MDAG MINUTES
June 14-15, 2023

SOUTHWEST POWER POOL
MODEL DEVELOPMENT ADVISORY GROUP MEETING

Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223
Face-to-Face
June 14, 2023 9:00 am – 4:00 pm (CST)
June 15, 2023 8:30 am – 12:00 pm (CST)

SUMMARY OF MOTIONS AND ACTION ITEMS

Action Items:

- **Action Item:** SPP staff to follow up with Dona Parks about EDST project.
- **Action Item:** Ensure 550 will be included in the next FG to discuss owner numbers for GOs. Data submitters will take this in house.
- **Action Item:** July 13th meeting 9-11am for approval of schedule/model selection.
- **Action Item:** AEP/SPP staff to take rate 3 to TWG
- **Action Item:** SPP to add this model review to the SPP roadmap process for next year.

Motions:

- **Motion: Scott Rainbolt motioned to approve the presented agenda as modified. Scott Schichtl seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**
- **Motion: Renee Miranda motioned to approve May 18, 2023, meeting minutes as presented. Jason Shook seconded the motion. The group did not voice any additional concerns during the discussion of the motion. The motion passed.**
- **Motion: Jason Shook motioned to table the discussion until the TWG concerns are resolved. Scott Schichtl seconded the motion. The group did not voice any concerns. The motion passes unanimously.**
- **Motion: Brianna Haug motioned to hold the next model selection and model schedule discussion on July 13th at 9:00 a.m. Alex Mucha seconded the motion. The group did not voice any concerns. The motion passes unanimously.**
- **Motion: Joe Fultz motioned to approve the MDAG Manual Version 7.0 as presented. Brianna Haug seconded the motion. Dustin Betz abstained from the vote. John Turner marked himself as a nay for voting purposes. The motion passes.**

MDAG MINUTES
June 14-15, 2023

Southwest Power Pool
MODEL DEVELOPMENT ADVISORY GROUP MEETING

June 14, 2023 9:00 am – 4:00 pm (CST)
June 15, 2023 8:30 am – 12:00 pm (CST)

Conference Call

MINUTES

AGENDA ITEM 1 – SPP WELCOME

SPP staff, Tony Green, welcomed the MDAG members to the 2023 in-person meeting.

AGENDA ITEM 2 – FACILITIES REVIEW

SPP staff, Darian Richards, went over the facilities review with the group.

AGENDA ITEM 3 – ADMINISTRATIVE ITEMS

AGENDA ITEM 3A & 3B – CALL TO ORDER AND ANTITRUST STATEMENT

SPP MDAG Chair, John Turner, called the meeting to order at 9:02 a.m. (CST) with Quorum. SPP Staff Secretary, Lottie Jones, read the anti-trust statement to the group.

MDAG MINUTES
June 14-15, 2023

AGENDA ITEM 3C & 3D – ATTENDANCE AND PROXIES

The following members attended or were represented by proxy:

MDAG Member	Present	In Person	Proxy	Present	Company
Tyler Baxter	No				Corn Belt Power Cooperative
Jerry Bradshaw	Yes				City Utilities of Springfield
Dustin Betz	Yes				Nebraska Public Power District
Preston Blinsky	Yes				Basin Electric Power Cooperative
Joe Fultz	Yes	X			Grand River Dam Authority
Brianna Haug	Yes				Western Area Power Administration, MDAG Vice-Chair
Steve Hohman	Yes				Omaha Public Power District
Reené Miranda	Yes	X			Southwestern Public Service
Alex Mucha	Yes				Oklahoma Municipal Power Authority
Scott Rainbolt	Yes	X			American Electric Power
Scott Schichtl	Yes	X			Arkansas Electric Cooperative Corporation
Jason Shook	Yes	X			GDS Associates
Liam Stringham	Yes		Tanner New		Sunflower Electric Power Corporation
John Turner	Yes	X			Western Farmers Electric Power, MDAG Chair
Lottie Jones	Yes	X			Southwest Power Pool, Inc., MDAG Secretary
John Vara	Yes	X			Golden Spread Electric
Ryan Baysinger	Yes				Evergy
Jesse Kreutzfeldt	Yes				Missouri River Energy Services

Material: JUNE14/15_Attach2 - 3c. MDAG Conference Call Attendance-06-14/15-2023

AGENDA ITEM 3E – AGENDA REVIEW **(APPROVAL ITEM)**

John Turner asked the group if they had a chance to review the agenda and if the group had any modifications to the agenda.

Scott Rainbolt motioned to sing happy birthday to Joe Fultz today.

Motion: Scott Rainbolt motioned to approve the presented agenda as modified. Scott Schichtl seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.

Material: JUNE14/15_Attach1 - 3e. MDAG Meeting Agenda

AGENDA ITEM 3F – PREVIOUS MAY 18, 2023 MEETING MINUTES **(APPROVAL ITEM)**

Lottie Jones asked the group if they had any proposed changes for the previous May 18, 2023, meeting minutes.

Motion: Renee Miranda motioned to approve May 18, 2023, meeting minutes as presented. Jason Shook seconded the motion. The group did not voice any additional concerns during the discussion of the motion. The motion passed.

Material: JUNE14/15_Attach3 - 3f. MAY 18, 2023, Meeting Minutes.docx

AGENDA ITEM 4 – REVIEW OF PAST ACTION ITEMS

Lottie Jones discussed outstanding issues highlighted in red font, including the action items added from the last meeting. Lottie walked the group through updates on action items collected at the previous session and updates for existing in-progress action items.

- Action Item 164 – In-Progress – Currently under area 550 discussion. Will be discussed later on the agenda.

AGENDA ITEM 5 – SPP IEEE 1547-2018 ADOPTION (APPROVAL ITEM)

SPP staff, Scott Jordan, shared the latest update on IEEE 1547-2018 with the group.

SPP Member Company requested additional information in regards to any questions/concerns from TWG during the last TWG meeting. SPP noted there were some concerns regarding jurisdiction during the meeting. Once IEEE 1547 is adopted this will set the expectation for the standards for DER developers. Although this is not currently a requirement, support would be provided by the AGIR.

SPP Member Company provided a resource to support this agenda item "Other Industry examples: MISO Guideline for IEEE Std 1547-2018 Implementation Recommendations on Requirements Impacting Transmission Systems".

https://cdn.misoenergy.org/MISO%20Guideline%20for%20IEEE%20Std%201547388042.pdf

SPP Member Company asked for clarification that this would not be additional work to TOs and modelers to request this information at this time. SPP confirmed, this is true and would not require additional work from the TOs or modelers at this time. The only current documents that point to the DER requirements are IEEE 1547-2003 or IEEE 1547-2014.

SPP Member Company is in favor of where this is going and the path moving forward in the future.

Motion: Jason Shook motioned to table the discussion until the TWG concerns are resolved. Scott Schichtl seconded the motion. The group did not voice any concerns. The motion passes unanimously.

AGENDA ITEM 6 – MODEL SELECTION STRAW POLL RESULTS

SPP staff, Lottie Jones, reviewed the results for the straw poll.

The favorable result was not adding additional models at this time with 81% of the votes.

SPS staff, Renee Miranda, mentioned that there should not be difficulty in creating additional summer models in the first 5 years. Is there anything that could be done for year 4?

Action Item: SPP to add this model review to the SPP roadmap process for next year.

Eddie mentioned that there is a process for adding models so SPP can provide this information to MDAG membership.

AGENDA ITEM 7 – CPPTF UPDATE & SCRIPT C3 COMMON MODEL SET GUIDANCE

SPP staff, Brandon Hentschel, updated the group on the updated CPPTF model proposal.

The MOD and EDST information should be the same as long as you don't change it in MOD. RR552 will remove the firm service requirement for resource inclusion for the ITP BR powerflow models. The proposal is to leave these generators in the model with an offline status, noting that pump storage will act similar how SPP handles batteries in the model.

AGENDA ITEM 8 – 2024 MODELING SCHEDULE AND MODEL SELECTION (APPROVAL ITEM)

SPP staff, Brandon Hentschel, provided the latest update on the 2024 model build schedule.

There is an update to row 36 and removal of the stars from the model selection table due to SPP modeling no longer exploring building 90/10 load models. Additionally the load amounts was removed from line 36 because load amount change thresholds was not discussed with membership and relates to late load data submissions via the 10.3 process.

SPP Member Company commented that the final MDAG models will be submitted on 4/5 to membership which may be too late for FERC 715 filing. SPP mentioned that the ITP models can be utilized for the FERC 715 filing in place of the MDAG models.

Modifications to posted agenda:

1. SPP will include a statement in the schedule regarding data submissions over the weekend.
2. Line 36 was updated to include "Last addition or removal chance for generators, loads, retirements, and transactions. After this pass, new loads will be required to go through a 10.3".
3. Line 23 and 24 update to correct dates
4. Correcting Dynamics modeling selection 27LL to 26LL

Is there a risk in using ITP models for the FERC 715 filing if there are 10.3 revisions after the models are finalized? There should not be an issue with any changes after the models are approved.

MDAG model updates after approval are handled by post-processing idevs; however, ITP model updates after initial final approval are handled by 10.3 submissions. The base models for MDAG do not change but the ITP models could change. However, SPP will submit the Initial Final ITP BR model for FERC 715 which would line up with the same model submitted by SPS for example.

SPP legal did not see any concerns with utilizing ITP models for FERC 715 filing.

Any comments, questions, votes, or concerns shall be submitted to SPP by July 6th for material posting.

Motion: Brianna Haug motioned to hold the next model selection and model schedule discussion on July 13th at 9:00 a.m. Alex Mucha seconded the motion. The group did not voice any concerns. The motion passes unanimously.

AGENDA ITEM 9 – BREAK

AGENDA ITEM 10 – 2024 MDAG MANUAL VERSION 7.0 (APPROVAL ITEM)

SPP staff, Brandon Hentschel, informed the group on the latest MDAG manual updates.

Adversely was added to the rating change language to give it more clarity and a row was added to the revision table for version 7.0.

MDAG Chair asked if any changes could be brought to MDAG prior to adding to the MDAG manual so that it may be approved prior to any changes and/or updates. These discussions could be held during the Focus Group meetings to avoid any confusion. If someone wants to make a change they should follow the change process and not simply bring it to SPP staff.

SPP Member Company asked for clarity that we are not re-approving items that were approved in May and simply approving the new items.

Motion: Joe Fultz motioned to approve the MDAG Manual Version 7.0 as presented. Brianna Haug seconded the motion. Dustin Betz abstained from the vote. John Turner marked himself as a nay for voting purposes. The motion passes.

AGENDA ITEM 11 – LUNCH

AGENDA ITEM 12 – AREA 550 DISCUSSION

MDAG MINUTES
June 14-15, 2023

Brianna Haug updated the group on the Area 550 discussion from the last MDAG meeting as well as the last Focus Group meeting.

The main purpose of this discussion is to start the conversation about defining and reorganizing how merchant generators are defined in the models. As mentioned in the Focus Group, it is possible to make this optional for those entities that are comfortable making the change.

Concerns/comments expressed by SPP Member Companies:

- Grabbing the correct data during topology comparisons.

- Generation is all in one zone and area which might make it a little easier to correctly model this data.

- There is difficulty in bringing consistency across the board. There is an unprecedented amount of generation sitting in the queue and it would be worthwhile to figure out how to deal with it ahead of time. There are studies that need geography as part of the study such as transfer studies. The concept in the common model set for CPPTF RR542 could tie in to the decision for this topic.

- Area 599 helps sort out some of these external areas. If we standardize the usage of the 599 area number we may get a scale of the size of the issue.

- Moving around area numbers for entities that reside in their area. Is the current issue going to go away if we move generators to a different area? Can Docucheck reference an owner number in place of an area number? Would SPP staff never contact the host TO for information on a non-host GO generator? What is to preclude anyone from changing generator area numbers today? The preference is to keep geographic area numbers in their respective area numbers. The GOs are responsible for maintaining and updating the data for their generators.

- The preferred option is to use owner number 599. Would it be possible to make a statement that entities are only responsible for what they own within the DocuCheck?

Brianna mentioned that there is benefit in moving external generation to owner number 599 as mentioned by several members previously. This topic will be discussed further in future meetings and is not close to consensus at this time.

John Turner asked for the simplest solution to this issue and that is not currently known at this time. This is something to think about for a future discussion.

Would it be possible to try out area/owner 599 and bring comments/concerns to the August Focus Group meeting?

Action Item: Ensure 550 will be included in the next FG to discuss owner numbers for GOs. Data submitters will take this in house.

AGENDA ITEM 13 – SHORT CIRCUIT DATABASE SUBMISSION

SPP staff, Eric Sullivan, updated the group on the next short circuit model build.

AGENDA ITEM 14 – POWERFLOW DATA SUBMISSION

SPP staff, Lottie Jones, updated the group on the next powerflow model build.

SPP Member Company mentioned that at one time there was an idev for tie line areas and outside entity corrections or updates. Is this still be utilized? There was some data that was put into MOD but was different in the final model submission. SPP commented that they can do a better job of ensuring that GRDA is on the emails sent by AECI to ensure that the tie lines between the two are correctly updated.

SPP Member Company asked if ratings are considered non-topological or topological. SPP staff commented that in MOD terminology the ratings go in a project file so they would be part of the topology instead of part of a profile.

AGENDA ITEM 15 – ACTIVITY

SPP staff, Estevan Padilla, shared an activity with the group.

AGENDA ITEM 16 – SPP MODEL COMPILATION

SPP staff, Hugh Benfer, provided the group with training on how SPP models are developed.

AGENDA ITEM 17 – MOD FILE BUILDER

SPP staff, David Duhart, provided a presentation on how to convert .raw to project (.prj) files.

AGENDA ITEM 18 – MOD WALKTHROUGH

SPP staff, Becca McCann, provided the group with a walkthrough of MOD including ratings and the anomaly log topics.

AGENDA ITEM 19 – SNACK

AGENDA ITEM 20 – EDST WALKTHROUGH

SPP staff, Kristie Brown, provided the group with a walkthrough of EDST.

AGENDA ITEM 21 – DYNAMICS DEMONSTRATION

SPP staff, Zach Sabey, provided the group with a dynamic model build demonstration.

AGENDA ITEM 22 – BREAKFAST

AGENDA ITEM 23A – 2023 SPP MDAG ROADMAP INITIATIVES SIR 544

SPP staff, Eric Sullivan, updated the group on the short circuit conversion of models from PSSE to ASPEN.

It is requested that this project be moved from planning to operations as they currently produce a node breaker model.

SPP is currently looking into how to produce a better PSSE model in order to make the conversion process a smoother experience.

This topic will be brought to future MDAG, TWG, and SPCAG for further discussion.

AGENDA ITEM 23B –2023 SPP MDAG ROADMAP INITIATIVES RATE 3

AGENDA ITEM 23BI – SURVEY RESULTS

SPP staff, Lottie Jones, updated the group on the Rate 3 survey results.

The majority of the group prefers that rate 3 data remain optional (no change) under the MDAG manual.

Would it be possible to transfer this over to TWG with the knowledge that MDAG prefers that this data remain optional?

FAC-008 states that you have to have this information so it may be best to send this to TWG in order to move it forward. This is a static rating and has nothing to do with AAR.

SPP Member Company requested to not add this data and/or keep it optional at this time. There is currently nothing that prevents someone from adding more ratings.

Action Item: AEP/SPP staff to take rate 3 to TWG

AGENDA ITEM 24 – 2023 SERIES MDAG MODEL BUILD/APPLICATION UPDATES

AGENDA ITEM 24A – DYNAMICS

SPP staff, Zach Sabey, updated the group on the 2023 series dynamic model build status.

AGENDA ITEM 25A – POWERFLOW

SPP staff, Lottie Jones, updated the group on the 2024 series MDAG powerflow model build.

AGENDA ITEM 25B – SHORT CIRCUIT

SPP staff, Eric Sullivan, updated the group on the 2024 series MDAG short circuit model build.

AGENDA ITEM 25C – GMD

SPP staff, Eric Sullivan, updated the group on the 2024 series MDAG GMD model build.

AGENDA ITEM 25D – MOD-033

SPP staff, Eric Sullivan, updated the group on the 2024 series MDAG MOD-033 model build.

AGENDA ITEM 25E – EDST

SPP staff, Kristie Brown, updated the group on EDST changes and updates including the rollover and lockdown.

AGENDA ITEM 26 – FERC ORDER 881

Lottie requested any questions or concerns related to FERC 881 to take back internally before working group discussions begin.

SPP Member Company asked what would change with the current model set. There is some discussion on the AARITF with regards to language changes that will need to be updated in the future. SPP commented, currently FERC Order 881 does not have any planning requirements though this will likely be standardized to make all studies have the same data.

SPP Member Company If companies move to AARs, how does that impact NTCs? How will SPP deal with that? This has been taken internally by SPP in order to determine how we would handle this scenario.

AGENDA ITEM 27 – SUMMARY OF ACTION ITEMS

Lottie discussed the action items from this meeting:

- **Action Item:** Follow up with Dona Parks about EDST.

- **Action Item:** Ensure 550 will be included in the next FG to discuss owner numbers for GOs. Data submitters will take this in house.
- **Action Item:** July 13th meeting 9-11am for approval of schedule/model selection.
- **Action Item:** AEP/SPP staff to take rate 3 to TWG.
- **Action Item:** Add model review to the SPP Roadmap.

AGENDA ITEM 28 – DISCUSSION OF FUTURE MEETINGS

a. MDAG: July 13, 2023 (9:00 AM – 11:00 AM)

b. MDAG FG: July 25, 2023 (1:00 PM – 3:00 PM)

c. Ambient Adjustment Ratings Implementation Task Force: July 10, 2023 (9:00 AM – 11:00 AM)

AGENDA ITEM 29 – ADJOURN

John Turner adjourned the meeting June 15th at 9:42 a.m. (CST)

Respectfully Submitted,

Lottie Jones
Secretary

Eric Sullivan
Secretary Assistant

Attachments

JUNE14_Attach1- 1e. MDAG Meeting Agenda.docx

JUNE14_Attach2 - 1c. MDAG Conference Call Attendance-06-14_15-2023

JUNE14_Attach3- 1f. April 20, 2023, Meeting Minutes.docx

JUNE14_Attach4- 8a. 2024 Modeling Schedule and Model Selection

JUNE14_Attach5- 8a. 2024 Modeling Schedule and Model Selection10. Draft_2024 MDAG Manual version 7.0

JUNE14_Attach6- MDAG Survey Results

Attendance worksheet

1. Input your group's name in A1

2. Enter your representative information

A. Enter the names of your rostered representatives in column A, beginning with your name (staff secretary) in row 7

B. Enter the company name for each of the rostered representatives in column B, beginning with "SPP" in row 7

2. Enter your meeting details

A. Enter your meeting dates begininng in column C, row 1 and continue across the worksheet until all meeting dates are entered

B. Enter the actual duration for each meeting beginning in column c, row 2. Round to the nearest .5 hours.

C. Enter the actual number of votes taken per meeting beginning in column c, row 3. **Do not count** administrative votes such as votes to approve the agenda or adjourn the meeting. When counting consent votes, count one vote for each item under the consent topic. Do not count a consent vote as 1 if it includes multiple items.

D. Enter the total number of attendees for each meeting beginning in column c, row 4

E. Enter the meeting format for each meeting beginning in column c, row 5

3. Track attendance at each meeting per representative

A. For yourself and each member note how the individual attended the meeting using the drop down for the cell. Options are webex, in-person, proxy, absent or non-member. Non-member is to be used for those who were members for only part of the assessment period. If you have a member that joined or left the group during the assessment period, utilize the non-member option for all meetings in which they were not considered a rostered member of the group.

