri 3/19/21** |
| **0 days** | **Mon 7/6/20** | **Mon 7/6/20** |
| **25 days** | **Mon 7/6/20** | **Fri 8/7/20** |
| **10 days** | **Mon 7/6/20** | **Fri 7/17/20** |
| **10 days** | **Mon 7/6/20** | **Fri 7/17/20** |
| ***0 days*** | ***Fri 7/17/20*** | ***Fri 7/17/20*** |
| **5 days** | **Mon 7/20/20** | **Fri 7/24/20** |
| **0 days** | **Fri 7/24/20** | **Fri 7/24/20** |
| **10 days** | **Mon 7/27/20** | **Fri 8/7/20** |
| **10 days** | **Mon 7/27/20** | **Fri 8/7/20** |
| ***0 days*** | ***Fri 8/7/20*** | ***Fri 8/7/20*** |
| ***0 days*** | ***Fri 8/7/20*** | ***Fri 8/7/20*** |
| **70 days** | **Mon 8/10/20** | **Fri 11/13/20** |
| **15 days** | **Mon 8/10/20** | **Fri 8/28/20** |
| **0 days** | **Fri 8/28/20** | **Fri 8/28/20** |
| **15 days** | **Mon 8/31/20** | **Fri 9/18/20** |
| **15 days** | **Mon 8/31/20** | **Fri 9/18/20** |
| **5 days** | **Mon 9/21/20** | **Fri 9/25/20** |
| ***0 days*** | ***Fri 9/25/20*** | ***Fri 9/25/20*** |
| **15 days** | **Mon 9/28/20** | **Fri 10/16/20** |
| **0 days** | **Fri 10/16/20** | **Fri 10/16/20** |
| **15 days** | **Mon 10/19/20** | **Fri 11/6/20** |
| **15 days** | **Mon 10/19/20** | **Fri 11/6/20** |
| **5 days** | **Mon 11/9/20** | **Fri 11/13/20** |
| **5 days** | **Mon 11/9/20** | **Fri 11/13/20** |
| ***0 days*** | ***Fri 11/13/20*** | ***Fri 11/13/20*** |

| | | |
|---|---|---|
| *0 days* | *Fri 11/13/20* | *Fri 11/13/20* |
| 45 days | Mon 11/16/20 | Fri 1/15/21 |
| 20 days | Mon 11/16/20 | Fri 12/11/20 |
| 0 days | Fri 12/11/20 | Fri 12/11/20 |
| 20 days | Mon 12/14/20 | Fri 1/8/21 |
| 20 days | Mon 12/14/20 | Fri 1/8/21 |
| 5 days | Mon 1/11/21 | Fri 1/15/21 |
| *0 days* | *Fri 1/15/21* | *Fri 1/15/21* |
| *0 days* | *Fri 1/15/21* | *Fri 1/15/21* |
| 45 days | Mon 1/18/21 | Fri 3/19/21 |
| 2 days | Tue 1/19/21 | Wed 1/20/21 |
| 15 days | Mon 1/18/21 | Fri 2/5/21 |
| 0 days | Fri 2/5/21 | Fri 2/5/21 |
| 10 days | Mon 2/8/21 | Fri 2/19/21 |
| 15 days | Mon 2/8/21 | Fri 2/26/21 |
| 5 days | Mon 3/1/21 | Fri 3/5/21 |
| *0 days* | *Fri 3/5/21* | *Fri 3/5/21* |
| 5 days | Mon 3/8/21 | Fri 3/12/21 |
| 10 days | Mon 3/8/21 | Fri 3/19/21 |
| *0 days* | *Fri 3/12/21* | *Fri 3/12/21* |
| *0 days* | *Fri 3/12/21* | *Fri 3/12/21* |
| *0 days* | *Fri 3/19/21* | *Fri 3/19/21* |
| *0 days* | *Fri 3/19/21* | *Fri 3/19/21* |
| | | |
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| | | |

| Model Build Schedule Color Identifier |
|---|
| **Orange: SPP Staff Lock Down Model on Demand and Engineering Data Submission Tool** |
| **Green: Data Submitters Review** |
| **Red: Data Submitters Updates Due** |
| **Black: SPP PowerFlow Build** |
| **Blue: Short Circuit Build** |
| ***Black Italic: SPP Posting or Pass Completion*** |
| **Purple: MDWG Face-to-Face Meeting** |
| ***Green Italic: Final SPP Staff / Member Conference Call Vote and Approval*** |

SPP Southwest Power Pool

# 2021 MDWG/2022 ITP MODEL SELECTION

SPP SYSTEM PLANNING MODELING

MICHAEL ODOM

JUNE 11, 2020

| Year Definition | | 2021 Series MDWG / 2022 ITP Model Selection | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **MDWG** | **ITP/TPL** | **Year** | **Season** | **MDWG PF** | **MDWG SC** | **MDWG DYN** | **ITP BR PF** | **ITP MPM F1** | **ITP MPM F2** | **ITP MEM F1** | **ITP MEM F2** | **ITP BR SC** |
| 0 | -1 | 2021 | Spring | 1 | | | | | | | | |
| 0 | -1 | 2021 | Summer | 1 | 1 | | | | | | | |
| 0 | -1 | 2021 | Fall | 1 | | | | | | | | |
| 0 | -1 | 2021 | Winter | 1 | | | | | | | | |
| 1 | 0 | 2022 | Light Load | 1 | | 1 | | | | | | |
| 1 | 0 | 2022 | Spring | 1 | | | | | | | | |
| 1 | 0 | 2022 | Summer | 1 | 1 | 1 | 1 | | | | | |
| 1 | 0 | 2022 | Fall | 1 | | | 1 | | | | | |
| 1 | 0 | 2022 | Winter | 1 | | 1 | 1 | | | | | |
| 2 | 1 | 2023 | Light Load | 1 | | | 1 | | | | | |
| 2 | 1 | 2023 | Spring | 1 | | | 1 | | | | | |
| 2 | 1 | 2023 | Summer | 1 | | 1 | 1 | 1 | | 1 | | |
| 2 | 1 | 2023 | Fall | | | | 1 | | | | | |
| 2 | 1 | 2023 | Winter | 1 | | | 1 | | | | | |
| 3 | 2 | 2024 | Light Load | 1 | | 1 | 1 | 1 | | | | |
| 3 | 2 | 2024 | Summer | 1 | | 1 | 1 | 1 | | 1 | | 1 |
| 3 | 2 | 2024 | Winter | | | | 1 | 1 | | | | |
| 5 | 4 | 2026 | Light Load | 1 | | 1 | | | | | | |
| 5 | 4 | 2026 | Summer | 1 | 1 | 1 | | | | | | |
| 5 | 4 | 2026 | Summer Shoulder | 1 | | | | | | | | |
| 5 | 4 | 2026 | Winter | 1 | | 1 | | | | | | |
| 6 | 5 | 2027 | Light Load | | | | 1 | 1 | 1 | | | |
| 6 | 5 | 2027 | Summer | | | | 1 | 1 | 1 | 1 | 1 | 1 |
| 6 | 5 | 2027 | Winter | | | | 1 | 1 | 1 | | | |
| 10 | 9 | 2031 | Summer | 1 | | 1 | | | | | | |
| 10 | 9 | 2031 | Winter | 1 | | 1 | | | | | | |
| 11 | 10 | 2032 | Light Load | | | | 1 | 1 | 1 | | | |
| 11 | 10 | 2032 | Summer | 1 | | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 11 | 10 | 2032 | Winter | | | | 1 | 1 | 1 | | | |
| | | **Totals** | **79** | **22** | **3** | **12** | **17** | **10** | **6** | **4** | **2** | **3** |

BR = Base Reliability, MPM = Market Powerflow Model, MEM = Market Economic Model, SC = Short Circuit, DYN = Dynamics

| 2021 MDWG / 2022 ITP Models - MOD/EDST Data Submissions | | | | | |
|---|---|---|---|---|---|
| **Year** | **Season** | **Load Profile** | **Generation Profile** | **Topology** | **Transactions** |
| 2021 | Spring | Yes | Yes | Yes | Yes |
| 2021 | Summer | Yes | Yes | Yes | Yes |
| 2021 | Fall | Yes | Yes | Yes | Yes |
| 2021 | Winter | Yes | Yes | Yes | Yes |
| 2022 | Light Load | Yes | Yes | Yes | Yes |
| 2022 | Spring | Yes | Yes | Yes | Yes |
| 2022 | Summer | Yes | Yes | Yes | Yes |
| 2022 | Fall | Yes | Yes | Yes | Yes |
| 2022 | Winter | Yes | Yes | Yes | Yes |
| 2023 | Light Load | Yes | Yes | Yes | Yes |
| 2023 | Spring | Yes | Yes | Yes | Yes |
| 2023 | Summer | Yes | Yes | Yes | Yes |
| 2023 | Fall | Yes | No | Yes | Yes |
| 2023 | Winter | Yes | Yes | Yes | Yes |
| 2024 | Light Load | Yes | Yes | Yes | Yes |
| 2024 | Summer | Yes | Yes | Yes | Yes |
| 2024 | Winter | Yes | No | Yes | Yes |
| 2026 | Light Load | Yes | Yes | Yes | Yes |
| 2026 | Summer | Yes | Yes | Yes | Yes |
| 2026 | Summer Shoulder | Yes | Yes | Yes | Yes |
| 2026 | Winter | Yes | Yes | Yes | Yes |
| 2027 | Light Load | Yes | No | Yes | Yes |
| 2027 | Summer | Yes | No | Yes | Yes |
| 2027 | Winter | Yes | No | Yes | Yes |
| 2031 | Summer | Yes | Yes | Yes | Yes |
| 2031 | Winter | Yes | Yes | Yes | Yes |
| 2032 | Light Load | Yes | No | Yes | Yes |
| 2032 | Summer | Yes | Yes | Yes | Yes |
| 2032 | Winter | Yes | No | Yes | Yes |

# RECOMMENDATIONS

- PSSE Version
  - SPP & MDWG Power Flow Focus Group recommends using PSSE v34.7
- MOD Version
  - SPP recommends moving to MOD v11
- Schedule and Models
  - SPP recommends approving the schedule and model selection included in the background material

# MODEL DEVELOPMENT PROCEDURE MANUAL

## Model Development Working Group

Version 4.0~~3.1~~ June-2020

Published on September 12, 2019

MODEL DEVELOPMENT WORKING GROUP

# REVISION HISTORY

| DATE OR VERSION NUMBER | AUTHOR | CHANGE DESCRIPTION | MODEL BUILD APPLICABILITY |
|---|---|---|---|
| 21JUN18 | SPP Engineering Modeling | Updated format | |
| 2018 v1.1 | SPP Engineering Modeling | Modified Bus Naming and Map / Model request information | |
| 2018 v1.2 | SPP Engineering Modeling | Updated Introduction & Dynamic modeling section | |
| 2018 v2.0 | SPP Engineering Modeling | Restructured the MDWG Procedure Manual | |
| 2018 v2.1 | SPP Engineering Modeling | Updated the On-Peak & Off-Peak model designations | |
| 2019 v2.2 | SPP Engineering Modeling | Updated the MOD-032-1 Attachment 1 links | |
| 2019 v2.3 | SPP Engineering Modeling | Updated Station Service section and Shunt Device section | |
| 2019 v2.4 | SPP Engineering Modeling | Updated Short Circuit and Dynamics sections | |
| 2019 v2.5 | SPP Engineering Modeling | Updated the Transformer section | |
| 2019 v3.0 | SPP Engineering Modeling | Updated Transformer section and general updates | 2020 Series MDWG Model Build |
| 2019 v3.1 | SPP Engineering Modeling | Updated to remove duplicate Generator Data section and added clarification for renewable dispatch | 2020 Series MDWG Model Build |
| 2020 v4.0 | SPP Engineering Modeling | Updated Aux Load, Shunt Data, ESR, DER data updates | 2021 Series MDWG Model Build |

# CONTENTS

# SECTION 1: INTRODUCTION

## PURPOSE

This manual establishes consistent modeling data requirements and reporting procedures for the development of Near-term and Long-term Transmission Planning Horizon models necessary to support analysis of the capability, reliability, and suitability of the SPP Transmission System. This section describes the applicability of entities, Data Owners, equipment, and Data Submitters to which this manual is germane.

The latest modeling data requirements and reporting procedures for the Planning Coordinator's planning area, the "SPP MDWG Model Development Procedure Manual" jointly developed with each of the PC's Transmission Planners, can be found on the SPP corporate website, www.spp.org. Additionally, the schedule for submission of data and the list of MDWG models (case types/scenarios) can also be found on the SPP corporate website, www.spp.org. The schedule for model development will also be sent with the first data request.

The primary deliverable of the SPP MDWG is a set of base transmission system models (base cases) that include a reasonable projection of the anticipated transmission system conditions as will be operated by the SPP Transmission Operators (TOPs) in coordination with the SPP Reliability Coordinator (RC). The primary intent of these base cases is to provide SPP member Transmission Planners (TPs) and the SPP Planning Coordinator (PC) an effective starting point for reliability planning and compliance assessments. In addition, the base cases are developed in support of various SPP planning processes in accordance with SPP model data and reporting procedures that include maintenance and coordination of steady state, short circuit, dynamic, and geomagnetic disturbance models.

These base cases are a collection of transmission system data, as submitted annually to the SPP PC by applicable Data Submitters, meant to represent the transmission system in the SPP region in a steady-state, system-intact condition. The system topology, generator dispatch, and system loads modeled in the base cases are intended to be respective and representative of the projected transmission system as will be operated within the SPP footprint under reasonably anticipated weather and time-of-day conditions for the year and season being represented in each base case. Reasonable projections within each case include all firm generator commitments, forecasted load commitments, firm interchange commitments, expected transmission topology and expected seasonal transmission or generation outages. Additionally, base cases may include reasonable system projections based on details specified in later sections of this document and based on historical data or projected data.

## SCOPE OF APPLICABILITY

It is well understood that transmission system modeling is a complex process predicated upon accurate and comprehensive data collection, review, and compilation. The SPP Model Development Working Group recognizes that to properly develop SPP Transmission System models, a constituency of responsible entities must collaborate in the model building effort. The transmission system subject to the SPP OATT including facilities 60kV and above must be accounted for in the SPP Transmission System models. Therefore, consistent with both the applicability of the NERC Data for

Power System Modeling and Analysis Reliability Standard (MOD-032-1)1,and the provisions of the SPP Open Access Transmission Tariff (OATT), as well as good utility practice, this manual is applicable to the following NERC-registered and non-NERC-registered entities:

- Planning Coordinator;
- Balancing Authority;
- Transmission Service Provider;
- Transmission Planners;
- Transmission Owners[2] of equipment within the SPP Planning Coordinator planning area and/or of equipment that is part of the SPP Transmission System;
- Owners or lessors of generating units, including Generator Owners, within the SPP Planning Coordinator planning area of Network Resource(s) designated by the SPP OATT and/or who have submitted a Generation Interconnection Request consistent with the SPP OATT.
- Resource Planners;
- Distribution Providers;
- Network Customers receiving Network Integration Transmission Service pursuant to the SPP OATT for designated Network Load and/or having arranged Point-To-Point Transmission Service for non-designated load;
- Native Load Customers of an SPP Transmission Owner;
- Transmission Customers pursuant to the SPP OATT.

It is noted that within the SPP Region, consistent with SPP Regional Transmission Organization (RTO) procedures and the SPP OATT, SPP serves as both a Balancing Authority[3] and Transmission Service Provider for the SPP Transmission System.

### *Applicable Data Owners*

A subset of the applicable entities annotated above comprise the Data Owners subject to the modeling data requirements and reporting procedures of this manual:

- Balancing Authority is responsible for submitting modeling data for aggregated existing and future load, integrated resource plans, and interchange obligations corresponding to the case conditions specified.
- Transmission Service Provider is responsible for submitting modeling data for their existing and future service commitments and obligations corresponding to the case conditions specified.

1 The NERC petition to remove the Load Serving Entity (LSE) registration was approved by 153 FERC ¶ 61,024, issued 15 October 2015. Therefore, the LSE registration is not discussed in this manual.

2 Capitalization is intended to include transmission-owning entities as defined in the NERC Glossary of Terms, as well as defined in the SPP OATT.

3 For Eastern Interconnection equipment only. WAPA-UGPR independently operates the WAUW BA area within the Western Interconnection for equipment which is under the SPP OATT.

- Distribution Providers are responsible for submitting modeling data for their aggregated existing and future load, and interchange obligations corresponding to the case conditions specified.
- Transmission Owners are responsible for submitting modeling data for their existing and future Transmission or sub-transmission equipment that they own or maintain.
- Owners or lessors of generating units, including Generator Owners, are responsible for submitting modeling data for the existing and future generating equipment that they own or maintain.
- Resource Planners are responsible for submitting modeling data for their existing and future long-term resource adequacy plan(s) of specific customer load demand and energy requirements, corresponding to the case conditions specified.
- Network Customers are responsible for submitting modeling data for their existing and forecasted load, existing and forecasted load transactions, as well as existing and forecasted resource transactions corresponding to the case conditions specified.
- Native Load Customers are responsible for submitting modeling data for their existing and forecasted load corresponding to the case conditions specified.
- Transmission Customers are responsible for submitting modeling data for their existing and forecasted transactions utilizing the SPP Transmission System, serving Network Load, or sales of Network Resources corresponding to the case conditions specified.

### *Applicable Data Submitters*

The Data Owner shall be the Data Submitter, subject to the modeling data requirements and reporting procedures of this manual. A Data Submitter may be designated as the entity who takes responsibility for collating, formatting, and corresponding a Data Owner's modeling data to SPP, as Planning Coordinator, in the approved format. A Data Submitter may be delegated only if the following are completed:

1. Data Submitter is designated in writing, showing mutual agreement by the Data Owner and Data Submitter.
2. Written notification is provided to SPP, as Planning Coordinator, regarding the specific data (e.g., load at bus X; generating unit Y; transmission branch Z) for which the Data Submitter will be responsible for.

A completed Letter of Notice identifying responsibilities between a Data Owner and a Data Submitter is required to be submitted to SPP. A contractual agreement may be submitted in lieu of the Letter of Notice. This Letter of Notice is included in the appendix section. The Data Coordination Workbook shall also be completed to reflect responsibilities between Data Owners and Data Submitters, including documentation such as a Letter of Notice.

Responsibility for the timely and accurate submission of Data Owner information to SPP, as Planning Coordinator, resides with the Data Owner.[4] When a Data Owner delegates the submission of data to a Data Submitter, all communication that would otherwise be sent to the Data Owner alone, will be

4 When delegated, the Data Submitter is not responsible for validating data provided by the Data Owner.

copied to the Data Submitter.

A Data Owner's submitted data shall not modify another Data Owner's data without explicit consent. Data Owners are encouraged to coordinate data submissions that may impact another Data Owner's system.

### *Applicable Equipment*

The modeling data required from Data Owners supports both the creation of the Electric Reliability Organization ("ERO"), or its designee, Interconnection-wide modeling cases, and the other Near-term and Long-term Transmission Planning Horizon cases required under the SPP OATT[5]. Planned equipment, as differentiated from existing equipment, consists of equipment expected to be in-service for the case conditions specified (e.g., month; year). Existing or planned[6] equipment for which non-equivalenced modeling data shall be reported include, but are not limited to:

1. All Facilities comprising the Bulk Electric System (BES).
2. All non-BES equipment 60 kV and above, subject to the SPP OATT[7].
3. All BES or non-BES equipment that includes a normally-open point that, when closed, shifts load or creates a network path affecting the SPP Transmission System.
4. All non-BES equipment interconnecting within the SPP Transmission System or interconnecting the SPP Transmission System with non-SPP Transmission System(s), subject to the SPP OATT[8].
5. All non-BES equipment known to have a significant interaction with the BES, including reactive resources.
6. All direct-current connections within the SPP region or interconnecting to Transmission outside of the SPP region.
7. All Network Resource generation assets, subject to the SPP OATT[9], excluding Small Generating Facilities (< 2MW).
8. All Network Resource (pursuant to Item 7) generator step-up transformers and generator interconnection equipment. Generator interconnection equipment shall include, at a minimum, collector electrical equivalent representations, where applicable.
9. All Resources that are registered in the SPP Integrated Marketplace, including the transmission equipment necessary to delivery that Resource to the SPP Transmission System when the registered Resource is not directly connected to the SPP Transmission System.
10. All Network Load, subject to the SPP OATT[10].
11. All firm power purchases served by SPP Network Resource(s) and firm power sales sunk to SPP Network Load, including all firm power transactions that result in an area interchange.

Other information regarding equipment not specified above may be requested by SPP, as the Planning Coordinator, or by Transmission Planner(s) for modeling purposes, as necessary. Likewise, consistent with MOD-032-1 Requirement R3, the Planning Coordinator or Transmission Planner may request additional data or clarification regarding technical concerns with modeling data submitted.

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5 Pursuant to the provisions of the OATT, equipment below the typical 100kV demarcation of the BES must be accounted for in the SPP Transmission System models.

6 As part of the MDWG model building process to support of the TPL-001-4 R1 model building requirement

7 Sixth Revised Volume No.1, Attachment AI, Part II-1.

8 Sixth Revised Volume No.1, Attachment AI, Part II-2.

9 Sixth Revised Volume No.1, Part III-30.

10 Sixth Revised Volume No.1, Part III-31

Written notification will typically be communicated through electronic means (e.g., email) to the Data Submitter and/or Data Owner and will include the technical concerns with the data submitted. Upon receipt of written notification, the Data Submitter and/or Data Owner shall respond to the notifying Transmission Planner or SPP, as the Planning Coordinator, with either updated data or an explanation with a technical basis for maintaining the current data in accordance with the reporting procedure schedule ("schedule") jointly developed by the Transmission Planners and Planning Coordinator.

### *Accountability*

SPP, through coordination with the MDWG, cannot be effective at building timely and accurate models without Applicable Entity participation. All Applicable Entities are responsible for providing the data necessary to model their Applicable Equipment. Likewise, Applicable Entities are accountable for meeting specific deadlines and milestones established by the MDWG, for model development, in the jointly developed schedule. The schedule will be made available to all Applicable Entities at the outset of each model-building period.

Clear and timely two-way communication between SPP, as Planning Coordinator, the Transmission Planners comprising the SPP PC, and Applicable Entities is vital to the successful compilation of modeling data, reporting, and ultimate production of accurate SPP Transmission System models. It is the responsibility of the Applicable Entity to communicate with SPP to establish the responsible contact for steady state, dynamic, and short circuit model data coordination.

Given that the MDWG relies upon Data Owner and Data Submitter input for the model building effort, the following are some of the established characteristics that support model-building best practices:

- Establishes a contact for model data coordination.
- Responds to model-building communications in a timely fashion.
- Data Owner begins coordinating data submittal well in advance of the initial model data submittal deadline.
- Submits model data ahead of established deadlines.
- Submit majority of model updates by initial model data submittal deadline.
- Ensures model data submitted is complete and accurate.
- Participates in MDWG conferences, calls and meetings.
- Performs a data integrity review of each model-building pass to identify and correct errors.
- Engages throughout the model-building process in a timely fashion.
- Keeps their respective managerial chain informed about model-building progress.
- Coordinates data submissions that may impact another Data Owner's system.

Following each model-building cycle, SPP staff, in conjunction with MDWG members, will prepare a lessons-learned and modeling best practice recommendations assessment. This assessment will focus on challenges experienced by the preceding model-building cycle, attempt to identify root causes, and suggest improvements for subsequent model-building cycles.

MDWG experience has shown that some natural obstacles exist to achieving model-building best practices. The following cautionary situations are examples for the purpose of Data Owner and Data Submitter awareness during the model-building process:

- Appropriate lead times. Data Owners may rely on other entities to provide data; therefore, Data Owners should consider lead times when requesting data from others (e.g., Data Owner entity X is the Market Participant and Network Load registrant who serves a municipal customer). Knowing that source data may be more difficult or slower to obtain, the Data Owner should act as early as possible so not to delay the submission of data until late in the model-building process.
- An early and complete submission of a Data Owner's modeling data does not eliminate the need for the Data Owner to participate in all model-building passes. In many cases, model parameters that affect multiple Data Owners within a region (e.g., load, generation dispatch, and transactions) may change between model iterations. The aggregation of these changes can have a pronounced effect on the model data that Data Owners have submitted and emphasizes the need for checking/re-checking the integrity of a Data Owner's model representations in each model iteration.

During each model iteration, an assessment of model-building progression and participation may be performed. Given that incomplete or late data submission has a tremendous impact upon the ability to meet the model-building schedule, any Data Owner who seeks to submit late data will be obligated to present before the MDWG about how proposed model changes will impact the models themselves, as well as impacts to the overall modeling schedule. The MDWG has the obligation to report its progress and achievement of model-building milestones to various SPP working groups/committees.

In cases where an Applicable Entity has not participated or otherwise supported MDWG efforts in good faith towards the achievement of published milestones, the MDWG may report non-participating entities to the TWG/MOPC.

# SECTION 2: GENERAL INFORMATION

## CONFIDENTIALITY AND PROPRIETORSHIP

The representation of future system elements in SPP data models is not an agreement to construct these elements when shown in the models or at any time. The configuration of each model system only reflects the necessary changes that the individual model system needs for maintaining reliable operation. The results of studies obtained through use of the data models developed by SPP will be the sole responsibility of the receiving party. The recipient of SPP data models must assure confidentiality and proprietorship.

SPP MDWG Steady-State, Dynamics, and Short Circuit Models are published according to the approved schedule.

## MDWG CASE TYPE SET

The current MDWG Case Type Set can be found on SPP's website, spp.org, under the documents section of the Model Development Working Group.

## STEADY-STATE AND SHORT CIRCUIT DATA FORMAT

PSS®E and MOD Users

The transmission modeling software approved by the SPP membership for performing planning and reliability studies is the Power Technologies Incorporated, Power System Simulator for Engineering (PSS®E) software. Data submitted for the building of the base SPP MDWG case types (models) needs to be in a format consistent with that used in PSS®E. The data shall be submitted via the SPP Models On Demand (MOD) Web Portal. Data submitted should be compatible with the MOD and PSS®E versions currently specified by SPP.

Non-PSS®E and Non-MOD Users

For those non-PSS®E users, load and generation profile data may be submitted via the Profile Submission form provided by SPP. SPP will aid with the submission of all other steady-state data in the correct PSS®E and MOD data formats. Any version changes will be discussed in the annual training provided by SPP.

The members are expected to contact the SPP Modeling Staff if there are any additional questions regarding the data format.

## TYPICAL ANNUAL MODELS

| | Season | | | Season |
|---|---|---|---|---|
| 1 | Annual Spring Peak | | 9 | Annual + 1 Summer Peak |
| 2 | Annual Summer Shoulder | | 10 | Annual + 1 Fall Peak |
| 3 | Annual Summer Peak | | 11 | Annual + 1 Winter Peak |
| 4 | Annual Fall Peak | | 12 | Annual + 2 Summer Peak |
| 5 | Annual Winter Peak | | 13 | Annual + 2 Winter Peak |
| 6 | Annual + 1 April Minimum | | 14 | Annual + 6 Summer Peak |
| 7 | Annual + 1 Spring Peak | | 15 | Annual + 6 Winter Peak |
| 8 | Annual + 1 Summer Shoulder | | 16 | Annual + 10 Summer Peak |

The typical yearly models developed by the SPP MDWG, as identified within the NERC TPL reliability standards, encompass both near-term (years one through five) and longer-term (years six through ten) transmission planning models. The SPP models are defined in the **Annual Models** table above with those transmission planning models representing the near-term planning horizon consisting of the MDWG case types 1 through 13 and those representing the longer-term planning horizon consisting of the MDWG case types 14 through 16. The longer-term models may be incremented or additional models may be included as required to support ERAG MMWG.

The annual series of models are developed by SPP staff with input from the Model Development Working Group and the Transmission Working Group.

The schedule for submission of data and list of MDWG models (case types) can be found on the SPP corporate website, www.spp.org.

## DATA TRANSMITTAL

Transmitting data to the Southwest Power Pool can be accomplished as follows:

1. **Electronic** --- GlobalScape

2. **E-MAIL** --- SPPEngineeringModeling@spp.org

The preferred method of submittal is through the "SPP MDWG File Sharing Site", GlobalScape. Include a file (excel, word, or equivalent) with description of data files submitted and which to which models they apply.

The transmitted data file should include the title of the first case and area name, followed by the changes to the first case, title of the second case and the area name, followed by the changes to the second case, etc. Case title lines should include the case title as in the following format examples: *04SP, *04FA, *04SH, *07SP (no spaces between characters).

## SPP MODEL RELEASE GUIDELINES

**Steady-State and Short Circuit Models**

SPP Base Case steady-state models and short circuit models are available to all SPP members. SPP and its members, by participating in SPP base case development, grant authority to the other participating members and SPP to release SPP Base Case steady-state models or reduced network equivalents of those models to government agencies. The public may receive models by filling out a SPP models order form and signing the appropriate SPP Confidentiality Agreement. For more information on requesting Base Case steady-state models, contact the SPP Model Contact.

Base case steady-state models of external systems, which are beyond the electrical borders of SPP and released under FERC Form 715 to government agencies, shall be the SPP models or a reduced network equivalent of the SPP models. If the external systems are equivalenced, such external models must be disclaimed, as equivalent representations not intended for study of the transmission systems in those external areas.

**SPP Model Contact:**
Please send all general modeling questions and concerns to SPPEngineeringModeling@spp.org.

**Request an SPP Map / Model**
You may request an SPP Transmission Map/Model through the Request Management System by clicking on the "Order Transmission Map/Model" quick pick option.

Questions? You may find it helpful to consult SPP Maps & Models FAQ.

*Last Updated July 26, 2018*

## MMWG DELIVERABLES
## REGIONAL COORDINATORS

The Regional Coordinators will provide the following to the MMWG Coordinator(s).

1. Steady-State Cases
   a. Data as needed to create the MMWG steady-state cases in RAWD or Saved Case format, regional representation shall be within an entire solved MMWG steady-state model in the proper PSS®E revision format
   b. Tieline and interchange data in the specified format
   c. IDEV files for any data changes
   d. PSS®E formatted contingency file containing five N-1 contingencies valid for all cases in the model series.
   e. Data Dictionary containing fields for Bus Number, 18 character PSS®E Bus Name, EIA Plant Code (U.S. only) and Non-Abbreviated Bus Name.
2. Dynamics Cases
   a. Dynamics input data in DYRE format for new models
   b. SDDB Excel worksheet for changes to the database
   c. FLECS code and documentation for user defined models
   d. Load conversion CONL file sorted by area
   e. List of netted generation buses
   f. Two contingency events per region in IDEV format

## MMWG COORDINATOR(S)

The MMWG Coordinator(s) will post the following to the ERAG Web Site.

1. Steady-State Cases
   Initialized steady state and regional contingency cases.
   a. Steady-State RAWD case file
   b. Conversion IDEV files
2. Dynamics Cases
   Dynamics case input data, output files and instructions including:
   a. Dynamics input data in DYRE format
   b. FLECS code for user defined models
   c. Load conversion CONL file sorted by area
   d. Any IPLAN or PYTHON programs necessary to set up the dynamics case
3. Complete dynamics database and User Manual
4. Final reports

**System Abbreviations & Area Number Assignments**
System Abbreviations & Area Number Assignments can be found on SPP's website, spp.org, under the documents section of the Model Development Working Group.

**MDWG Contact List**

The MDWG Contact List can be found on SPP's GlobalScape under Modeling (CEII, RSD) → SPP Modeling Contacts → 3. Final Modeling Contacts

**NOTE** – A complete listing of other SPP acronyms can be found on the SPP website at SPP Glossary

**Compliance**

1. MDWG Model Development Procedure Manual
   Note: The latest document can be found on SPP.org

2. MDWG Power flow, Short Circuit, and Dynamic model schedule and list
   Note: The latest document can be found on SPP.org

3. Data Submittal Forms (This is a separate document)
   Note: The latest document is posted with every model set

4. MDWG Procedure for late or no data submittal (FUTURE)

# SECTION 3: STEADY-STATE DATA REQUIREMENTS

Steady-State models are developed for an annual series of SPP and ERAG MMWG cases. Specific models are prepared and modified for use in SPP designated studies as required by the OATT and Planning Criteria. In order to establish consistent Steady-State models which represent the planning horizon necessary to support analysis of the reliability of the interconnected transmission system, the following Steady-State modeling requirements. Dynamic and Short-Circuit models are derived from the Steady-State models.

The Steady-State models are developed using data gathered through the SPP database Model On Demand (MOD) in conjunction with the Engineering Data Submission Tool (EDST). MOD data is divided into three parts: a Base Case, Projects, and Profiles (Bus, Loads, Generation, and Device Control). Modeling updates for transmission system topology can be made by submitting a Project to MOD. Non-topological modeling updates that are season specific can be made by submitting Profiles to MOD.

## *ENGINEERING DATA SUBMISSION TOOL*

MOD data should be kept current for each pass during the MDWG model build. The EDST contains informational data as well as modeling data that Data Submitter shall keep current for each pass of the MDWG model build.

1. Transactions – Firm and non-firm reservations with other entities that shall be coordinated before submission to SPP (Reference appendix VIII for more information).
2. Generators – Required generator data that is not otherwise captured in the models including but not limited to the generator type, long name, and associated Auxiliary load.
3. SPP Modeling Assignments – Contains PSS®E modeling area, owner, zone, and bus range information pertinent to SPP.
4. Load Details – Identify loads not served by native model areas.
5. Bus Details – List of all buses in the models that includes long names, voltage level, area, owner, and EIA plant codes.
6. Interregional Ties – PC to PC branch and transformer ties that shall be coordinated before submission to SPP.
7. Outages – Outages known during the annual model building process for buses, generators, branches, transformers, and shunts that meet TPL-001 requirements shall be modeled. Data Submitters are responsible for annotating known outages to be modeled within the EDST, as well as ensuring that the known outages are correctly modeled in the appropriate season(s) when the known outage is scheduled. MOD projects shall be submitted with effective dates corresponding to the scheduled period of the known outages.

**Table 1: Season Date Range and Cutoff Dates**

| Season | Date Range | Cutoff (On or Before) |
|---|---|---|
| Spring | April 1 – May 31 | May 1 |
| Light | April 1 – May 31 | May 1 |
| Summer | June 1 – September 30 | August 1 |
| Summer Shoulder | June 1 – September 30 | August 1 |
| Fall | October 1 – November 30 | November 1 |
| Winter | December 1 – March 31 | February 1 (yyyy+1)* |

*Example of 2017 Winter: 12/1/2017 – 3/31/2018; yyyy = 2017, yyyy+1 = 2018

## LOAD FORECAST

Load forecasting methodologies vary throughout the electric industry. SPP depends on load forecasts from Data Submitters to apply to the planning models. These load forecast amounts are to be not Coincident to the SPP region, meaning that the hour that a Data Submitter's system experiences a peak demand for a particular season, might not be the same hour that SPP, as a region, experiences a peak demand. In order to bring consistency and equivalency to the load forecast data submitted to SPP, load forecast data shall be based on a 50/50 forecast.

A 50/50 load forecast relates to a forecasted load amount having an equal probability of being either higher or lower than the amount forecasted. The forecasted load value is at the 50th percentile of a normal or similarly shaped distribution curve and is typically discussed in terms of exceedance such that there is a 50% probability that the load forecast will be exceeded due to abnormal weather.

Some loads within the planning models are non-conforming and should not be scaled (e.g. arc furnace, irrigation load that is either on or off). These loads should be modeled as non-scalable in PSS®E.

Some studies may require load forecasts other than a 50/50 load forecast and may be requested for such special studies. For example, a 90/10 load forecast has a 10% probability that the load forecast will be exceeded, which means the load forecast amount is higher than a 50/50 load forecast amount and would be considered atypical for general SPP transmission planning purposes.

There are various methods used to develop such forecasts and the forecasts are dependent upon many factors such as historical load values, temperature, humidity, economic forecasts, time of day, day of week, holidays, special events, and load uncertainty. Other factors, some of which are controllable, also impact the amount of forecasted load. Controllable Demand Side Management (DSM) and Distributed Energy Resources (DERs) are such factors.

Load forecasts shall not be reduced for application of controllable DSM. There is control over whether or not the load will be shed by an operator or end-user and therefore cannot be guaranteed that the load will be reduced during peak hours. Load forecasts should be reduced for application of non-controllable DSM. This load has a high probability of being shed during peak hours without manual intervention. For purposes of transmission planning, it is recommended that Distributed Energy Resources should not be applied to a Data Submitter's load forecast amount for incorporation into the SPP planning models.

When it becomes necessary or desirable to make changes in delivery point facilities, to upgrade, retire, replace or establish a new delivery point, including metering or other facilities at such location, the provisions set forth in Attachment AQ of the OATT shall apply. Loads that have completed the Attachment AQ process or any other applicable SPP process, and have an updated service agreement, or are in the process of finalizing a service agreement, if applicable, should be included in the Data Submitter's load forecast by the load submittal deadline in the MDWG model build schedule. SPP may reject any MOD projects or PSS®E idevs that attempt to add, delete or modify delivery points that have not been studied either through the Attachment AQ or any other applicable SPP process. Data Submitters are required to assign the appropriate type and status to load projects in MOD.

Summary of Data Submitter's load forecast data comprisal:

1. Not Coincident to the SPP region
2. 50/50 load forecast
3. Load forecast amount includes non-controllable Demand Side Management
4. Load forecast amount excludes controllable Demand Side Management
5. Load forecast amount excludes Distributed Energy Resources (recommended)

## *ON-PEAK/OFF-PEAK MODELS*

Seasonal peak models developed by SPP include: Summer On-Peak, Winter On-Peak, Spring On-Peak, and Fall On-Peak. These four seasonal models are built to represent the expected coincident seasonal peak based on each Data Owner/Data Submitter system peak load. Data Owner/Data Submitter peak load may not be coincident to the SPP Balancing Authority Coincident Peak.

In addition to the seasonal On-Peak models, SPP develops two Off-Peak models, which are Spring Light Load and Summer Shoulder models.

The Light Load model is developed with the intent to capture a Data Owner/Data Submitter system minimum load during the spring timeframe.

The Summer Shoulder Off-Peak model is typically defined to be 70% - 80% of the total Summer On-Peak load level confined within each of the individual Data Owner/Data Submitter's transmission system. The Summer Shoulder Off-Peak loading is representative of the average of the anticipated summer season daily peak hours, but is not a seasonal Summer Peak representation.

| **Model** | **Timeframe** |
|---|---|
| Spring On-Peak (G) | April 1$^{st}$ through May 31$^{st}$ |
| Summer On-Peak (S) | June 1$^{st}$ through September 30$^{th}$ |
| Fall On-Peak (F) | October 1$^{st}$ through November 30$^{th}$ |
| Winter On-Peak (W) | December 1$^{st}$ through March 31$^{st}$ |
| Spring Light Load Off-Peak (L) | April 1$^{st}$ through May 31$^{st}$ |
| Summer Shoulder Off-Peak (SH) | June 1$^{st}$ through September 30$^{th}$<br>Typically 70% - 80% of Summer On-Peak load level |

Data Owners of load that is pseudo-tied into SPP shall submit load forecasts to both SPP and the entity in which the load is embedded. Owners of load that is pseudo-tied out of SPP should submit load forecasts to the entity in which the load is embedded.

External load is load not affiliated with load forecasts submitted by SPP Data Submitters to SPP for planning model building purposes.

## *LOAD DATA*

Load data is maintained in MOD via a profile file which is applied to the model. Profiles, Loads can belong to an Area that is not the same as the Bus Area. The default solution technique will solve the case with Tie Lines and Loads. The Tie Lines and Loads solution option assumes that the Loads Area generation serves the load.

The non-scalable Loads will be identified in the non-scalable Load worksheet of the EDST. This allows model builders to modify models without changing the loads that are constant.

Loads that are owned by municipal utilities should be modeled with an identifier in front of the number (i.e. Rayburn County load one should have the ID "R1"). These loads should be maintained in the Load Mapping worksheet of the EDST.

## *AREA SUMMARY REPORT*

The Area Summary Report is an important part of data preparation and should be the initial step of the update process. This report, though not part of the steady-state input forms, is an important part of the data coordination process. As such, the report should be distributed to all appropriate systems at least one week before the initial update data is due at the SPP Office. The standard area abbreviations should be used on the area summary report and in the steady-state input data of area interchange and transactions. The following sequence of steps is to be used in completing this report:

1. The system name and area number, along with the name and phone number of the person that prepared the report, should be entered at the top of the form in the appropriate location.
2. The area slack bus and bus number. The area slack bus is to adjust for individual system losses only. It is not necessary for the area slack bus to be used for area load control in actual operation. Generation dispatch should be made to prevent the area slack bus from going to negative power output or power output above the stated rating of the unit when accounting for area losses. It is best that the area slack bus not represent a base load unit. The estimated slack bus generation should also be entered (Item 7). There should be room left on the slack bus for generation movement up & down.
3. For consistency, it is important that each system continue using a particular area slack bus rather than choosing a different bus from year-to-year, unless a specific reason exists to justify such a change. There is a new row on the Area Summary Sheet to identify the slack bus. To aid in solution time of the cases, the area slack bus should be located on a relatively strong portion of the system.
4. Use of a renewable resource should be avoided unless there are no other resources to designate as the area slack. If a renewable resource must be used then approval must be given by the MDWG.
5. An entity's area slack machine shall be modeled within the entity's model area.
6. In the case where a model area has no slack machine designated or in-service, an imbalance situation could occur and the imbalance will go to the system swing machine leading to an undesirable state. Load plus losses, generation, and transactions must balance in the model area without a slack machine.
7. The case year and season should be entered in the appropriate locations in chronological order.
8. The current system official load forecast should be entered as net load (Item 6).
9. The estimated losses should be entered (Item 5). The reference cases can be used as a starting point to estimate system losses.

10. Load equals net load minus estimated losses (Item 4).
11. Purchases and sales should be entered (Item 2). These values must be coordinated with the parties involved in the interchange transaction prior to data preparation. The algebraic sum of these transactions should be equal to the total area interchange.
12. Net power (Item 3) must equal net load (Item 6). Generation (Item 1) is equal to the net power plus interchange.

## TIE LINE COORDINATION

Each SPP system will receive a tie-line data comparison summary for the initial base case and after the final models are published. The member **must** coordinate with its neighbors on the tie line representation in the models being developed.
This coordination should consist of:

1. Agreement on which bus is to be metered for area loss accounting,
2. The in-service and out-of-service dates, if applicable,
3. Tie line characteristics and ratings
4. System responsible for supplying the update data.

SPP Member tie data (Intra-SPP) is maintained in a MOD Project file. The majority owner of the tie is responsible for maintaining the tie's steady-state, sequence, and ratings data.

SPP tie data with external entities (Inter-PC) is maintained in the MMWG PC tie line list. Entities must submit changes using the latest list, which will be posted with the latest case set. Changes are to be highlighted in order for SPP Staff to easily discern the submitted changes. The file name shall contain the company name of which is submitting the change. There will be other lower voltage SPP ties which are not listed in the NERC list. They will be checked using the SPP tie line reports.

## LINE AND TRANSFORMER DATA

Additions to the system tend to move from year-to-year based on changing load growth forecasts and budget requirements. As a result, future lines and transformers may move through several future cases. Line and Transformer Data is contained in MOD Projects and phases. The Project Type, Status, and Phase Effective Date determine if the data will be included in a particular model.

The following steps should be considered when preparing line and transformer data:

1. The device code (Bus, Branch, Transformer) specifies what data is being added to the base case. The action code (Add, Modify, Delete) specifies the action to be taken with the Project data. Specifying the deletion of a bus will require a similar record to delete all associated or connected devices with the bus (lines, generators, loads, transformers, etc.) from the base case.

2. The "from bus," "to bus", and circuit number identify the line or transformer. The order in which bus numbers are entered is important for tie lines to identify which bus is metered for loss accounting in some data formats. The "from bus" is assumed to be the metered end (unless the "to bus" is entered with a negative) and the "to bus" area will collect loss responsibility. For transformers, this order is also important in all formats because it specifies to which bus the Load Tap Changer (LTC) will attempt to maintain voltage and/or which bus is tapped. The code U in the branch data allows the user to select proper metered and tapped side by always entering the tapped side as the "from bus" or first bus number after the change code.

The “from bus” is the metered end unless the “to bus” or second bus number is a negative number. Remember to include the circuit identifier.

3. The positive, zero, and negative sequence branch impedance parameters shall be provided on a 100 MVA base (per unit value). The smallest allowable reactance is 0.00011 P.U. on a 100 MVA base. Reactance values less than minimum will cause the steady-state program to treat the line as a zero impedance line to reduce solution time.

4. The positive, zero, and negative sequence line charging data (conductance and susceptance) shall be provided on a 100 MVA base (per unit value) as applicable. A default value of zero will be assumed if no data is provided. Line charging data will be provided in the appropriate units depending on the specific format being utilized. Accuracy is needed to ensure a proper voltage profile in the model.

5. Each Data Submitter shall submit normal and emergency ratings for each branch (AC Transmission Line or Circuit, two-winding, and three-winding transformer). Each branch must have a specified Rate 1(normal, continuous) and Rate 2(emergency) entered in the first two fields (RATE1 and RATE2, respectively) for each seasonal model; use of the third rating field (RATE3) is optional

6. Circuit mileage should be entered in the appropriate line length field of branch data. Ownership data for the line should also be entered in the appropriate fields of branch data. This mileage and ownership data will be used to validate and calculate Megawatt-mile for the OATT. Circuit mileages should be coordinated on all jointly owned lines. Invalid line lengths result in inaccurate revenue allocations.

7. All NERC flowgates must be included in the data submitted by each region to the MMWG such that those flowgates are not equivalenced in the steady-state models. A flowgate is a selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage stability, rotor angle stability, and contractual system constraints to power transfer. Enough detail should be added to model the flowgate accurately.

## BUS DATA

For all SPP steady-state models, systems will model buses within their SPP allocated bus range. For the sake of consistency, the bus names and numbers should remain constant from case to case and year to year. When a change in bus voltage occurs, a new bus number will be given to the new higher voltage bus. This enables SPP to track when the old bus voltage changes. All interregional tie bus names should conform to the entries in the Master Tie Line Database as approved by the Regional MMWG Coordinators. All tie line bus names and numbers should be standard and unique within each area in all models in a case series. Changes in tie line bus names and numbers from one series to the next must be kept to a minimum to reduce changes in computer support programs. Unique generator bus names, base voltages, and unit id combinations should be consistent from case to case within a model series. This will help ensure that the SPP bus names do not conflict with ERAG MMWG Standards.

The following steps describe options and data for most bus data formats:

1. The device code and the change code determine describes what action(s) are taken with the data supplied (addition, deletion, modification, etc…).

**NOTE:** When a bus is deleted or removed from service, all associated network devices (lines, transformers, loads, generators, etc.) must also be deleted or connected to a different bus in the applicable model(s).

Although voltage codes have no uniform association with voltage classes, historical consistency is encouraged amongst entities within a highly integrated network. Bus names can have up to 12 characters with the first character, preferably, alphabetic rather than numeric. The name should be left justified. Characters which can aid in filtering or association are allowed excluding the following characters: commas, asterisks, single quotes and double quotes. The last character field of the bus name should be the SPP voltage code described as follows. The historical SPP voltage code list shown below is recommended, but not required:

| | | |
|---|---|---|
| 1 - Below 69 kV | 4 - 138 kV | 7 - 345 kV |
| 2 - 69 kV | 5 - 161 kV | 8 - 500 kV |
| 3 - 115 kV | 6 - 230 kV | 9 - 765 kV or above |

1. For generator regulated buses, a desired voltage set point will be given. Generator buses should be modeled with operating characteristics as close to actual as possible. Generator ratings should also be specified for each generation bus (whether on or off-line) as described in SPP Planning Criteria Section 7.1. Generators shall model the gross output of the generating facility and explicitly model the Station Service or Auxiliary load. The practice of using generator for voltage support only (i.e. no real power output), should be avoided unless a synchronous condenser or static var controller physically exists on that bus or nearby in the system. When a generator is modeled offline (status 0), the MW (PGEN) and MVAR (QGEN) fields should be zeroed. Regulating transformers should not be located at a bus with a controlling generator or regulating shunt device.

2. Bus loads should be specified with the real and reactive power values provided as a pair in all entries. The load should be modeled to reflect the expected in-service/out-of-service status.

3. When scaling area load, it is important to consider the reactive power as well as real power. This is particularly true when referencing a case of a different season. Realistic reactive load representation has a major effect on the overall case voltages. Reactive requirements are different for the various season models.

4. Capacitors, reactors, and SVCs represented in the models should be consistent with actual seasonal operation. These devices should be used in future cases calling for local area voltage support, rather than falsely regulating a bus. Attention should be given to these installations in cases that are referencing a different season model. Tertiary reactors should be modeled on the low voltage bus of transformers if the tertiary is not modeled explicitly.

## SHUNT DATA

Shunt reactive devices are key components used, in conjunction with generating unit excitation, to regulate transmission system voltage, as well as facilitate operating flexibility while assisting to maximize transmission capacity. Shunt reactive devices are typically characterized as either static or dynamic, based upon their responsiveness to system voltage variations.

Static reactive devices tend to respond more slowly, either through automatic or manual switching according to a broader voltage schedule or range of system voltage conditions. Dynamic reactive devices tend to respond very quickly, automatically adjusting their reactive contributions to the system so as to maintain a voltage set point (Regulating device). The four primary static and dynamic reactive device categories are:

- **Fixed shunt device (Locally-switchable static devices) -** Typically require a switchman to physically close a switch in the field under de-energized conditions. These devices require human interaction at the location of the device in order to change the status and are not self-switching. These devices should be represented as fixed shunt devices in software simulations.

- **Switched Shunt, Locked mode (Remotely-switchable static devices) –** Can be placed in, or taken out of, service by a System Operator remotely operating a switch from a Control Center. These devices require human interaction in order to change the status, are not self-switching, are not used for automatic system adjustments, but are used for manual system adjustments (regulating device). These devices should be represented as switched shunt devices in locked mode (0) in software simulations and set to their expected seasonal Mvar (Binit) values.

- **Switched Shunt, Discrete mode (Automatically-switchable static devices) –** Can be placed in, or taken out of, service by an automatic controller (e.g., the Protection System) that actuate powered switch closure. These devices are self-switching, are used for automatic system adjustments (regulating device), but not used for manual system adjustments. These devices should be represented as switched shunt devices in a discrete switching mode (1, 3, 4, 5, or 6) in software simulations.

- **Switched Shunt, Continuous mode (Automatically-switchable dynamic devices) –** Reactive contribution is adjusted by an automatic controller. These devices are used for automatic system adjustments (regulating device), but not used for manual system adjustments. Examples of dynamic reactive devices include: static VAR compensators (SVC), static compensators (STATCOM), and direct current voltage source converters (VSC). These devices should be represented as switched shunt devices in a continuous switching mode (2) in software simulations.

Load flow software offers multiple options for modeling shunt reactive devices and care must be used when selecting the appropriate representation. The primary modeling capability considerations for non-rotating mass reactive devices are:

- Shunt implementation: fixed, or switched.
- Simulated control mode: Locked, discrete, or continuous.
- Regulated voltage band limits: high (*Vhi*) and low (*Vlo*).

Upon selecting the appropriate modeling representation for the non-rotating mass shunt reactive device, the Data Owners/Data Submitter shall ensure that the following is entered for:

*Non-regulating shunt capacitor or reactor device (static, locally-switchable device)*

- Fixed shunt (no control mode) with a unique shunt ID.
- Total reactive device admittance[11] (MW and MVAR) that represents the aggregated contribution of the reactive banks or blocks installed as a fixed device.
- In-service status, set to zero (0) if the device is not in-service.