Org Report Survey worksheet

1. Enter member demographic data

A. Indicate Yes if the member is current and No if they are no longer a part of the group

B. Enter the type of member for each representative in column D

C. Enter the sector type for each representative in column E

D. If a reprsentative leaves mid assessment period add a red asterick in front of their name

2. Enter Yes or No to indicate the status of your scope review in L8

3. Enter Assessment Period in A2

Model Development Advisory Group

		Meeting Date(s)	########	########	########	5/18/2023	6/14/2023	6/15/2023
		Meeting Length (hrs)	2.5	3	2	3	7	1.25
		Number of Votes Taken	2	5	3	3	4	0
		Overall Attendance	61	68	69	68	70	56
		Meeting Format	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Member Name	**Company**	**Current Member**						
Alex Mucha	Oklahoma Municipa	Yes	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Brianna Haug (Vice Chair)	Western Area Powe	Yes	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Dustin Betz	Nebraska Public Po	Yes	WebEx	WebEx	WebEx	Proxy	WebEx	WebEx
Jason Shook	GDS Associates	Yes	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Jerry Bradshaw	City Utilities of Spri	Yes	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Jesse Kreutzfeldt	Missouri River Energ	Yes	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Joe Fultz	Grand River Dam Au	Yes	WebEx	WebEx	Absent	WebEx	In-Person	In-Person
John Turner (Chair)	Western Farmers Ele	Yes	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
John Vara	Golden Spread Elec	Yes	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Liam Stringham	Sunflower Electric P	Yes	WebEx	WebEx	WebEx	WebEx	Proxy	Proxy
Lottie Jones (Staff Secretary)	SPP	Yes	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Preston Blinsky	Basin Electric Power	Yes	WebEx	WebEx	Absent	WebEx	WebEx	WebEx
Reené Miranda	Southwestern Publi	Yes	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Ryan Baysinger	Evergy	Yes	Absent	WebEx	WebEx	WebEx	WebEx	WebEx
Scott Rainbolt	American Electric Po	Yes	WebEx	WebEx	WebEx	Absent	In-Person	In-Person
Scott Schichtl	Arkansas Electric Co	Yes	WebEx	WebEx	WebEx	Proxy	In-Person	In-Person
Steve Hohman	Omaha Public Powe	Yes	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Tyler Baxter	Corn Belt Power Co	Yes	WebEx	WebEx	Proxy	WebEx	Absent	Absent
Guest Name	**Company**	**Current Member**						
Adam Mummert	Burns & McDonnell	No	WebEx					
Adam Nmili	Oklahoma Gas and	No	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Afshin Salehian	SPP	No						
Adam Schieffer	OPPD	No		WebEx			WebEx	
Ala Wadi	Liberty Utilities	No	WebEx	WebEx	WebEx	WebEx	WebEx	
Amine Chenaf	DNV	No						
Andrew Berg	Missouri River Energ	No	WebEx	WebEx				
Andrew Howard	Lincoln Electric Syst	No	WebEx			WebEx	WebEx	WebEx
Antonio Barrera	Southwestern Publi	No			WebEx	WebEx	WebEx	WebEx
Armin Sehic	Nebraska Municipal	No	WebEx	WebEx	WebEx	WebEx		WebEx
Aster Amahatsion	Nebraska Municipal	No		WebEx				
Ben Hammer	WAPA	No	WebEx					
Becca McCann	SPP	No	WebEx	WebEx	WebEx		In-Person	In-Person
Ben Mitchell	SPP	No					In-Person	In-Person
Blake Poole	Evergy	No						
Bobby Gray	Liberty Utilities	No	WebEx	WebEx				
Brandon Hentschel	SPP	No	WebEx	WebEx		WebEx	In-Person	In-Person
Brenda Harris	OXY	No					WebEx	
Brian Johnson	AEP	No		WebEx			WebEx	
Brooke Keene	SPP	No						
Bruce Doll	Nebraska Municipal	No						
Calvin Coates	Kansas Power Pool	No	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Casey Cathey	SPP	No						
Charles Costello	Siemens	No						
Cho Wang	American Electric Po	No						
Chris Colson	Western Area Powe	No	WebEx		WebEx			
Chris Davis	SPP	No			WebEx			
Chris Gidlen	Tri State	No						
Chris Rich	Oklahoma Gas and	No		WebEx		WebEx	In-Person	In-Person
Clarence Campbell	SPS	No		WebEx	WebEx	WebEx		
Claire Vigesaa	Burns & McDonnell	No						
Conner Sweet	City Utilities of Spri	No	WebEx	WebEx	WebEx		WebEx	WebEx
Curtis Miller	Western Farmers Ele	No						
Dale Reinhold	Hastings Utilities	No	WebEx					
Damien Burbage	AECI	No						
Danielle Borg	Sunflower Electric P	No		WebEx	WebEx	WebEx	In-Person	In-Person
Darian Richards	SPP	No			WebEx	WebEx	In-Person	In-Person
David Bromberg	Pearl Street Technol	No						
David Duhart	SPP	No	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
David Mendoza	Grand River Dam Au	No	WebEx	WebEx	WebEx			
David Zhong	American Electric Po	No		WebEx	WebEx	WebEx	In-Person	In-Person
Derek Brown	Evergy	No						
Devon Pehrson	National Grid Renev	No	WebEx					
Diego Toledo	Grand River Dam Au	No	WebEx	WebEx		WebEx	In-Person	In-Person
Douglas Bowman	SPP	No						
Dona Parks	Grand River Dam Au	No	WebEx	WebEx		WebEx	WebEx	WebEx
Donald Hargrove	Oklahoma Gas and	No						
Dustin Mooehr	Liberty Utilities	No			WebEx		In-Person	In-Person
Dylan Fate	Tri State	No						
Dylan Haas	Evergy	No				WebEx	In-Person	In-Person
Ebrahim Rezaei	American Electric Po	No						
Eddie Watson	SPP	No	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Edin Terzic	Lincoln Electric Syst	No						
Eli Nyambegera	Sunflower Electric P	No						
Elijah Salinas	LES	No	WebEx		WebEx	WebEx		
Ellen Cook	SPP	No						
Eric Jones	Omaha Public Powe	No	WebEx	WebEx	WebEx	WebEx	WebEx	
Eric Sullivan	SPP	No	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Erin Cathey	SPP	No						
Erik Voice	Salem Electric	No		WebEx				
Estevan Padilla	SPP	No	WebEx	WebEx	WebEx		In-Person	In-Person
Frank Favela	Southwestern Publi	No						
Garrick Nelson	Western Area Powe	No			WebEx			
Gary Boerger	Oklahoma Gas and	No					In-Person	In-Person
Gavin Novotny	Evergy	No						
Glen Halley	City Utilities of Spri	No		WebEx				
Grace Bouziden	Oklahoma Gas and	No						
Hannah Mason	Light Source BP	No						
Harriet Walsh	Orsted	No						
Hugh Benfer	SPP	No	WebEx	WebEx	WebEx			
James Okenfuss	Savion Energy	No						
Jason Menke	Nebraska Public Po	No			WebEx	WebEx	In-Person	In-Person
Jeff Knottek	City Utilities of Spri	No						
Jeff McDiarmid	SPP	No						
Jeff Plew	NextEra	No						
Jeffrey Taylor	ITC	No	WebEx	WebEx	WebEx	WebEx		
Jens Boemer	EPRI	No					WebEx	
Jerad Ethridge	Oklahoma Gas and	No						
Jeremy Severson	Basin Electric Power	No	WebEx					
Jesse Kreutzfeldt	Missouri River Energ	No						
Joe Williams	Western Farmers Ele	No						
Joel Huber	Basin Electric Power	No					WebEx	
John Boshears	City Utilities of Spri	No						
John Mayhan	Omaha Public Powe	No			WebEx			
John Vara	Golden Spread Elec	No						
John Varnell	Tenaska	No						
John Wilson	Southern Current LL	No						
Jon Langford	Orsted	No						
Jonah Montgomery	Evergy	No					WebEx	
Jonathan Aus	East River	No						
Jordan Skillern	Western Farmers Ele	No					In-Person	In-Person
Jose Cordova	EPRI	No					WebEx	
Josh Hesselbein	Arkansas Electric Co	No	WebEx		WebEx	WebEx	In-Person	In-Person
Joshua Pilgrim	SPP	No			WebEx			
Josie Daggett	WAPA	No			WebEx			
Juliano Freitas	SPP	No						
Justin Helt	1890 and Company	No						
Kadeem Brown	AEP	No	WebEx	WebEx	WebEx	WebEx	WebEx	WebEx
Kalun Kelley	WFEC	No	WebEx		WebEx			
Kelsey Allen	SPP	No						
Kim Grogan	Evergy	No						
Kimberly Woods	SPP	No						
Kristie Brown	SPP	No	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Kristen Darden	SPP	No						
Larry Brusseau	Corn Belt Power Co	No			WebEx			
Liz Gephardt	SPP	No						
Logan Peterson MPC	Minnkota	No	WebEx		WebEx			
Luke Zahner	Kepco	No					WebEx	WebEx
Mae Cruz	Southwestern Publi	No		WebEx	WebEx	WebEx	In-Person	In-Person
Marc Moor (Evergy)	Evergy	No				WebEx		
Margaret Kristian	National Grid Renev	No						
Martin Green	American Electric Po	No		WebEx		WebEx	In-Person	In-Person
Mason Favazza	SPP	No						
Matthew Alvardo	IUB	No						
McKady Kellam	Evergy	No						
Miah Archambault	Enel	No		WebEx				WebEx
Michael Bowman	City Utilities of Spri	No		WebEx				
Mike Swan	Omaha Public Powe	No	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person
Moses Rotich	Gridliance	No						
Mostafa Sedighizadeh	SPP	No						
Nathan Davis	Liberty Utilities	No		WebEx	WebEx	WebEx	In-Person	In-Person
Nathan McNeil	Midwest Energy	No						
Nicholas Hoelzeman	Evergy	No		WebEx				
Nicole Hicks	WAPA	No		WebEx				
Nitin Kushwaha	National Grid Renev	No						
Neeya Toleman	NextEra	No			WebEx	WebEx	WebEx	WebEx
Nolan Fertig	SPP	No						
Pallab Datta	Evergy	No	WebEx	WebEx	WebEx	WebEx		
Paul Vovk	Omaha Public Powe	No	WebEx		WebEx	WebEx	WebEx	
Peter Jones	Savion	No						
Phil Westby	BEPC	No	WebEx					
Prajakta Pawar	Quanta Technology	No			WebEx			
Rakib Rahman	Evergy	No					WebEx	WebEx
Ransome Egunjobi	Enel	No						
Richard Miner	Liberty Utilities	No						
Ryan Baysinger	Evergy	No						
Ryan Benton	Oklahoma Gas and	No	WebEx			WebEx	WebEx	
Scott Holland	SWPA	No				WebEx		
Scott Jordan	SPP	No		WebEx			WebEx	
Scott Mijin	Southwestern Powe	No	WebEx	WebEx	WebEx	WebEx		
Seth Cochran	DC Energy	No	WebEx					
Shalini Gupta	Apex Clean Energy	No						
Shannon Mickens	SPP	No				WebEx		
Shawn Geil	Kepco	No					WebEx	
Shawna Satterwhite	Oklahoma Gas and	No					WebEx	
Sherri Maxey	SPP	No			WebEx			
Steve Hardebeck	Oklahoma Gas and	No						
Steve Purdy	SPP	No						
Steven Park	Sunflower Electric P	No						
Sunny Raheem	SPP	No		WebEx	WebEx			
Tanner New	Sunflower Electric P	No	WebEx			WebEx		
Thomas Burns	SPP	No						
Theo Brown	SPP	No		WebEx	WebEx	WebEx	In-Person	In-Person
Timothy Sell	ITS	No		WebEx			WebEx	WebEx
Todd Chwialkowski	EDF	No						
Tom Belshe	Evergy	No						
Tom Mayhan	Omaha Public Powe	No						
Tony Green	SPP	No	WebEx				In-Person	
Walt Shumate	Shumate & Associate	No	WebEx	WebEx	WebEx	WebEx	WebEx	
Xiaoyu Wang	Enel	No				WebEx		
Yasmin Sakalla	Enel	No						
Ying Yang	Duke Energty	No		WebEx	WebEx			
Zach Andera	Burns & McDonnell	No						
Zach Sabey	SPP	No	WebEx	WebEx	WebEx	WebEx	In-Person	In-Person

Model Development Advisory Group

August 2021 - July 2022

Name	Company	Is Current Member?
Alex Mucha	Oklahoma Municipal Power Authority	Yes
#REF!	#REF!	#REF!
Brianna Haug (Vice Chair)	Western Area Power Administration	Yes
Dustin Betz	Nebraska Public Power District	Yes
#REF!	#REF!	#REF!
Jason Shook	GDS Associates	Yes
#REF!	#REF!	#REF!
#REF!	#REF!	#REF!
Jerry Bradshaw	City Utilities of Springfield	Yes
Joe Fultz	Grand River Dam Authority	Yes
#REF!	#REF!	#REF!
Liam Stringham	Sunflower Electric Power Corporation	Yes
Preston Blinsky	Basin Electric Power Cooperative	Yes
Reené Miranda	Southwestern Public Service	Yes
#REF!	#REF!	#REF!
Scott Rainbolt	American Electric Power	Yes
Scott Schichtl	Arkansas Electric Cooperative Corporation	Yes
Steve Hohman	Omaha Public Power District	Yes
#REF!	#REF!	#REF!
Tyler Baxter	Corn Belt Power Cooperative	Yes
Amine Chenaf	DNV	No
Andrew Howard	Lincoln Electric System	No
Antonio Barrera	Southwestern Public Service	No
Armin Sehic	Nebraska Municipal Power Pool	No
Becca McCann	SPP	No
Brandon Hentschel	SPP	No
Brooke Keene	SPP	No
John Turner (Chair)	Western Farmers Electric Power	Yes
Bruce Doll	Nebraska Municipal Power Pool	No
Casey Cathey	SPP	No
Chris Colson	Western Area Power Administration	No
Conner Sweet	City Utilities of Springfield	No
David Duhart	SPP	No
David Zhong	American Electric Power	No

Diego Toledo	Grand River Dam Authority	No
Edin Terzic	Lincoln Electric System	No
Eli Nyambegera	Sunflower Electric Power Corporation	No
Ellen Cook	SPP	No
Frank Favela	Southwestern Public Service	No
Garrick Nelson	Western Area Power Administration	No
Grace Bouziden	Oklahoma Gas and Electric Company	No
James Okenfuss	Savion Energy	No
Jason Menke	Nebraska Public Power District	No
Jeff Plew	NextEra	No
Jeremy Severson	Basin Electric Power Cooperative	No
Jesse Kreutzfeldt	Missouri River Energy Services	Yes
Joe Williams	Western Farmers Electric Power	No
John Mayhan	Omaha Public Power District	No
John Vara	Golden Spread Electric	Yes
#REF!	#REF!	#REF!
Kimberly Woods	SPP	No
Mae Cruz	Southwestern Public Service	No
Marc Moor (Evergy)	Evergy	No
McKady Kellam	Evergy	No
Mike Swan	Omaha Public Power District	No
Moses Rotich	Gridliance	No
Nolan Fertig	SPP	No
Peter Jones	Savion	No

Member Type	Sector	Present	Proxy	Absent	Percent Present
Staff	RTO	18	0	2	90%
Staff	RTO	#REF!	#REF!	#REF!	N/A
TO	Investor Owned Utility	20	0	0	100%
TU	Cooperative	18	2	0	100%
TU	Cooperative	#REF!	#REF!	#REF!	N/A
TO	Cooperative	17	0	3	85%
TU	Municipal	#REF!	#REF!	#REF!	N/A
TO	State	#REF!	#REF!	#REF!	N/A
TO	Cooperative	18	1	1	95%
TO	State	17	1	2	90%
TO	Investor Owned Utility	#REF!	#REF!	#REF!	N/A
TO	Federal	17	3	0	100%
TO	State	16	2	2	90%
TU	Investor Owned Utility	15	5	0	100%
TU	Municipal	#REF!	#REF!	#REF!	N/A
TU	Investor Owned Utility	17	2	1	95%
TU	Investor Owned Utility	17	3	0	100%
TU	Cooperative	19	1	0	100%
TO	Cooperative	#REF!	#REF!	#REF!	N/A
TO	Cooperative	14	2	4	80%

Annual Assessment Totals	
Average Length of Meetings (hrs)	3
Number of Votes Taken	78
Average Overall Attendance	61
Total Meetings this Assessment	23
Live	3
Teleconference	20
Scope Reviewed	No
Transmission Owner(s)	7
Transmission User(s)	5
Director(s)	0
Investor Owned Utility	4
Cooperative	5
Municipal	0
State	2
Federal	1
Independent Power Producer / Marketer	0
Independent Transmission Company	0
Large Retail	0
Alt Power / Public Interest	0
Small Retail	0

SOUTHWEST POWER POOL, INC.

MODEL DEVELOPMENT ADVISORY GROUP MEETING

Southwest Power Pool

201 Worthen Drive
Little Rock, AR 72223

Face-to-Face

June 14th, 2023

9:00 a.m. – 4:00 p.m. (CST)

June 15th, 2023

8:30 a.m. – 12:00 p.m. (CST)

AGENDA

1. SPP Welcome .... Tony Green (10 mins)
2. Facilities Review .... Darian Richards (15 mins)
3. Administrative Items .... John Turner (10 mins)
    a. Call to Order
    b. Antitrust Statement
    c. Attendance
        i. In Person Attendance
    d. Proxies
    e. Agenda Review (***Approval Item***)
        i. Acknowledgment for the posting of meeting materials
    f. Previous May 18th, 2023 Meeting Minutes (***Approval Item***)
4. Review of Past Action Items .... Lottie Jones (5 mins)
5. SPP IEEE 1547-2018 Adoption (***Approval Item***) .... Scott Jordan (15 mins)
6. Model Selection Straw Poll Results .... MDAG (30 mins)
    a. SPS lead discussion
7. CPPTF Update & SCRIPT C3 Common Model Set Guidance .... Brandon Hentschel (45 mins)
    a. 2024 / 2025 SPP expectations
        i. Data submittal
        ii. Communication

b. Supplemental SPP CPP Concept Education for MDAG

8. 2024 Modeling Schedule and Model Selection **(Approval Item*)** ....Brandon Hentschel (30 mins)

    a. Highlight differences

9. Break .... (5 mins)

10. 2024 MDAG Manual version 7.0 **(Approval Item*)** .... Brandon Hentschel (10 mins)

    a. Revisions table

    b. Manual formatting

11. Area 550 Discussion..Briana Haug (45 mins)

12. Lunch .... (60 mins)

13. Short Circuit Data Submission.. Eric Sullivan (15 mins)

14. Powerflow Data Submission...Darian Richards/Lottie Jones (20 mins)

15. Activity ....Estevan Padilla (15 mins)

16. SPP Model Compliation ....Hugh Benfer (15 mins)

17. MOD File Builder ....David Duhart (15 mins)

    a. Converting .raw to .prj file

18. MOD Walk Through ....Becca McCann/Darian Richards (20 mins)

    a. Updating ratings

    b. MOD Anomaly File Review

19. Snack.. (5 mins)

20. EDST Walk Through ....Kristie Brown (30 mins)

    a. Creating a changeset

    b. Uploading workbook

21. Dynamics Demonstration .... Zach Sabey/Theo Brown (30 mins)

Day 2

22. Breakfast .... (starts at 8:30 am CST)

23. 2023 SPP MDAG Roadmap Inititaves

    a. SIR 544 .... Eric Sullivan (15 mins)

    b. Rate 3 ....Lottie Jones (15 mins)

        i. Survey results

24. 2023 series MDAG Model Build/Application Updates

    a. Dynamics..Zach Sabey/Theo Brown (15 mins)

25. 2024/2025 series ITP/MDAG Model Build/Application Updates

a. Powerflow .... Darian Richards/Hugh Benfer/Lottie Jones (15 mins)

i. MOD Commitment

ii. Kick off

b. Short Circuit .... Eric Sullivan (10 mins)

i. Kick off

c. GMD .... Eric Sullivan (5 mins)

d. MOD-033 .... Eric Sullivan (10 mins)

e. EDST .... Kristie Brown (10 mins)

i. Rollover

ii. Lock down

iii. Production Installation

26. FERC Order 881 .... MDAG (30 mins)

27. Summary of Action Items .... Lottie Jones (5 mins)

28. Discussion of Future Meetings .... John Turner (5 mins)

All meeting times are represented in the central time zone

a. MDAG: August 17, 2023 (9:00 AM – 12:00 PM)

b. MDAG Focus Group: July 25, 2023 (1:00 PM – 3:00 PM)

c. Ambient Adjustment Ratings Implementation Task Force: July 11, 2023 (9:00AM 11:00AM)

29. Adjourn .... All

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

MDAG MINUTES
April 20, 2023

SOUTHWEST POWER POOL
MODEL DEVELOPMENT ADVISORY GROUP MEETING

April 20, 2023 9:00 am – 12:00 pm (CST)

Conference Call

SUMMARY OF MOTIONS AND ACTION ITEMS

Action Items:

- **Action Item:** MDAG to discuss a path forward via email for future discussions on the Rate 3 topic.
- **Action Item:** Review how the current MDAG dispatch workbook is being populated and look for areas of improvement.