*Regulating shunt devices*

- Switched shunt with 'SW' shunt ID (forced by software).
- Total reactive device admittance[12] (MVAR only), differentiated into quantities of admittance that represent the installed controllable device reactive banks or blocks, as appropriate.
- Regulated voltage band limits, either as a schedule (*Vhi* ≠ *Vlo*) for static reactive devices or as a set point (*Vhi* = *Vlo*) for dynamic reactive devices, appropriate to the equipment.
- Reactive limits, for dynamic reactive devices only.
- Control mode-of-operation, as listed above:
    - Static, remotely-switchable device – locked, control mode (0).
    - Static, automatically-switchable device - unlocked, discrete control modes (1, 3, 4, 5, or 6).
    - Dynamic device – unlocked, continuous control mode (2).
- Assignment of the regulated bus, for switched shunt representations only.
- In-service status, set to zero (0) if the device is not in-service.

The Data Owners/Data Submitter should consider the load flow numerical solution stability implications of the regulated voltage band limits (*Vhi*, *Vlo*) when entering data for the shunt reactive devices. The ability of the load flow numerical solver to derive an acceptable voltage state may be impeded by a switched shunt with a discrete control mode whose reactive contribution, when switched, pushes the voltage of its connected bus outside of convergence tolerances. Therefore, a limit difference of less than 0.025 pu shall not be used when entering the regulated voltage band limits (*Vhi*, *Vlo*) for a switched shunt reactive device. Similarly, switched shunts shall not be connected to generator buses or to a generator bus through a zero-impedance branch.

All shunt reactive devices attached at transmission-level buses (i.e., 60 kV or greater) or attached to the tertiary of a transmission-level power transformer shall be modeled explicitly and not as loads or aggregated with loads. Further, static reactive devices connected to transmission lines are known as line shunts. The PSS®E load flow software allows line shunts to be modeled as part of the BRANCH

11 Shunt conductance and susceptance quantities are entered in units of MW and MVAR representing the total per-unit admittance at rated voltage, on system base MVA.

12 Shunt susceptance quantities (conductance is assumed to be zero) are entered in units of MVAR representing the total per-unit admittance at rated voltage, on system base MVA.

data record. An alternative approach is to model the line shunt explicitly by using an intermediate bus and zero-impedance branch (ZBR), as shown in Figure 1, even when the line shunt is locally-switchable only and expected to match the in-service status of the connected branch. In this scenario, losing the transmission line, but not the line shunt, can cause low voltage conditions that may not be realistic.

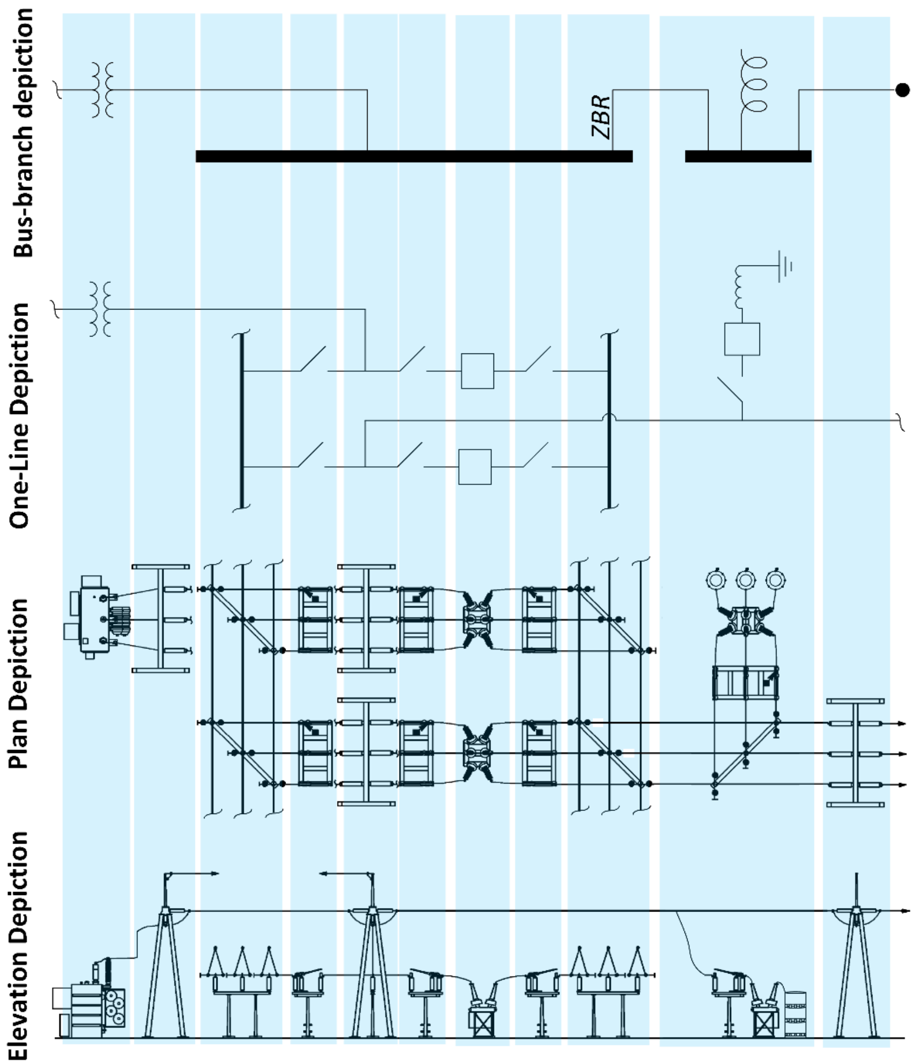



**Figure 1. Example depiction of line reactor modeling.**

The Data Owner/ Data Submitter must remember that the switched shunt reactive device control mode employed by the load flow software offers significantly more flexibility than shunt reactive devices implemented in the transmission system. Care should be taken to best represent the actual operation of installed shunt reactive devices and not allow unlocked control modes when inappropriate. During the model build process, similar to the process of case conditioning prior to analysis, remotely-switchable devices may be unlocked and automatically-switchable devices may be locked, expressly for the purpose of obtaining a converged load flow solution. However, care must be taken to ensure that the final state of the model contains the correct control mode, including locking, appropriate to the shunt reactive devices represented. The Data Owners/Data Submitters should also consider individual device protection settings as they relate to voltage control mode and limits.

## *GENERATOR DATA*

Generating unit MW and MVAR output shall be submitted such that the unit is within the PMAX, PMIN, QMAX, QMIN and MVA base limits with consideration of MOD-025-2 and SPP Planning Criteria 7.1.1., or company-specific procedure for testing the gross capability of the generator. Generator real power capability shall be set to the gross maximum and minimum values (PMAX and PMIN) with Auxiliary load modeled explicitly. Reactive power capability maximum and minimum values (QMAX and QMIN) in the models should be based on unit test data at real power capabilities.

For steady state analysis, the synchronous impedance of a generating unit is not used in load flow calculations. However, the representation for complex machine impedance for the generating unit, called ZSOURCE (alternatively known as ZSORCE) is composed of components ZR + j ZX, and is a critical parameter in performing switching studies, fault analysis, and dynamic simulations. ZSOURCE shall be calculated based upon the Machine MVA Base (MBASE). The Data Owner shall ensure that accurate and appropriate ZSOURCE data (ZR and ZX) are entered into the Machine Data Record according to XSOURCE Table.

For dynamic simulation, **this complex impedance must be set equal to the unsaturated subtransient impedance for those generators modeled by subtransient level machine models**, and to transient impedance for those modeled by classical or transient level models. Machine MVA Base (MBASE) and Machine Impedance (ZSOURCE, ZR + j ZX) values for the steady-state models must match dynamic data and should be established through manufacturer data or generator testing.. Future Generators that are in the models but are not budgeted for construction need to be identified in the Generator Data worksheet of the EDST.

Energy storage (pumped hydro, battery, flywheel, etc.) shall be modeled with the generator rated capabilities and a dispatch amount (Pgen) no greater than the rated output that can be sustained continuously for a minimum of one (1) hour.

For synchronous machines, the short circuit model should be comprised of saturated transient and subtransient impedance data. The Data Owner shall ensure accurate and appropriate saturated transient, subtransient, positive sequence, negative sequence, zero sequence, and (if applicable) grounding impedance data. This data shall be entered into the generator Sequence Impedance Data Record. In some cases, resistances for units may be assumed negligible, as long as reactance information is provided.

When modeling mothballed and future retired units, the unit will be modeled offline (in-service status = 0. The capability amounts for PMAX, PMIN, QMAX, and QMIN should not be changed until the unit is fully decommissioned) similar to units that are not dispatched in the particular seasonal model. Unit retirement information will be provided in a separate document and posted through a secure website. Decommissioned units should be removed from the models.

**Modeling Process for Generator Parameters**

a. The Generator parameter $P_{MAX}$ shall be modeled as a gross seasonal maximum capability based on SPP Planning Criteria 7.1 testing and reporting procedures and in consideration of MOD-025-2, or company-specific procedure for testing the gross capability for the generator.

b. Generating plant Station Service load and Auxiliary loads shall be represented in normal plant configuration, corresponding to the load appropriate to operation of the generating plant. All Station Service load and Auxiliary load representations shall:
   i. Be modeled explicitly on the appropriate bus[13], corresponding to the voltage to which the Auxiliary load is served. Model representations of Auxiliary load connected to the generating unit bus (Figure VII-1), Auxiliary load modeled with separate transformation (Figure VII-2), and Auxiliary load modeled on the high-side bus of the station service transformer (Figure VII-3) are acceptable.
   ii. Be annotated as non-scalable.

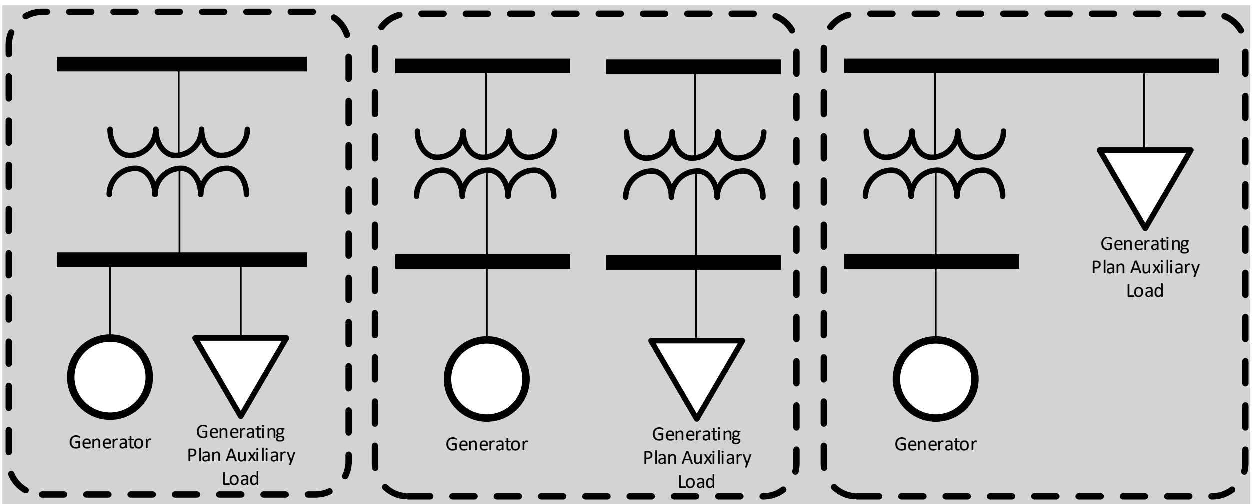



**Figure VII-1. Common bus representation**

**FigureVII-2. Separate transformation representation**

**FigureVII-3. Transformer high-side representation**

c. Experience has shown that generating plant Station Service load and Auxiliary load may vary considerably based upon generating plant dispatch and operating conditions. Therefore, generating plant Station Service load and Auxiliary load may be modeled as aggregated or non-aggregated generating plant load, representing the total quantity of fixed and variable Station Service load and Auxiliary load.

   If generating plant Station Service load and Auxiliary load is **aggregated**, the total load quantity shall properly reflect the total real and reactive loading for the generating units. The aggregated generating plant Station Service load and Auxiliary load shall use "S*n*" in the Load ID for one or more aggregated generating plant Station Service loads (Figure VII-4a).

   If generating plant Station Service load and Auxiliary load is **not aggregated**, each load quantity shall properly reflect the real and reactive loading expected during the corresponding dispatch (e.g., generating plant Pgen may be less than Pmax) and operating conditions for the generating units. Combined loads are analogous to aggregating generating plant Station Service load and Auxiliary load, with additional detail specifying the fixed and variable portions of total generating plant load (Figure

13 Station Service load and Auxiliary load shall not be netted against generating plant dispatch by reducing the Pgen of a unit with an amount corresponding to the plant Auxiliary load.

VII-4b). The combined or discrete (Figure VII-4b and Figure VII-4c) load representations shall:

i. Use "F*n*" in the Load ID field[14] to designate fixed load quantities that do not vary with plant dispatch.
ii. Use "V*n*" in the Load ID field[14] to designate variable load quantities that do vary with plant dispatch.

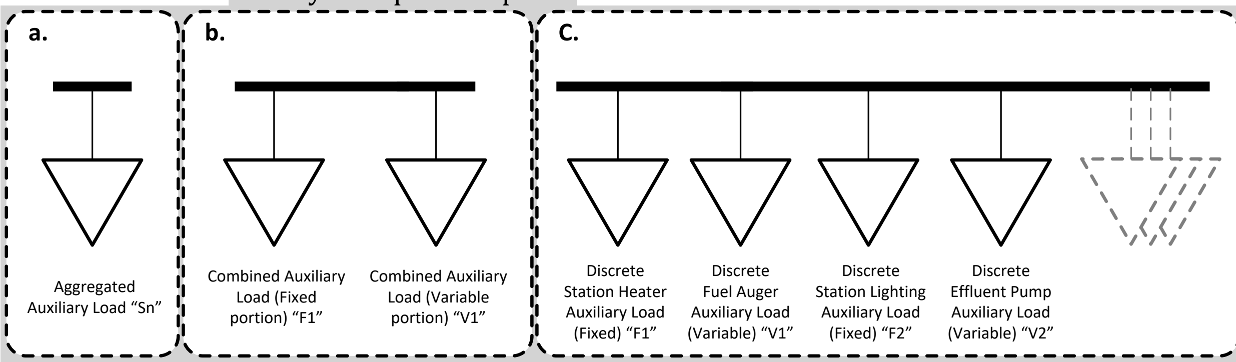



**Figure VII-4. Examples of generating plant Auxiliary load representations (aggregated, combined, and discrete).**

Only generating plant Station Service load or Auxiliary load IDs should be labeled with "S*n*", "F*n*", or "V*n*"; all other load types should be labeled differently.

Station Service or Auxiliary load modeling should be done in accordance with the state of the generator as follows:

| Generator State | Aggregated "Sn" SS or Aux Load | Variable "Vn" SS or Aux Load | Fixed "Fn" SS or Aux Load |
|---|---|---|---|
| Online | In-Service | In-Service | In-Service |
| Offline | In-Service | Offline | In-Service |
| Decommissioned | Removed from model | Removed from model | Removed from model |

Aggregated Station Service or Auxiliary loads shall be updated to reflect the dispatch of the associated generator.

### Modeling of Wind/Solar Renewable Resources $P_{GEN}$

- Spring Light Load Off-Peak models: Output of renewable resources with long-term firm transmission service will be modeled in the light load model at each facility's latest five-year average (or replacement data if unavailable) for the SPP minimum load hour corresponding to the season of the Light Load case, not to exceed each facility's firm service amount. The methodology used to calculate replacement data is described in the ITP Manual. Solar resources will be modeled at zero MW output in the light load case regardless of the facility's long-term firm transmission service amount.

14 "*n*" represents a unique numeric value. PSS®E requires each load placed at a bus to have a unique Load ID.

- On-Peak & Summer Shoulder Off-Peak models: Output of renewable resources with long-term firm transmission service will be modeled in the case(s) at each facility's latest five-year average (or replacement data if unavailable) for the applicable seasonal SPP coincident[15] peak, not to exceed each facility's firm service amount.
- SPP will make available the initial dispatch of renewable resources with long-term firm transmission service based on historical seasonal five-year average with the initial model pass of the each SPP MDWG model build. Any renewable resource modeling data submitted to the PC, after the initial dispatch list is provided, will be dispatched at the seasonal state dispatch percentage of the renewable resource's nameplate amount.
- When an affected party disagrees with the dispatch amount for a facility, the affected parties involved should coordinate to update the dispatch amount. If agreement cannot be reached, the case can be brought to the MDWG for a decision.
- Responsibility for validating and providing renewable resource dispatch updates falls to the affected parties.
- For resources that do not have firm service, $P_{GEN}$ values should not exceed average historical seasonal values for the Light Load, Spring Peak, Summer Peak, Summer Shoulder Off-Peak, Fall Peak, and Winter Peak Cases. If historical data is unavailable then the rated net capability of a resource determined according to SPP Planning Criteria section 7.1.5.3 should be followed.

## *SHORTFALL GUIDANCE PROCESS*

Under no circumstances in the Near-Term Transmission Planning Horizon shall generating resources be dispatched in excess of the firm transmission rights allotted to that resource. In the Long-Term Transmission Planning Horizon, if the resources within a modeling area and firm transactions from neighboring modeling areas are insufficient to serve customer load, the following should be investigated as potential modeling solutions to the shortfall:

1. Coordinate reciprocal non-firm transaction(s) with other modeling area(s). All parties are required to add their respective coordinated reciprocal record(s) to the transaction worksheet of the EDST.
2. Future generation resources that have progressed, at minimum, to the Interconnection Facility Study (per Attachment V, subsection 8.9) stage in the Generation Interconnection (GI) queue, may be modeled (in the Long-Term Transmission Planning Horizon models only) following these requirements.
   a. The in-service date shall be based on the expected in-service date of the GI study.
   b. In order to identify future GI queued generation, the unit name shall be the GI gen number (e.g. GEN-2017-898) and contain a unit ID of Zx (where x is any second ID designation appropriate in PSS®E).
   c. Projects files that add future generation shall have the appropriate Type and Status which can be found in the SPP MOD Project Type/Status Matrix.
3. Future Exploratory Generation resources may be modeled in the Long-Term Transmission Planning Horizon models following these constraints:
   a. In order to identify future Exploratory Generation, the unit ID of Zx (where x is any second ID designation appropriate in PSS®E) shall be used.
   b. When available, Exploratory Generation should be based upon the host TO Resource Plan.

15 SPP coincident peak equals the highest demand including transmission losses for energy measured over a one clock hour period during the defined season.

c. Projects files that add future generation shall have the appropriate Type and Status which can be found in the SPP MOD Project Type/Status Matrix.
d. The addition of Exploratory Generation shall be consistent with modeling practices that minimize the impact to power flows in neighboring transmission systems (e.g., exercise diligence in siting the exploratory generator topologically proximate to the load that uses its resource).

## EXTERNAL RESOURCE MODELING

**Purpose**
This procedure assures that members adhere to a uniform process when modeling external resources in SPP.

**Modeling Process**
If a member acquires external resources outside their Model Area, the following modeling process should be followed:

1. All buses should be assigned numbers that are in the host's Model Area bus number range.
2. Area Number/Name should be the host's Model Area number.
3. Zone Number/Name should be in the host's Model Area zone range.
4. Generation Owner Number should be the owner's designated ID number and percentage ownership.
5. The generation recipient should coordinate the output level and the inter-area transfer with the host control area.

### *Owner Data and Line Mileage Data (SSAE Control)*

To meet the Statement on Standards for Attestation Engagement (SSAE) requirement for the Reactive Matrix (MW-Mile) the SPP models must include the most recent owner data and line-mileage data, which will be obtained from the current seasonal MDWG model; therefore; it is important that Members keep the data current in MOD.

The MMWG Procedure Manual contains information related to the following:

1. Zone Range and Modeling Area Assignments
2. System Codes
3. Utilized DC Lines

### *Initial Run Review*

After all systems prepare and submit data, an initial run is made which assembles all system data, checks for errors, and results in a solved case. The initial run shows all entered data and diagnostic messages. This data is shown first in the initial run printout. Each system should review the data changes and solved case, making corrections as needed in the subsequent runs.

1. **Area Interchange**
   The area interchange report shows the area control bus, generation on the area control bus, and the net area interchange. The detail of area interchange among SPP systems is shown in the transaction data. The transaction workbook will include the NODE, Provider, and OASIS reservation number. The transaction workbook will use code DDD for transactions that do not have an OASIS reservation number. This data should be checked to ensure accuracy. Discrepancies in the transactions

between reporting systems will be noted in the diagnostic messages.

2. **Tie Line Metering**
The tie line report shows the tie lines and inter-company power interchange for each system. The tie line metered end should be verified, and should reflect line loss responsibility as accurately as possible. Any changes should be coordinated with the neighboring company involved.

3. **Area Totals**
The system generation and load should be checked on the system area summary. This data should be near expected values. The detail of generation is shown in the generation summary. If load is not the expected value, individual bus loads listed in the steady-state detail report should be examined. If loads were scaled from a reference case, the scaling factor should be checked. The load power factor should also be checked as power factors change seasonally. Check Power-factor of loads. The load supplying entities for the MDWG case types will validate each load power-factor with the most current system snapshot that represents that models load level (summer peak, winter peak, light load).

4. **Network**
Basic to the accuracy of the steady-state model is the accuracy of the network. The layout of the system representation should be checked. Purely conjectural facilities should not be included. Planned facilities which were modeled in previous steady-state models and have since been delayed or cancelled should be removed entirely from the steady-state model. These facilities cause solution problems for some steady-state programs if left in the model with an off-line status. Planned projects, including reactive resources such as capacitor banks, are to be included in the models. These projects are to be added through MOD in accordance with the MOD Type/Status Matrix of the Web Based Steady-State Model Development Procedure Manual.

5. **Review of Output**
The steady-state report should be checked for the flow on major transmission lines and selected bus voltages. This check can locate unusual results, which does not necessarily mean that data is in error, but rather indicates that additional checking of the model may be appropriate.

6. **Three useful reports for locating problems include:**
   a. The voltage summary,
   b. The overloaded branch summary, and
   c. The generation summary.

   a. **Voltage Summaries**
   Low or high voltages may be caused by a number of factors. Shunt devices may be sized inappropriately. Capacitors should have a positive value and reactors should have a negative value. (Check the CAP/REAC column of the steady-state report). The bandwidth (difference between VSWHI and VSWLO) of switched shunt devices should be wide enough that switching one block of admittance does not move the voltage at the bus completely through the bandwidth, thus causing solution problems at the bus. It is recommended that the minimum voltage bandwidth be 4% if only switched shunts are

used to regulate voltage. Switched shunts should not regulate voltage at a generator bus, nor should they be connected to the network with a zero impedance tie.

Transformer tap settings may also affect voltages. The steady-state report should be checked for tap settings. Particular attention to LTC-equipped transformers should be given to make sure the proper bus is regulated.
A tap setting of less than 1.000 on the tap bus results in an increase in voltage on the non-tap bus. A tap setting greater than 1.000 on the tap bus results in a decrease in voltage on the non-tap bus.

The inclusion of LTC regulation makes tap setting more important. With LTC-equipped transformers, fixed taps may also exist. The LTC tap range should be adjusted to compensate for the effects of fixed taps if necessary. The minimum and maximum number of ULTC and NLTC taps should comply with common industry standard practices.

Transmission line or transformer impedance errors may also affect voltages if the errors are large. See Section 6-A. for guidelines of typical transmission line or transformer impedance data.

b. **Summary of Overloaded Branches**
This summary shows each overloaded circuit, the flow on the circuit, and the normal and emergency ratings. Overloading may be caused by an incorrect rating. Both normal and emergency ratings should be given. Emergency ratings must never be less than normal ratings, though the ratings may be equal. The impedance of a circuit element or of a parallel element may also cause overloading. See Section 6-A for guidelines of typical transmission line or transformer impedance data.

c. **Generation Summary**
All buses with generation as well as all buses with voltage regulation are shown in this summary. Generators should not be modeled as unregulated buses.

The MW ratings, Mvar ratings, machine base (MBASE), and ZSOURCE must be supplied for each generator. Generator PMAX ratings should represent the net capability of each machine connected to the bus. Ratings should be adjusted seasonally in consideration of scheduled outages. The generation should be shown on the correct bus. Generation must not exceed the rating. Generator MBASE values should be equal to the nameplate MBASE rating of the unit. Each unit should be explicitly modeled and listed in the SPP Generation tab of the EDST.
The generator workbook will be updated to include both the saturated and unsaturated impedance for each machine. Fuel types, especially wind farms, should be identified in the appropriate column.

The reactive output limits (MAX and MIN) should be realistic values as defined in SPP Planning Criteria. For generators, a general rule of thumb sets MVAR limits as:

i. QT --- MAX = one-half of MW rating
ii. QB --- MIN = negative one-third of MW rating

If the slack bus generation changes significantly from the input value, it indicates an error in the model data. Regulated buses are not limited to generators, but also include other equipment such as synchronous condensers and static var controllers. If the actual voltage does not match the desired voltage, a reactive limit will be reached. The desired voltage for each regulated bus should be checked seasonally.

The Generator Owners/Data Submitters of utility scale wind and solar resources shall provide an equivalent representation consisting of all collector bus(es) and the main power step-up transformer(s) from the collector bus(es) to the transmission point of interconnection (POI). Additionally, a single step-up transformer and feeder parameters for each connected generator model, from the generator terminals to a collector bus, shall be included in the equivalent representation, with wind/solar devices lumped together to represent the aggregate wind turbines or solar inverters in each collection network. The equivalent representation shall be an as-built representation (as reasonably as possible) with all transformer data reflective of manufacturer test report information. Any future changes or updates to equipment (wind turbines or solar inverters) or electrical topology shall include an updated equivalent representation to the Transmission Planner before submitting to the Planning Coordinator.

Generator facilities comprised of more than a single inverter (battery, flywheel, etc.) and other similar technology should have similar equivalent model representation. Figure 1 and Figure 2 below are illustrations provided for use as guidance for the equivalent representations of such renewable resources; however, Figure 2 shall be the representation in the planning models.

Generator Owners/Data Submitters should coordinate with their host Transmission Owners to obtain valid SPP bus numbers for use in the equivalent representation of the generator resources. Bus names shall conform to the bus naming section of this manual. There are several industry best practice documents explaining how to represent equivalent representation of generator resources (examples: WECC Wind Power Plant Power Flow Modeling Guide and PV Plant Power Flow Modeling Guide).

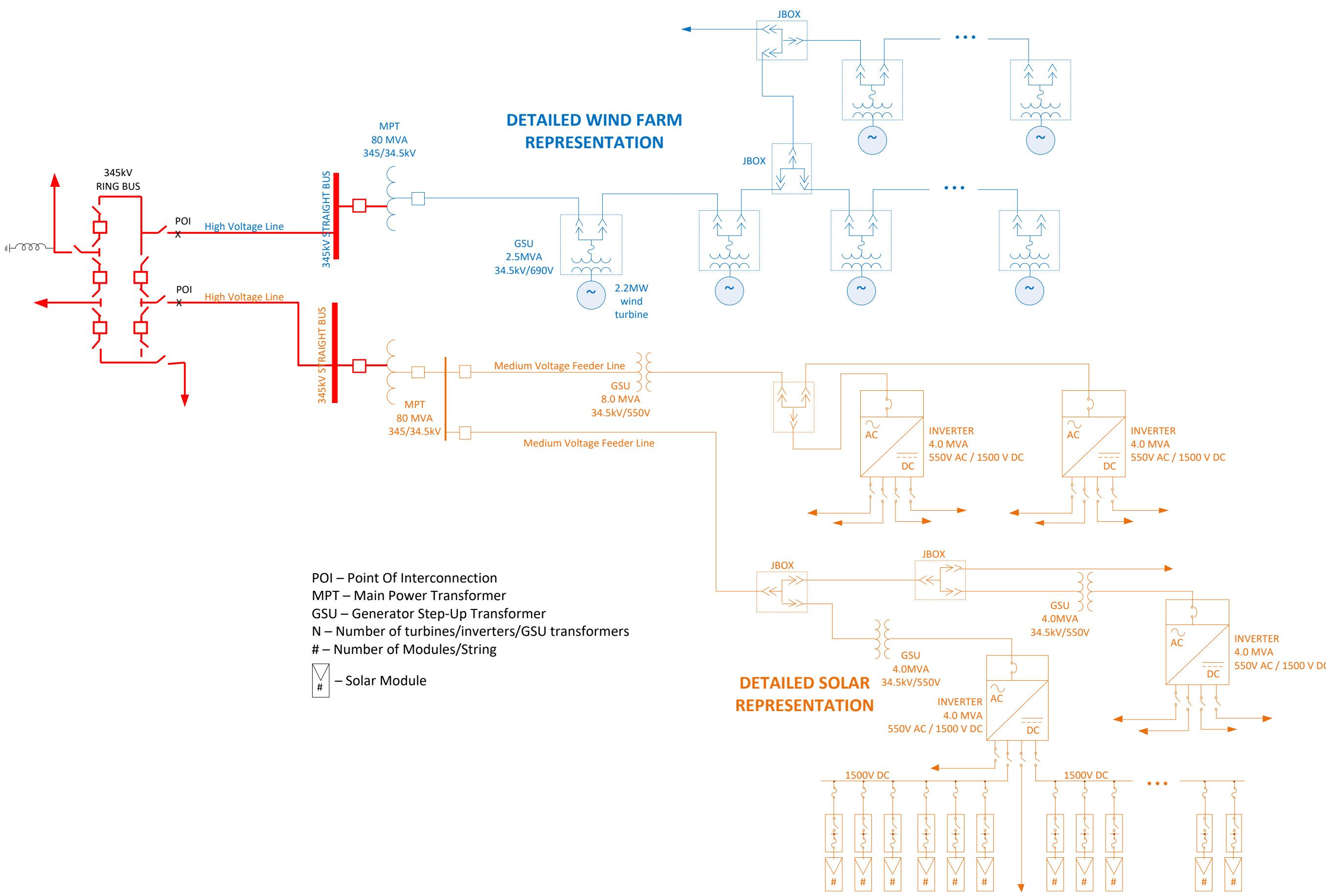
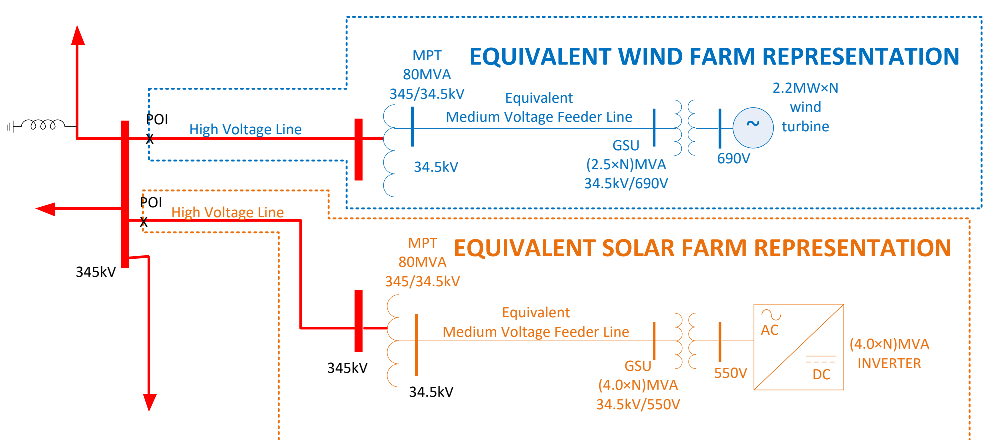



**Figure 1: Detailed Wind and Solar Farm Representation (Not to be used for planning models)**




POI – Point Of Interconnection
MPT – Main Power Transformer
GSU – Generator Step-Up Transformer
N – Number of turbines/inverters/GSU transformers

**Figure 2: Equivalent Wind and Solar Farm Representation (Required representation for planning models)**

## *Periodic Model Updates*

After the annual update process is complete, it may become necessary to perform an update to the information contained in the model(s). Some of the reasons for updating the model(s) and the procedure for doing so are listed below.

**System Impact Studies/Expansion Options Studies (Long-Term)**
SPP performs transmission planning studies and assessments for various eligible customers. These model sets are developed in accordance with the SPP Planning Modeling Process and include models used for the SPP Transmission Expansion Plan, Transmission Service Studies, and Generation Interconnection Studies, which all use the data submitted to MOD as a base for model development.

**MDWG Updates**
At some point after the current models are extracted out of MOD some data will need to be updated to reflect pertinent changes to the system (i.e., lost or added transmission capability, lost or added generation, improved data, etc…) There are several ways of submitting changes to the steady-state models.

Two of these methods are:

1. Using the steady-state update procedure to update MOD.
2. Submitting a PTI, IDEV format file to perform the RDCH operation**. This method should only be used for profile changes. Each company should only submit one IDEV file per modeling pass. Under special circumstances topology changes can be submitted in an IDEV file as long as a MOD Project is submitted in MOD.**

   **It is imperative that any information submitted to SPP be error free and complete to avoid delays in the implementation of the changes.**

The most current update to the models will always be posted on the SPP file sharing site.

## *Program Operation*

The SPP steady-state models are created, modified, and maintained utilizing the Power Technologies, Incorporated (PTI) Power System Simulator for Engineers (PSS®E) software package. The PSS®E program is installed on SPP computer facilities located in Little Rock, Arkansas.

**PTI-PSS®E Data Format**
Steady-State data is input to the models from computer text data files structured in the formats described in the PSS®E Program Operation Manual Volume I, Chapter 4: Section 1.1. All data is read in "free format" with data fields separated by a **<u>comma</u>** (**<u>not</u>** blanks). Each type of data category is terminated by the specification of a zero in the first field of the record with the exception of the model identification data.

Data is **added** to the SPP steady-state models as specified in these format structures for records where no corresponding component is found in the model. The **modification** of existing data in the model is accomplished using the same format structure, except that only the values that need modification are specified.

Data may also be deleted from the models. When a bus is specified for deletion, all associated data for that bus will be removed (e.g., branches, transformers, generators, and loads). **The user cannot delete a piece of equipment and then add it with new data. For example, to upgrade a bus from one voltage to another, the bus data must be <u>modified</u>.** Data currently in the model is used as the default value for data fields not specified in the format.

**Steady-State Solution**

The steady-state solution will have "Area interchange control" with the "Tie Line and Loads" option selected to meet ERAG MMWG model building requirements.

**Error Screening**

The following data error screening checks will be used to check case quality:

1. Interchange and tie line data not matching the raw data will not be accepted until either the interchange data or the raw data are corrected. *
2. All CNTB errors shall be corrected. (Exceptions will be documented.)
3. All instances of mode=1 switched shunts with VHI – VLO < .005 per unit shall be corrected.
4. Any regulation by any regulating device of a bus more than one bus away, except where there is a three-winding transformer in which case no more than two buses away, shall be corrected.
5. All instances of voltage controlling bandwidth less than twice the transformer tap step size shall be corrected.
6. All transmission lines 69 kV and above, transformers with a secondary voltage of 69 kV and above, and Generator Step Up (GSU) transformers shall not have overloads (loading above 100% of RATE1~~ate A~~) in the base case. Exception: 10 year cases may have overloads.

   The effect of this check will be to delay acceptance of the applicable submittal until the problem is corrected.

## STEADY-STATE MODELING REQUIREMENTS

## GENERATORS

1. All steady-state generators, including synchronous condensers and Static VAr Compensators (SVCs) modeled as generators, shall be identified by a bus name and unit id. All other dynamic devices, such as switched shunts, relays, and HVDC terminals, shall be identified by a bus name and base kV field. The bus name shall consist of eight characters and shall be unique within the Eastern Interconnection. Any changes to these identifiers shall be minimized.
2. Where the step-up transformer of a synchronous or induction generator or synchronous condenser is not represented as a transformer branch in the steady-state cases, the step-up transformer shall be represented in the steady-state generator data record. Where the step-up transformer of the generator or condenser is represented as a branch in the steady-

state cases, the step-up transformer impedance data fields in the steady-state generator data record shall be zero and the tap ratio unity. The mode of step-up transformer representation, whether in the steady-state or the generator data record, shall be consistent from case to case within a model series.

3. Where the step-up transformer of a generator, condenser, or other dynamic device is represented in the steady-state generator data record, the resistance and reactance shall be given in per unit on the generator or dynamic device nameplate MVA. The tap ratio shall reflect the actual step-up transformer turns ratio considering the base kV of each winding and the base kV of the generator, condenser or dynamic device.
4. In accordance with PTI PSS®E requirements, the XSOURCE value in the steady-state generator data record must match data contained in dynamic model records and shall be as follows:

XSOURCE Table:

| GENERATOR TYPE | DESIRED PARAMETERS FOR XSOURCE |
|---|---|
| <u>Synchronous:</u> Detailed Subtransient | Unsaturated sub-transient reactance ($X''_d$) [PU] |
| <u>Synchronous:</u> Non-Detailed Classical or Transient | Unsaturated transient reactance ($X'_d$) [PU] |
| <u>Renewable:</u> Wind Type 1 Wind Type 2 | Unsaturated transient reactance ($X'_d$) of single machine [PU*]<br><br>OR<br><br>Locked rotor reactance (sum of rotor and stator leakage reactances) [PU] |
| <u>Renewable:</u> Wind Type 3 | Unsaturated transient reactance ($X'_d$) of single machine [PU] |
| <u>Renewable:</u> Inverter-Based Solar PV Wind Type 4 | $V_{rated} = Rated\ Voltage = 1.0\ [PU]\ (assumed)$<br>$I_{rated} = Rated\ Current\ From\ GO\ [PU]$<br>$XSource = \frac{V_{rated}}{I_{rated}}\ [PU]$ |
| <u>Renewable:</u> Wind Type 5 | Unsaturated sub-transient reactance ($X''_d$) [PU ] |

* PU values should be based on the rated terminal voltage and machine MVA base

5. Generally, SVCs should be represented in steady-state as continuously variable switched shunts rather than as generators. In iterative steady-state solutions, a generator that reaches a VAR limit on solution iteration will lock at that value, but a switched shunt will move off the limit in a subsequent iteration if appropriate. PSS®E provides dynamic library models compatible with either representation. If a user model representing particular SVC

and the associated control features is to be used and that model assumes generator representation, the SVC should be represented as a generator in the steady-state.

6. Renewable generator facilities comprised of more than a single technology type should have similar, equivalent model representation for each technology type. Examples of multiple technology types at a single facility are: Type 3 and Type 4 wind turbines at the same plant, Type 3 wind turbines coupled with solar PV, solar PV coupled with battery storage, etc. Figure 1 and Figure 2 (located in the Initial Run Review Section) below are illustrations provided as guidance for the equivalent representations of such renewable resources; however, Figure 2 shall be the representation used in planning models.

   Modeling of multiple equivalent machines for a single renewable facility is acceptable when trying to model:
   a. Different turbine manufacturers and/or types if the 2nd generation (or later) generic renewable models are not being used
   b. Equivalent collector circuits that are separated by a normally open breaker or switch at the collector substation
   c. Different development phases
      i. These representations should be combined as the phases are placed in service as applicable

## OTHER DEVICES

1. Modeling Detail – Each bus should be assigned the appropriate area, owner, and zone. All transmission lines 115 kV and above and all transformers with a secondary voltage of 115 kV and above should be modeled explicitly. Significant looped transmission less than 115 kV should also be modeled.
2. Nominal Bus Voltage – All bus voltages are expressed as a phase-to-phase voltage. All buses should have a non-zero nominal voltage. Nominal voltages of buses connected by lines, reactors, or series capacitors should be the same. The following nominal voltages are standard for AC transmission and sub-transmission in the United States and Canada and should generally be used: 765, 500, 345, 230, 161, 138, 115, 69, 46, 34.5 and 26.7 kV. In addition, significant networks exist in Canada having the following nominal voltages: 735, 315, 220, 120, 118.05, 110, 72, and 63.5 kV.
   Nominal voltages of generator terminal and distribution buses less than 25 kV are at the discretion of the reporting entity.
   If transformers having more than two windings are modeled with one or more equivalent center point buses and multiple branches, rather than as a 3-winding transformer model, it is recommended that the nominal voltage of center point buses be designated as 999 kV. Because this voltage is above the standard range of nominal voltages, it can easily be excluded from the range of data to be printed in steady-state output.
3. Islanded Buses – Islanded buses shall not be modeled.
4. Generator Modeling of Loads – Fictitious generators should not be used to "load net" (by showing negative generation) a model of other nonnative load imbedded in steady-state areas. It is recommended that a separate zone be used to model such loads to allow exclusion from system load calculations.
5. Zero Impedance Branches – Bus ties that are opened to represent switching during contingencies may be modeled in detail. Zero impedance branches are permitted to model bus ties using R=0.00000 + X=0.0001 and B=0.00000. These values facilitate differentiating

between bus ties and other low impedance lines, utilizing the zero impedance threshold THRSHZ in the PSS®E program. When connected between two voltage controlled (generator, switched shunt, or TCUL controlled), bus ties or other low impedance lines should be modeled using an impedance of R=0.0001 + X=0.002 and B=0.00000. This allows use of near-zero impedance attached to controlled buses that will be large enough to avoid significant solution problems.

6. Impedance of Branches In Network Equivalents – Where network representation has been equivalenced, a maximum cutoff impedance of 3.0 p.u. should be used.
7. Negative Branch Reactances – Except for series capacitors, negative branch reactances do not represent real devices. Their use in representing three winding transformers is obsolete. Negative branch reactances limit the selection of steady-state solution techniques and should be avoided.
8. Transformers –To adequately model transformers, the following parameters, at a minimum, are required:
   a. Nominal voltage of windings and bus reference to which the appropriate winding is connected

      When entering transformer data, the rated voltage[16] for all applicable windings should be specified. For non-LTC transformers, the winding voltage should be set to the tap voltage.

      A recommended approach is to model three-winding transformers such that the winding buses map to the transformer windings as follows:
      - H, or High-Voltage, Winding = Winding 1
      - X, or Low-Voltage, Winding = Winding 2
      - Y, or Tertiary-Voltage, Winding = Winding 3

      A recommended approach is to model two-winding transformers such that the winding buses map to the transformer windings as follows:
      - H, or High-Voltage, Winding = Winding 2
      - X, or Low-Voltage, Winding = Winding 1

      The two-winding[17] transformer winding map is in this order by default since PSS®E requires all two-winding transformers with Load Tap Changers (LTCs) to specify the tap bus as Winding 1. While not all LTC transformers have the tap on the X winding, this is common with most transformers.

   b. Impedance(s)

      A recommended approach to modeling transformer impedance is to set the winding MVA base to the system MVA base which is 100 MVA, entered as positive sequence data in pairwise (delta) format. Care should be taken to when entering transformer impedance data to ensure that the data entered corresponds to the appropriate base (system or winding).

      Enter zero sequence data in the format appropriate to the connection code.

16 Care should be taken to enter the rated voltage, which may be different than the nominal voltage of the system for all transformer windings. There can be a difference between the rated voltage of the system and the transformer (nominal).

17 Two winding representation in PSS®E allows the user to select which bus number (from or to) the winding 1 resides.

Connection codes <10:

- The zero sequence data must be entered as T-model format

Connection codes >10:

- The zero sequence data must be entered in pairwise (delta) format

c. Tap ratios

Depending on the PSS®E winding code used for the transformer, the setting should be either p.u. or kV. It should be noted, “tap ratio”, “winding ratio”, and “turns ratio” are synonymous.

- For transformers with no taps, use nominal (“1.00” for p.u. or transformer nominal winding kV) for the tap ratio.
- For transformers with automatically adjusting, under-load tap changers (ULTC), it is recommended to initially use nominal (“1.00” for p.u. or transformer nominal winding kV) for the tap ratio.
    - For parallel transformers, it is recommended to initially use nominal (“1.00” for p.u. or transformer nominal winding kV) for the tap ratio for both transformers in order to prevent circulating VARs.
- For transformers with non-automatically adjusting, under-load tap changers (ULTC), it is recommended to use the tap ratio as set in the field.
- For transformers with no-load tap changers (NLTC), it is recommended to use the tap ratio as set in the field.
- It is recommended that Delta-Wye phase angle differences are incorporated appropriately in the models.

d. Minimum and maximum tap position limits

- Minimum and maximum tap position limits (RMIN and RMAX) shall be modeled based on transformer test report or manufacturer nameplate data.

e. Number of tap positions (for both the ULTC and NLTC)

- Under-load tap changers (ULTC) control bus, total number of tap positions, and tap setting shall be specified.
- No-load tap changers (NLTC) total number of tap positions and the tap setting shall be specified.
- Transformer tap positions are discrete. The total number of transformer tap positions is a fixed quantity and shall be entered. The maximum and minimum transformer tap positions represent the physical boundaries of the transformer’s capability to modify its winding impedance to achieve a control objective. Transformer tap changing control modes may include voltage regulation, as well as real and reactive power control. Automatically-adjusting under-load tap changing transformers (ULTC) shall specify a control mode, the bus that is being controlled, and the control limits[18] defined by the maximum and minimum transformer tap positions.

18 It is noted that PSS®E provides transformer tap changer limit fields called VMAX and VMIN, regardless of control mode. For example, if a real power control mode is selected, the user must enter MW quantities in the VMAX and VMIN fields.

- For transformers with untapped windings, the number of tap positions shall be "99" to indicate that there are no taps. PSS®E does not allow a value of "1" to be used as a tap position.

f. Regulated bus (for voltage regulating transformers)
- The regulated bus is the location where the transformer is regulating voltage. Typically this regulated bus is connected to a transformer winding bus.
- A limit difference of less than 0.0125 p.u. shall not be used when entering the regulated voltage band limits (VMAX, VMIN) for an automatically adjusting, under-load tap changers (ULTC) transformer.
- It is recommended that the voltage band limits VMAX and VMIN be no less than 0.025 p.u., to prevent toggling of the ULTC during simulation iterations.

g. In-service status
- In-service status, set to zero (0) if the device is not in-service.

h. Vector group and Connection code
- The vector group shall match the topological configuration of the buses representing where the windings are connected (e.g. A 115/69 kV load serving transformer with a vector group of Dyn11 must show the winding 1 bus [Delta winding] as the 115 kV bus).
- Transformer connection codes[19] and transformer winding angle (phase displacement) shall be provided. The connection code data incorporates concepts of the transformer core type, the vector group (phase differences between windings, standardized with clock notation indicating phase displacement), and physical conductor orientation. The transformer winding angle further specifies the inherent phase shift between transformer windings based upon configuration (vector group). Data Owners are reminded that changes to connection codes do not automatically alter the modeled phase displacement used for positive sequence load flow calculations.
- The transformer core construction should be considered (shell type or core type) [20]

i. Transformers Controlling Reactive Power Flow
- The upper and lower limits of off-nominal turns ratio and the number of tap positions available are entered for winding 1 of transformers controlling reactive power flow. Default values of 1.1, 0.9 and 33 are representative of U.S. practice. The upper and lower MVAR limits are entered for transformers controlling reactive power flow and these limits should differ by at least 10 MVAR. Limits should accurately represent the actual operation of automatic control devices.

19 Reference PSS®E Program Operation Manual section: Two Winding Transformer Zero Sequence Network Diagrams and Connection Codes or Three Winding Transformer Zero Sequence Network Diagrams and Connection Codes.

20 Reference the TPL-007-1 Data Collection Template User Guide document under the Transformers section/Core Type. https://www.spp.org/spp-documents-filings/?id=197519

9. Remote Regulation – Regulation of a bus voltage more than one bus away (not counting hidden center point buses of three winding transformers) from the regulating device should be avoided. The sign of parameter CONT determines whether the off-nominal turns ratio is increased or decreased to increase voltage at the bus whose voltage is controlled by this transformer.
10. Phase Shifting Transformers (PSTs) – Manufacturer tested capability and operational limits must be provided to SPP in order to allow corrective actions to be developed by SPP planning staff for transmission planning purposes.
    PSTs will be represented in the planning models as Two-winding transformers with both windings at the same nominal voltage level. The active power flow into winding 1 is entered. The tolerance should be no less than 5 MW; i.e., a 10 MW dead band. The controlling band should be at least 10 degrees. The following characteristics should be considered by the entity submitting PST modeling data for the planning models:
    a. Real-time operational auto or manual adjustment operation of the PST.
    b. Real-time operational average MW flow for a particular season (e.g. average hourly MW flow is +18MW [directional based] during the Summer Peak Season, June 1 – September 30) in order to represent what is typically flowing through the PST during a particular season. This applies to PSTs that are not modeled for auto adjustment, in order to appropriately model the phase shift angle and relative MW flow, but should also consider the capability of the transformer regardless of the type of operation.
    c. Real-time operational MW flow limits (e.g. ±20 MW).
    d. Real-time operational phase shift angle range (e.g. -52.9° to 31.4°).
    e. The applicable planning model impedance table should reflect the impedance correction adjustments as the phase shift angle moves through the various angle steps.
    f. Applicable long-term firm transmission service levels for the PST.
11. AC transmission line or circuit modeling status – Out-of-service AC transmission lines or circuits should be modeled with an in-service status equal to zero. In-service AC transmission lines or circuits should be modeled with an in-service status equal to one.
12. Generator Step-Up Transformers (GSU) – When modeled implicitly, the GSU Resistance, reactance and tap setting (all in per unit values) shall be provided along with the Generator data. Whenever modeled explicitly, a GSU shall be modeled similar to a power transformer and the GSU nominal winding voltages, impedance(s), tap ratios, minimum and maximum tap position limits, number of tap positions, regulated bus (as applicable), normal and emergency ratings and in-service status data shall be provided. GSUs may be modeled explicitly as deemed necessary by either the transmission owner or the Regional Reliability Organization. Their modeling should be consistent with the associated dynamics modeling of the generator. Generator step-up transformers of cross-compound units should be modeled explicitly.
13. Generator modeling status – Out-of-service generators should be modeled with an in-service status equal to zero. In-service generators should be modeled with an in-service status equal to one.
14. Generator MW Limits – The generation capability limits specified for generators (PMIN and PMAX) should represent realistic seasonal unit output capability for the generator in that given base case. PMAX should always be greater than or equal to PMIN. Net maximum and minimum unit output capabilities should be used unless the generator terminal bus is explicitly modeled, the generator step up transformer is modeled as a branch, and unit load is modeled at the bus or buses from which it is supplied.
15. Generator MVAR Limits – The MVAR limits specified for generators (QMIN and (QMAX) should represent realistic net unit output capability of the generator modeled. QMAX should always be greater than or equal to QMIN. Net maximum and minimum unit output

capabilities should be given unless the generator terminal bus is explicitly modeled, the generator step up transformer is modeled as a branch, and unit load is modeled at the bus or buses from which it is supplied.