Motions:

- **Motion: Steve Hohman motioned to approve the presented agenda as modified. Brianna Haug seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**
- **Motion: John Vara motioned to approve March 20, 2023, meeting minutes as presented. Steve Hohman seconded the motion. Reene Miranda abstained from the motion. The group did not voice any additional concerns during the discussion of the motion. The motion passed.**
- **Motion: Jason Shook motioned to approve the date, time, and location for the MDAG in-person workshop meeting June 14-15 at SPP Campus. John Vara seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.**

Southwest Power Pool
MODEL DEVELOPMENT ADVISORY GROUP MEETING

April 20, 2023 9:00 am – 12:00 pm (CST)

Conference Call

MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

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

SPP MDAG Chair, John Turner, called the meeting to order at 9:02 a.m. (CST) with Quorum. SPP Staff Secretary, Lottie Jones, read the anti-trust statement to the group.

AGENDA ITEM 1C & 1D – ATTENDANCE AND PROXIES

The following members attended or were represented by proxy:

MDAG Member	Present	Proxy	Present	Company
Tyler Baxter	No	Larry Brusseau	Yes	Corn Belt Power Cooperative
Jerry Bradshaw	Yes			City Utilities of Springfield
Dustin Betz	Yes			Nebraska Public Power District
Preston Blinsky	No			Basin Electric Power Cooperative
Joe Fultz	No			Grand River Dam Authority
Brianna Haug	Yes			Western Area Power Administration, MDAG Vice-Chair
Steve Hohman	Yes			Omaha Public Power District
Reené Miranda	Yes			Southwestern Public Service
Alex Mucha	Yes			Oklahoma Municipal Power Authority
Scott Rainbolt	Yes			American Electric Power
Scott Schichtl	Yes			Arkansas Electric Cooperative Corporation
Jason Shook	Yes			GDS Associates
Liam Stringham	Yes			Sunflower Electric Power Corporation
John Turner	Yes			Western Farmers Electric Power, MDAG Chair
Lottie Jones	Yes			Southwest Power Pool, Inc., MDAG Secretary
John Vara	Yes			Golden Spread Electric
Ryan Baysinger	Yes			Evergy
Jesse Kreutzfeldt	Yes			Missouri River Energy Services

Material: APR20_Attach2 - 1c. MDAG Conference Call Attendance-04-20-2023

AGENDA ITEM 1E – AGENDA REVIEW **(APPROVAL ITEM)**

John Turner asked the group if they had a chance to review the agenda and if the group had any modifications to the agenda.

Motion: Steve Hohman motioned to approve the presented agenda as modified. Brianna Haug seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.

Material: APR20_Attach1- 1e. MDAG Meeting Agenda

AGENDA ITEM 1F – PREVIOUS MARCH 20, 2023 MEETING MINUTES **(APPROVAL ITEM)**

Lottie Jones asked the group if they had any proposed changes for the previous March 20, 2023, meeting minutes.

Lottie mentioned one correction to the previous minutes including removing Michael Swan as Steve Hohman's proxy.

Motion: John Vara motioned to approve March 20, 2023, meeting minutes as presented. Steve Hohman seconded the motion. Reene Miranda abstained from the motion. The group did not voice any additional concerns during the discussion of the motion. The motion passed.

Material: APR20_Attach3- 1f. March 20, 2023, Meeting Minutes.docx

AGENDA ITEM 2 – REVIEW OF PAST ACTION ITEMS

Lottie Jones discussed outstanding issues highlighted in red font, including the action items added from the last meeting. Lottie walked the group through updates on action items collected at the previous session and updates for existing in-progress action items.

- Action Item 164 – In-Progress – SPP staff presented to MVTF and is currently benchmarking requesting input from MDAG members as well.
- Action Item 200 – Complete – Training to be performed during the MDAG in-person workshop.
- Action Item 202 – In-Progress – To be marked complete after discussion during this meeting.

AGENDA ITEM 3 – MDAG IN-PERSON MEETING (APPROVAL ITEM)

AGENDA ITEM 3A – JUNE 14-15, 2023 – SPP – WORKSHOP

SPP staff, Lottie Jones, requested a motion to approve the meeting date for the June MDAG in-person workshop at SPP on June 14-15.

John Vara asked for clarification that the location is still set for SPP offices.

Motion: Jason Shook motioned to approve the date, time, and location for the MDAG in-person workshop meeting June 14th-15th at SPP Campus. John Vara seconded the motion. The group did not voice concerns during the discussion of the motion. The motion passed unanimously.

AGENDA ITEM 4 – RATE 3

AGENDA ITEM 4A – DPP PROCESS

SPP staff, Chris Davis, updated the group on the Rate 3 discussion and how conductor data is utilized in the DPP process for transmission planning.

SPP Member Company requested that there is a check to see if the data request has been sent out to members as they have not found the request from SPP.

SPP Member Company asked the group if the data is already submitted during the project stage of the DPP window if they are terminally limited. This is a competitive process so the expectation is that these would be submitted as projects. Does submitting this data throw them out of the competitive process? This data would probably not result in a competitive project. A competitive upgrade determination is considered final after legal review. Facility rating determinations are not considered competitive as the equipment is already existing and are part of the model development process. If a rating impact is shown in year 8 would that be considered competitive? Ratings are not considered in the competitive process. When SPP receives DPP this data is utilized for automation but does not make it competitive. Do DPP submitters submit these projects to do terminal upgrades? Yes, but not always and SPP staff is creating solutions for these uprate solutions as well.

SPP Member Company asked SPP if this data request be tied to as standard such as FAC-008 or MOD-032? This data could be tied to a standard if it is applicable but this would be a good add as it is not currently in the data request. SPP Member Company mentioned that it might be more relevant to tie this request to MOD-032 and not to FAC-008.

SPP Member Company asked how FAC-008-5 R8 relates to the request for ratings during the DPP process? This data point in FAC-008 is limited to operations planning and not the DPP process. SPP Member Company would caution any correlation between the annual data request and the FAC-008-5 R8 standard. SPP Member Company also suggested a rewrite of the annual data request as SPP Member Company has not provided additional data since 2020 as the conductor information has not changed since that period. There is currently a seven day period for responses and this should be sufficient for the data request. Ask the host TO for any updated data required during the DPP process. A middle ground would be to include a question during the request as to whether the conductor is terminally limited or conductor limited. Solutions cannot be concluded from this as we need the rating data as well.

Staff mentioned that the annual data request is put into place to allow TOs to have a look for the entire year to plan for future data requirements.

SPP Member Company asked if the rating data is designed to provide higher quality data when it could be something like a jumper that needs to be replaced rather than a conductor limit rating. What is the result if we are upgrading everything beyond the conductor rating? There could be some alternatives as well. The conductor rating allows SPP the immediate solution to upgrade everything up to the conductor rating.

SPP Member Company asked for clarification that SPP is asking for the rating of the transmission line minus any terminal limits? What is the rating of the line minus any equipment on either side? The lines would go in the same bucket as the substation equipment. The transmission element itself minus any switches, breakers, etc. absent the switching devices and measuring devices.

SPP Member Company commented that the currently rated conductors do not typically change over time. SPP Member Company experience is that the rating value is entered and locked in for a long period. Has staff seen an instance where the conductor limit needs to be changed after the initial value entry? This is an SPP assumption so it is fine if the data does not change over time.

SPP Member Company added a few comments to the discussion based upon her experience providing the planning level cost estimates. When talking about the conductor limit is it SAG limited and how many structures do you have to replace to raise the conductor. In most cases, there is a bright line between the line conductor limit and terminally limited conductors as far as the cost. There is currently seven days or less to provide this data and it is currently a challenge to come up with a somewhat accurate planning level cost estimate. This is an additional burden for the modelers to submit this information. Also, individuals who are not the planner or TO are not going to have this Rate 3 data to provide to SPP. They could run with a false assumption and not ask for confirmation from the TO.

Staff mentioned that this type of estimation needs to be done during the cost estimate process so that they can determine if there is anything that needs to be upgraded around the conductor. Upgrading to the conductor limit would address any terminally limited issues.

Staff mentioned that we need to put some focus into the suggestion from SPP Member Company so that we may be able to use this as a price suggestion. The current data submittals is creating a mixed bag of the data that we currently receive from members if the data and conductor ratings has not been updated. What we are doing today may not hold water in the future if we do not receive conductor ratings from TOs.

SPP Member Company mentioned that a check box for the data may not be enough and you may have to dig into the terminal equipment as well. You may have to upgrade more than you are touching with this checkbox and the DPP window is used to figure out what is needed for a good project.

SPP Member Company mentioned that though this request does not seem like it would take a lot of effort; from a model building perspective, there are several items that would cause this request to add to the modeling effort for WAPA and others.

AGENDA ITEM 5 – RATE 3 STRAW POLL

SPP staff, Lottie Jones, asked the group how they would like to proceed with the straw poll after this last discussion.

John suggested that we skip the straw poll and SPP staff and MDAG members work through an appropriate path moving forward through email communication.

Action Item: MDAG to discuss a path forward via email for future discussions on the Rate 3 topic.

AGENDA ITEM 6 – CPPTF COMMON MODEL UPDATE

SPP staff, Brandon Hentschel, updated the group on the CPPTF common model discussion.

SPP Member Company asked what the asterisks represent in the proposed schedule. These coincide with the 90/10 load option discussion.

SPP Member Company proposed building additional models for 28S/W and 30S/W and would like to discuss it during the MDAG workshop topics discussion.

SPP Member Company commented that the comparison between MDAG and ITP is worthwhile from a modeling perspective.

Staff mentioned that it would be worthwhile to ask TWG if it would be possible to use the EIA data for the ITP BR models. Jason Shook did not voice any concerns with SPP presenting this discussion and bringing it to TWG.

SPP Member Company mentioned that he does not think the user interface for MDAG would carry over well to ITP. There are some challenges with the current spreadsheet. SPP Member Company mentioned that he would be supportive of a change to the current process.

Staff mentioned that an EDST survey will be coming soon and asked MDAG membership to participate in this survey.

AGENDA ITEM 7 – BREAK (5 MINUTES)

AGENDA ITEM 8 – 2023 SERIES MDAG MODEL BUILD/APPLICATION UPDATES

AGENDA ITEM 8A – DYNAMICS

SPP staff, Zach Sabey, updated the group on the 2023 series Dynamics model build.

AGENDA ITEM 8B – MOD-033 EVENT SELECTION

SPP staff, Eric Sullivan, updated the group on the next MOD-033-2 East event selection.

AGENDA ITEM 9 – FOCUS GROUP UPDATES

SPP staff, Eric Sullivan, provided the group with the upcoming MDAG Focus Group topics and requested any additional topics.

AGENDA ITEM 10 – RAD TF

SPP staff, David Duhart, updated the group on the RAD Task Force goal and participation.

The primary goal of the group is to streamline the 5 year average process.

SPP would like to ask for participation from the MDAG members as well.

AGENDA ITEM 11 – MDAG WORKSHOP TOPICS

SPP staff, Lottie Jones, updated the group on proposed MDAG workshop topics.

Staff will be sending out a Google Form Survey as well as a PDF version so that members may add some additional topics that they would be interested in covering during the workshop.

Mae Cruz requested a topic discussion covering additional models that SPS would like to see in the next model build. This can be covered by SPP and would likely be an approval item as well.

AGENDA ITEM 12 – DISCUSSION OF FUTURE MEETINGS

MDAG Chair, John Turner, updated the group on upcoming meetings.

a. MDAG: May 18, 2023 (9:00 AM – 12:00 PM)

b. MDAG FG: April 25, 2023 (1:00 PM – 3:00 PM)

AGENDA ITEM 12 – SUMMARY OF ACTION ITEMS

Lottie discussed the action items from this meeting:

- **Action Item:** MDAG to discuss a path forward via email for future discussions on the Rate 3 topic.
- **Action Item:** Review how the current MDAG dispatch workbook is being populated and look for areas of improvement.

AGENDA ITEM 13 – ADJOURN

John Turner adjourned the meeting at 11:18 a.m. (CST)

Respectfully Submitted,

Lottie Jones
Secretary

Eric Sullivan
Secretary Assistant

Attachments

APR20_Attach1- 1e. MDAG Meeting Agenda.docx

APR20_Attach2 - 1c. MDAG Conference Call Attendance-04-20-2023

APR20_Attach3- 1f. Mar 20, 2023, Meeting Minutes.docx

Task Name
2024MDAG/2025 ITP BR Model Series (Powerflow, Short Circuit, Geomagnetic) - PSS/E v35.3# - MOD v11.2 (MOD-032 East) - MDAG Manual 7.0
Data Submitters provide Powerflow (PF) and Short Circuit (SC) data Updates through MOD and EDST
Data Submitter Updates (Load, Generation, MOD Committ, Transaction, Topology & Sequence Data) Due
SPP Staff send out kick-off email
2025 ITP BR Pass 1: Coordinate & Submit Load, Generation, Transaction, Topology, SC Data, Geomagnetic Data Updates
Pass 1: SPP Staff Lock Down MOD and EDST
SPP Staff compiles EDST/MOD data, dispatch information, and review projects
SPP Staff Build/Solve Pass 1 Powerflow Models
SPP Staff Review/Build Pass 1 Short Circuit Models
SPP Staff Post Pass 1 PF and SC models, Report Card, Retirement List, DocuCode, and Geomagnetic Data for Data Submitter Review
2025 ITP BR Pass 2: Coordinate & Submit Load, Generation, Transaction, Topology, SC Data, Geomagnetic Data Updates
Data Submitters review Pass 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
SPP Holidays - Labor Day
Pass 2: SPP Staff Lock Down MOD and EDST
SPP Staff compiles EDST/MOD data, dispatch information, and review projects
SPP Staff Build/Solve Pass 2 Powerflow Models
SPP Staff Post Pass 2 PF models and DocuCode for Data Submitter Review
2025 ITP BR Pass 3: Coordinate & Submit Load, Generation, Transaction, Topology, SC Data, Geomagnetic Data Updates
Data Submitters review Pass 2 models and submit PF and SC data updates through MOD and EDST for use in Pass 2 - Trial 1 Models
Data Submitter Updates (Load, Generation, Transaction, Topology & Sequence Data) Due
Pass 3: SPP Staff Lock Down MOD and EDST
SPP Staff compiles EDST/MOD data, dispatch information, and review projects
SPP Staff Build/Solve Pass 3 Powerflow models
SPP Staff Post Pass 3 PF and DocuCode for Data Submitter Review
2025 ITP BR Pass 4: (Generation Dispatch, DocuCheck Issues and Topology Updates, Voltage Schedule Review)
Data Submitters review Pass 3 models and submit PF and SC data updates through MOD and EDST for use in Pass 4 Models
Data Submitter Updates (Load, Generation, Transaction, Topology & Sequence Data) Due
SPP Staff for Pass 4 Lock Down MOD and EDST
SPP Staff compiles EDST/MOD data, dispatch information, and review projects
Data Submitters provide Geomagnetic Model Updates
SPP Staff Build/Solve Pass 4 Powerflow models (Merge with latest MMWG models)
SPP Holidays - Thanksgiving days
SPP Staff Post Pass 4 PF and DocuCode for Data Submitter Review
2025 ITP BR Pass 5: (Last addition or removal chance for generators, retirements, loads and transactions)
SPP incorporate 2023 AG1 Transmission Service updates into EDST
Data Submitters review Pass 4 models, provide Final Transmission Service Inputs (AG1) Data and submit PF and SC data updates through MOD and EDST for use in Pass 5 Models
SPP Holidays - Christmas days
SPP Holidays -New Years days
Data Submitters provide Transmission Service Inputs (AG1) Data

Data Submitter Updates (Load, Generation, Transaction, Topology & Sequence Data) Due, review Pass 4 models/data submission through MOD, Final update load and generation (Pmax, Pmin, retirement) reports/reconcile transaction discrepancies. Last chance for addition or removal for generators, loads, retirements, and transactions. After this pass new
SPP Holidays - Dr. Martin Luther King, Jr. Day
SPP Staff for Pass 5 Lock Down MOD and EDST
SPP Staff compiles EDST/MOD data, dispatch information, and review projects
SPP Staff Build/Solve Pass 5 Powerflow models
SPP Staff Post Pass 5 PF models and DocuCode for Data Submitter Review
SPP Staff Review/Build Initial Final Pass ITP BR Short Circuit Models (Merge with latest SERC SC Models)
SPP Staff Post ITP BR SC models and DocuCode for Data Submitter Review
Voltage Schedule Review)
Member/Stakeholder Holidays -Presidents' Day
Data Submitters Review Pass 5 Models, Submit PF and SC corrections through idevs only for use in the Initial Final Pass Models
Data Submitters submit FINAL Generation Dispatch, DocuCheck Corrections and Topology data updates
SPP Staff Build/Solve Initial Final Pass ITP BR Powerflow Models and apply MOD System Alteration Projects, non-firm transactions, disaptch and solve Initial MDAG Models
SPP Staff Review/Build Initial Final Pass ITP BR Short Circuit Models
SPP Staff Post ITP BR Initial Final PF, MDAG Pass 1 PF and ITP BR SC models and DocuCode for Data Submitter Review
2024 MDAG: (Generation Dispatch, System Intact Alteratons, DocuCheck Issues, Voltage Schedule Review)
Data Submitters Review MDAG Pass 1 Models, Submit PF and SC corrections through idevs only for use in the Pass 2 MDAG Models
Data Submitters submit DocuCheck Corrections idevs and Coordinate any dispatch or interchange updates
SPP Staff apply idevs, re-disaptch if neccessary and solve MDAG Models
SPP Staff Post Pass 2 2024 MDAG models and DocuCode for Data Submitter Review
Data Submitters Review MDAG Pass 2 Models, Submit PF and SC corrections through idevs only for use in the Final MDAG Models
Data Submitters submit DocuCheck Corrections idevs and Coordinate any dispatch or interchange updates
SPP Staff apply idevs, re-disaptch if neccessary and solve MDAG Models
SPP Staff Post Final 2024 MDAG PF models and DocuCode for Data Submitter Review
SPP Staff Review/Build Final Pass MDAG Short Circuit Models
SPP Staff Post MDAG Final SC models and DocuCode for Data Submitter Review
Finalization - MDAG Net Conference to Vote and Approve 2024 MDAG Powerflow Models as Final
Finalization - MDAG Net Conference to Vote and Approve 2024 MDAG Short Circuit Models as Final
Finalization - TWG to Vote and Approve 2025 ITP Powerflow Models as Initial-Final
Finalization - TWG to Vote and Approve 2025 ITP Short Circuit Models as Initial-Final
MDAG Face-to-Face Meeting

Modeling data shall be submitted per this schedule. For data submittals due on a Friday, data submission is allowed through the weekend until Monday at 8:00 AM. If that Monday falls a SPP Holiday, data submissions are due on Tuesday by 8:00 AM. SPP may extend the data submittal periods in the schedule, if the SPP Models On Demand and Engineering Data Submittal Tool (EDST) web portals suffer technical difficulties during the data

Duration	Start	Finish	Count of Models posted
182 days	Mon 7/24/23	Fri 4/12/24	
83 days	Mon 3/27/23	Mon 7/24/23	
0 days	Mon 7/24/23	Mon 7/24/23	
0 days	Mon 7/24/23	Mon 7/24/23	
20 days	Mon 7/24/23	Fri 8/18/23	
20 days	Mon 7/24/23	Mon 8/21/23	
5 days	Mon 7/24/23	Fri 7/28/23	
10 days	Mon 7/31/23	Fri 8/11/23	
5 days	Mon 8/14/23	Fri 8/18/23	
0 days	Fri 8/18/23	Fri 8/18/23	19 PF Models/9 SC Models
24 days	Mon 8/21/23	Fri 9/22/23	
10 days	Mon 8/21/23	Fri 9/1/23	
0 days	Fri 9/1/23	Fri 9/1/23	
1 day	Mon 9/4/23	Mon 9/4/23	
19 days	Tue 9/5/2023	Mon 9/25/23	
4 days	Tue 9/5/2023	Fri 9/8/23	
10 days	Mon 9/11/23	Fri 9/22/23	
0 days	Fri 9/22/23	Fri 9/22/23	19 PF Models
20 days	Mon 9/25/23	Fri 10/20/23	
10 days	Mon 9/25/23	Fri 10/6/23	
0 days	Fri 10/6/23	Fri 10/6/23	
10 days	Mon 10/9/23	Mon 10/23/23	
5 days	Mon 10/9/23	Fri 10/13/23	
5 days	Mon 10/16/23	Fri 10/20/23	
0 days	*Fri 10/20/23*	*Fri 10/20/23*	19 PF Models
38 days	Mon 10/23/23	12/15/2024	
10 days	Mon 10/23/23	Fri 11/3/23	
0 days	Fri 11/3/23	Fri 11/3/23	
28 days	Mon 11/6/23	Mon 12/18/23	
5 days	Mon 11/6/23	Fri 11/10/23	
0 days	Fri 11/13/23	Fri 11/13/23	
23 days	Mon 11/13/23	Fri 12/15/23	
2 days	Thu 11/23/23	Fri 11/24/23	
0 days	Fri 12/15/23	Fri 12/15/23	19 PF Models
27 days	Mon 12/18/23	1/26/2024	
0 days	Fri 12/15/23	Fri 12/15/23	
17 days	Mon 12/18/23	Fri 1/12/24	
2 days	Thu 12/25/23	Fri 12/26/23	
1 day	Mon 1/1/24	Mon 1/1/24	
0 days	Fri 1/12/24	Fri 1/12/24	

0 days	Fri 1/12/24	Fri 1/12/24	
1 day	Mon 1/15/24	Mon 1/15/24	
10 days	Mon 1/15/24	Mon1/29/24	
5 days	Mon 1/15/24	Fri 1/19/24	
5 days	Mon 1/22/24	Fri 1/26/24	
0 days	Fri 1/26/24	Fri 1/26/24	19 PF Models
5 days	Mon 1/29/24	Mon 2/2/24	
0 days	Fri 2/2/24	Fri 2/2/24	9 SC Models
31 days	Mon 1/29/24	Fri 2/23/24	
0 days	Mon 2/19/24	Mon 2/19/24	
10 days	Mon1/29/24	Fri 2/9/24	
0 days	Fri 2/9/24	Fri 2/9/24	
5 days	Mon 2/12/24	Fri 2/16/24	
5 days	Mon 2/19/24	Fri 2/23/24	
0 days	Fri 2/23/24	Fri 2/23/24	31 PF Models/9 SC Models
35 days	Mon 2/26/24	4/12/2024	
10 days	Mon 2/26/24	Fri 3/8/24	
0 days	Fri 3/8/24	Fri 3/8/24	
10 days	Mon 3/11/24	Fri 3/22/24	
0 days	Fri 3/22/24	Fri 3/22/24	17 PF Models
5 days	Mon 3/25/24	Fri 3/29/24	
0 days	Fri 3/29/24	Fri 3/29/24	
5 days	Mon 4/1/24	Fri 4/5/24	
0 days	Fri 4/5/24	Fri 4/5/24	17 PF Models
5 days	Mon 4/8/24	Fri 4/12/24	
0 days	Fri 4/12/24	Fri 4/12/24	6 SC Models
0 days	*Mon 4/15/2024*	*Mon 4/15/2024*	
0 days	*Mon 4/15/2024*	*Mon 4/15/2024*	
0 days	*TBD*	*TBD*	
0 days	*TBD*	*TBD*	
2 days	June TBD	June TBD	

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: MDAG Potential Face-to-Face Meeting
Green Italic: Final SPP Staff / Member Conference Call Vote and Approval

Abbreviation
MDAG PF
MDAG SC
MDAG DYN
ITP BR PF
ITP MPM F1
ITP MPM F2
ITP MEM F1
ITP MEM F2
ITP BR SC

2024 Series MDAG/2025 ITP Model Selection
Red: MMWG Models
Black: MDAG and ITP Models- Posted on GlobalScape

Description
MDAG Powerflow
MDAG Short Circuit
MDAG Dynamics
ITP Base Reliability Powerflow
ITP MPM Future 1 (TBD)
ITP MPM Future 2 (TBD)
ITP MEM Future 1
ITP MEM Future 2
ITP Base Reliability Short Circuit

Year Definition	2024 Series MDA				
	Year	Season	MDAG PF	MDAG SC	MDAG DYN
1	2025	Light Load	1		1
1	2025	Spring	1		
1	2025	Summer	1	1	1
1	2025	Fall	1		
1	2025	Winter	1		1
2	2026	Light Load	1		1
2	2026	Spring	1		
2	2026	Summer	1		1
2	2026	Fall			
2	2026	Winter	1		
3	2027	Light Load	1		
3	2027	Summer	1		1
5	2029	Light Load	1		1
5	2029	Summer	1	1	1
5	2029	Summer Shoulder	1		
5	2029	Winter	1		1
10	2034	Light Load			
10	2034	Summer	1		1
10	2034	Winter	1		1
Total	63		17	2	11

G / 2025 ITP Model Selection					
ITP BR PF	**ITP MPM F1 (TBD)**	**ITP MPM F2 (TBD)**	**ITP MEM F1**	**ITP MEM F2**	**ITP BR SC**
1	1				
1					
1					
1	1				
1					
1	1		1		1
1					
1					
1	1	1			
1	1	1	1	1	1
1					
1	1	1			
1	1	1	1	1	1
1					
14	7	4	3	2	3

2024 MDAG / 2025 ITP Mod		
Year	**Season**	**Load Profile**
2025	Light Load	Yes
2025	Spring	Yes
2025	Summer	Yes
2025	Fall	Yes
2025	Winter	Yes
2026	Light Load	Yes
2026	Spring	Yes
2026	Summer	Yes
2026	Fall	Yes
2026	Winter	Yes
2027	Light Load	Yes
2027	Summer	Yes
2029	Light Load	Yes
2029	Summer	Yes
2029	Summer Shoulder	Yes
2029	Winter	Yes
2034	Light Load	Yes
2034	Summer	Yes
2034	Winter	Yes

lels - MOD/EDST Data Submissions		
Generation Profile Review	**Topology**	**Transactions**
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes
Yes	Yes	Yes

Southwest Power Pool

MODEL DEVELOPMENT PROCEDURE MANUAL

Model Development Advisory Group

Version ~~6~~7.0

Published on ~~7~~x/~~8~~x/~~2022~~2023

MODEL DEVELOPMENT ADVISORY 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 MDAG 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 MDAG Model Build
2019 v3.1	SPP Engineering Modeling	Updated to remove duplicate Generator Data section and added clarification for renewable dispatch	2020 Series MDAG Model Build
2020 v4.0	SPP Engineering Modeling	Updated Aux Load, Shunt Data, GMD, Data Quality Assurance, Node Breaker updates	2021 Series MDAG Model Build
2021 v5.0	SPP Engineering Modeling	MDAG and EDST reference updates, Updated DER/ESR Language, MDAG Economic Dispatch Language, TPL-001 outage review, node breaker update and removal of lat/long data	2022 Series MDAG Model Build

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	MODEL BUILD APPLICABILITY
2022 v6.0	SPP Engineering Modeling	Added dynamic model testing and initialization of offline wind. Added battery modeling and seasonal dispatching approach. Added POI injection limit dispatching. Added more detail regarding generator retirements. Added SATOA modeling.	2023 Series MDAG Model Build
2023 v7.0	SPP Engineering Modeling	Updated MOD matrix to a word table instead of an image and added a reference to the Planning Criteria for Material Modifications. Updated how to request an SPP transmission map or model based on the latest RMS version. Added clarification for mothballed generation.	2024 Series MDAG 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 MDAG 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 MDAG 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 MDAG 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 Advisory 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 modeling contact list 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 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[6].
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[7].
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[8], 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[9].
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. 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

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

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

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

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

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 MDAG, 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 MDAG, 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 MDAG 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 MDAG 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 MDAG 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.

MDAG 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 MDAG about how proposed model changes will impact the models themselves, as well as impacts to the overall modeling schedule. The MDAG 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 MDAG efforts in good faith towards the achievement of published milestones, the MDAG 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 MDAG Steady-State, Dynamics, and Short Circuit Models are published according to the approved schedule.

MDAG CASE TYPE SET

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

1	Annual + 1 April Minimum	10	Annual + 3 April Minimum
2	Annual + 1 Spring Peak	11	Annual + 3 Summer Peak
3	Annual + 1 Summer Peak	12	Annual + 5 April Minimum
4	Annual + 1 Fall Peak	13	Annual + 5 Summer Shoulder
5	Annual + 1 Winter Peak	14	Annual + 5 Summer Peak
6	Annual + 2 April Minimum	15	Annual + 5 Winter Peak
7	Annual + 2 Spring Peak	16	Annual + 10 Summer Peak
8	Annual + 2 Summer Peak	17	Annual + 10 Winter Peak
9	Annual + 2 Winter Peak		

The Annual references in the **Annual Models** table are determined based on the calendar year the MDAG powerflow models are completed. Year One in accordance with NERC Glossary of Terms, is considered Annual + 1 for the year out seasonal models.

The typical yearly models developed by the SPP MDAG, 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 MDAG case types 1 through 15 and those representing the longer-term planning horizon consisting of the MDAG case types 16 through 17. 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 Advisory Group and the Transmission Working Group.

The schedule for submission of data and list of MDAG 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 MDAG 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.~~submitting:

Request Template: Submit Information

Request Type: Submission

Subtype 1: Map/Model Order

Subtype 2: Map Order

An SPP transmission map order form will be uploaded upon request receipt.

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

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 Advisory Group.

MDAG Contact List

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

2. MDAG 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. MDAG 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 MDAG model build. The EDST contains informational data as well as modeling data that Data Submitter shall keep current for each pass of the MDAG 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 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

MODEL AREA SYSTEM LOAD

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.

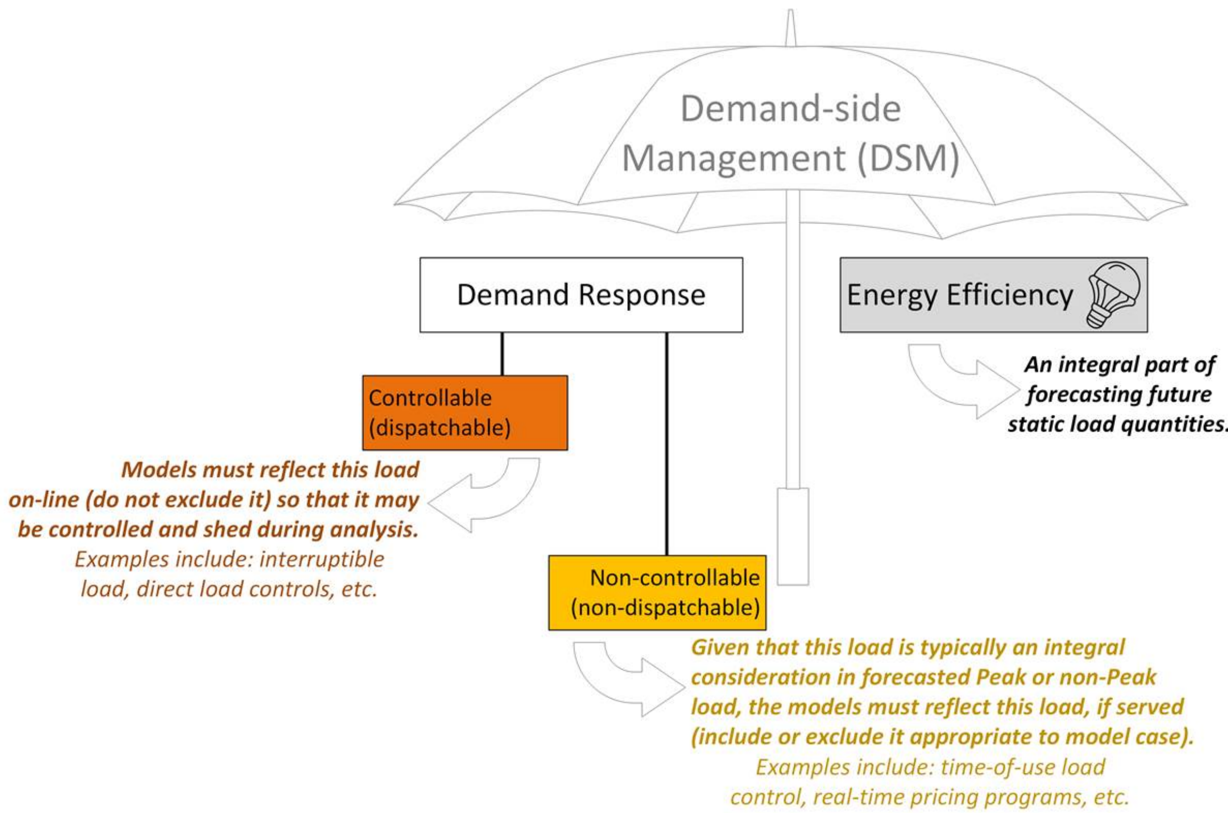
Some studies may require load forecasts other than a 50/50 load forecast and may be requested for such special studies. For example, a 90/10 load forecast has a 10% probability that the load forecast will be exceeded, which means the load forecast amount is higher than a 50/50 load forecast amount and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

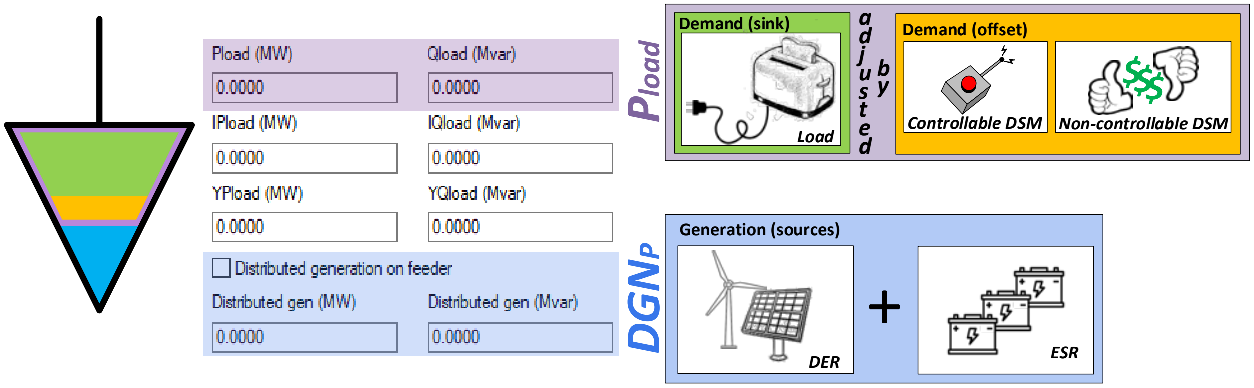
Load forecasts shall not be reduced for application of controllable DSM (e.g. dispatchable Demand Response). There is control over whether or not the load will be shed by an operator or end-user and therefore it cannot be guaranteed that the load will be reduced during peak hours. Load forecasts should be reduced for application of non-controllable DSM. This load has a high probability of being shed during peak hours without manual intervention. Distributed Energy Resources and Energy Storage Resources shall not be applied to a Data Owner's/Data Submitter's forecasted load quantity for incorporation into the SPP planning models, but shall be modeled as either generation or as part of the load record (see DER and ESR Modeling).

Load forecasts may consider multiple variables that either should or should not be considered in the planning model area load amount. A Data Owner/Data Submitter should ensure that the modeled loads (e.g., the sink MW/MVAR at unique load points) meet the following criteria:

1. The modeled loads of a model area for a given model shall be the projected coincident loads of the model area for the conditions represented by the model, independent of SPP regional load, rather than the model-area loads that would be coincident with the projected SPP regional load for the conditions represented by the model.
2. Represents a 50/50 projected, typical- or normalized-weather load forecast. The 50/50 forecast is based upon a median demand expectation that has a 50% probability of being too high and 50% probability of being too low during the period represented by the specific seasonal case. An example of a 50/50 load forecast derivation is given in Section 12 Appendix VIII.
3. DSM shall be considered when developing modeled load.
   a. The model load quantity shall not reflect the load reduction that results from the controllable DSM.
   b. The model load quantity shall reflect the load reduction that results from the non-controllable DSM
4. Distributed Energy Resources and Energy Storage Resources shall not be applied to a Data Submitter's forecasted load quantity for incorporation into the SPP planning models, but shall be modeled as either generation or as part of the load record (see DER and ESR Modeling). In other words, a forecasted load quantity (sink MW/MVAR at a unique load point) and the Distributed Energy Resources/Energy Storage Resources quantity (source MW/MVAR at a unique load point) are separately and explicitly modeled (PLOAD MW/QLOAD MVAR vs. DGN MW/MVAR).



The composition of a network load record in the steady-state model is shown in the figure below, reflecting the distinction between demand and generation specified as part of the record.



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 SPP 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 MDAG model build schedule. A service agreement is considered in the process of finalization from the time the communication to update the SPP service agreement is received by SPP to prior to execution of the agreement. 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.

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 1st through May 31st
Summer On-Peak (S)	June 1st through September 30th
Fall On-Peak (F)	October 1st through November 30th
Winter On-Peak (W)	December 1st through March 31st
Spring Light Load Off-Peak (L)	April 1st through May 31st
Summer Shoulder Off-Peak (SH)	June 1st through September 30th 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 MDAG.
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[10] (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[11] (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 ($Vhi \neq Vlo$) 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

10 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.

11 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.

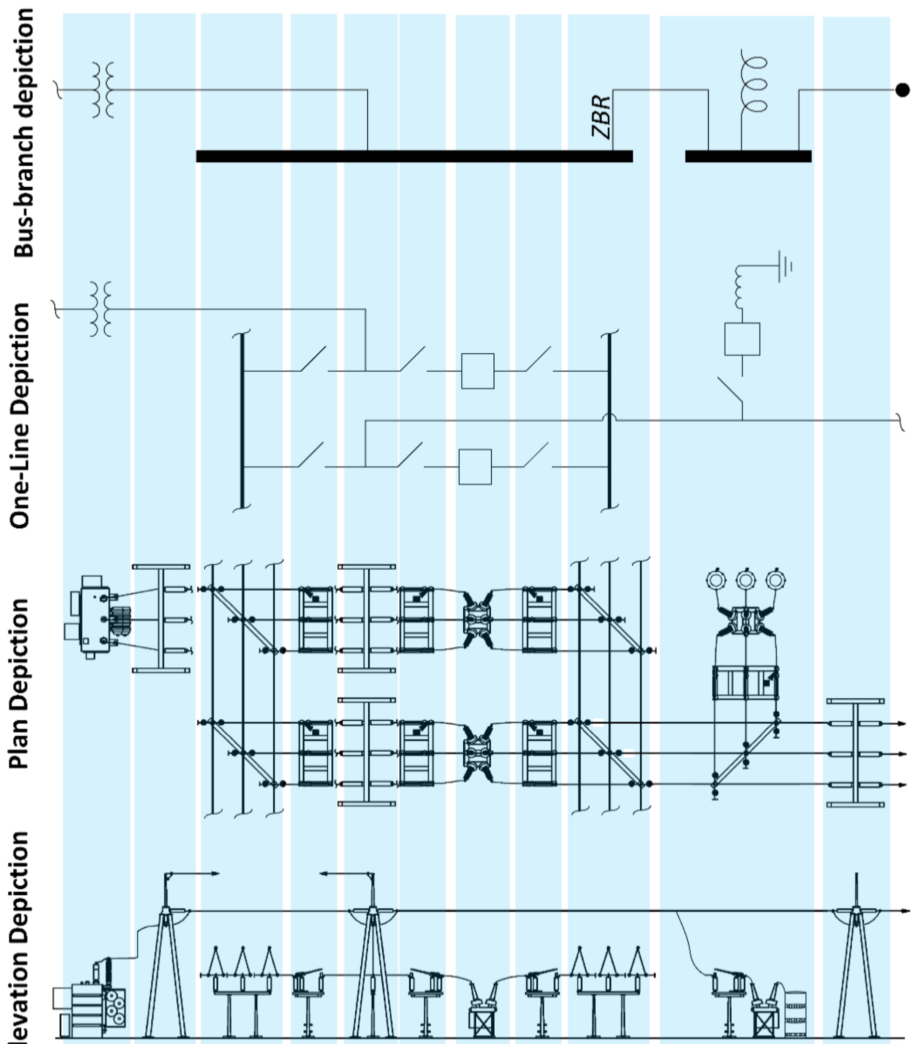


Figure 1. Example depiction of line reactor modeling.