16. Small Generators, Capacitors, and Static VAR Devices – Small generators (e.g., 10 MVA), small capacitors, and small SVCs have limited reactive capability and cannot effectively regulate transmission bus voltage. Modeling them as regulating increases solution time. Consideration should be given to modeling them as non-regulating by specifying equal values for QMIN and QMAX. If several similar machines or devices are located at a bus and there is a need to regulate with these units, they should be lumped into an equivalent to speed solution.
17. Coordination of Regulating Devices – Multiple regulating devices (generators, switched shunt devices, tap changers, etc.) controlling the bus voltage at a single bus, or multiple buses connected by Zero Impedance Lines as described above, should have their scheduled voltage and voltage control ranges coordinated.
    Also, regulated bus voltage schedules should be coordinated with the schedules of adjacent buses. Coordination is inadequate if solving the same model with and without enforcing machine regulating limits causes offsetting MVAR output changes greater than 500 MVAR at machines connected no more than two buses away.
18. Over and Under Voltage Regulation – Regulation of voltage schedules exceeding 1.10 per unit, or below 0.90 per unit should be avoided.
19. Flowgates – All transmission elements comprising part of one or more flowgates should be included in the data submitted by each region. A flowgate is a selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage stability, rotor angle stability, and contractual system constraints to power transfer.
20. Fixed Shunts – All fixed shunt elements at buses modeled in the steady-state should be modeled explicitly (not as loads or included with load). The status should be set to zero if the shunt is not in service. Fixed shunt elements that are directly connected to a bus should be represented as bus shunts. Fixed shunt elements that are directly connected to and switch with a branch should be represented as line shunts.
21. Switched Shunts – Switched shunt elements at buses modeled in the steady-state should be modeled explicitly. Continuous mode modeling using a switched shunt should not be used unless it represents actual equipment (e.g. SVC or induction regulator). The number and size of switched admittance blocks should represent field conditions. The bandwidth (difference between VSWHI and VSWLO) of switched shunt devices should be wide enough that switching one block of admittance does not move the voltage at the bus completely through the bandwidth, thus causing solution problems at the bus. It is recommended that the minimum voltage bandwidth be 4% if only switched shunts are used to regulate voltage. Switched shunts should not regulate voltage at a generator bus, nor should they be connected to the network with a zero impedance tie.
22. Static Var Systems – Static var elements should be modeled with accurate reactive power (leading/lagging) limits. An accurate voltage set point, as well as any associated fixed/switched shunt equipment should also be modeled based on actual seasonal operation. Out-of-service Static Var Systems should be modeled with an in-service status equal to zero. In-service Static Var Systems should be modeled with an in-service status equal to one.
23. DC Transmission systems – DC transmission systems must be represented with a sufficiently detailed model to simulate its expected behavior.
24. Interchange Tolerances – In a solved case, the actual interchange for any area containing a Type 3 (swing) bus should be within 25 MW of the specified desired interchange value.

(Note that PSS®E does not enforce the interchange deviation for areas containing Type 3 buses.)

25. Scheduled Interchange vs. Scheduled Tie Line Flows – Scheduled interchange between areas directly connected solely by ties with flows controlled to a specific schedule (PAR-controlled AC or DC) should be consistent with the PAR or DC scheduled flows.
26. Other information requested by the PC or TP – Information which the PC or TP deems necessary for modeling purposes can be requested from Data Owners/Data Submitters.

### *Causes of Non-convergence and Problems in Merged Base Case Models*

**Causes of Non-convergence**

1. A line whose impedance is very small as compared to that of a line connected in series with it.
   (Solution: If possible, add impedance of short and long series-connected lines and represent as one line.)
2. Tie lines are missing because they were not picked up by model creation or tie lines are connected incorrectly.
3. An impedance or susceptance value whose magnitude is extremely large. A decimal point may have been misplaced, or large cutoff impedance was specified during Equivalencing.
4. A system's regulating (slack) bus is in a different system. This is probably due to an incorrect data entry in changing a model.
5. An isolated system (island) has been inadvertently created. Voltage phase divergence will be flagged immediately and the program will stop calculating after the first iteration.
6. Unrealistic tap changing transformer tap limits.
7. Radial system is very large.
8. Poor voltage regulation such as:
   a. Unequal voltage schedules at generating units connected by a low impedance line.
   b. Regulation of a radial line at both ends at unequal voltages.
   c. (Solution: Do not regulate a radial bus; hold MVAR output of a radial bus constant at the value obtained in last iteration.)
   d. Conflicting voltage regulation.
   e. Unreasonably small voltage range for switched shunts.
   f. Remote regulation of more than one bus away.
9. Over-Equivalencing of outside Regions in regional base case models.
10. Not solvable from flat start.
11. Fictitious regulation of buses.
12. Extremely low voltage schedules.
13. Not following the approved MMWG sign convention for phase shifters (see page 3 of this **Appendix**) or not adhering to minimum MW tolerance for phase-shifting-under load transformers.
14. Zero or very low reactance branches. Minimum reactance = 0.0001 per unit.
15. Inconsistent representation of delta-wye transformers, typically by two companies interconnected at both voltage levels.

## TROUBLESHOOTING

1. Duplicate bus names in an area(s).
2. The data will not permit steady-state calculations, such as:
   a. Zero voltage regulation, resulting in division by zero. Notify Regional Coordinator.
   b. Interchange does not net to zero. Save the data but do not calculate until the Coordinator has given instructions for correcting the data.
   c. High R/X ratios in equivalent area causing non-convergence. Delete line or reduce ratio.
3. Missing tie lines. These tie lines may or may not be in the base case model. The program flags the tie lines as missing because of its tie line checking routine. A review of the data dump will verify the inclusion of a tie line if it is included and has been flagged as missing. Likewise, the validity of the error message will be verified by a review of the data dump.
4. Phase Shifting Transformers
   a. The first-named bus in the branch data is taken as the “From” bus and the second-named bus is taken as the “To” bus. The “From” bus is also taken as the tapped bus.
   b. If phase shift angle is specified in CDF as positive, $\square_A < \square_B$.
   c. Assuming $\square_A$ and $\square_B$ stay relatively constant for small changes, an increase in this positive phase shift angle will tend to change the voltage phase angle of Bus A in a lagging direction relative to that for Bus B. This causes an incremental increase in real power flow in the direction of B to C regardless of the direction of the initial real power flowing through the transformer.
   d. A desired positive real power flow into the phase shifting transformer at the "From" bus or tapped bus is specified with positive real power limits.
   e. The "Controlled Bus" specified should be the same as the tapped bus to be consistent and avoid confusion.

**Note:** The PTI PSS®E steady-state program currently being used by AEP to process MMWG models requires the above convention. Therefore, it is desirable that all phase shifter models sent to AEP conform to this convention. If the data submitted does not conform to the above convention, AEP must be notified so that appropriate corrections can be made.

## BALANCING AND TRANSACTIONS

A core principal of steady-state power flow modeling[21] is the balance between load and generation. A system swing generating unit is a fundamental requirement of the modern formulation of the linear power flow problem (net complex power injection into nodal admittance network). In the balanced three-phase power flow formulation, a swing generator serves the imbalance of power for the entire electrical network. However, in real power systems, Balancing Authorities ensure that frequency regulation is achieved by matching generation to load within a subsection of the entire interconnected power system. Thus, in most power flow software, a vast impedance network may be segregated into groups of busses representing a model area[22]. While typically analogous to a

[21] The traditional power flow formulation is the matrix algebraic calculation of voltage phasor (magnitude and angle) at each interstitial connectivity node (bus) within an impedance network under balanced three-phase, steady-state conditions.

[22] Model areas typically have a single generator designated as the area slack machine, although this is not a modeling constraint. The area slack machine is analogous to the system swing machine in that it compensates for the power imbalance within the model area, when the power flow solution is solved to respect inter-area transfers (area net interchange control).

Balancing Authority Area or control area, the concept of a model area is straightforward: model areas allow the electrical network to be sectioned in such a way as to pool together generation, loads, and losses for the purpose of scheduling power flows throughout the electrical network. Model areas are not limited to being demarcated by physical load balancing boundaries; on the contrary, model areas are very effective at allowing individual generation and load-serving companies to properly allocate resources and demand, including transactions with other model areas. While most power flow software enforces that each generating unit inherits its model area designation from the bus to which it is connected, many modern power flow software packages allow ZIP[23] loads and induction machine loads to be assigned to model areas that may be different than the busses to which they are connected. In this way, each generating unit and load is grouped into common balancing pools, represented by the model area (Figure 1).

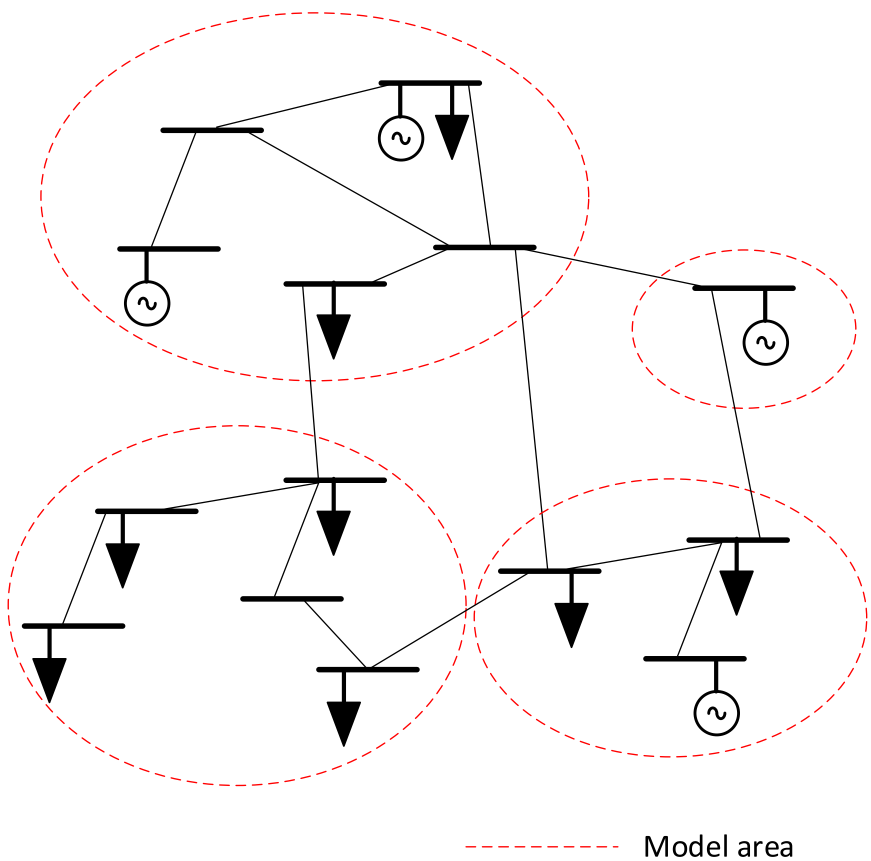



**Figure 1. Example of interconnected model areas.**

To be clear: it is inappropriate to refer to either a “generation area” or a “load area”. Instead, it is important to understand that the modeling concept of the “Area” field designated for bus, load, and generation refers to the model area to which that model object belongs. To reiterate, the model area to which a load is assigned indicates which generation resources will serve that load, independent of the model area of the bus to which that load is attached. This concept is of particular importance when interchange is used to obtain power flow solutions.

[23] ZIP refers to constant impedance, constant current, or constant power load representations, including a combination of each.

Within each model area that contains generating units, a single generating unit must be designated as the slack machine. While the dispatch (Pgen) of each non-slack generating unit is set to a prescribed value, the slack machine dispatch varies to compensate for any imbalance within the model area. In many cases, load obligations and transmission losses associated with delivering power to the loads within a model area may not be totally served by the capacity of resources in-service within a model area. In these situations, inter-area transfers are common, representing power purchase agreements (PPA) that reflect the firm purchase or sale of power from generation resource in one model area to another for the purpose of serving load. Similarly, intra-area transfers representing contractual or PPA obligations between resource and load owners within a model area are also common. In total, all inter- and intra-area transfers are referred to as “transactions” and must be properly accounted for to achieve power flow model balancing and accurate model area tie-line loading.

Across the entire interconnected impedance network, one-and-only-one generating unit must be designated as the system swing unit. The system swing serves any overall imbalance arising from imbalanced exchanges between individual model areas. In its simplest expression, the model area designation facilitates the analysis of scheduled power flow between interconnected regions of the impedance network, which is useful for assessing conventional tie-line loading. More broadly, however, the use of model areas allows exchanges of generating resources that are intended to serve loads that may be very distant from the actual generating unit, giving rise to bilateral transactions across model area boundaries, integrated market operations, and efficient resource dispatch, as well as others.

Load is generally served by generation resources within a common model area. Likewise, both the load and the bus to which the load is connected reflect a common model area (as shown in the Area field of each). The same principle applies to transacted resource-to-load; loads that serve as the sink portion of a transacted real power quantity will reside in the model area of the sink Data Owner (and may retain the load ID of the Data Owner of the load itself). Exceptions are called pseudo-ties, representing where the resource that serves the load is outside of the model area where the load resides. Pseudo-tied loads are typically found when the Area field assigned to the load is different than the Area field of the bus, to which the load is connected, however generation pseudo-ties are possible, as well. For modeling purposes, pseudo-tie representations are permitted between two model areas within the SPP Balancing Authority (referred to an intra-SPP pseudo-tie), as well as between a model area within the SPP Balancing Authority and a model area of a non-SPP Balancing Authority (referred to an inter-SPP pseudo-tie). Intra-SPP pseudo-ties can be an effective means of differentiating which model area provides resource to unique load delivery obligations, but may be problematic if used to avoid proper resource, load, and loss accounting through model area transactions. Separately, inter-SPP pseudo-tie arrangements are typically unique contractual arrangements where firm transmission service (e.g., network services, point-to-point) has been pre-arranged to direct resource from/to an external model area, into/out of a model area where the load resides (see Figure 2). Inter-SPP pseudo-tied loads are generally an exception to the norm and the use of inter-SPP pseudo-tied loads should be justified (e.g., reference to an SPP load-balancing meter point, pseudo-tie registration in the SPP marketplace, etc.). Data Owners shall not create pseudo-tie modeling representations of load that incorporates fictitious topology; Data Owners may create pseudo-tie modeling representations of generation necessary, given the load flow software constraints.

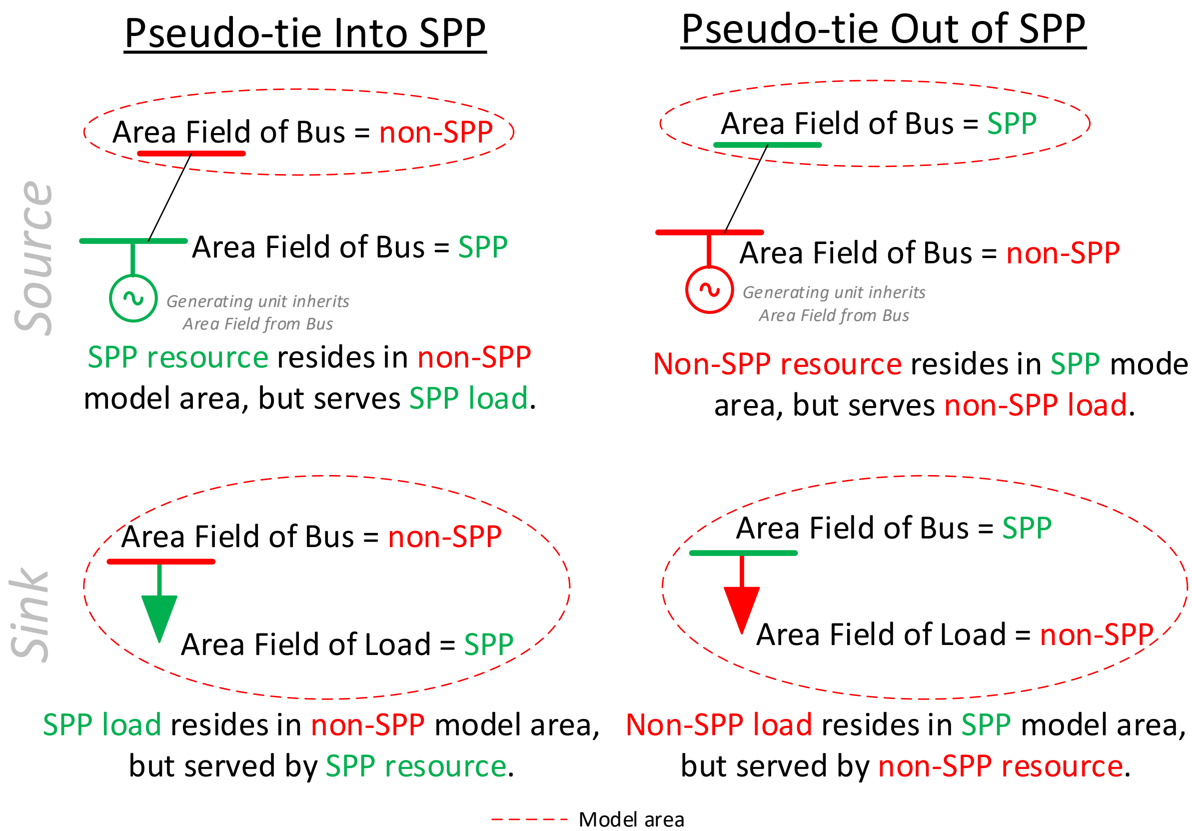



**Figure 2. Four types of inter-SPP pseudo-ties.**

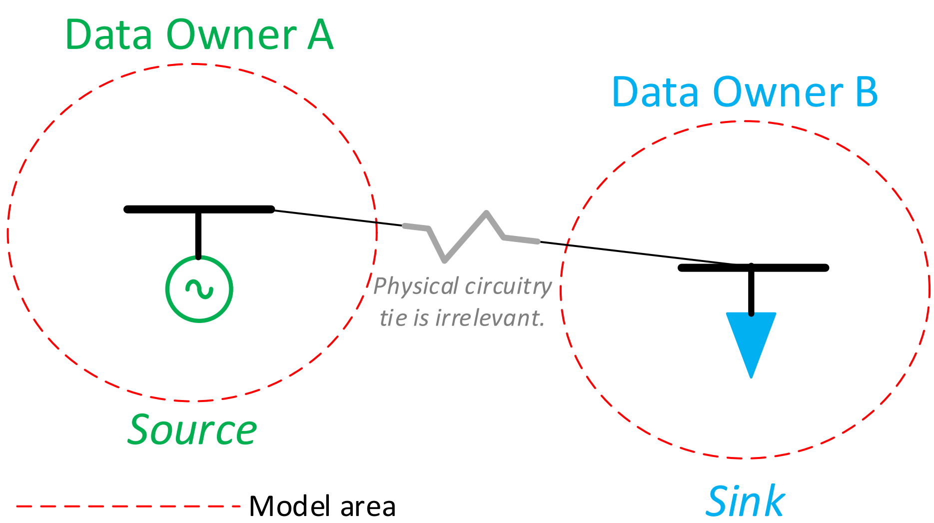
**Transactions Data Requirements**

Data Owners shall submit all transactions data via the MDWG EDST. Additionally, Data Owners shall:

1. Coordinate all bilateral transactions data with all Data Owners who are party to the transaction, prior to submitting the data.
2. Submit only the bilateral portion of the transaction for which the Data Owner is responsible. For example, in a bilateral transaction between two Data Owners (SPP-members), each Data Owner shall submit one half of the transaction (source or sink). In the case of a bilateral transaction between a Data Owner (SPP-member) and a non-SPP member, such as a MISO-member, the Data Owner (SPP-member) shall submit their portion (source or sink) of the bilateral transaction, upon coordination with the non-SPP member. SPP staff will then submit the non-SPP member portion (source or sink) of the bilateral transaction.
3. Review and update transactions data according to the model building schedule.
4. Load and resource transactions may be inter-area (i.e., reciprocal transaction from an SPP Market Participant to another SPP Market Participant, both within the SPP Balancing Authority Area) or external area (i.e. traditional BA-to-BA interchange). Transactional data collected by Data Owners often have tens of kilowatts precision. However, for the purposes of the ERO, or its designee, Interconnection-wide models, external net interchange schedules are required to be entered as whole MW quantities. Therefore, Data Owners shall submit transaction data according to:

   a. Inter-area transactions (transactions of load and resource that are wholly contained within the SPP Balancing Authority Area) are preferred to be integer values (i.e. whole MW); however, shall not exceed tens of kilowatt precision (i.e., two decimal MW precision; 0.01MW).
   b. External area transaction (i.e. scheduled net interchange between the SPP Balancing Authority and an external Balancing Authority) shall be rounded to the nearest integer (i.e. whole MW).

5. Ensure that source transactions have positive polarity, while sink transactions have negative polarity (Figure 3 and Figure 4).




Inter-area Bilateral transaction description

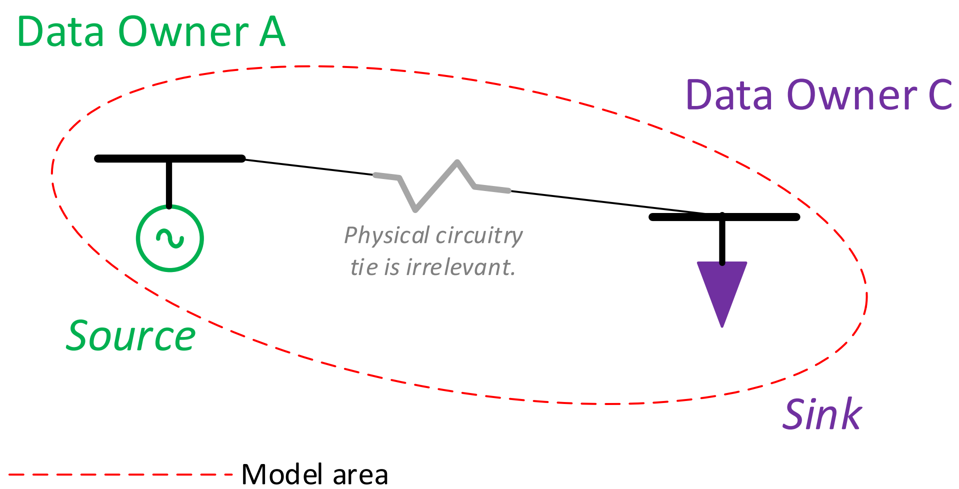
Data Owner A exports MW to Data Owner B

Data Owner B imports MW from Data Owner A

Transaction accounting in Data Submittal Workbook

| PC | From Area # | From Area | From Resp Entity # | From Resp Entity Name | To Area # | To Area | To Resp Entity # | To Resp Entity Name | ID | Start | Stop | Firm | 201x Series MDWG Model - 18G |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | 1 | Area 1 | 1 | Data Owner A | 2 | Area 2 | 2 | Data Owner B | ABC111 | 12/1/2013 | 3/1/2020 | X | MW |
| Not SPP | 2 | Area 2 | 2 | Data Owner B | 1 | Area 1 | 1 | Data Owner A | ABC111 | 12/1/2013 | 3/1/2020 | X | -MW |

**Figure 3. Example of Inter-area transfer (transaction).**




Intra-area Bilateral transaction description

Data Owner A exports MW to Data Owner C

Data Owner C imports MW from Data Owner A

Transaction accounting in Data Submittal Workbook

| PC | From Area # | From Area | From Resp Entity # | From Resp Entity Name | To Area # | To Area | To Resp Entity # | To Resp Entity Name | ID | Start | Stop | Firm | 201x Series MDWG Model - 18G |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | 1 | Area 1 | 1 | Data Owner A | 1 | Area 1 | 1 | Data Owner C | XYZ112 | 12/1/2013 | 3/1/2020 | X | MW |
| SPP | 1 | Area 1 | 1 | Data Owner C | 1 | Area 1 | 1 | Data Owner A | XYZ112 | 12/1/2013 | 3/1/2020 | X | -MW |

**Figure 4. Example of Intra-area transfer (transaction).**

6. Complete the following required EDST data fields for each source and sink portion of a bilateral transaction:
   a. Planning Coordinator (PC).
   b. From Area #.
   c. From Area Name.
   d. From Responsible Entity #.
   e. From Responsible Entity Name.
   f. To Area #.
   g. To Area Name.
   h. To Responsible Entity #.
   i. To Responsible Entity Name.
   j. Transaction ID.
   k. Transaction Start date.
   l. Transaction Stop date.
   m. Firm or Non-Firm Transaction.
   n. Transaction quantity (in MW) for all appropriate seasonal MDWG Model Series cases.

7. When a part or all of a bilateral transaction is referenced by an Open Access Same-Time Information System (OASIS) number, used by the marketer for scheduling, enter the OASIS number in the appropriate EDST field.

8. The following EDST information is reserved for SPP staff usage and is not required from the Data Owner of each bilateral transaction:
   a. From Attributes.
   b. To Attributes.
   c. Link Number.
   d. Plant.
   e. Capacity.
   f. Roll Over Rights.
   g. S0 Scalable.
   h. S5 Scalable.
   i. OASIS Comment.
   j. Comments.
   k. Related Reference.

**Transaction Update**

The transaction workbook should be updated to show a transaction from the control area where external resource is located to the generation owner control area. If the external resource is owned by multiple owners, then multiple transactions should be modeled.

The SPP transaction workbook must not include transactions for sales to loads in other control areas if the loads are specifically identified with source control area number. If the loads in an external control area are not identified with the source control area's number, then a transaction is necessary to schedule to this load. See example below for more details for a load that Source Area XXX has the obligation to serve:

<u>No Transaction Needed</u>
Source Area: XXX
Sink Area: YYY
Sink Load: XXX

<u>Transaction Needed</u>
Source Area: XXX
Sink Area: YYY
Sink Load: YYY

Loads may be modeled on the foreign area bus as long as it is identified as belonging to the owning area.

SPP will identify remote SPP loads in the base cases, pass 1, pass 2, and pass 3 models.

Transactions modeled in all base cases should be limited to expected firm schedules and should not include other transfers such as emergency power or opportunistic economy energy even though they may be provided for in contractual agreements. Due to FERC's ruling of Roll-over rights, Long Term Firm Transactions should be considered in the models that extend into the future even if the transaction has a stop date. For a transaction to be considered firm, the transaction must be confirmed at both the source end and the sink end. Southwest Power Pool will do its best to confirm delivery of transactions outside of the Pool boundaries.

Firm transmission load includes capacity dependent interruptible loads with buy through provisions. In other words load that may be interrupted if the source runs out of capacity should still be modeled if the load has a choice and opportunity to purchase power from another source. This firm transmission load should be modeled in all cases. The load modeling entity is responsible for scheduling the power from a source and updating the transaction worksheet (see Appendix VIII).

System representatives should be responsive with good modeling techniques. SPP data models are used by individual systems for studying future needs in developing construction forecasts. Not planning a major expenditure by one year due to inaccurate data could be very expensive, since funding allocation for major construction projects requires more time resources. In addition, ATC, megawatt-mile and incremental losses are currently being calculated with these Steady-State models. With the large amount of interconnection within SPP, the impact of one system on another must be recognized and respected. Therefore, each system should prepare data consistent with its most recent official system forecasts in all data submitted to SPP including Energy Information Agency (EIA-411) Data. It is also important that the models represent the expected operation of the SPP system consistent with this manual and Planning Criteria.

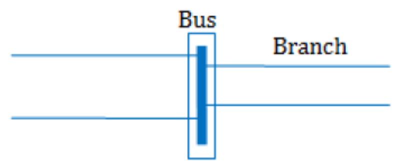
### *AC Contingency Analysis*

SPP will perform AC Contingency Analysis on all models contained in the steady-state case type set. The purpose of this contingency analysis is to validate the models. Member updates for errors found due to contingency analysis are to be submitted during the next member data submission period per the latest [MDWG model building schedule].

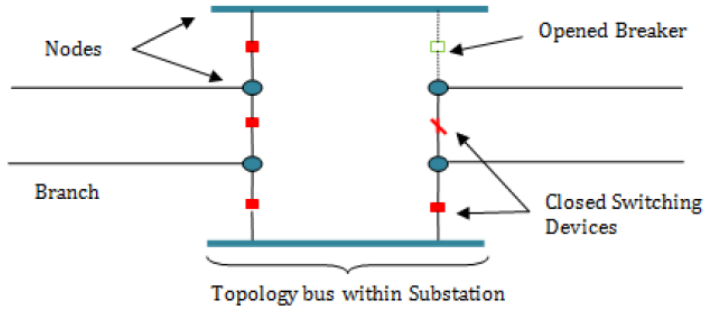
## *SUBSTATION NODE-BREAKER MODELING*

Detailed substation node-breaker data is fully integrated into the PSS®E engine beginning with version 34. Substation node-breaker data is an extension to the bus-branch model, and is a container of nodes and switching devices. With the node-breaker data, there are a few data fields that represent the substation that must be uniquely specified within SPP, as well as the Eastern Interconnection; therefore, requirements must be set in place. For this section, the term substation also includes switching station.

Data Submitters shall submit node-breaker modeling information for any Extra High Voltage (EHV) substations within the SPP footprint in the approved format; node-breaker modeling information for non EHV substations may also be submitted.




Standard Bus-Branch model

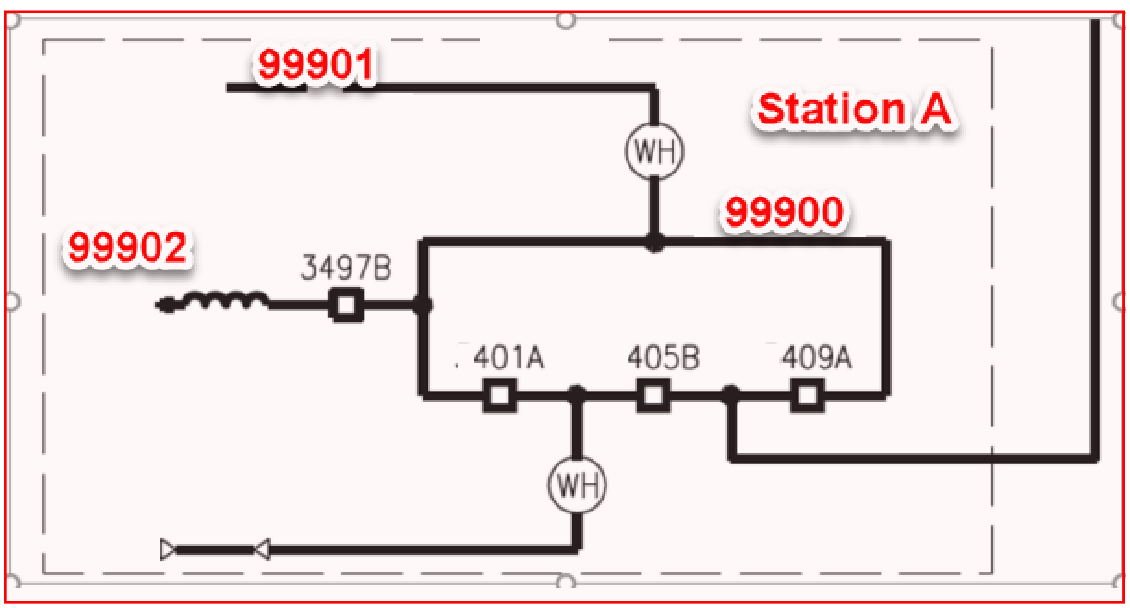



The same bus expanded to show the node-breaker model

**SUBSTATION NUMBERING**

The substation number should reflect the bus number of the highest voltage bus modeled at the station. By picking an existing bus number for the substation to represent the substation number, this ensures uniqueness in the model. The existing bus-branch model for a substation may be modeled with more than one bus for the same base kV, at which time a choice must be made. Preferably the bus number that has the most elements connecting to it should be used, and typically this is the lower bus number, however, it is up to the discretion of the Data Submitter to pick a bus number.

Example:



This one-line diagram shows that STATION A has only one 345kV bus, but since there is a reactor in that substation, MDWG might model another bus # 99902 for that reactor. This new bus # is only in PSSE and not in the one-line diagram or EMS model, thus the substation # should be 99900 and not 99902 since 99900 has the most elements connected to it.

### SUBSTATION NAMING CONVENTION

The substation name should reflect the substation name with an SPP identifier and must be unique to the Eastern Interconnection. Substation names can have up to 40 characters, and the naming convention shall include a prefix of "SPP_", followed by the substation name as determined by the Data Submitter, up to 36 characters. Additionally, the substation names shall be limited to alphanumeric characters, hyphens, and underscores.

**Example: Substation Name: "XXXXYYYY"**

- XXXX represents an "SPP_" prefix (4 characters including underscore)
- YYYY represents the specific station name determined by the company (up to 36 characters)
- Example: "SPP_TECUMSEH_HILL" or "SPP_WERE-TECUMSEH-HILL"

### SUBSTATION PHYSICAL DATA

Additional physical information is retained as part of the node-breaker Substation network record. This information is used directly for geomagnetically-induced current calculations and indirectly for displaying relative bus locations on a single-line diagram. Geographic latitude and longitude shall be submitted in decimal degrees with at least three decimal precision (e.g., 45.001) for each substation that includes equipment operated at 200kV and above. Only positive decimal degree values between 25°N and 50°N latitude (e.g., 25.000 to 50.000) and longitudes to the west of the Prime Meridian between 85°W and 115°W (e.g., -85.000 to -115.000) are acceptable. Substation grounding resistances shall be submitted in Ohms with at least one decimal precision (e.g., 0.2 Ohms) or, in the rare instance when a substation is ungrounded, as "-1".

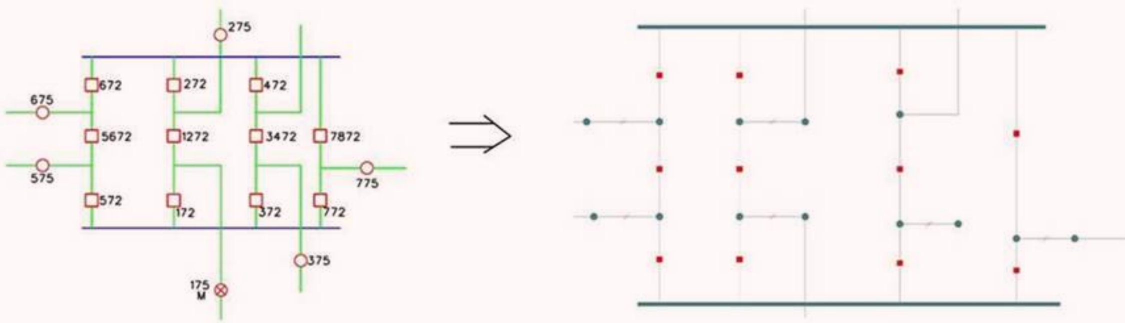
### SUBSTATION NODES

Substation nodes create the mapping for the node-breaker model. Minimal information is required for these including Node Number, Node Name, and the Bus Number that they are represented within. Node numbers need to be unique to that substation.

### SUBSTATION SWITCHING DEVICES

Substation switching devices need to be modeled in order to capture the full impacts of a detailed substation node-breaker model. A switching device name does not need to be unique to that substation. There are a few different device options including a breaker, which acts as an interruptible device in the event of a fault, a switch, which is used to simulate a manual opening of a device, or a generic connector, which is used to represent bus work without an applicable switching device. Although higher levels of detail for a substation node-breaker model are not required to appropriately simulate contingency events, fault current interrupting devices shall be modeled. By modeling these devices, advanced contingency events can be automatically identified during analysis.

**Example:**




The diagram on the left is a one-line diagram with various switching devices whereas the diagram on the right shows the same topology translated into a node-breaker model in PSS®E

Similar to branches, switching devices have sets of ratings. These ratings are optional, but if used, should represent Rate 1 (normal, continuous) and Rate 2 (emergency) entered in the first two fields (RATE1 and RATE2, respectively) for each seasonal model. Although higher levels of detail for a substation node-breaker model allow for ratings of terminal equipment and breakers to be modeled explicitly, the branch (line and transformer) model ratings should continue to consider this equipment as part of its rating. This is to allow for the bus-branch model to continue to have accurate ratings incorporated in the models if the substation node-breaker model is not used. Breaker interrupting capability ratings shall not be included as part of the ratings for switching devices.

# SECTION 4: DYNAMIC DATA REQUIREMENTS

The MDWG Dynamic models reflect detailed dynamic model representations for SPP resources and equivalized external representations of external resources beyond specified tiers in reduced cases and detailed dynamic model representations for all of the Eastern Interconnection resources in full cases. The initialized no-fault models can be solved with quarter-cycle and half-cycle time steps. The MDWG Dynamic model update is used to support SPP reliability studies and ERAG MMWG Dynamic modeling requirements. It is important for all generating entities that interconnect to the SPP transmission to support the SPP RTO with current detailed dynamics data in the proper SPP model format. The current MDWG Dynamic model format is PSS®E dynamics DYRE and RAWD formats.

The Dynamic model data includes:

1. Steady-State models
2. Files applied (if applicable) to steady-state models for dynamic initialization purposes
3. Dynamic model data in Siemens PTI PSS®E DYRE format
4. User written model source and object code

The schedule for submission of Dynamic data and list of MDWG Dynamic models (case types) can be found on the SPP corporate website, www.spp.org.

### *Dynamics Data Submittal Requirements and Guidelines*

1. All synchronous generator and synchronous condenser modeling and associated data shall be detailed except as permitted below. Detailed generator models consist of at least two direct axis circuits and one quadrature axis equivalent circuit.
   The use of non-detailed synchronous generator or condenser modeling shall be permitted for units with nameplate ratings less than or equal to 50 MVA under the following circumstances:
   a. Detailed data is not available because manufacturer no longer in business.
   b. Detailed data is not available because unit is older than 1970.
   The use of non-detailed synchronous generator or condenser modeling shall also be permitted for units of any nameplate rating under the following circumstances only:
   a. Unit is a phantom or undesignated unit in a future year MMWG case.
   b. Unit is on standby or mothballed and not carrying load in MMWG cases.
   The non-detailed PSS®E model types are GENCLS and GENTRA. When complete detailed data are not available, and the above circumstances do not apply, typical detailed data shall be used to the extent necessary to provide complete detailed modeling.
2. All synchronous generators and condensers shall also include representations of the generator, excitation system, turbine-governor, power system stabilizer, and reactive line drop compensating circuitry. The following exceptions apply:
   a. Excitation system representation shall be omitted if unit is operated under manual excitation control.

   b. Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units in pumping mode and synchronous condensers.
   c. Power system stabilizer representation shall be omitted for units where such device is not installed or not in continuous operation.
   d. Representation of reactive line drop compensation shall be omitted where such device is not installed or not in continuous operation.
3. All other types of generating units and dynamic devices including induction generators, static VAR compensators (SVC), high-voltage direct current (HVDC) systems, static compensators (STATCOM), Flexible AC Transmission System (FACTS), wind turbines, and photovoltaic systems shall be represented by the appropriate PSS®E dynamic models.
4. All demand data shall include a load model which represents the expected dynamic behavior of the loads. Non-scalable loads greater than or equal to 10 MW are required to have a dynamic load model representation. For all other types of loads, absent detailed dynamic load models, the real portion (MW) of all demand data is converted to 100% constant current and the reactive portion (Mvar) of all demand data is converted to 100% constant admittance.
5. Other information requested by the PC or TP – Information which the PC or TP deems necessary for modeling purposes can be requested from Data Owners/Data Submitters.
6. Standard PSS®E dynamic models shall be used for the representation of all generating units and other dynamic devices unless both of the following conditions apply:
   a. The specific performance features of the user-defined modeling are necessary for proper representation and simulation of inter-regional dynamics, and
   b. Standard PSS®E dynamic models cannot adequately approximate the specific performance features of the dynamic device being modeled.
7. When user-defined modeling is used, written documentation shall be supplied explaining the dynamic device performance characteristics. The documentation for all user-defined models shall be provided as a separate document and must include the characteristics of the model, including block diagrams, values and names of all model parameters, and a list of all state variables. Any benign warning messages that are generated by the model code at compilation time should also be documented.
   Source code for User Models shall be submitted in the FLECS language of the current PSS®E revision, C, or FORTRAN. User models created in MATLAB/SIMULINK are not permitted because users of the SDDB cannot run them without purchase of additional software.
8. Netting of small generating units, synchronous condensers, or other dynamic devices with bus load shall be permitted only when the unit or device nameplate rating is less than or equal to 20 MVA. (Note: any unit or device which is already netted with bus load in the MMWG cases need not be represented by a dynamic model.)
9. Lumping of similar or identical generating units at the same plant shall be permitted only when the nameplate ratings of the units being lumped are less than or equal to 50 MVA. A lumped unit shall not exceed 300 MVA. Such lumping shall be consistent from case to case within a model series.
10. Where per unit data is required by a dynamic model, all such data shall be provided in per unit on the generator or device nameplate MVA rating as given in the steady-state generator data record. This requirement also applies to excitation system and turbine-

governor models, the per unit data of which shall be provided on the nameplate MVA of the associated generator. The maximum and minimum power of cross compound units should be provided on the nameplate MVA of one machine in accordance with PSS®E model IEEEG1 conventions.

11. Exceptions will be approved by MMWG on a case by case basis and the reason for each exception will be documented in the SDDB.

### *Miscellaneous Other (MINS) Dynamic models*

1. If a generator, transformer, or capacitor has in-service relay protection that operates in 10 seconds or less, then the relay models shall be submitted when available. Inverter-based generator resources shall have frequency and voltage protective relay models.
2. PSS®E Model Instance (MINS) values for "Miscellaneous Other" models should be a unique eight digit number. The first six digits should be the bus number at which the model is being applied. The last two digits should be a unique number designating a particular application of a "Miscellaneous Other" model at the bus. Under no circumstance shall a unique eight digit MINs number be repeated.

   MINS example: 59999900 VTGDCAT
   Bus number = 599999
   Unique identifier = 00
   Relay model = VTGDCAT

3. Unique MINS values are required for VTGDCAT/VTGTPAT, FRQDCAT/FRQTPAT, SAT2T, and SWCAPT relay models.

   PSS®E Miscellaneous Other (MINS) Dynamic model types:

| Model | Description |
|---|---|
| VTGDCAT/VTGTPAT | Under/over voltage generator bus disconnection relay.<br>Under/over voltage generator trip relay. |
| FRQDCAT/FRQTPAT | Under/over frequency generator bus disconnection relay.<br>Under/over frequency generator trip relay. |
| SAT2T | Transformer saturation model. |
| SWCAPT | Switched capacitor bank model. |

## PROCEDURE FOR INITIALIZATION AND NO-DISTURBANCE CHECKS OF LIBRARY DYNAMICS CASES

Note: PSS®E activities relevant to the following steps are shown in brackets.

1. Create a converged load flow case with as few limit violations and questionable data items as possible.
   a. Solve the case after each set of major changes [FNSL, FDNS, SOLV, or MSLV] and save it to minimize rework if a change has unintended consequences. If all of the following constraints

are satisfied, convergence within tolerance, even from a flat start, should not take more than the default number of iterations. However, there is usually no reason to use a flat start if the case being updated was solved.

b. Generator checks using a list of all data to spot unrealistic, typically default, generator data values. [LIST, option 5] There is no checking activity listing only machines having suspect values of the following

    i. Machine MVA on the default base of 100. Although models will work if all load flow and dynamic model parameters are entered on this basis, limit checks will not work correctly.
    ii. Source impedance of 1.0 p.u. on machine MVA base. This value is substantially higher than normal for synchronous machines.
    iii. Source impedances equal to or less than zero. These will cause generator conversion to fail.
    iv. Real and/or reactive power limits of +9999 or –9999.

c. Checks which report abnormal values

    v. Branch flows exceeding normal ratings. [RATE or OLTL and OLTR]
    vi. Bus voltages below 0.95 p.u. except in the case of generator terminal voltage buses connected to the transmission bus by a step-up transformer with a tap ratio significantly off nominal. [VCHK]
    vii. Overloaded generators. [GEOL]. Note that this activity checks machine output against the machine MVA base, MBASE, not against PMAX, PMIN, QMAX, and QMIN.
    viii. Branches with extreme impedances or tap ratios [BRCH]. Suggested options are:

        a) Small impedance. Note that very small impedances can be treated as zero impedance ties by selection of parameter THRSHZ and these will not be a problem.
        b) Negative reactance. These are typically found in Y representations of three winding transformers. Solution activity SOLV may not be used on cases containing such branches and MSLV may not be used if they are present at a Type 2 or 3 (generator) bus.
        c) Charging. Values exceeding the default upper check limit (5.0 p.u.) are normal on long EHV lines but others should be checked. Negative values are occasionally used for magnetizing impedance on transformers but this usage is not recognized in the PSS®E Program Operation Manual.
        d) Parallel transformers. Minor tap ratio differences may simply reflect field conditions, but differences exceeding one step should be checked to guard against inadvertent errors.
        e) High tap ratios.
        f) Low tap ratios.

d. Interactive checks: the user is asked to enter new value(s) for each exception, or hit “carriage return” for no change.

    i. Generators dispatched outside their real power limits [SCAL]. Scaling areas or zones should be used cautiously if generators having default PMAX (+9999) and PMIN (-9999) limits are present.

ii. Inconsistent targets at a bus whose voltage is controlled by two or more system elements: local generation, switched shunts, and voltage controlling transformers. [CNTB]. There is a tendency not to recognize different summer and winter operating strategies where appropriate.

iii. Questionable voltage or flow controlling transformer parameters. [TPCH]

iv. Buses in "islands" not containing a system swing bus. [TREE]. Note that there can be multiple islands each of which does contain a system swing bus, with DC links connecting them.

2. To confine the initialization to a subset of the original load flow, for instance the areas comprising one region, proceed as follows.
   a. Create a raw data file containing only the area(s) of interest. [RAWD, AREA]
   b. Read in the raw data file just created. [READ]
   c. If no system swing bus is in the area kept, change the type of a generator bus from 2 to 3 to make it the system swing bus. [CHNG]
   d. Locate any islands created by the subsetting operation and either connect or drop them. [TREE].
   e. Replace flows on tie lines severed by the subsetting operation with equivalent <u>loads</u> (positive for flows out, negative for flows in). [BGEN]
3. Net generation with load at any buses where a generator(s) exists for which no dynamic models are available. [GNET].
4. Convert the generators in the load flow [CONG], solve, [ORDR, FACT, TYSL] and save converted case.[SAVE]
5. From the dynamics entry point, read in the dynamic model data file [DYRE] (Load flow case must also be in memory.)
   a. Specify CONEC, CONET, and COMPILE files.
   b. It is highly desirable to include a SYSANG model in the DYRE file, although this makes it mandatory to recompile even if no user models are included. This model provides six monitoring output channels, which can be used to scan a no-disturbance simulation for stability without attempting to select individual machines to monitor.
6. Concatenate FLECS code for user models onto CONEC or CONET files.
7. Compile.
8. Execute CLOAD4.
9. Restart from the dynamics entry point, this time using "user dynamics".
   a. Read converted load flow [CASE].
   b. Read in the dynamic data file [DYRE]
   c. Specify channels to record appropriate states and variables as simulation outputs [CHAN]. Include SYSANG variables if this model was included in the dynamics data file as suggested above.
   d. Check consistency of dynamic models [DYCH, option 1].
   e. Initialize dynamic simulation [STRT]. The output of this activity may have several important parts and it is desirable to keep a log file for reference while debugging.

i. Warning messages for

a) Generators in the load flow for which there is no active machine model.
b) Models, usually of excitation systems or governors, initialized out of limits.
c) The number of iterations required to initialize the initial-conditions steady-state.

ii. A tabulation of conditions at each online machine

a) Terminal voltage
b) Exciter output voltage
c) Real and reactive power output
d) Power factor
e) Machine angle in degrees
f) Direct and quadrature axis currents on machine base.

iii. A diagnosis of initial conditions, either

a) "Initial conditions check OK", or
b) A listing of suspect initial conditions generally states whose time derivative is not "small" (relative to the value of the state). These may be caused by inconsistencies between the real and reactive power scheduled for a unit by the load flow (including automatic changes in reactive power to hold bus voltage at a target level) or by parameter errors.

iv. For models flagged in steps i) through iii), consider using activity [DOCU] to identify parameters which may be causing problems. This activity will also give the automatically calculated values of exciter model parameters, which are derived if the corresponding parameters, as read in, are 0. Other warnings may indicate errors in the steady-state model.

f. Modify model parameters or the load flow as appropriate and repeat steps up to this point until there are no warning messages nor suspect initial conditions.

10. Record a snapshot [SNAP] of dynamic state values prior to application of any disturbance or simulation of any time period.
11. Simulate undisturbed operation [RUN] for at least 20 seconds. Printing the convergence monitor [RUN,CM] can indicate where problems are, but considerably increases the amount of output.
12. Stop simulation. Review output values in tabular and/or graphical form.
13. Validate exciter model response to a step change in set point. [ESTR] and [ERUN]. Field voltage and terminal voltage will be output for each exciter model and may be reviewed in tabular or graphical form. Satisfactory response is indicated if the terminal voltage settles to the specified value within a few seconds, if the field voltage is reasonable, and the response is free of
    a. Excessive overshoot
    b. Sustained oscillations
    c. High frequency noise (may be caused by using too long a simulation time step.)
    d. Unexpected discontinuities in the output variables or their derivatives (except IEEE Type 4 "non-continuous" regulator models).
14. Validate governor model response to a step change. [GSTR] and [GRUN]. Mechanical power and speed deviation will be output for each shaft where a governor model is present and may be reviewed in tabular or graphical form. Models of cross-compound unit governors specify two machines so four output variables are used. Steam or combustion turbine unit governors may require up to 20 seconds to attain equilibrium, and hydro units even longer, even if they are well tuned. Satisfactory response is indicated if speed deviation settles to approximately (- K) = (-1 / R), mechanical power to (1-1/K) times the specified value, and the response variables are free of excessive overshoot or sustained oscillations.

**Dynamic Data Format**

PSS®E Users

Dynamics data needs to be submitted in the form of a flat text file or dyre file compatible with Siemens PTI PSS®E dyr file software. Dyre file submittals can be of changes to individual components from the existing dyre entries or of entire new representation of machines. Dynamic ready models are developed using the PSS®E software program. The data should be submitted via GlobalScape or email. Data submitted must be compatible with the PSS®E version currently specified by SPP.

Non-PSS®E Users

Dynamics data needs to be submitted in the form of a flat text file or dyre file compatible with Siemens PTI PSS®E software. Siemens PTI PSS®E Software contains dyre file models for most conventional machines, exciters, governors, SVCs, HVDC ties, wind resources, and solar resources. SPP Modeling staff will work with the responsible entity or its designee to translate operational test data into the appropriate dyre file format compatible with the PSS®E version currently specified by SPP.

**Acceptable Dynamic Model Information**

The PSS®E simulation software dynamic machine models may be used as long as they are included on the NERC List of Acceptable Models for Interconnection-Wide Modeling and not identified as unacceptable models on that list. The NERC acceptable dynamic model list can be found on the NERC SAMS website→SAMS Reference Materials→NERC Acceptable Model List.

Significant improvements to models may occur over time and models may become obsolete, not recommended, or unacceptable models. Unacceptable models might still be available in the PSS®E software; however, those models must be replaced with more suitable current acceptable models.

User-written dynamic models will only be allowed under the following conditions:

1. Technical basis as to why the user-written model should be used in place of the Siemens PTI PSS®E standard library model in consideration of a regional transmission system analysis
2. Dynamic model data is submitted in .dyr format
3. Dynamic model data is submitted in .lib or .dll format for compilation and linking purposes.
4. Documentation, including Block Diagram, in .pdf or .docx format
5. A written commitment from the Data Owner to SPP, as PC, indicating that user-written models will be converted to the applicable acceptable dynamic model within 18 months of being notified of request for conversion to an acceptable model by SPP or Transmission Planner.

MDWG developed a subset list of acceptable dynamic models based on the NERC acceptable dynamic model list and adheres to the guidance outlined in the MDWG Dynamic Models Guidelines document.

**Dynamics Data Validation Requirements**

1. All dynamics modeling data shall be screened according to the SDDB data screening checks.
2. All data items not passing these screening tests shall be resolved with the generator or dynamic device owner and corrected.
3. All regional data submittals to the MMWG coordinator shall have previously undergone satisfactory initialization and 20-second no-disturbance simulation checks for each dynamics case to be developed. The procedures outlined in Section III.H* of this manual (*yet to be written) may be applied for this purpose.