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. Generator PMAX, PMIN, QMIN, and MVA limits shall be provided through SPP MOD generation profile submission.

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 generation that is not dispatched and/or is non-operational that can be put back into service and has not yet gone through the Attachment AB process for retirement (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. As part of the posting of the initial set of models for an MDAG model series, SPP staff will post a spreadsheet of planned Base Case unit retirement information for Data Owner and/or Data Submitter review through a secure website. The generator retirement spreadsheet will be posted for Data Owner and/or Data Submitter review for all the model passes identified in the model build schedule for the model series. Ideally, most of the planned retirement edits should be identified with the review of the initial posting of the retirement sheet. Decommissioned units that are not registered in the Integrated Marketplace should be removed from the models. Generators that are registered in the Integrated Marketplace must satisfy the provisions of OATT Attachment AB Generator Retirement Process before the units are removed from the models. Section 2 of Attachment AB requires the GO to submit notification to SPP, as the Transmission Provider, no less than one year from the expected retirement date. SPP may reject retirements that have not been studied in Attachment AB and are within a year of the expected retirement date.

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[12], 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.

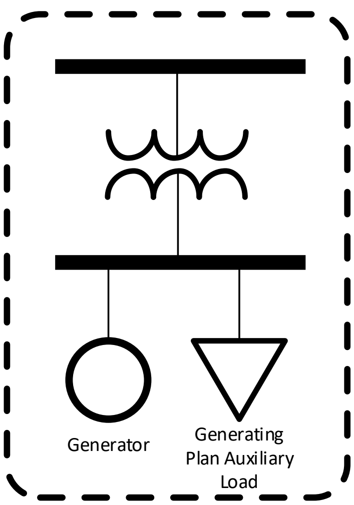
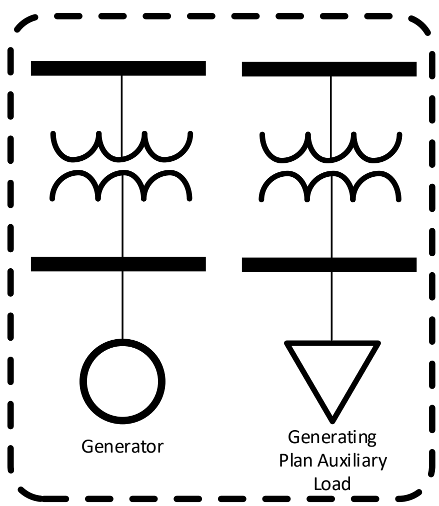
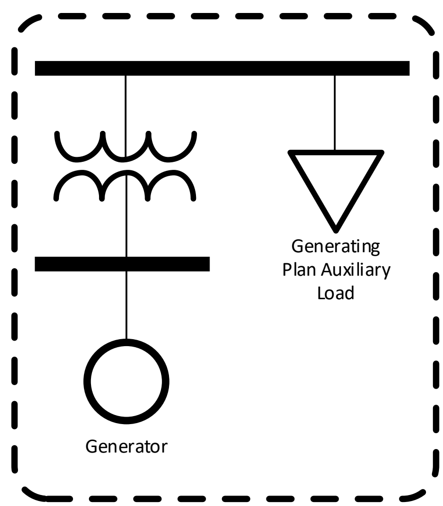


Figure VII-1. Common bus representation



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.

12 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.

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 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[13] to designate fixed load quantities that do not vary with plant dispatch.
ii. Use "V*n*" in the Load ID field[13] to designate variable load quantities that do vary with plant dispatch.

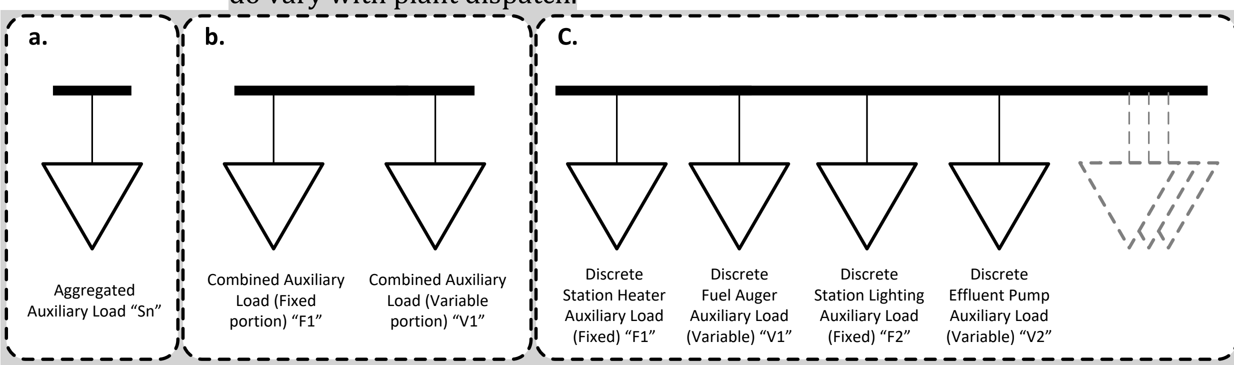


Figure VII-4. Examples of generating plant Auxiliary load representations (aggregated, combined, and discrete).

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.

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

Modeling of Conventional Generation P_{GEN}
MDAG conventional generation methodology employs a common economic data set based upon publicly available information published by the Energy Information Administration (EIA) of the US Department of Energy (DOE). The detailed economic data set is included in Table 2 and Table 3 of the MDAG Economic Dispatch White Paper.

The following activities shall occur before starting each annual model development build to ensure the SPP Common Economic Data Set remains aligned with the latest publicly available information.

- The PC will obtain the latest available cost and performance characteristic data available from EIA
- The PC will compare the EIA information to the approved SPP Common Economic Data Set to identify any cumulative year-to-year heat rate quantity or fuel cost variations
- The PC will coordinate updated quantities in the SPP Common Economic Data Set with MDAG for data variations exceed ± 10%

SPP Economic Data Worksheet
The SPP Common Economic Data Set annotates the default average heat rates for each conventional generator technology and fuel source modeled in the SPP footprint. The purpose of the SPP Common Economic Data Set is to formulate meaningful economic data that is both representative and transparent, originating from publicly available information.

For each generating unit, the following information shall initially be populated by the PC in the SPP Economic Data Worksheet using generator data from EDST, MOD, and the SPP Common Economic Data Set:

Bus Number (Unit)
Unit ID
PMax [MW]
PMax, NET [MW]
PMin [MW]
Generation Type
Average Heat Rate [MMBtu/MWh]
Fuel cost [$/MMBtu]

After the PC provides the initial SPP Economic Data Worksheet, each individual generating unit should be reviewed by the Data Submitter and can be modified. Renewable resources, including Hydro, generating setpoints are derived through their specific requirements as mentioned in this manual.

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.
- 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[14] 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 MDAG 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 MDAG 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.

Modeling of Battery Resources P_{GEN}

- Spring Light Load Off-Peak models: Output of battery resources with long-term firm transmission service for purposes of charging will be set to a negative MW amount not to exceed the facility's charging firm service amount or the Pmin (max charging capability). Batteries without firm service for purposes of charging will be set to zero output with online status.
- On-Peak models: Output of battery resources with long-term firm transmission service for purposes of discharging will be modeled in the case(s) at each facility's firm service amount not to exceed the Pmax (max discharging capability).
- Summer Shoulder Off-Peak models: Output of battery resources will be modeled online at zero output regardless of long-term transmission service.

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

- SPP will make available the initial dispatch of battery resources with long-term firm transmission service with the initial model pass of the each SPP MDAG model build. Battery dispatch updates submitted to the PC, after the initial dispatch list is provided, will be applied if the proposed dispatch is within the battery's Pmax/Pmin tolerance.
- When an affected party disagrees with the battery 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 MDAG for a decision.
- Responsibility for validating and providing battery dispatch updates falls to the affected parties.

POI Injection Limit Modeling Pgen

Generation resources of different resource, electrical interface, or controller types that share a common POI may have a MW injection limit at the POI that is less than the total MW capacity of all the generation injecting at that POI. SPP staff will update the SPP Economic Common Data set with a unique identifier (likely the Surplus unit GI Queue #) and GIA or Surplus GIA POI injection limit for each generator that has a POI injection limitation. The dispatch for these resources may need to be adjusted down to respect the firm Transmission Service amount or POI limit adjusted for Station Service load or Auxiliary load behind the POI. If that is case, then generation will be reduced by season in the orders shown below. Affected parties are responsible for coordinating and providing desired dispatch updates.

- Summer Peak Models:
  1. Conventional
  2. Battery
  3. Wind
  4. Solar
- Winter/Spring/Fall Peak Models:
  1. Conventional
  2. Battery
  3. Solar
  4. Wind
- Spring Light Load Models:
  1. Conventional
  2. Wind
- Summer Shoulder Models:
  1. Conventional
  2. Wind
  3. Solar

Examples:

If a solar farm and battery are in a configuration with a 100MW POI injection limit, 100MW of firm Transmission Service and the solar historical data dispatch for summer peak is 95MW, then the battery will be limited to a dispatch of up to 5MW plus the total MWs of any Station Service loads or Auxiliary loads.

If a wind farm and battery are in a configuration with a 100MW POI injection limit, 100MW of firm Transmission Service and the wind historical data dispatch for summer peak is 40MW, then the battery will be limited to a dispatch of up to 60MW plus the total MWs of any Station Service loads or Auxiliary loads.

DER and ESR Modeling

DER and ESR modeled explicitly as a Generator:

- **BES-scale Electric/Energy Storage Resources (ESRs):** shall be modeled as generating units submitted by the registered GO.
  - o Batteries will be modeled with a Pmax representing the max discharge capability and a negative MW amount for Pmin representing the full charging capability.
- **Non-BES-scale Designated Network Resources under RTO OATT**: utility-scale DER (including renewables) or ESRs that are registered in a market or under an OATT should always be modeled as generating units with the appropriate amount of associated auxiliary load representing their operation, submitted by the Data Submitter of the Designated Network Resource or FERC Order 2222 DER Aggregator.
- For unregistered non-BES-scale DER/ESR, the Data Submitter may submit the resource as generation. The unregistered non-BES-scale generation shall be modeled out-of-service (machine STAT = 0) or modeled in-service (machine STAT = 1) with MDAG concurrence.
- The Data Submitter shall provide EDST Generator information for ESR/DERs modeled as generators.

SATOA – Storage As Transmission Only Asset

- Will be identified through the ITP DPP process and modeled if granted an NTC.
- These projects are to be added through MOD in accordance with the MOD Type/Status. Matrix in Section 10 Appendix 4.
- **Modeled explicitly as a battery:**
  - o SATOA batteries will be modeled offline in all the models.

DER and ESR modeled as part of a Load record:

- If the above criteria for generation modeling are not met, then the DER/ESR shall be represented as part of a load record. When possible, the Data Submitter should explicitly reflect the presence of and forecasted net generation amount of the DER/ESR in the Distributed Generation data items of the load record (DGENP, DGENQ) instead of simply reducing the forecasted load quantity by the amount of the DER/ESR generation. It is recommended that Data Submitters submit a dynamic load model representation that includes the DER/ESR parameters (CMLDxxDGU2).

All registered or BES DER and ESR modeling data (dynamic, steady-state, short-circuit) shall be submitted in accordance with the requirements of this manual and the table in Attachment 1 of MOD-032-1.

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.
    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 MDAG 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 MDAG 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 in Section 10 Appendix 4.

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).

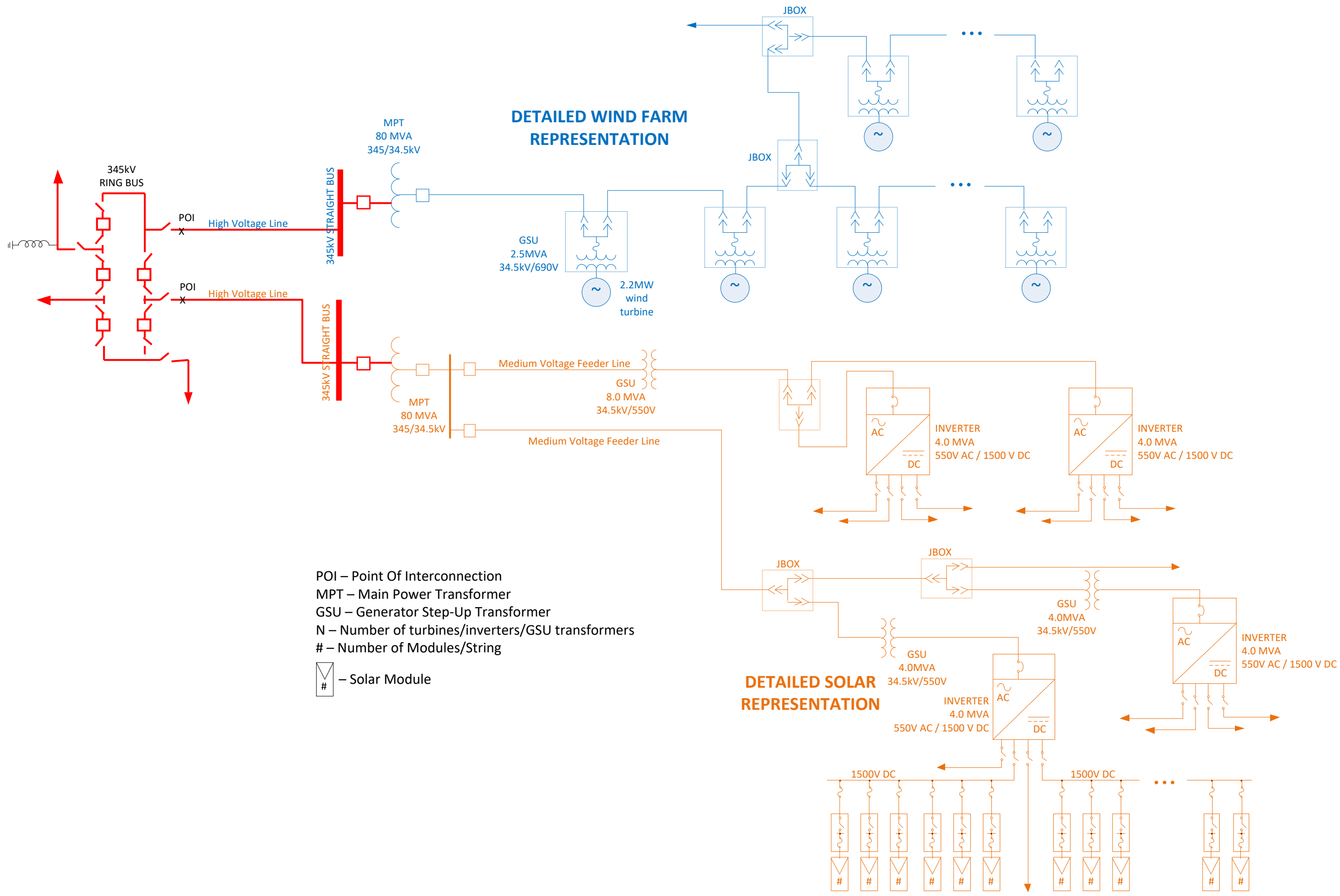
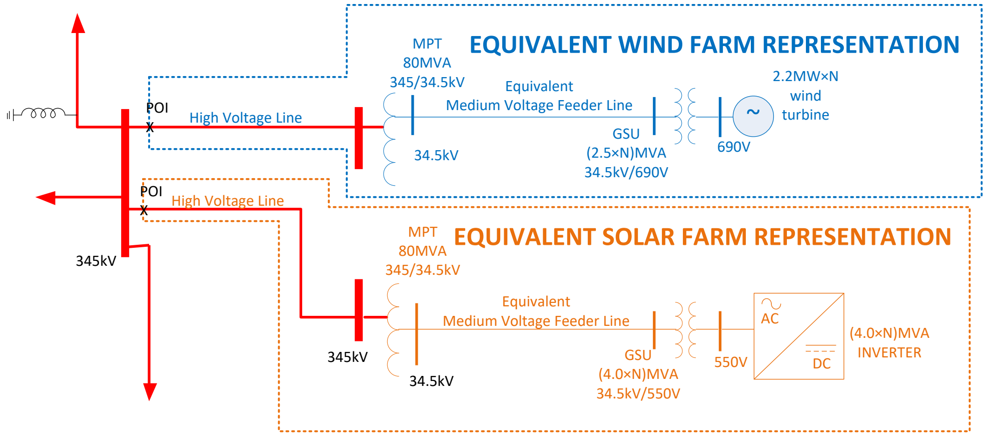


Figure 1: Detailed Wind and Solar Farm Representation (Not to be used for planning models)



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.

MDAG 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 <u>errors</u> 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) 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*] OR

	Locked rotor reactance (sum of rotor and stator leakage reactances) [PU]
Renewable: Wind Type 3	Unsaturated transient reactance (X'$_d$) of single machine [PU]
Renewable: Inverter-Based Solar PV Wind Type 4	$V_{rated} = Rated\ Voltage = \ 1.0\ [PU]\ (assumed)$ $I_{rated} = Rated\ Current\ From\ GO\ [PU]$ $XSource = \frac{V_{rated}}{I_{rated}}\ [PU]$
Renewable: 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[15] 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

15 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).

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[16] 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.

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

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

- 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[17] defined by the maximum and minimum transformer tap positions.
   - 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[18] and transformer winding angle (phase displacement) shall be provided. The connection code data incorporates

17 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.

18 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.

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) [19]

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.

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.

19 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

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. 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.

21. DC Transmission systems – DC transmission systems must be represented with a sufficiently detailed model to simulate its expected behavior.
22. 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.)
23. 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.
24. 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, $\Phi_A < \Phi_B$.
    c. Assuming Φ_A and Φ_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[20] 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[21]. While typically analogous to a

[20] 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.

[21] 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[22] 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).

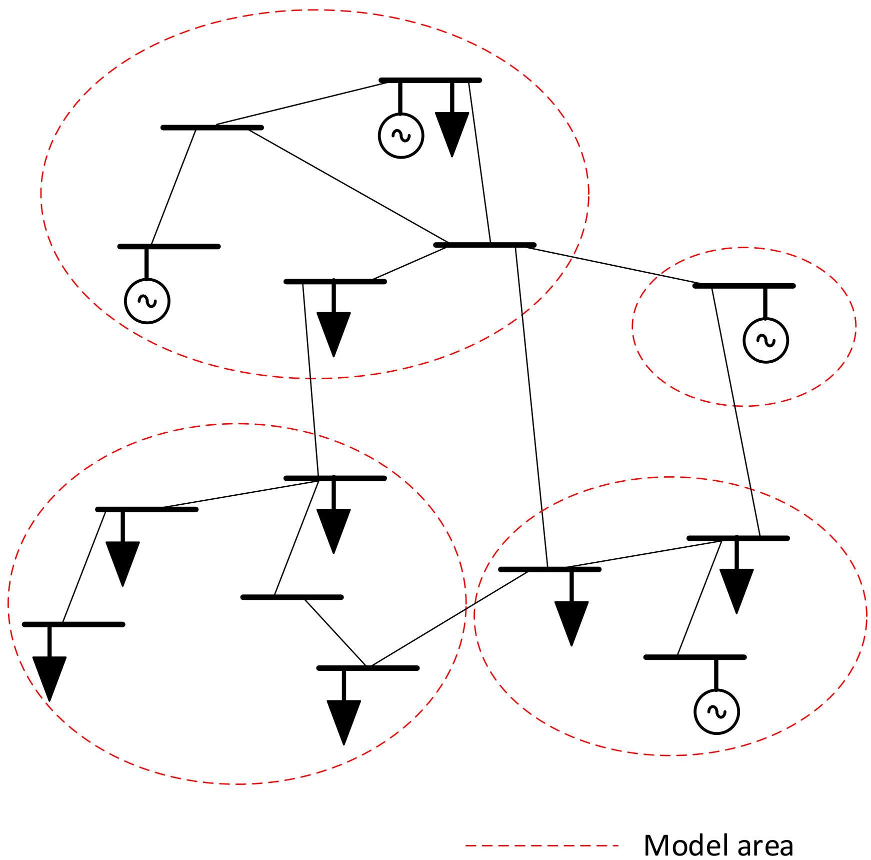


Figure 1. Example of interconnected model areas.