**Guidelines**

1. Dynamics data submittals containing typical data should include documentation which identifies those models containing typical data. The CON conservation models, such as GENROA and GENSAA, which essentially copy dynamics data from one unit to another, may be useful for this purpose. When typical data is provided for existing devices, the additional documentation should give the equipment manufacturer, nameplate MVA base and kV, and unit type (coal, nuclear, combustion turbine, hydro, etc.).
2. The voltage dependency of loads should be represented as a mixture of constant impedance, constant current, and constant power components (referred to as the ZIP model). The Regions should provide parameters for representing loads via the PTI PSS®E CONL activity. These parameters may be specified by area, zone, or bus. Other types of load modeling should be provided to MMWG when it becomes evident that accurate representation of interregional dynamic performance requires it.

**Procedures for Submission of Dynamics Data to the MMWG Coordinator**

Regional Coordinators have two options, described below, for submitting dynamics data to the MMWG Coordinator.

## *DYNAMICS DATA UPDATES USING EXCEL TEMPLATE*

Regional dynamics data updates are incremental to the dynamics data in the previous year release of SDDB. Regional Coordinators should therefore verify that bus names and unit IDs in SDDB are consistent with those in the MMWG steady-state to be made dynamics ready.
The table below describes the various types of updates and the required data and information that should be provided on the Excel template and in a separate DYRE file.

| **Type of Update** | **Template Entries** | **Complete DYRE format record** | **Examples / Comments** |
|---|---|---|---|
| Change one or more parameters of a dynamics model | Bus name, unit ID, model name, parameter name, new value | No | The voltage regulator gain is changed to the value determined by test. |
| Add a new model to an existing unit | No | Yes | A stabilizer is being added to a unit which did not have one. |

| | | | |
|---|---|---|---|
| Delete a model | Bus name, unit ID, model name | No | A stabilizer is removed. |
| Replace a model with another model of the same equipment group | Bus name, unit ID, model name for deleted model. | Yes for new model. | 1. A DC exciter is replaced by a static exciter.<br>2. A classical machine model is replaced by a detailed model. |
| Change bus name and/or unit ID for all models of an existing unit | Old and new names; old and new unit IDs | No | |
| Change bus number | No | No | Maintain the same name and unit ID and the model data will follow automatically. |
| Add dynamic models for a new generating unit | Bus name, unit ID, in service and out of service dates, MVA base, Zsource, RPM, unit type | Yes | Same requirements whether unit is at new or existing bus. |
| Remove a unit and all associated models | Bus name, unit ID | No | |

## COMPLETE SET OF DYNAMICS DATA

The regional dynamics data must be in the format of a PSS®E DYRE file. The data must be compatible and consistent with the MMWG steady-state selected for the dynamics cases that are being developed. One file for all cases is preferable.

**System Dynamic Data Base and Dynamic Simulation Cases**

SPP Dynamic Base Case Models are available to all SPP members. SPP and its members, by participating in MMWG dynamics database (SDDB) and dynamics simulation case development, grant authority to the other participating Regions, to receive and use the SDDB and dynamics simulation cases. Regional members may send dynamics simulation cases or dynamics data to third parties provided that the third party executes a SPP confidentiality/non-disclosure agreement. The MMWG Dynamics Database (SDDB) remains the property of and is for the sole use of the MMWG participating Regions of NERC and their members.

# SECTION 5: SHORT CIRCUIT DATA REQUIREMENTS

The Short Circuit models are developed using data gathered through the SPP database Model On Demand (MOD) in conjunction with the Engineering Data Submission Tool (EDST). MOD data is divided into three parts: a Base Case, Projects, and Profiles (Bus, Loads, Generation, and Device Control). Modeling updates for transmission system topology can be made by submitting a Project to MOD. Additional required data is submitted through the EDST which is identified in the data preparation section of this manual.

SPP MDWG Short Circuit Models are published according to the approved schedule.

**TRANSMITTED DATA FILE EXAMPLES (Refer to MOD Procedure Manual)**

**PTI-PSS®E SHORT CIRCUIT DATA FORMAT**

The SPP Short Circuit data is included in MOD Base Case (Network) and Project data and is submitted/updated in alignment with the MDWG Powerflow model build. The sequence data is comprised of zero sequence data and, specific to generators the positive and negative sequence data must also be provided. Short circuit data that is missing in the MOD Base Case must be entered in MOD via a MOD Project with the Project Type of Network and Project Status of Update, additionally the associated sequence file must be attached to the project file. Missing Project sequence data must be updated by applying a sequence file to the Project in MOD. All Short-circuit applicable MOD projects must have updated sequence data attached with the MOD project.

The PC (SPP) prior to presenting short circuit models to the MDWG for approval shall verify that all submitted member data has been correctly added to the short circuit models. The short circuit models shall be checked for errors and validated as usable by the PC. Any errors in the sequence data shall be brought to the attention of the Data Submitter. The usability checks shall include the PC performing data checks for missing sequence data and testing of models. The test of the models shall consist of fault analysis for three-phase, single-line-to-ground, and double-line-to-ground. The testing of the models is to ensure the models are ready for fault analysis by the SPP membership and absent of modeling errors.

For retired generators, GSUs are kept in service if there is an interrupting device on the low side of the GSU in order to produce accurate short circuit results.

## *MUTUAL IMPEDANCE*

Mutual coupling exists between two or more transmission lines that are routed in parallel for a substantial distance due to the magnetic fields and flux linkage between the parallel conductors. For these configurations, a fault on one line can induce a large zero-sequence current (i.e. ground current) in the un-faulted parallel line and may lead to inappropriate tripping of the un-faulted line. Zero-sequence current is only present during ground faults, so the consideration of mutual coupling effects only applies to the derivation of ground fault protective element settings. Mutual impedance can be constructive or destructive; in other words, it may increase or decrease the zero-sequence fault current. It is important that the mutual impedances between all line pairs be calculated and included when developing the system model.[24]

A best practice approach for identifying and submitting the correct mutual impedance data is by synchronizing all short circuit databases across the different software platforms (CAPE, ASPEN, PSS®E, etc.) in each respective company's footprint. In synchronizing the short-circuit data across the different software platforms, verification of which database is the primary source for the short-circuit data is imperative. Typically the approach for determining when mutual impedance data is required in the PSS®E models can be identified by checking when mutual impedance data is modeled and updated in a company's primary database.

Mutual impedance data shall be submitted by attaching it to the applicable MOD project.

***Member submitted sequence via an IDEV file applied to a model will not be included in the next published model (Pass N or Final).*** The reason that sequence data is not carried over from one model set to the next model set is that sequence data is exported from MOD. Post MOD model processing IDEV files are not applied to the next model set; therefore, a MOD project which includes the sequence data must be submitted to MOD and accepted before it is included in the next MOD exported model.

Short Circuit models are developed annually using a subset of the MDWG Powerflow models. All base MDWG steady-state models will include sequence data (including applicable mutual line impedance data) for the SPP footprint. The following 3 versions of short circuit models will be built:

1. MDWG steady-state base model
2. MDWG steady-state with PSS®E Classical assumptions
3. Maximum Fault case

The Base MDWG Short Circuit models are built by performing the following steps:

1. Extract the SPP RAW and SEQ data with ties from the final MDWG steady-state model
2. Extract the first tier company's RAW and SEQ data without ties from the final SERC Short Circuit model built by the Short Circuit Database Working Group (SCDWG)
3. Merge the two data sets together

The Classical assumptions MDWG Short Circuit Models are built by performing the following step:

1. Apply Classical assumptions to the Base MDWG Short Circuit model as described in the PSS®E Program Operation Manual

Maximum Fault cases are built by performing the following steps:

1. Place in-service (Apply a status of '1') all SPP planned and available existing generation and transmission facilities to the Base MDWG Short Circuit model
2. Apply Classical assumptions

All transformers shall have a Vector Group and corresponding Connection Code in PSS®E 33+ format. Prior to presenting the short-circuit models to MDWG, SPP staff will conduct a preliminary

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analysis of three phase balanced and unbalanced faults for the purpose of validating the integrity of the modeled sequence information prior to finalization.

Other information requested by the PC or TP – Information which the PC or TP deems necessary for modeling purposes can be requested from Data Owners/Data Submitters.

# SECTION 6: DEFINITIONS

These definitions are defined for purposes of model building and are not applicable outside the scope of the MDWG Model Building Procedure Manual.

**Auxiliary or Station Service load** – Real and reactive power necessary to operate a generating unit or other load that is directly related to the production of energy.

**Coincident Peak (Model)** – SPP coincident peak equals the highest demand including transmission losses for energy measured over a one clock hour period during the defined season.

**Demand Side Management** – Demand Side Management consists of activities or programs that an entity invokes to achieve a reduction in Demand and may consist of controllable and/or non-controllable systems.

**Data Owner**[25] – The entity that is responsible for ensuring the accuracy and timely submission of data to the SPP, as Planning Coordinator, in accordance with the SPP Model Development Procedure Manual.

**Data Submitter**[1] – The entity that is responsible for submitting data to the SPP, as Planning Coordinator, in accordance with the SPP Model Development Procedure Manual.

**Distributed Energy Resources** – Power resources on the distribution system that can be aggregated together to provide power to meet Peak Demand.

**Engineering Data Submission Tool (EDST)** – A web-based application for storing, coordinating, and facilitating data between Data Submitters and SPP.

**Equivalencing** – The general technique that substitutes power system equipment with a simplified representation that closely approximates the characteristics and behavior of the actual equipment.

**Exploratory Generation** – Generation resources that have a strong likelihood or commitment to be implemented, but have not completed the Generation Interconnection process. These generation resources may be added to the appropriate models for shortfall purposes only.

**Interchange (Model)** – Energy transfers that cross Balancing Authority boundaries. The algebraic sum of purchases and sales for a modeling area where a positive value is considered is a power export and a negative value is considered a power import.

25 Not a NERC functional entity

**Model Area** – The collection of model objects comprising an entity's network and uniquely numbered in PSS®E**.**

**Peak Demand** – The highest demand including transmission losses for energy measured over a one clock hour period.[26]

**PSS®E** – Siemens PTI's Power System Simulator for Engineering software tool for electrical transmission analysis used to model the SPP transmission system.

**PSS®E MOD** – A distributed web-based application for power transmission planning model management and provision of study models using a single consolidated data repository.

**PSS®MOD File Builder** – A stand-alone Siemens tool that is designed to help PSS®E users capture model changes in the form of PSS®MOD Modeling projects by comparing PSS®E models.

**Transaction (Model)** – A modeled purchase and/or sale of power.

**Non-scalable load** – Load that does not conform to the daily load duration curve.

**On-Peak (Model)** – Those hours or other periods typically considered periods of higher electrical demand.

**Off-Peak (Model)** – Those hours or other periods typically considered periods of lower electrical demand.

**Regulating device** – Equipment that manipulates power system parameters towards a setpoint or setpoints (e.g. a static reactive device maintaining system voltage).

**Shortfall** – Occurs when an entity does not have enough dispatchable generation to serve the entity's load.

**Tie Line (Model)** – A circuit connecting two Model Areas.

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# SECTION 7: APPENDIX I
# MASTER TIE LINE FILE DATA FIELDS

**Branch Data Fields**

In Service Date,
Out Service Date,
From Region Name,
From Area#,
From Area Name,
From Bus#,
From Bus Name,
From Bus kV,
To Region Name,
To Area#,
To Area Name,
To Bus#,
To Bus Name,
To Bus kV,
Metered End (F,T),
CKT,
R,
X,
B,
Summer Rating A,
Summer Rating B,
Summer Rating C,
Winter Rating A,
Winter Rating B,
Winter Rating C,
GI (pu),
BI (pu),
GJ (pu),
BJ (pu),
STATUS (0,1),
LEN (mi),
Owner 1,
Fraction 1,
Owner 2,
Fraction 2,
Owner 3,
Fraction 3,
Owner 4,
Fraction 4

**Two Winding Transformer Data Fields**

In Service Date,
Out Service Date,
From Bus Region Name,
From Bus Area#,
From Bus  Area Name,
From Bus Number,
From Bus Name,
From Bus kV,
To Bus Region Name,
To Bus Area#,
To Bus Area Name,
To Bus Number,
To Bus Name,
To Bus kV,
Tapped Side,
CKT,
CW,
CZ,
CM,
MAG1,
MAG2,
Metered Side,
NAME,
STATUS (0,1),
Owner 1,
Fraction 1,
Owner 2,
Fraction 2,
Owner 3,
Fraction 3,
Owner 4,
Fraction 4,
R1-2,
X1-2,
SBase1-2,
WindV1,
NomV1,
Ang1,
Summer Rating A1,
Summer Rating B1,
Summer Rating C1,
Winter Rating A1,
Winter Rating B1,
Winter Rating C1,

**Two Winding Transformer Data Fields - continued**

COD1,
Volt Control Bus Region Name,
Volt Control Bus Area Number,
Volt Control Bus Area Name,
Volt Control Bus Number (CONT1),
Volt Control Bus Name,
Volt Control Bus kV,
RMA1,
RMI1,
VMA1,
VMI1,
NTP1,
TAB1,
CR1,
CX1,
WindV2,
NomV2

**Three Winding Transformer Data Fields**

In Service Date,
Out Service Date,
Winding 1 Region Name,
Winding 1 Area#,
Winding 1 Area Name,
Winding 1 Bus#,
Winding 1 Bus Name,
Winding 1 Bus kV,
Winding 2 Region Name,
Winding 2 Area#,
Winding 2 Area Name,
Winding 2 Bus#,
Winding 2 Bus Name,
Winding 2 Bus kV,
Winding 3 Region Name,
Winding 3 Area#,
Winding 3 Area Name,
Winding 3 Bus#,
Winding 3 Bus Name,
Winding 3 Bus kV,
CKT,
CW,
CZ,
CM,
MAG1,
MAG2,
NMETR(1,2,3),
NAME,
STATUS(0,1),
Owner 1,
Fraction 1,
Owner 2,
Fraction 2,
Owner 3,
Fraction 3,
Owner 4,
Fraction 4,
R1-2,
X1-2,
SBase1-2,
R2-3,
X2-3,
SBASE2-3,
R3-1,

**Three Winding Transformer Data Fields - continued**

X3-1,
SBASE3-1,
VMSTAR,
ANSTAR,
WindV1,
NomV1,
Ang1,
Summer Rating A1,
Summer Rating B1,
Summer Rating C1,
Winter Rating A1,
Winter Rating B1,
Winter Rating C1,
COD1,
Control Bus 1 Region,
Control Bus 1 Area Number,
Control Bus 1 Area Name,
Control Bus #(CONT1),
Control Bus Name,
Control Bus KV,
RMA1,
RMI1,
VMA1,
VMI1,
NTP1,
TAB1,
CR1,
CX1,
WindV2,
NomV2,
Ang2,
Summer Rating A2,
Summer Rating B2,
Summer Rating C2,
Winter Rating A2,
Winter Rating B2,
Winter Rating C2,
COD2,
Control Bus 2 Region,
Control Bus 2 Area Number,
Control Bus 2 Area Name,
CONT2,
Control Bus 2 Name,
Control Bus 2 KV,
RMA2,

**Three Winding Transformer Data Fields - continued**

RMI2,
VMA2,
VMI2,
NTP2,
TAB2,
CR2,
CX2,
WindV3,
NomV3,
Ang3,
Summer Rating A3,
Summer Rating B3,
Summer Rating C3,
Winter Rating A3,
Winter Rating B3,
Winter Rating C3,
COD3,
Control Bus 3 Region,
Control Bus 3 Area Number,
Control Bus 3 Area Name,
CONT3,
Control Bus 3 Name,
Control Bus 3 KV,
RMA3,
RMI3,
VMA3,
VMI3,
NTP3,
TAB3,
CR3,
CX3

**Two Terminal DC Tie Data Fields**

In Service Date,
Out Service Date,
I,
MDC,
RDC,
SETVL,
VSCHD,
VCMOD (1,0),
RCOMP,
DELTI,
METER (R,I),
DCVMIN,
CCCITMX,
CCCACC,
IPR REGION NAME,
IPR AREA#,
IPR AREA NAME,
IPR Bus#,
IPR BUS NAME,
IPR BUS Kv,
NBR,
ALFMX,
ALFMN,
RCR,
XCR,
EBASR,
TRR,
TAPR,
TMXR,
TMNR,
STPR,
ICR REGION NAME,
ICR AREA#,
ICR AREA NAME,
ICR BUS#,
ICR BUS NAME,
ICR BUS kV,
IFR REGION NAME,
IFR AREA#,
IFR AREA NAME,
IFR BUS#,
IFR BUS NAME,
IFR BUS KV,
ITR REGION NAME,
ITR AREA#,

**Two Terminal DC Tie Data Fields**

ITF AREA NAME,
ITR BUS#,
ITR BUS NAME,
ITR BUS KV,
IDR,
XCAPR,
IPI REGION NAME,
IPI AREA#,
IPI AREA NAME,
IPI Bus#,
IPI BUS NAME,
IPI BUS Kv,
NBI,
GAMMX,
GAMMN,
RCI,
XCI,
EBASI,
TRI,
TAPI,
TMXI,
TMNI,
STPI,
ICI REGION NAME,
ICI AREA#,
ICI AREA NAME,
ICI BUS#,
ICI BUS NAME,
ICI BUS kV,
IFI REGION NAME,
IFI AREA#,
IFI AREA NAME,
IFI BUS#,
IFI BUS NAME,
IFI BUS KV,
ITI REGION NAME,
ITI AREA#,
ITI AREA NAME,
ITI BUS#,
ITI BUS NAME,
ITI BUS KV,
IDI,
XCAPI

**Notes:** (1) The data formats must be compatible with PSS®E input requirements.
(2) The in-service and out-of-service dates will be expressed as mm/dd/yyyy.

# SECTION 8: APPENDIX II
# UTILIZED IMPEDANCE CORRECTION TABLES

| Table Number | Tap or Angle | 1 Factor | Tap or Angle | 2 Factor | Tap or Angle | 3 Factor | Tap or Angle | 4 Factor | Tap or Angle | 5 Factor | Tap or Angle | 6 Factor | Tap or Angle | 7 Factor | Tap or Angle | 8 Factor | Tap or Angle | 9 Factor | Tap or Angle | 10 Factor | Tap or Angle | 11 Factor |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | -60 | 1 | -36 | 0.358 | -24.4 | 0.192 | -12.4 | 0.054 | -8.3 | 0.024 | 0 | 0.01 | 8.3 | 0.024 | 12.4 | 0.054 | 24.4 | 0.192 | 36 | 0.358 | 60 | 1 |
| 2 | -70 | 1 | -43 | 0.78 | -32 | 0.85 | 0 | 0.5 | 32 | 0.85 | 43 | 0.78 | 70 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | -180 | 1 | -150 | 0.5 | 0 | 0.5 | 150 | 0.5 | 180 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | -152 | 1 | -121.5 | 0.625 | -85.4 | 0.372 | -42.2 | 0.217 | 0 | 0.157 | 42.2 | 0.217 | 85.4 | 0.372 | 121.5 | 0.625 | 152 | 1 | 0 | 0 | 0 | 0 |
| 8 | -40 | 1.848 | -30 | 1.468 | 0 | 1 | 30 | 1.538 | 40 | 1.83 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | -25 | 1.995 | 0 | 1 | 25 | 1.995 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | -25 | 1.995 | 0 | 1 | 25 | 1.995 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | -40 | 1.66 | -29.5 | 1.331 | -25.1 | 1.228 | -20.6 | 1.145 | 0 | 1 | 20.6 | 1.145 | 25.1 | 1.228 | 29.5 | 1.331 | 40.1 | 1.66 | 0 | 0 | 0 | 0 |
| 13 | -40 | 1.849 | -30 | 1.402 | -20 | 1.196 | -10 | 1.045 | 0 | 1 | 10 | 1.045 | 20 | 1.161 | 30 | 1.366 | 40 | 1.741 | 0 | 0 | 0 | 0 |
| 16 | -30 | 1.913 | 0 | 1 | 30 | 1.913 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | -47 | 6.34 | -41.7 | 5.44 | -33.3 | 4 | -27.5 | 3.06 | -18.5 | 2 | 0 | 1 | 18.5 | 1.76 | 27.5 | 3.278 | 33.3 | 3.643 | 41.7 | 5.25 | 47 | 1 |
| 18 | -40 | 2.31 | 0 | 1 | 40 | 2.31 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | -40 | 7.35 | -30 | 4.85 | -20 | 2.9 | -10 | 1.6 | 0 | 1 | 10 | 1.6 | 20 | 2.9 | 30 | 4.85 | 40 | 7.35 | 0 | 0 | 0 | 0 |
| 20 | 0.937 | 1.641 | 1 | 1 | 1.03 | 1.02 | 1.1 | 1.427 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | 0.889 | 0.575 | 1.04 | 1 | 1.2 | 2.89 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | 0.8 | 1.563 | 0.85 | 1.384 | 0.9 | 1.235 | 0.95 | 1.108 | 1 | 1 | 1.05 | 0.907 | 1.1 | 0.826 | 1.15 | 0.756 | 1.2 | 0.694 | 1.25 | 0.64 | 1.3 | 1 |
| 23 | -10 | 1 | 5 | 0.655 | 20 | 1.449 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 25 | -60 | 9.2 | -46.38 | 4.69 | -32.3 | 1.87 | -20 | 1 | 0 | 1 | 18 | 1 | 32.3 | 3 | 46.38 | 5.54 | 60 | 9.2 | 0 | 0 | 0 | 0 |
| 31 | -15 | 2.076 | 0 | 1 | 15 | 2.076 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 32 | -15 | 1.62 | 0 | 1 | 15 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | -5.7 | 2.061 | 0 | 1 | 5.7 | 2.061 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 34 | -10 | 1.782 | 0 | 1 | 10 | 1.782 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 35 | -30 | 1.65 | 0 | 1 | 30 | 1.65 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 37 | -15 | 2.076 | 0 | 1 | 15 | 2.076 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 40 | -40 | 1 | -35 | 0.75 | -25 | 0.6 | -12.5 | 0.55 | -7.5 | 0.52 | 0 | 0.5 | 7.5 | 0.52 | 12.5 | 0.55 | 25 | 0.6 | 35 | 0.75 | 40 | 1 |
| 42 | -42.5 | 1.784 | -32.6 | 1.497 | -22 | 1.26 | -11.1 | 1.07 | 0 | 1 | 11.1 | 1.05 | 22 | 1.193 | 32.6 | 1.443 | 42.5 | 1.782 | 0 | 0 | 0 | 0 |
| 44 | -52.9 | 1.9024 | -43.6 | 1.6768 | -33.7 | 1.4512 | -23.2 | 1.2256 | -12.3 | 1 | -1.2 | 1.1385 | 9.9 | 1.2769 | 20.9 | 1.4154 | 31.4 | 1.5539 | 0 | 0 | 0 | 0 |

# SECTION 9: APPENDIX III
# DESIGNATING MOD-032-1 DATA SUBMITTAL ASSIGNMENT

See Page Below

## Letter of Notice
## Designating MOD-032-1 Data Submittal Assignment

On this ______ day of ____________, 20_____, ___________________ and ______________________, provide notice to Southwest Power Pool, Inc. (SPP) of the following:

On ________________, 20____, ___________________, Data Owner, and _____________________, Data Submitter, entered into an agreement through which _____________________ has agreed to submit on behalf of _____________________ the (select one):

☐ information required to be provided to SPP as its Planning Coordinator pursuant to NERC Reliability Standard MOD-032-1, R2.

☐ following information required to be provided to SPP as its Planning Coordinator pursuant to NERC Reliability Standard MOD-032-1, R2:

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

The accuracy of the data is the responsibility of the Data Owner. This notice does not shift the compliance obligation from the Data Owner to the Data Submitter. The MOD-032 data to be submitted is set forth in MOD-032-1 Attachment 1. The schedule to submit data shall be set forth in the SPP modeling data requests and the then-effective SPP MOD-032 Model Development Procedure Manual data requirements and reporting procedures.

The above designation will remain in effect pursuant to this notice until revoked by either the Data Owner or the Data Submitter in writing to SPP at SPPEngineeringModeling@spp.org.

On behalf of DATA OWNER:

By: __________________________

Printed Name: __________________

Title: _________________________

Date: ______________

SPP hereby acknowledges receipt of this notice.

By: __________________________

Printed Name: __________________

Title: _________________________

Date: ______________

On behalf of DATA SUBMITTER:

By: __________________________

Printed Name: __________________

Title: _________________________

Date: ______________

# SECTION 10: APPENDIX IV SPP MODEL ON DEMAND (MOD) MATRIX

## SPP MOD Project Type/Status Matrix

| Type | Description | Status | Description | Applied to this Model Set: MDWG | ITP | TS | GI | Special Study | Notes |
|---|---|---|---|---|---|---|---|---|---|
| SPP-approved Transmission System Upgrade | **Must have an NTC for:**<br>**1) transmission service request(s);**<br>**2) transmission changes originating from the integrated transmission planning (ITP) process;**<br>**3) transmission changes originating from the Balanced Portfolio process;**<br>**4) transmission changes directed by the high priority study process;**<br>**5) transmission changes associated with Sponsored Upgrades.** | Approved | | X | X | X | X | X | Transmission changes that materially-modify the SPP Transmission System. Projects associated with changing the generation or load components interconnected to the SPP Transmission System in accordance with SPP OATT Attachment V and AQ processes, are submitted separately under the "Generation Interconnection" or "Attachment AQ Load" MOD Types.<br><br>MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, NTC/PID/UID number.<br>**Example Prj/Idv Name:**<br>-659_Patent_Gate_NTC300.prj<br>-659_BEPC_Build_New_Line_SUS-###.pr<br>-659_Patent_Gate_PID2230.prjj |
| Planned Transmission System Change | **An expected change to the SPP Transmission System that does not yet have or does not require an NTC, including:**<br>**1) transmission changes budgeted for or planned by the TO;**<br>**2) transmission changes budgeted for by a Transmission Customer or other entity;**<br>**3) transmission changes resulting from an emergency (e.g., unplanned equipment failure);**<br>**4) transmission, load, or generation changes that otherwise have a strong likelihood or commitment to implement (e.g., load changes not yet approved by Attachment AQ, a GI with an IA but on suspension, a GI without an IA, etc.)** | Acknowledged | Material transmission changes that have been acknowledged by SPP and may be included in model sets. | X | X | X | X | X | **For material changes, Data Submitters shall submit an RMS ticket as a way of notifying SPP.**<br>**The status for this MOD type will only be changed to "Acknowkldeged" by Data Submitters after receiving a notification from SPP for inclusion in the model sets.** |
| | | Requested | Material transmission changes that have not yet been submitted to SPP and may not be included in model sets | | | | | | This MOD Project Type & Status **is the default** to represent transmission changes expected to be implemented in the future, but are not yet, or will not be, part of any SPP planning processes under Attachment O to the SPP OATT.<br><br>Do not use this MOD Project Type to submit speculative changes to the transmission model that simply correct basecase system conditions (See MOD Project Type "System Intact Alteration"). |
| | | Non-material | Non-material transmission change that does not affect reliability or transmission service. | X | X | X | X | X | |
| Attachment AQ | **Changes to load and/or delivery points approved in accordance with Attachment AQ, including any transmission changes associated with the Attachment AQ project (e.g., equipment upgrades, changes to normally-open/closed topology).** | Approved | | X | X | X | X | X | Load changes and transmission changes, including upgrades and changes to normally-open/closed topology, associated with the approved Attachment AQ load modification.<br><br>MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, DPA/DPNS number.<br>**Example Prj/Idv Name:**<br>a. Project name: 525_WFEC_Midwest-Franklin_Rebuild_NTC2002 OR 525_WFEC_Midwest-Franklin_Rebuild_DPA-2018-Month-###.prj OR 525_WFEC_Midwest-Franklin_Rebuild_DPNS-20##-Month-###.prj<br>b. Profile name: 659_BEPC_2017MDWGP4-18S.raw or Nextera_2017MDWGP4-18S.raw |
| Generation Interconnection | **Additions or changes to generating units, including any transmission changes associated with the Generation Interconnection Service project(s), approved in accordance with the Generator Interconnection Procedure (GIP) that:**<br>**1) have an executed Interconnection Agreement (IA) or executed Interim Generator Interconnection Agreement (IGIA), and**<br>**2) are not suspended.** | Approved | | X | X | X | X | X | Generation changes and transmission changes, including upgrades that may not have been included in the executed IA, associated with the approved GI.<br><br>MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, NTC/PID/UID number.<br>**Example Prj/Idv Name**:<br>822_NextEra_Add_Blue_Cloud_Wind_GEN-20YY-###.prj |
| Network Status | **Changes to the existing SPP Transmission System network topological status only (both placed out-of-service or returned to service).** | Update | | X | X | X | X | X | Applicable equipment must already be included in the MOD database (constructed; pre-existing) to be placed in- or out-of-service. |
| Modeling Correction | **Changes to the transmission model necessary to correct or update the existing transmission model represented by the MOD network data.** | Update | | X | X | X | X | X | Projects with this status will be immediately committed to the MOD base case upon review. |
| System Intact Alteration | **Changes to the transmission model necessary to correct basecase system intact voltage (e.g., to conform to MMWG voltage criteria), thermal criteria violations, or other basecase condition modifications (e.g., addition of an exploratory generating unit which provided resource for shortfall).** | Update | | X | | | | | Projects with this status will not be applied to any models except to those models submitted to MMWG. |

# SECTION 11: APPENDIX VII GMD/GIC DATA COLLECTION TEMPLATE USER'S GUIDE

## *GEOMAGNETIC DISTURBANCE MODELING DATA*

Additional modeling data is necessary to supplement the MDWG steady-state models to support geomagnetic disturbance (GMD) analysis. The SPP GMD Model Set combines GMD-related system information (described below) with the MDWG AC-equivalent representation of the SPP transmission system. This composite of modeling data yields a DC-equivalent representation used to calculate geomagnetically-induced current (GIC) flows. These GIC magnitudes can then be applied to the MDWG AC-equivalent model to yield steady-state effects to System voltages and transformer MVAR losses. Appropriate simulations of GMD effects to the BES cannot be achieved without the incorporation of the following modeling information:

### Substation Data

Substation modeling data encompasses geographical information related to power system topological information, as represented by the bus-branch model.

<u>Bus Number (Planning Model)</u>: This is the actual bus from the Planning Model. This bus will be associated with a substation on the Substations sheet.

<u>Substation Bus Number (Planning Model):</u> Choose one bus to serve as the substation reference. In other words, the bus number annotated in this field will serve as the geographic reference for the entire substation. The recommendation is for the model Data Submitter to pick the highest voltage bus in a station to serve as this reference.

<u>Substation DC Grounding Resistance (Ohms)</u>: This can be a measured, calculated, or assumed value for the grounding resistance in Ohms. Caution: do not convert this grounding resistance to per unit Ohms; retain the actual Ohmic quantity. In the unlikely event that a substation/switchyard is ungrounded, the model Data Submitter may enter "-1" here, not zero. Measured values come from ground grid testing, while calculated values are derived from detailed design modeling. When a substation is commissioned or periodic maintenance is performed, grounding integrity or ground grid data is typically collected.

<u>Grounding Resistance (Method)</u>: This field indicates how the grounding resistance information was obtained.

<u>Geographic Latitude (decimal degrees):</u> This latitude will be used for all busses assigned to this station on the "Busses" sheet. Given that the entire SPP footprint is in the Northern Hemisphere, only positive decimal degree values are acceptable for latitude.

Geographic Longitude (decimal degrees): This longitude will be used for all busses assigned to this station on the "Busses" sheet. Caution: longitudes to the west of the Prime Meridian are between 0 and -180°. Given that the entire SPP footprint falls between the 85th west meridian and the 115th west meridian, only negative decimal degree values are acceptable for longitude.

Earth Model (Name): This field assigns the one-dimension earth conductivity model to the geographical location of the substation reference bus. The earth model is based upon the standard earth conductivity models developed by the United States Geological Survey (USGS). The following table shows the cross-reference between the USGS reference and the software code that should be placed in the “Earth Model (Name)” field. On the “1D Earth Model Reference" sheet, a tool is provided to assist in determining the proper earth model by latitude and longitude.

| USGS Earth Conductivity Model | Equivalent to: | Siemens/PTI software code (enter into the “Earth Model Name” field) | Description |
|---|---|---|---|
| AK-1A | | AK1A | Adirondack Mountains-1A |
| AK-1 B | | AK1B | Adirondack Mountains-1B |
| AP-1 | | AP1 | Appalachian Plateaus |
| AP-2 | | AP2 | Northern Appalachian Plateaus |
| ATLANTIC | | ATLANTIC | Northeastern Atlantic Coast, Nova Scotia |
| BC | | BC | British Columbia (BC) |
| BR-1 | | BR1 | Northwest Basin and Range |
| CL-1 | | CL1 | Colorado Plateau |
| CO-1 | | CO1 | Columbia Plateau |
| CP-1 | | CP1 | Coastal Plain (South Carolina) |
| CP-2 | | CP2 | Coastal Plain (Georgia) |
| CS-1 | | CS1 | Cascade-Sierra Mountains |
| FL-1 | | none | Florida |
| IP-1 | | IP1 | Interior Plains (North Dakota) |
| IP-2 | | IP2 | Interior Plains |
| IP-3 | | IP3 | Interior Plains (Michigan) |
| IP-4 | | IP4 | Interior Plains (Great Plains) |
| MID-ATL | PT-1 | PT-1 | Mid-Atlantic |
| NE-1 | | NE1 | New England |

| USGS Earth Conductivity Model | Equivalent to: | Siemens/PTI software code (enter into the "Earth Model Name" field) | Description |
|---|---|---|---|
| OZARK | CP-2 | CP-2 | Ozarks |
| PB-1 | | PB1 | Pacific Border (Willamette Valley) |
| PB-2 | | PB2 | Pacific Border (Puget Lowlands) |
| PRAIRIES | | PRARIES | Alberta (AB), Saskatchewan (SK), Manitoba (MB) |
| PT-1 | | PT1 | Piedmont |
| RM | CL-1 | CL-1 | Rocky Mountain |
| SD | PB-1 | SHIELD | Ontario (ON), Quebec (QC) |
| SL-1 | | SL1 | St. Lawrence Lowlands |
| SU-1 | | SU1 | Superior Upland |

## Transformers

The Transformers sheet is intended to collect all of the information necessary to properly determine the magnitude of GIC that will arise within a given transformer. It is important to note that transformer winding resistance data collected from transformer specification sheets or test reports may represent the total resistance of the three phases combined.

While well known to model Data Submitters, the convention for MDWG model data is consistent with most load flow software that requires data be submitted per phase. Therefore, any combined three-phase transformer winding resistance data must be divided by three prior to submitting quantities. Similarly, when DC resistances of transformer windings are unknown (estimated values should only be used when data are unavailable), a reasonable assumption is to substitute actual data with 50% of the per phase copper loss resistance. It is noted that total copper loss resistance may be converted to per phase by dividing by three, and all values should be entered as Ohms, not in per unit base. For example, transformer test reports typically report the total copper loss of a transformer, derived from a short-circuit test[27], either as a total copper loss power [W] or as the total winding resistance [ohms] calculated from the total copper loss power. In either case, these quantities represent the total copper loss effects of three windings combined and must be divided by three to properly reflect the per phase resistance. The model Data Submitter is expected to provide the following data:

<u>Core Type:</u> This indicates the number of cores in transformer core design and is used to calculate transformer reactive power loss from GIC flowing in its winding. This field is only used by the software when a K-factor quantity is not specified by the model Data Submitter for the transformer.

[27] Also known as a transformer impedance test, a typical transformer short-circuit test is performed by shorting the low-voltage winding and increasing the high-voltage winding voltage until transformer rated current is observed in the high-voltage winding. This test recognizes that core loss is negligible, yielding the resistive losses in the primary winding circuit.

In other words, if you know the K-factor for the transformer (or have a better assumption), enter the quantity in the "GIC Reactive Loss Factor {K-factor}" field and it diminishes the importance of the “Core Type” field. Otherwise, the values for this field are limited to:

| Code | Core Design Type |
|---|---|
| -1 | Three-phase shell configuration |
| 0 | Unknown core design |
| 1 | Three separate single phase cores design |
| 3 | Three phase, 3-legged core configuration |
| 5 | Three phase, 5-legged core configuration |
| 7 | Three phase, 7-legged core configuration |

If the core configuration is unknown, stating as such in the Core Type field is acceptable. When this is done, the software will make an assumption for K-factor based upon the voltage level of the highest winding voltage of that transformer. All transformers in the SPP MDWG model series are expected to have vector groups defined, so that T-modeling of transformers in the DC network is permitted.

Connection Code (CC): This is the field for the Data Submitter to update the Connection Code shown in the Existing Connection Code (CC) field, if warranted. This field is included because experience has shown that prior model-building efforts may not have focused on this data, but it is critical to GIC modeling. It is suggested that the model Data Submitter review vector group and winding order to ensure proper CC submittal.

Vector Group: This is key data required to properly model the grounding characteristics of a transformer. While potentially misleading, most load flow software packages embed the transformer per phase winding configuration information under short-circuit data category. The confusing aspect is that winding configuration is meaningful in situations other than under short-circuit conditions; for example, with GIC that arise from GMD. As a reminder, the Connection Code data contained within the load flow model representation embodies concepts of the transformer core type, the vector group (phase differences between windings, standardized with clock notation indicating phase displacement), and physical conductor orientation.

GIC Reactive Loss Factor {K-factor}: The K-factor is an important aggregated assumption that helps formulate the transformer sensitivity to half-cycle saturation that arises from the contribution of GIC. In other words, the K-factor indicates a measure of increased reactive power losses in the transformer when subjected to GICs. The units of K-factor are MVAR per Ampere; the larger the K-factor the larger expected reactive power losses in the transformer. K-factor is used to calculate additional transformer reactive power losses according to:

$Q_{loss}$ = Effective GIC Winding Current x K-Factor.

There is much debate in industry about how to measure, calculate, and assume values for K-factor. In general, if a K-factor is not specified on a transformer data sheet or in test reports, the following table annotates appropriate assumed values. It is noted that the following assumptions for K-factor are consistent with those integrated into the Siemens/PTI software:

| Core Type Code | Highest Winding kV | K-factor |
|---|---|---|
| -1 | Any | 0.33 |
| 0 | <=200 kV | 0.6 |
| 0 | > 200kV, <= 400kV | 0.6 |
| 0 | > 400kV | 1.1 |
| 1 | Any | 1.18 |
| 3 | Any | 0.29 |
| 5 | Any | 0.66 |
| 7 | Any | 0.66 |

<u>DC Resistance of From, To, and Tertiary Windings (Ohms/Phase):</u> The preferred value is measured, typically derived from a transformer specification sheet or test report. This data should be the measured DC resistance of single winding at nominal tap and adjusted to 75 °C. **Caution**: do not convert this resistance to per unit Ohms per phase; retain the actual Ohmic quantity.

<u>From, To, and Tertiary Windings Grounding Resistance (Ohms):</u> The preferred value is measured or calculated, typically derived from a ground grid design, transformer test report, or other test report. This data should be the measured DC resistance of single winding at nominal tap and adjusted to 75 °C. **Caution:** do not convert this resistance to per unit Ohms per phase; retain the actual Ohmic quantity.

<u>Blocking Device Status (From, To, and Tertiary Windings):</u> Indicate whether a GIC blocking device is installed and is operational on the From winding in this field. GIC blocking devices on transformer windings are rare.

<u>DC Resistance of From, To, and Tertiary Windings Blocking Device (Ohms):</u> Currently, most load flow software tools that support a GIC analysis module assume that if a blocking device is installed and active, that the DC resistance of that block is infinite. In other words, the winding is either blocked from participating in GIC flow or not. It is expected that in future versions GIC analysis modules that software will support an actual DC resistance for the blocking device to more precisely model GIC flow through the transformer winding. Input the known DC resistance of the blocking device in Ohms, if known.

Transformer Model in DC Network: Entered as 0 to represent the transformer according to its vector group, or entered as 1 to represent the transformer as a T-model. **Important note:** given that all transformers in the SPP MDWG model series are expected to have vector groups defined, the model Data Submitter should avoid entering 1 in this field. In future revisions of the MDWG model data collection, this field may be eliminated. However, due to an outstanding PSS®E software ambiguity for symmetric phase shifting transformers, this field is retained.

Symmetric phase shifting transformers modulate real power flow, typically to a narrow specified range. These are represented in the load flow model by two-winding transformer representations that utilize the "MW symmetrical PAR" or "MW asymmetrical PAR" control mode. These transformers should be modeled as the YNa vector group with Connection Codes (CC) 9 or 19, reflecting that the winding 1 impedance represents the zero sequence impedance of the regulating transformer, the winding 2 impedance represents the zero sequence impedance of the series transformer, and the shunt branch represents the tertiary winding impedance. If the symmetric phase shifting transformer is entered this way, the "Transformer Model in DC Network" (TMODEL) should be entered as 0. However, in those rare cases when a vector group is not specified for the symmetric phase shifting transformer, the PSS®E software needs to establish a default for the transformer T-model representation in DC analysis. This is accomplished by entering the "Transformer Model in DC Network" (TMODEL) as 1.

### Shunts

The Shunts sheet is intended to collect information necessary for modeling direct paths to ground that contribute to the magnitude of GIC flow on the power system. There are two key observations that need to be considered when submitting shunts data for MDWG model data collection. First, Switch Shunt capacitor devices are not considered by GIC analysis software. This is due to the expectation that capacitive shunts are GIC blocks and inductive devices would be intentionally placed out-of-service so as to not exacerbate GIC during GMD events. Second, line reactor devices are very important for modeling GIC. However, the practice of representing line reactors is inconsistent amongst model builders, where some explicitly model line reactor shunts at buses in the transmission line path, while others incorporate the impedance of the line shunt into the data record of the transmission line branch itself. It is important to confirm how line shunts are being modeled. The model Data Submitter is expected to provide the following data:

From, To Bus Number (Planning Model): Self-explanatory; where the fixed shunt is located. In the case where the line shunt is modeled as part of the transmission line branch, enter the bus number of the branch terminal end that is closest to the physical location of the line reactor. If line reactors reside at both ends of the branch, make two separate line item entries (e.g., separate rows) to reflect two separate line reactors.

Line or Bus (Planning Model): Enter the method of modeling the shunt device, as either explicitly at a bus or as part of a line (branch).

Located at which end (From, To, or Both): For line shunts modeled as part of the transmission line branch, enter at which terminal ends the line reactor is installed. Otherwise, leave this field blank.

Winding Connection Type: This information is not currently used as part of the analysis, but may be relevant in future assessments. Enter the winding configuration as Wye, Grounded-Wye, or Delta. This information should be annotated on the shunt specification sheet or as part of a test report.

Shunt DC Resistance (Ohms/Phase): The preferred value is measured, typically derived from the shunt specification sheet or test report. This data should be the measured DC resistance of single phase and adjusted to 75 °C. **Caution:** do not convert this resistance to per unit Ohms per phase; retain the actual Ohmic quantity.

Shunt Grounding Resistance (Ohms): The preferred value is measured or calculated, typically derived from a ground grid design, shunt test report, or other test report. This data should be the measured DC resistance of single phase and adjusted to 75 °C. **Caution:** do not convert this resistance to per unit Ohms per phase; retain the actual Ohmic quantity.

## Branch

The Branch sheet is intended to reflect the characteristics of the transmission lines that serve as the current-carrying conductors participating in the varying magnetic field, giving rise to GIC. It is noted that most of the information for transmission lines is already part of load flow models. The model Data Submitter is expected to provide the following data:

Branch Resistance (pu): Most branch resistances are known in per unit, so an automatic conversion to ohms per phase is included here. The ohms per phase quantity can be entered explicitly in the DC Resistance cell or, if Branch Resistance (pu) is left as zero, the GIC module will use the AC branch resistance already in load flow model. It is important to note: this "Branch Resistance" field refers to the DC branch resistance that will characterize the transmission line in the DC model representation for GIC analysis. For the purpose of the MDWG model data collection, all transmission line conductor DC resistances shall be entered at 50 °C.

For an identical temperature, transmission line branch per phase resistances vary slightly between DC resistance and AC resistance. However, for large diameter transmission line conductors, the difference between AC and DC resistances may exceed 10%, at a common temperature. This is especially important when considering whether a transmission line employs bundled conductors. For the purpose of MDWG model data collection, it is acceptable to use the AC branch resistance already in the load flow model, if the AC resistance is based on 50 °C or less. However, care must be taken when using AC resistances as approximations of the DC resistance, especially when the AC resistance is based on temperatures greater than 50 °C. While conductor resistivity increases approximately linearly with temperature between 20 °C to 75 °C, the difference between DC and AC resistances may vary non-linearly with temperature given other transmission line characteristics, leading to significant differences in resistance. In other words, knowing that transmission line AC resistances are often entered[28] into the load flow models at 25 °C, using this AC resistance as a conservative approximation for DC resistance is acceptable. However, any AC resistance entered into

[28] The Transmission Line Characteristics (TMLC) software and Line Properties Calculator (LineProp) software are common tools used by model Data Submitters to calculate AC transmission line branch impedances. Both of these software packages do not allow any other conductor temperature assumption other than 25 °C, when calculating AC resistance calculation, unless default manufacturer data tables are overwritten. Typical transmission line conductor tables furnished by manufacturers provide AC resistances at 25 °C, 50 °C, and 75 °C.

the load flow model using temperatures greater than 50 °C must be corrected to 50 °C prior to using the quantity as the approximation for DC resistance.

Ultimately, to perform a conservative study of GMD effects, the smaller the transmission line DC resistance, the larger the GIC that will be developed. Therefore, DC resistances entered at 50 °C are preferred. AC resistances corrected to and entered at 50 °C or less are an acceptable alternative.

Real part of total branch GMD-induced electric field (volts): This field is intended to allow a particular branch to experience a higher or lower induced electric field than the uniform field applied to other branches. In other words, if there is a reason to expect a particular transmission line will experience more or less induced field during a benchmark GMD event (line length times the TPL-007-3 reference geoelectric field of 8V/km), enter the alternative real-part electric field in volts. **Caution:** do not enter zeros into this field unless the transmission line is not intended to participate in the development of an electric field due to GMD. Rare examples of when this may be the case include buried or undersea transmission cable. Leave this field blank to apply the uniform electric field automatically.

Imaginary part of total branch GMD-induced electric field (volts): This field is intended to allow a particular branch to experience a higher or lower induced electric field than the uniform field applied to other branches. In other words, if there is a reason to expect a particular transmission line will experience more or less induced field during a benchmark GMD event (line length times the TPL-007-3 reference geoelectric field of 8V/km), enter the alternative imaginary-part electric field in volts. **Caution:** do not enter zeros into this field unless the transmission line is not intended to participate in the development of an electric field due to GMD. Rare examples of when this may be the case include buried or undersea transmission cable. Leave this field blank to apply the uniform electric field automatically.

## Loads

**Note: loads for GMD data submittal are expected to be exceptions and are uncommon!** Albeit rare, the possibility exists that a relevant load may be connected at EHV/HV levels that offers a ground path for GIC. Likewise, it may be desirable for a Data Submitter to include data for a solidly-grounded load direct-served through an EHV/HV autotransformer (uncommon), such as with a large industrial load. All loads do not need to be entered into the Loads sheet! The Loads sheet is intended to collect information necessary for modeling the rare direct paths to ground introduced due to load connections that contribute to the magnitude of GIC flow on the power system. The model Data Submitter is expected to provide the following data:

Winding Connection Type: This information is not currently used as part of the analysis, but may be relevant in future assessments. Enter the winding configuration as Wye, Grounded-Wye, or Delta. For loads with a dedicated step-down transformer, this information may be annotated on the step-down transformer specification sheet or as part of a test report for the primary winding (non-autotransformer) or the primary-secondary autotransformer winding configuration.

Load DC Resistance (Ohms/Phase): The Data Submitter should take care when entering this value. Remember, for autotransformers, the common winding (primary and secondary) is likely grounded. When determining the load DC resistance, consider that the actual impedance of the load to ground is connected to the secondary in parallel with the tapped common winding. The preferred value is measured DC resistance of single phase and adjusted to 75 °C, but the common winding to ground resistance may be a suitable proxy for DC analysis. **Caution:** do not convert this resistance to per unit Ohms per phase; retain the actual Ohmic quantity.

Load Grounding Resistance (Ohms): The preferred value is measured or calculated, typically derived from the step-down transformer test report indicating the transformer neutral grounding. This data should be the measured DC resistance of single phase and adjusted to 75 °C. **Caution:** do not convert this resistance to per unit Ohms per phase; retain the actual Ohmic quantity.

# SECTION 12: APPENDIX V MOD-032-1 ATTACHMENT 1

## MOD-032-1 – ATTACHMENT 1

*The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[29] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.*

| **steady-state**<br>*(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)* | **dynamics**<br>*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)* | **short circuit** |
|---|---|---|
| 1. Each bus [TO]<br>a. nominal voltage<br>b. area, zone and owner<br>2. Aggregate Demand[29] [LSE]<br>a. real and reactive power*<br>b. in-service status*<br>3. Generating Units[30] [GO, RP (for future planned resources only)]<br>a. real power capabilities - gross maximum and minimum values<br>b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above<br>c. station service auxiliary load for normal plant configuration (provide | 1. Generator [GO, RP (for future planned resources only)]<br>2. Excitation System [GO, RP(for future planned resources only)]<br>3. Governor [GO, RP(for future planned resources only)]<br>4. Power System Stabilizer [GO, RP(for future planned resources only)]<br>5. Demand [LSE]<br>6. Wind Turbine Data [GO]<br>7. Photovoltaic systems [GO]<br>8. Static Var Systems and FACTS [GO, TO, LSE]<br>9. DC system models [TO]<br>10. Other information requested by the Planning Coordinator or | 1. Provide for all applicable elements in column "steady-state" [GO, RP, TO]<br>a. Positive Sequence Data<br>b. Negative Sequence Data<br>c. Zero Sequence Data<br>2. Mutual Line Impedance Data [TO]<br>3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP] |

29 For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

2 For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. An LSE is responsible for providing this information, generally through coordination with the Transmission Owner.

3 Including synchronous condensers and pumped storage.

| | | |
|---|---|---|
| data in the same manner as that required for aggregate Demand under item 2, above).<br>d. regulated bus* and voltage set point* (as typically provided by the TOP)<br>e. machine MVA base<br>f. generator step up transformer data (provide same data as that required for transformer under item 6, below)<br>g. generator type (hydro, wind, fossil, solar, nuclear, etc)<br>h. in-service status*<br>4. AC Transmission Line or Circuit [TO]<br>a. impedance parameters (positive sequence)<br>b. susceptance (line charging)<br>c. ratings (normal and emergency)*<br>d. in-service status*<br>5. DC Transmission systems [TO]<br>6. Transformer (voltage and phase-shifting) [TO]<br>a. nominal voltages of windings<br>b. impedance(s)<br>c. tap ratios (voltage or phase angle)*<br>d. minimum and maximum tap position limits<br>e. number of tap positions (for both the ULTC and NLTC)<br>f. regulated bus (for voltage regulating transformers)*<br>g. ratings (normal and emergency)*<br>h. in-service status* | Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP] | |

| | | |
|---|---|---|
| 7. Reactive compensation (shunt capacitors and reactors) [TO]<br>a. admittances (MVars) of each capacitor and reactor<br>b. regulated voltage band limits* (if mode of operation not fixed)<br>c. mode of operation (fixed, discrete, continuous, etc.)<br>d. regulated bus* (if mode of operation not fixed)<br>e. in-service status*<br>8. Static Var Systems [TO]<br>a. reactive limits<br>b. voltage set point*<br>c. fixed/switched shunt, if applicable<br>d. in-service status*<br>9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP] | | |