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.

[22] 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.

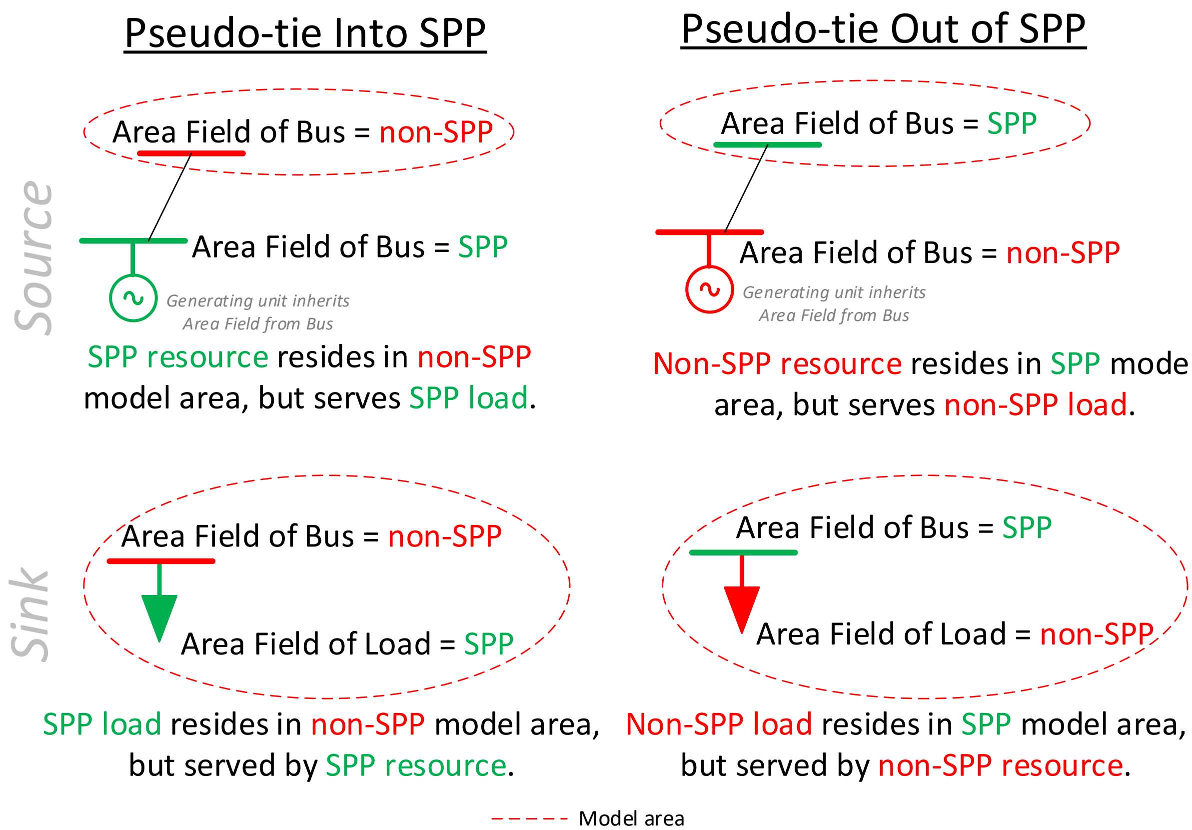


Figure 2. Four types of inter-SPP pseudo-ties.

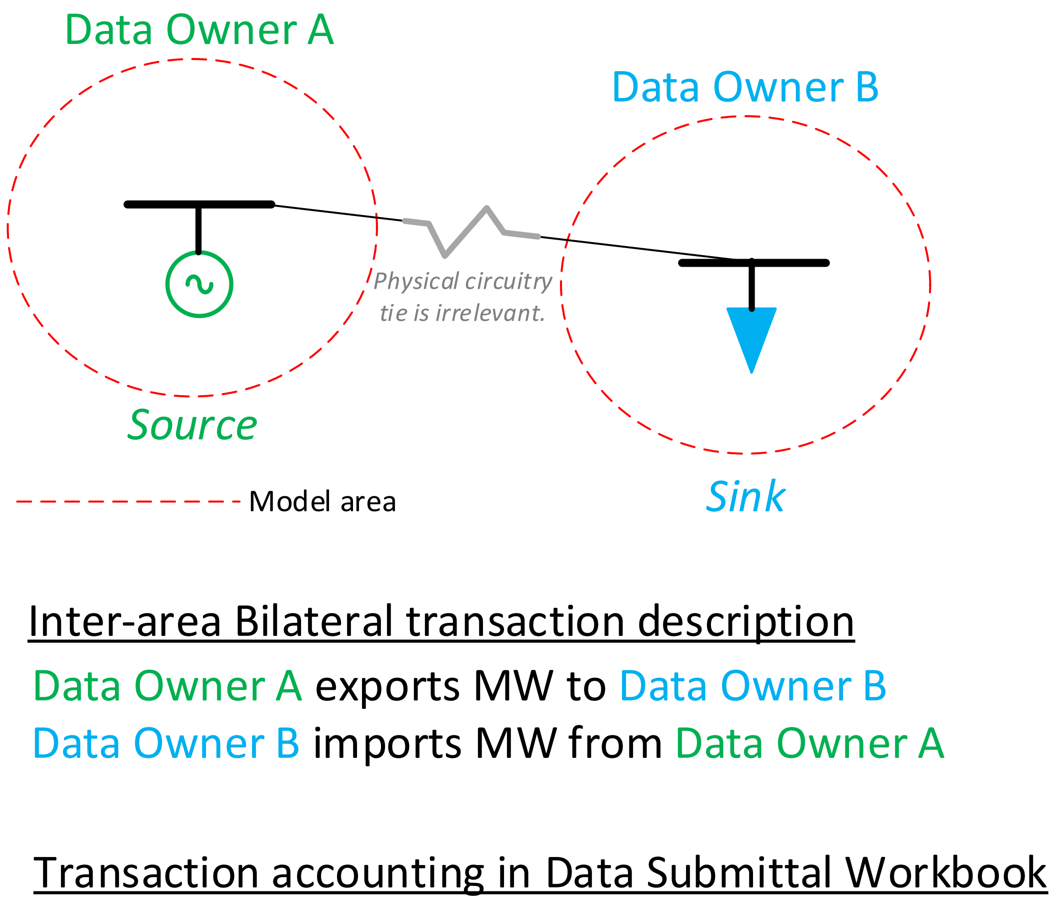
Transactions Data Requirements

Data Owners shall submit all transactions data via the MDAG 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:

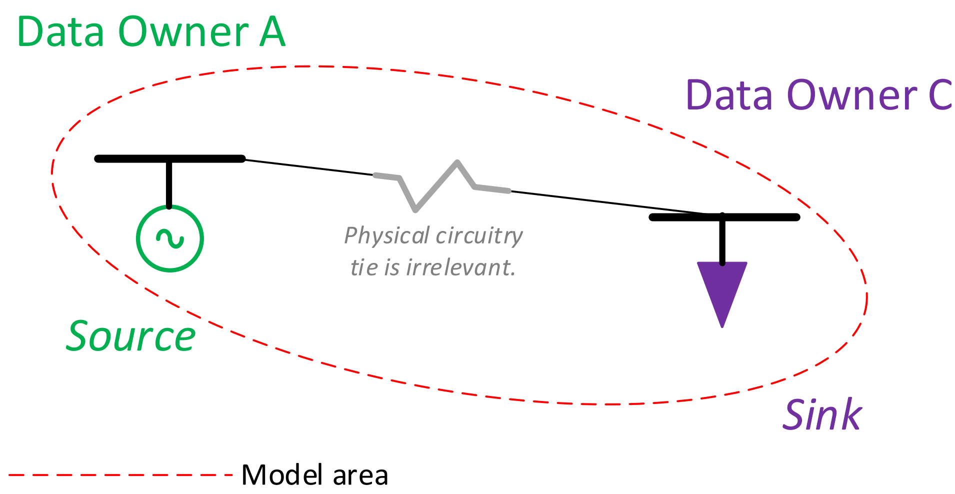
a. Inter-area transactions (transactions of load and resource that are wholly contained within the SPP Balancing Authority Area) are preferred to be integer values (i.e. whole MW); however, shall not exceed tens of kilowatt precision (i.e., two decimal MW precision; 0.01MW).
b. External area transaction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



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 MDAG 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 EDST transaction data 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 in EDST 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.

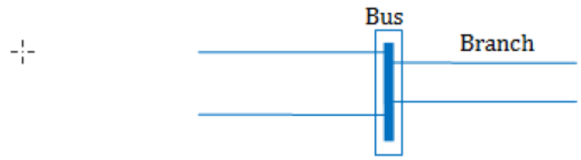
Firm transmission load includes capacity dependent interruptible loads with buy through provisions. In other words load that may be interrupted if the source runs out of capacity should still be modeled if the load has a choice and opportunity to purchase power from another source. This firm transmission 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.

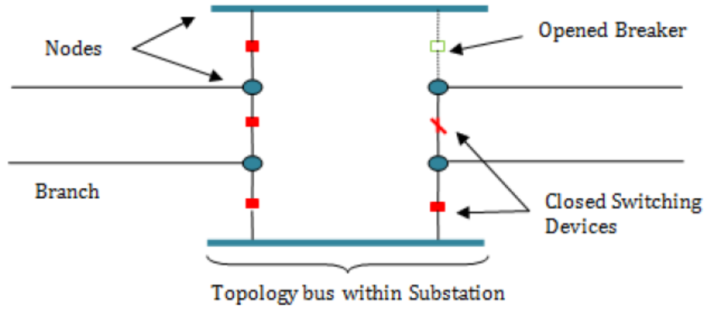
SUBSTATION NODE-BREAKER MODELING

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

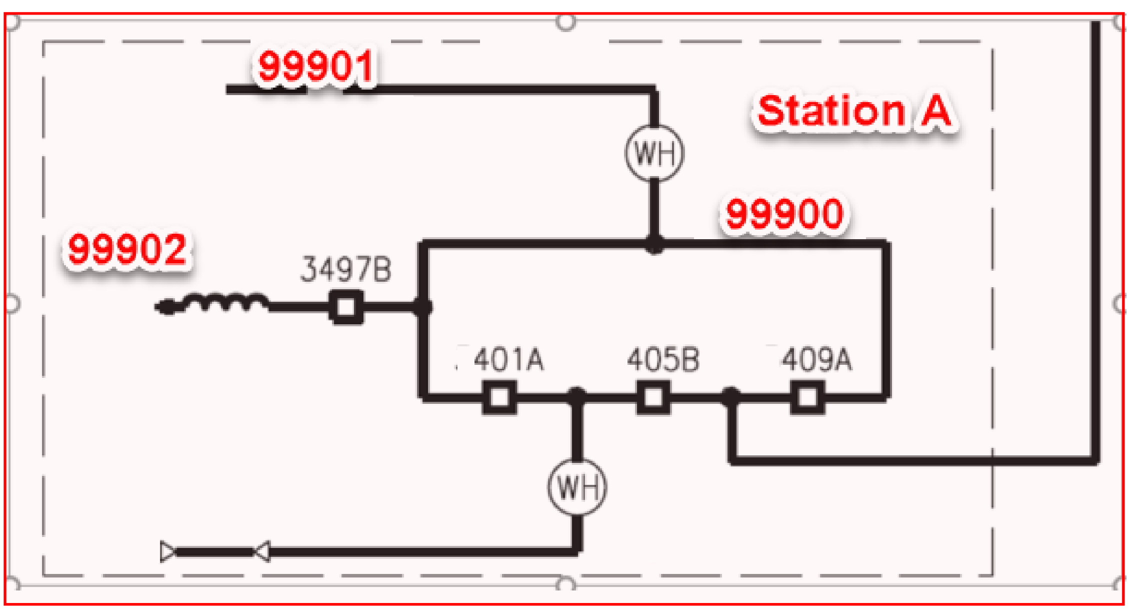


The same bus expanded to show the node-breaker model

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, MDAG 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 DATA

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".

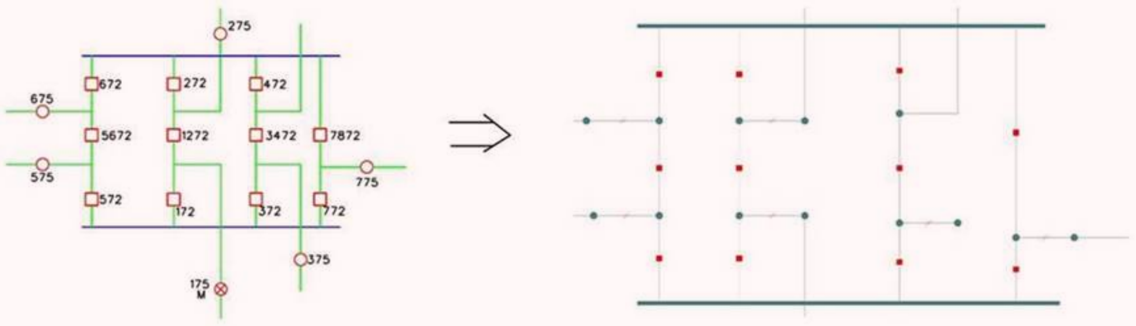
SUBSTATION NODES

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.

MDAG MODEL QUALITY ASSURANCE

Data Owners are expected to ensure their data is correct before submitting to SPP. Data correction or addition by MDAG or SPP Staff is considered the last resort and will follow the SPP quarterly MOPC reporting process.

The model building process is split into incremental passes where Data Owners, Data Submitters, and SPP Staff compile new or updated modeling information with prior information to create a revised set of model cases. Ultimately, this process culminates with a final pass that yields a set of model cases ready to be approved by MDAG. Once approved, this set of approved MDAG model cases is available for use by stakeholders.

To assess the efficacy and completeness of the modeling data that comprises the model sets, SPP Staff makes two synopses available upon each completed model pass: DocuCode and an AC Contingency Calculation (ACCC) summary. Prompt and thorough review by Data Owners and Data Submitters helps assure case quality as the model building process progresses through to completion.

DocuCode Fidelity Checks

SPP Staff uses an automated routine to summarize and tabulate model case information for succinct end-of-pass review. The DocuCode tables include basic case information, as well as highlight unacceptable model data residing in the case set. The following unacceptable data shall be addressed in each model pass and shall be corrected prior to the MDAG approval of the final model set:

<table>
<tr><th>Unacceptable model data</th><th>Means to correct unacceptable data</th></tr>
<tr><td>Branch Overloads</td><td rowspan="10">Resolve or designate as an “Exception.”</td></tr>
<tr><td>Voltage-controlled Bus Check (CNTB) Errors</td></tr>
<tr><td>Gen Reactive Limit Power Factor</td></tr>
<tr><td>Poor Load Power Factor</td></tr>
<tr><td>Small Voltage Band Shunts</td></tr>
<tr><td>Small Voltage Band Transformer</td></tr>
<tr><td>Transformer (three-winding) Overloads</td></tr>
<tr><td>Connection Code 4 Transformer (Sequence Data)</td></tr>
<tr><td>Wye Delta GSUs (Sequence Data)</td></tr>
<tr><td>SEQ Read Warning (Sequence Data)</td></tr>
<tr><td>Branch Rating Errors</td><td rowspan="6">Resolve or designate as “Overridden.”</td></tr>
<tr><td>Bus Voltage Violations (>1.10pu or <0.90pu)</td></tr>
<tr><td>Default Branch Length</td></tr>
<tr><td>Default Branch Owner</td></tr>
<tr><td>Gen Rsource-Xsource Ratio</td></tr>
<tr><td>Incorrect Branch kV</td></tr>
</table>

Mbase Below Pmax	
Node Voltage Regulation	
Offline Missing Slack Machines	
Raw Read Warnings	
Transformer Voltage Band Limits	
Wind Control Mode	
Wind Machine Voltage	
Zero Impedance ID	
Missing Generator Data	
Default Branch Seq Data (Sequence Data)	
Negative Delta Tertiary Reactance (Sequence Data)	
Retired Gen GSU Conflicts (Sequence Data)	

Dynamic unacceptable model data may be modified by SPP and coordinated with the applicable Data Submitter. Lack of response by the Data Submitter will be considered as acceptance of the modified data until the next model build pass.

In rare occasions, model data identified as unacceptable in the DocuCode checks are legitimate exceptions. When allowed by the table above and requested by the applicable Data Owner or Data Submitter, unacceptable model data shown in DocuCode may be re-designated as an MDAG "Exception" by SPP Staff based on Data Owner or Data Submitter request. All MDAG "Exception(s)" will be separately annotated in the DocuCode summary.

Under explicit conditions, the MDAG and SPP Staff must proactively protect the data integrity of a model case(s) when unacceptable data persists in subsequent model passes. An uncommon scenario necessitating that specific unacceptable model data be overridden occurs when a Data Owner or Data Submitter does not respond to or resolve unacceptable model data. In this limited and targeted situation, the MDAG in conjunction with SPP Staff may act to modify unacceptable model data: when allowed by the table above, unacceptable model data may be overridden to a default quantity determined by engineering judgement (e.g., a non-responsive Data Owner has both VSWHI and VSWLO voltage setpoints for a switched shunt set at 1.00 per unit; these quantities would be overridden and replaced with 1.03 and 1.00 per unit, respectively). Neither MDAG, nor SPP Staff, assumes the obligation of the non-responsive Data Owner or Data Submitter when substituting overridden data for unacceptable data and the act of substitution is made in the interest of overall model integrity. All MDAG "Overridden" data shall be separately annotated in the DocuCode summary, reflecting both the overridden unacceptable data and the replacement data used.

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 and provide meaningful feedback to Data Owners and Data Submitters. Data Owner / Data Submitter updates to address modeling errors found from contingency analysis should be submitted during the next data submission period per the latest MDAG model building schedule.

SECTION 4: DYNAMIC DATA REQUIREMENTS

The MDAG 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 MDAG 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 MDAG 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 MDAG 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. Under/over voltage generator trip relay.
FRQDCAT/FRQTPAT	Under/over frequency generator bus disconnection relay. 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.

15. Testing and initialization of offline wind. Offline wind units will be switched in at 100% of Pmax to initialize in the 5 year summer peak case and existing online wind will be ramped down to compensate. If there are initialization issues that occur, the PC will attempt to provide proposed corrections through a powerflow update IDEV or a Dyre Change command. The data submitter would still be responsible to make any corrections through MOD or new dyre entries for subsequent model builds. The original dispatch from the approved powerflow cases will be the final dispatch for the dynamic models.

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 Reliability Assessment and Performance Analysis →Resources → 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.

MDAG developed a subset list of acceptable dynamic models based on the NERC acceptable dynamic model list and adheres to the guidance outlined in the MDAG 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. 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 MDAG 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 MDAG 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 MDAG 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.[23]

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 MDAG Powerflow models. All base MDAG 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. MDAG steady-state base model
2. MDAG steady-state with PSS®E Classical assumptions
3. Maximum Fault case

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

1. Extract the SPP RAW and SEQ data with ties from the final MDAG 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 SERC's Short Circuit Database Working Group (SCDWG)
3. Merge the two data sets together

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

1. Apply Classical assumptions to the Base MDAG 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 MDAG 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 MDAG, SPP staff will conduct a preliminary

23 [NERC Lesson Learned: Consideration of the Effects of Mutual Coupling when Setting Ground Instantaneous Overcurrent Elements]

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 MDAG 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[24] – 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.

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24 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.[25]

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.

25 Attachment AA Resource Adequacy Section 2

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

Type	Description	Status	Applied to this Model Set: MDAG	ITP	TS	GI	Special Study	Notes
SPP-approved Transmission System Upgrade	Must have an NTC for: 1) transmission service request(s); 2) transmission changes originating from the integrated transmission planning (ITP) process; 3) transmission changes originating from the Balanced Portfolio process; 4) transmission changes directed by the high priority study process; 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. MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, NTC/PID/UID number. **Example Prj/Idv Name:** -659_Patent_Gate_NTC300.prj -659_BEPC_Build_New_Line_SUS-###.prj -659_Patent_Gate_PID2230.prj
Planned Transmission System Change	For Material[26] Planned Transmission System Changes, Data Submitters shall submit an RMS ticket to notify SPP. An expected change to the SPP Transmission System that does not yet have or does not require an NTC, including: 1) transmission changes budgeted for or planned by the TO; 2) transmission changes budgeted for by a Transmission Customer or other entity; 3) transmission changes resulting from an emergency (e.g., unplanned equipment failure); 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	X	X	X	X	X	**Material transmission changes that have been acknowledged by SPP and may be included in model sets.** The status for this MOD type will only be changed to "Acknowledged" by Data Submitters after receiving a notification from SPP for inclusion in the model sets.
		Requested	-	-	-	-	-	**Material transmission changes that have not yet been acknowledged by 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 in the SPP OATT. 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").

26 Material Modifications are defined in section 5.2 of the SPP Planning Criteria.

Type	Description	Status	Applied to this Model Set: MDAG	ITP	TS	GI	Special Study	Notes
		Speculative	-	-	-	-	-	**Forecasted and unbudgeted material transmission changes that have not yet been acknowledged by SPP and will not be included in model sets.** This MOD Project Type & Status is to represent planned transmission changes that are uncertain due to budgetary commitments or other reasons and shall not be part of any SPP planning processes under Attachment O in the SPP OATT. Speculative projects will not be reviewed by SPP.
		Non-material	X	X	X	X	X	**Non-material transmission change that does not adversely affect reliability or transmission service.**
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. MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, DPA/DPNS number. **Example Prj/Idv Name:** 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 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: 1) have an executed Interconnection Agreement (IA) or executed Interim Generator Interconnection Agreement (IGIA), and 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. MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, NTC/PID/UID number. **Example Prj/Idv Name:** 822_NextEra_Add_Blue_Cloud_Wind_GEN-20YY-###.prj

Type	Description	Status	Applied to this Model Set:					Notes
			MDAG	ITP	TS	GI	Special Study	
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.

SPP MOD Project Type/Status Matrix

Type	Description	Status	Description	Applied to this Model Set:					Notes
				MDWG	ITP	TS	GI	Special Study	
SPP-approved Transmission System Upgrade	**Must have an NTC for:** **1) transmission service request(s);** **2) transmission changes originating from the integrated transmission planning (ITP) process;** **3) transmission changes originating from the Balanced Portfolio process;** **4) transmission changes directed by the high priority study process;** **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. MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, NTC/PID/UID number. **Example Prj/Idv Name:** -659_Patent_Gate_NTC300.prj -659_BEPC_Build_New_Line_SUS-###.pr -659_Patent_Gate_PID2230.prjj
Planned Transmission System Change	**For Material Planned Transmission System Changes, Data Submitters shall submit an RMS ticket to notify SPP. An expected change to the SPP Transmission System that does not yet have or does not require an NTC, including:** **1) transmission changes budgeted for or planned by the TO;** **2) transmission changes budgeted for by a Transmission Customer or other entity;** **3) transmission changes resulting from an emergency (e.g., unplanned equipment failure);** **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	**The status for this MOD type will only be changed to "Acknowledged" by Data Submitters after receiving a notification from SPP for inclusion in the model sets.**
		Requested	Material transmission changes that have not yet been acknowledged by 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 in the SPP OATT. 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").
		Speculative	Forecasted and unbudgeted material transmission changes that have not yet been acknowledged by SPP and will not be included in model sets						This MOD Project Type & Status is to represent planned transmission changes that are uncertain due to budgetary commitments or other reasons and shall not be part of any SPP planning processes under Attachment O in the SPP OATT. Speculative projects will not be reviewed by SPP.
		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. MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, DPA/DPNS number. **Example Prj/Idv Name:** 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 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:** **1) have an executed Interconnection Agreement (IA) or executed Interim Generator Interconnection Agreement (IGIA), and** **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. MOD Projects must contain area/owner/zone number, area/owner/zone abbreviated name, NTC/PID/UID number. **Example Prj/Idv Name**: 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 V GMD/GIC DATA COLLECTION TEMPLATE USER'S GUIDE

GEOMAGNETIC DISTURBANCE MODELING DATA

Additional modeling data is necessary to supplement the MDAG steady-state models to support geomagnetic disturbance (GMD) analysis. The SPP GMD Model Set combines GMD-related system information (described below) with the MDAG 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 MDAG 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.

<u>Geographic Longitude (decimal degrees)</u>: 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
OZARK	CP-2	CP-2	Ozarks
PB-1		PB1	Pacific Border (Willamette Valley)

USGS Earth Conductivity Model	Equivalent to:	Siemens/PTI software code (enter into the “Earth Model Name” field)	Description
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 MDAG 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:

Core Type: 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. 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:

[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.

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 MDAG 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.

<u>Transformer Model in DC Network:</u> 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 MDAG 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 MDAG 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 MDAG 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:

<u>From, To Bus Number (Planning Model):</u> 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.

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

<u>Located at which end (From, To, or Both):</u> 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.

<u>Winding Connection Type:</u> 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 MDAG 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 MDAG 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 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.

[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.

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 VI 50/50 LOAD FORECAST EXAMPLE

Numerous generalized and proprietary methods exist for utility forecasting of future load demand. This is a simplistic example intended to illustrate how a historical demand dataset may be used to project a median load expectation (population) into the future as a load forecast which includes observed growth.

Consider Feeder A, with the following historically observed peak-hour demand during past summer seasons:

	Historical summer peak hour demand on Feeder A [MW]
2012	13
2013	9
2014	13
2015	12
2016	20
2017	15
2018	18
2019	20
2020	16
	Median = 15

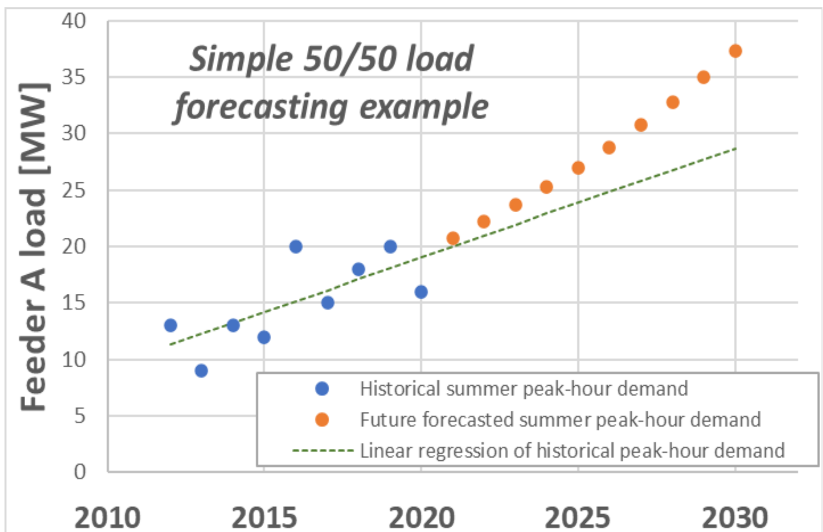
By linear regression, the trend (slope) of the summer peak-hour demands is +0.9667 MW/year. Assuming a compound annual growth rate (CAGR) of the load demand fit to the 2012-2020 historical data, this equates to a 6.73% year-to-year growth in future years. This information, along with the median loading (e.g., 15 MW) and median of the period (e.g., 2016), allows the following model of a forecasted load demand to be constructed:

$$L(n) = m(1 + r)^{(n-Y)}$$

where, the load forecast expectation, L, for a future year, n, given that the load CAGR, r, and the median year, Y, are known, as well as the median load, m, satisfies both $P(X(n) \leq L(n)) = \frac{1}{2}$ and $P(X(n) \geq L(n)) = \frac{1}{2}$ for a continuous probability distribution of a random variable, $X(n)$, representing the actual load for future year n.

For this simplistic example, this median-based model (Y = 2016; m = 15) yields the following future projected summer peak-hour demand, depicted in tabular form to the left below, and relative to the historical data in the plot to the lower right.

	Forecasted 50/50 (median) summer peak-hour demand on Feeder A, including projected load growth based on a fixed historical trend [MW]
2021	20.8
2022	22.2
2023	23.7
2024	25.3
2025	27.0
2026	28.8
2027	30.7
2028	32.8
2029	35.0
2030	37.4



SECTION 13: APPENDIX VII 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[25]~~ 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 *(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** *(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] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[30]~~[31]~~ [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[32]~~[33]~~ [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 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).

[30] 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. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

~~[31] 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.~~

[32] Including synchronous condensers and pumped storage.

~~3 Including synchronous condensers and pumped storage.~~

steady-state *(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** *(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**
b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO]	8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	

steady-state *(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** *(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**
a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or		

steady-state *(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** *(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**
Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

SURVEY RESULTS

MDAG

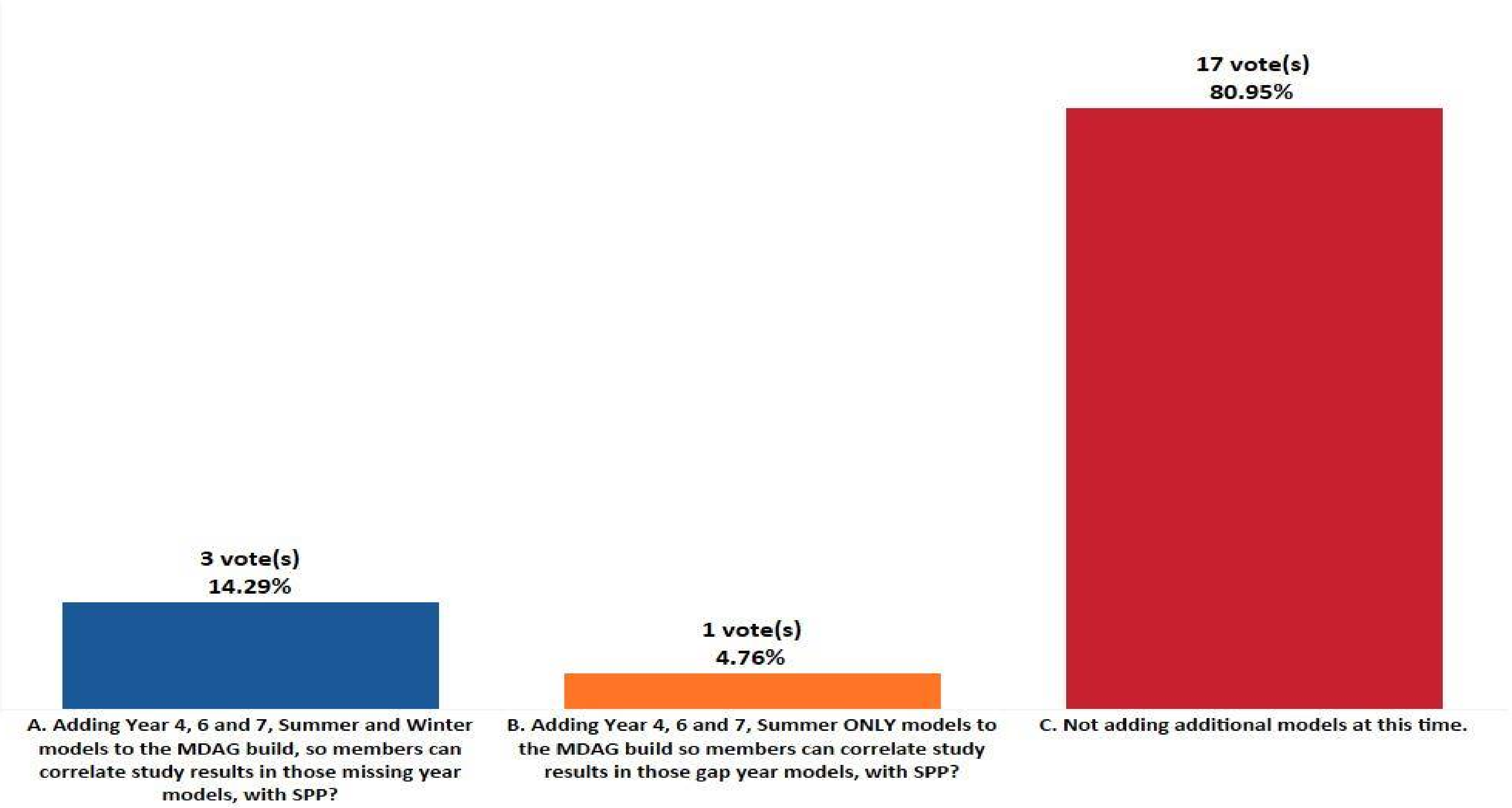
MDAG STRAW POLL

SURVEY RESULTS

MDAG Straw Poll Results

21 Responses

Per an action item from the 5/18/23 MDAG meeting, a poll was taken on adding additional models.



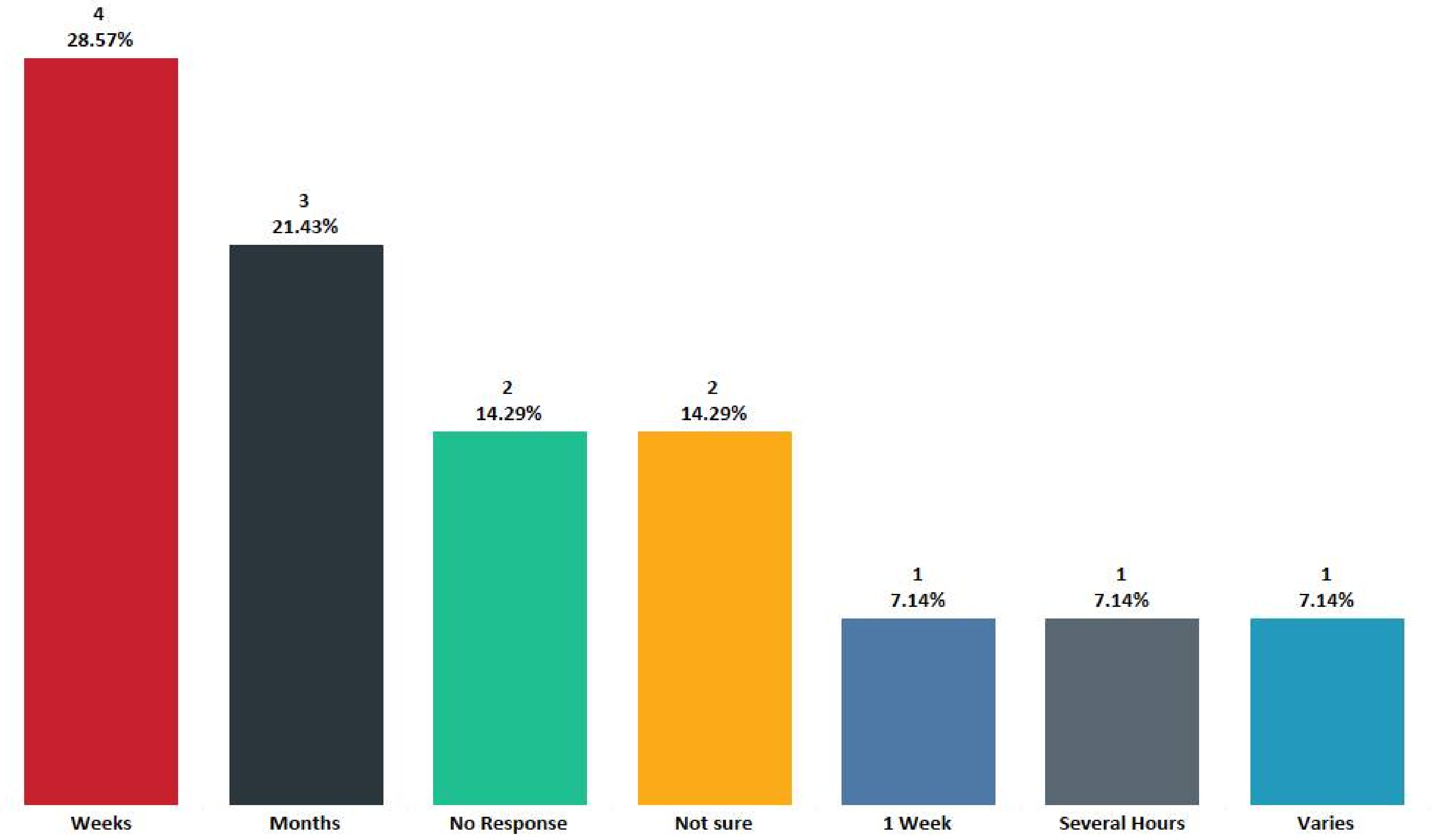
RATE 3

SURVEY RESULTS

MDAG Rate 3 Survey

14 Responses

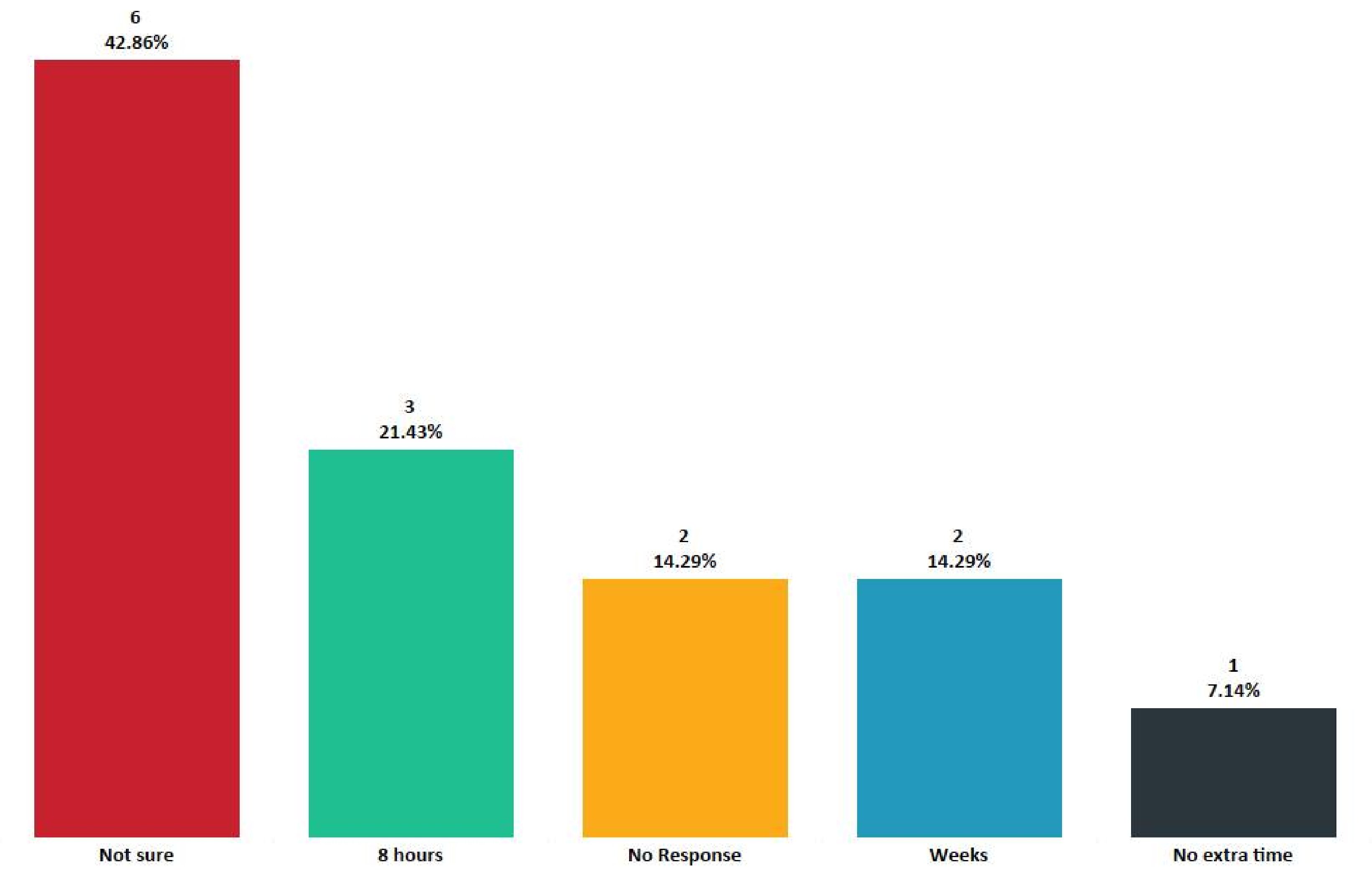
1. How much time does it take to compile MOD-032 data?



MDAG Rate 3 Survey

14 Responses

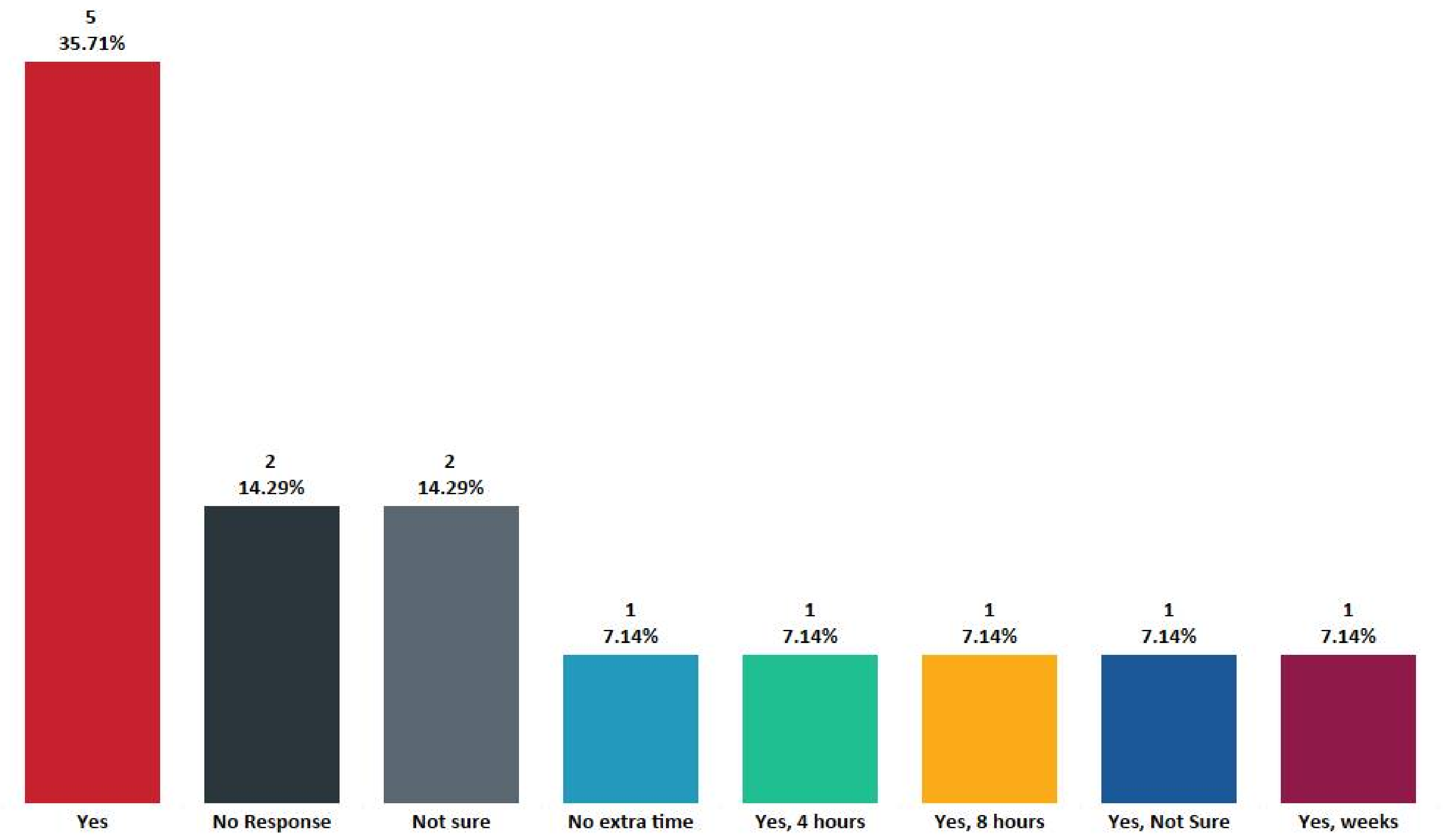
2. How much time would you estimate is needed to compile Rate 3 (conductor only) data?



MDAG Rate 3 Survey

14 Responses

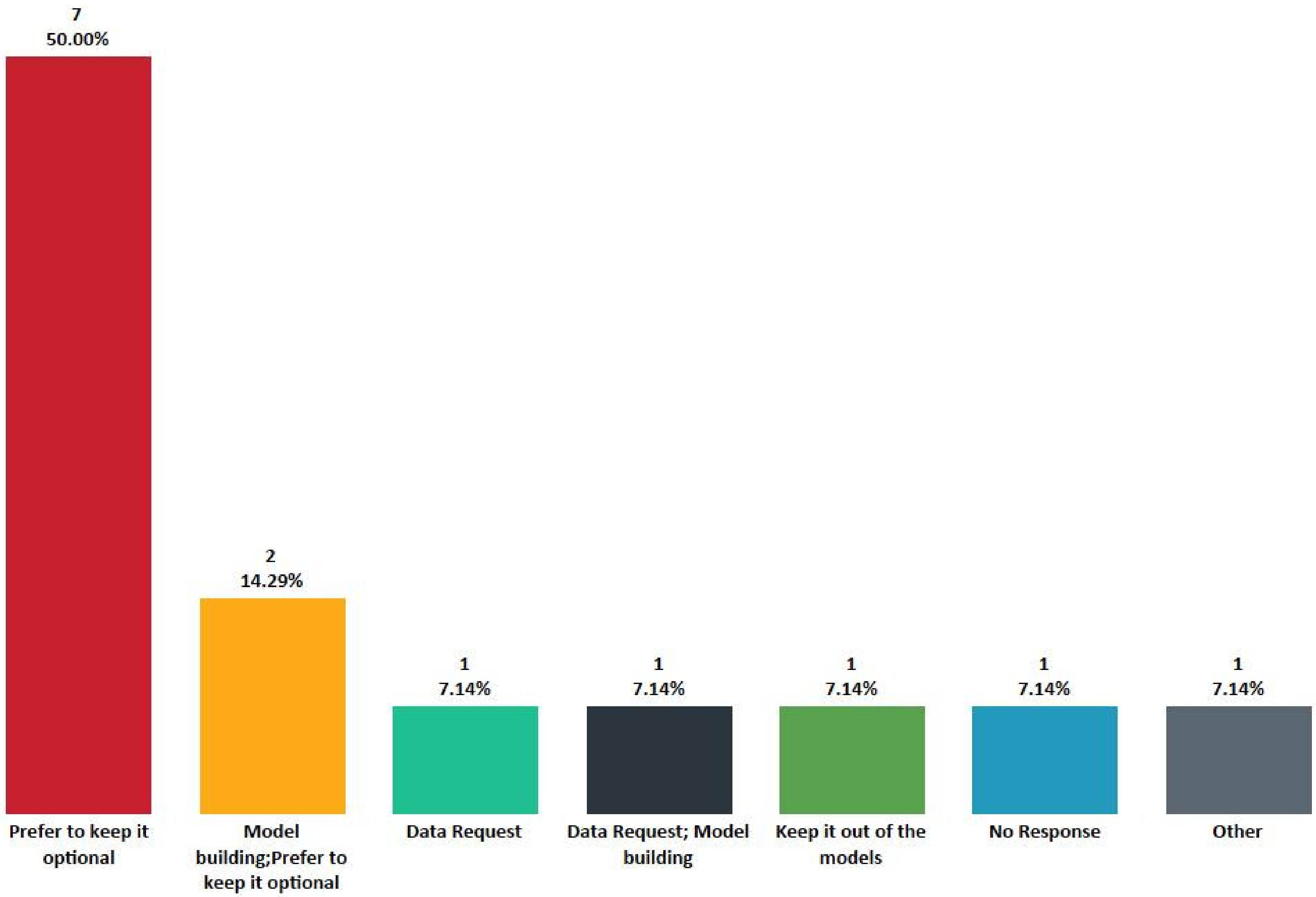
3. **Would Rate 3 included in the MOD-032 process add time to your compliance obligations? If so, how much?**



MDAG Rate 3 Survey

14 Responses

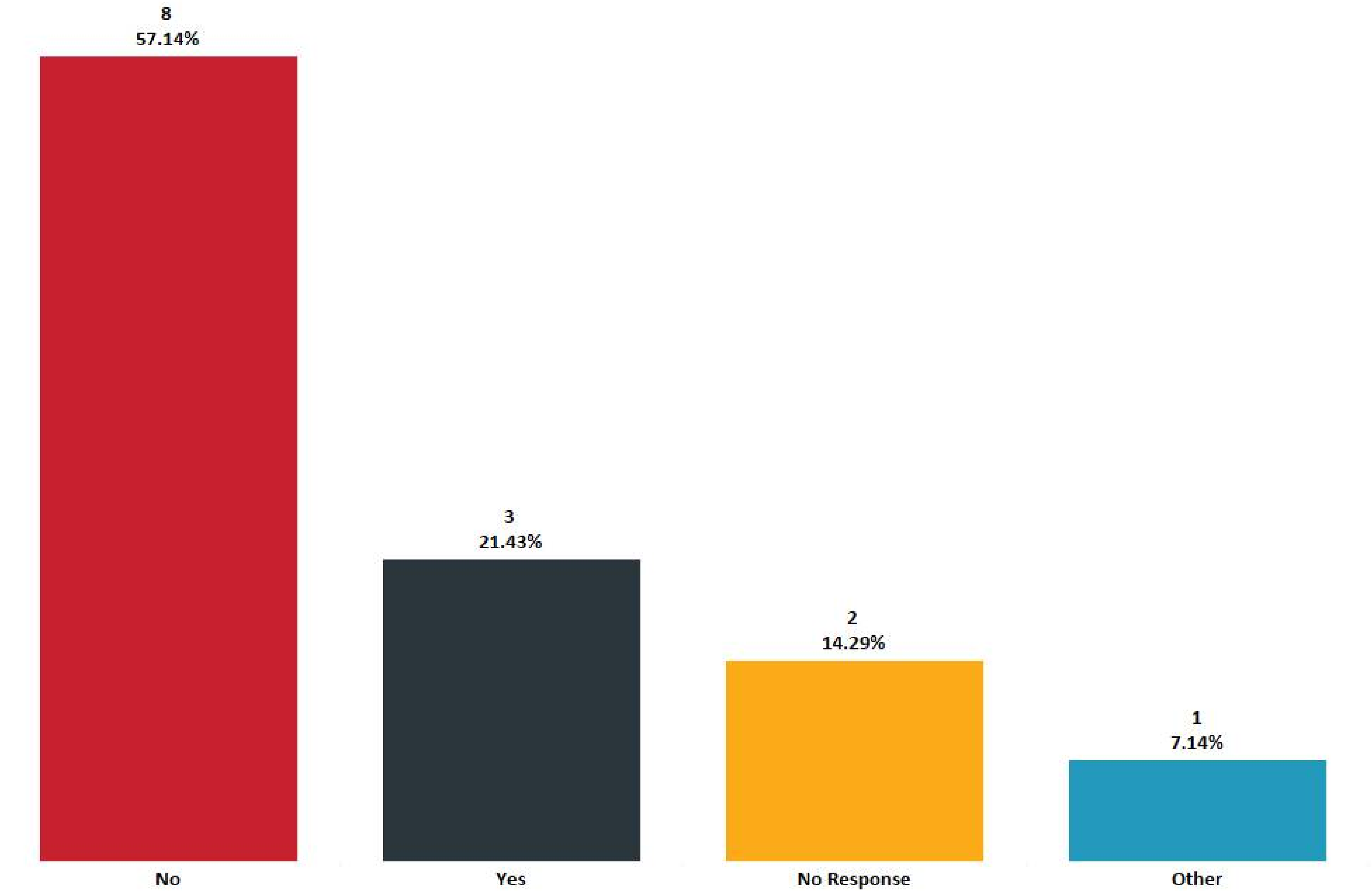
4. How would you prefer to submit Rate 3 data?



MDAG Rate 3 Survey

14 Responses

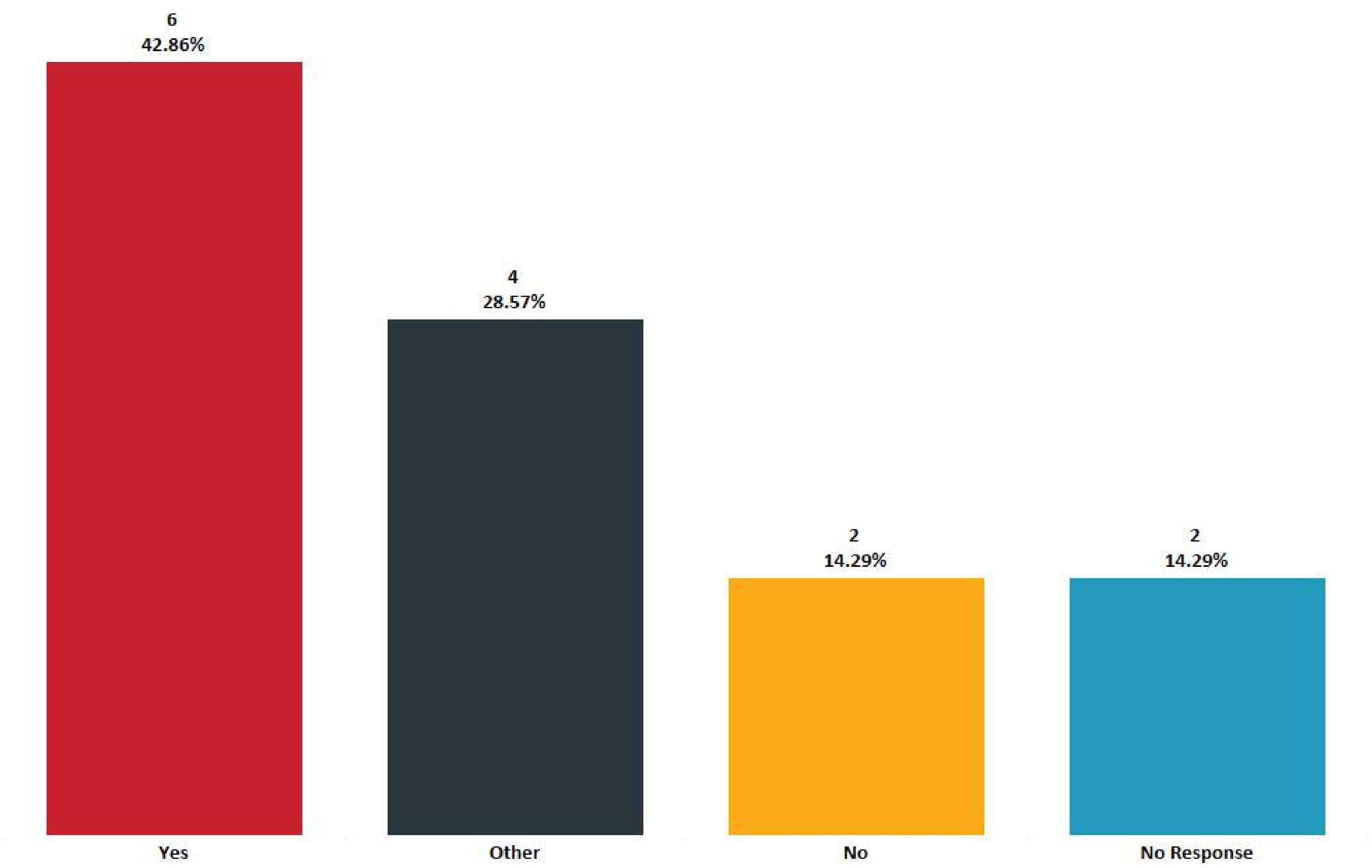
5. Do you think Rate 3 would provide benefits for your company? For "Other" below, please explain.



MDAG Rate 3 Survey

14 Responses

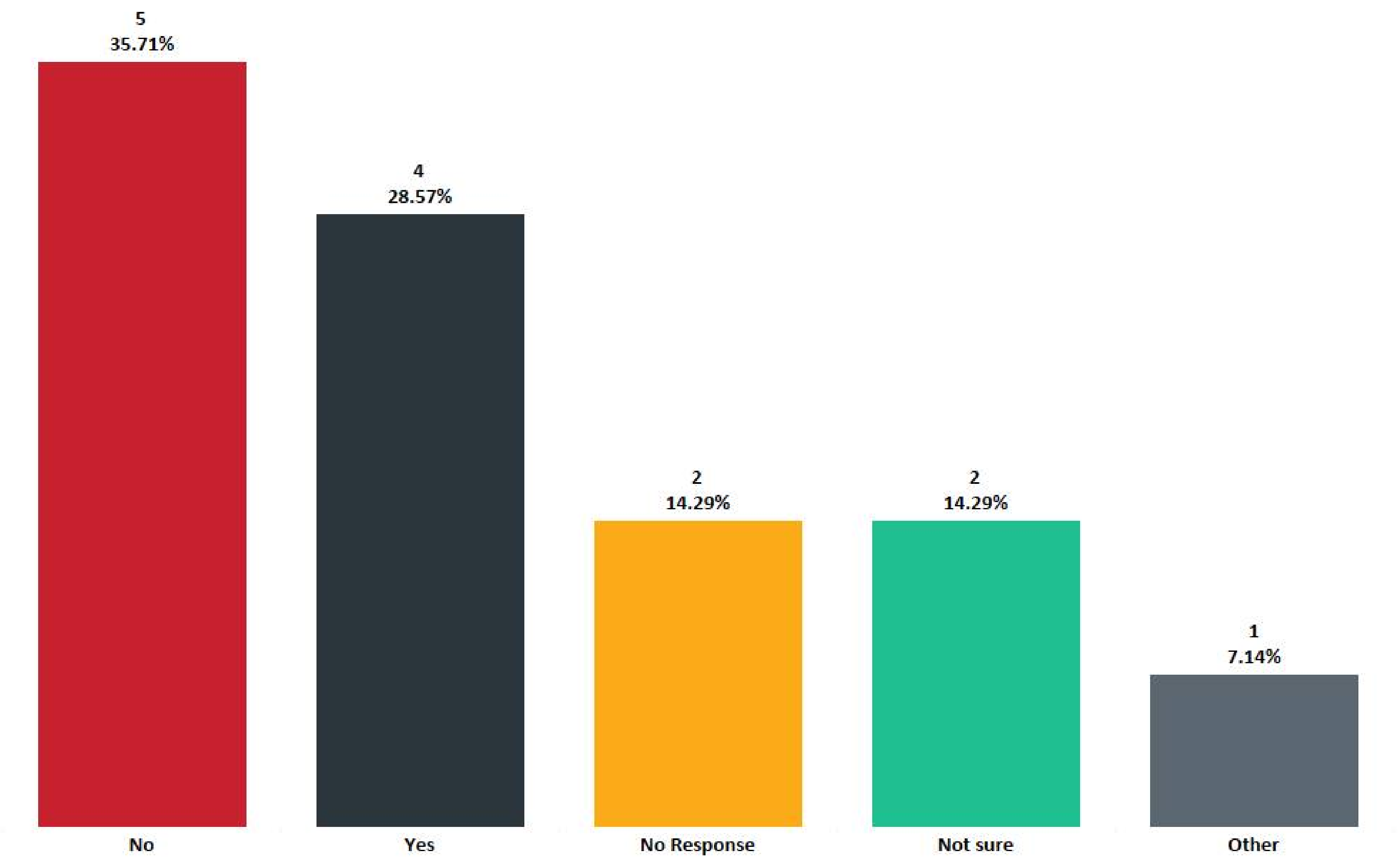
6. Do you think Rate 3 would have costs for your company? For "Other" below, please explain.



MDAG Rate 3 Survey

14 Responses

7. Would a proof of concept provide better data to help your company decide? For "Other" below, please explain.



MDAG Rate 3 Survey

14 Responses

8. Which option does your entity prefer?