Southwest Power Pool

Southwest Power Pool
MODEL DEVELOPMENT WORKING GROUP
September 17, 2014
Conference Call
1:00 – 4:00 P.M.

• M I N U T E S •

Agenda Item 1 - Administrative

The meeting was called to order at 1:00 p.m. The following Model Development Working Group (MDWG) members were in attendance:

Joe Fultz, Chair – Grand River Dam Authority
Nate Morris, Vice Chair – Empire District Electric Company
Dustin Betz – Nebraska Public Power District
John Boshears - City Utilities of Springfield
Derek Brown – Westar Energy
Mike Clifton – Oklahoma Gas & Electric
Nathan McNeil – Midwest Energy
Reené Miranda – Southwestern Public Service
Scott Rainbolt – American Electric Power
Scott Schichtl – Arkansas Electric Cooperative
Brian Wilson – Kansas City Power & Light

SPP Staff in attendance included Anthony Cook (Secretary), Mitch Jackson, Scott Jordan and, James Bailey.

The following guests were also in attendance:
Peter Howard –Kansas City Power & Light
Jerry Bradshaw - City Utilities of Springfield
Holli Krizek – Western Area Power Administration
Wayne Haidle – Basin Electric
William Hawkins – Western Farmers Electric Cooperative
Gayle Nansel – Western Area Power Administration
Gimod Olapurayil – ITC Great Plains
Justin Radl – Xcel Energy
Dona Parks – Grand River Dam Authority
Martin Green – Grand River Dam Authority
Mark Reinart – Golden Spread Electric Cooperative
Kevin Foflygen - City Utilities of Springfield
Alan Burbach – Lincoln Electric System

Meeting Agenda
The agenda was reviewed by the group. Derek Brown requested to add an item to discuss MOD 32 & 33 Gap Analysis to agenda item 4. Derek Brown motioned to approve the agenda as amended; Brian Wilson seconded the motion. The motion passed unopposed.
(**Attachment 1 - MDWG Meeting Agenda 20140917.docx**)

Meeting Minutes
The July 1, 2014 minutes were open for review. Reené Miranda asked for the minutes to include the discussion that took place. Anthony stated that he didn't have the discussion written down and that members would have to submit the discussion based on their notes. The minutes will be postponed for review for the next meeting.

AI: Members are to submit their discussion notes to Anthony by September 26, 2014.

The August 14, 2014 minutes were open for review. The group decided to wait until the next meeting to approve all minutes at once.

Meeting Materials
Anthony Cook asked if anyone had any issues or needed more time to review the posted material. Derek Brown stated that there is a newer version of the document for item 4b. There were no concerns from anyone for this meeting.

<u>Agenda Item 2 – MDWG Model Building Activities:</u>

2014 Series Dynamic Update
Scott Jordan gave an update of the dynamics models being posted and at a point awaiting approval by the MDWG. He discussed the issue found in the 2020L and out cases seeing an issue with the case crashing. This issue was traced back to a new computer being used during the dynamic case build that had a different version of Visual Studio causing a difference in the DLL file and has been corrected.

2015 Series Schedule
Anthony presented the proposed Short Circuit portion of the schedule. Gayle Nansel asked how WAPA should submit seq data to SPP since they haven't been added to the MOD system. Anthony state that a global update can be made when the MOD base case is updated with the IS data.

Nathan McNeil asked if the new TPL standard would have an impact on the schedule. Anthony stated that he believes it would be minimal. Nathan then asked if both the PSS/e and the ASPEN User sets still need to be made. Anthony stated he would ask Brandon Hentschel.

AI: Anthony to ask Brandon if both sets of Short Circuit models are needed.

Scott Rainbolt asked about the amount of detail in the SERC model. Anthony stated that he is waiting for Trial 1 to find out.

Anthony presented the proposed Dynamic portion of the schedule. Scott Jordan stated the only possible change from staff would be to the “Final Data Update” changing from 5 days to 10 days. Reené asked about the Generation Interconnection process. Scott stated that the GI department reviewed the models at the same time as the members and provided feedback. He stated that only necessary changes were applied and is working to figure out a best practice to get updates implemented with TO approval.

The group further discussed adding the additional 5 days for SPP to build the final models. They then asked for 10 days to review and 5 days to vote. Reené motioned to approve the proposed schedules as amended. Nate Morris seconded the motion. The motion passed unopposed. (**Attachment 2 - 2015 MDWG Series Powerflow, Short Circuit and Dynamics Models.pdf)**

AI: Staff to post approve 2015 Series schedule.

Agenda Item 3 – Model Development Procedure Manual:

General Updates
Anthony presented the changes made to the manual. He stated that many of the changes were suggestions made by the legal department. Also, based on the August MDWG meeting, a section was added to describe the method of modeling mothballed, retired, and decommissioned units. The group made additional edits to reword a few sections. Reené Miranda motioned to approve the updates. Derek Brown seconded the motion. The motion passed unopposed.
(**Attachment 3 - SPP MDWG Model Development Procedure Manual (Public).doc**)

AI: Anthony to make changes to manual and post updated manual.

Agenda Item 4 – Other:

TPL-001-4 R2.3
Nathan McNeil stated that the TPL TF has an action item to discuss Requirement 2.3 of TPL-001-4 with the MDWG. TPL-001-4 R2.3 requires short circuit analysis stating "...using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area." Nathan added that the group needs to discuss whether it should produce short circuit models with all available generation online rather than with just the dispatch as it was in the power flow model. If the MDWG short circuit models do not include this type of model, then SPP Staff may have to develop one for running the TPL studies one to meet compliance with the new standard. The group discussed adding models to the set that turn on planned generation accept those for planned retirement. Nathan motioned to add to the Short Circuit build, models to include all available generation on-line and all transmission facilities which could be in-service in accordance with TPL-001-4 R2.3. Scott Rainbolt seconded the motion. (**Attachment 4 - TPL-001-4.pdf**)

AI: Staff to provide outage report of facilities for TPL-001-4 R2.3.
AI: Add to manual the 3 types of short circuit models.

TPL-007-1
Derek Brown wants the group to start discussing TPL-007-1 since it is to be approved early 2015 with Requirement 1 effective 6 months after approval. He stated that this will require an additional module for PSS/e to perform the analysis. It is likely that a regional study may need to be performed. (**Attachment 5 - Project201303GeomagneticDisturbanceMitigation_tpl_007_1_20140421_clean.pdf**)

AI: Members need to review TPL-007-1.
AI: Staff to compile a list of transformers with Y-connection, High-side 200kV or greater. Due September 30, 2014.

Addition of IS and other to 2015 Series
Anthony stated that the MRO footprint was updated in Pass 2 of the 2015 Series MDWG models. This was done in an effort to allow those entities of the Integrated System (IS) the ability to participate in the model build. These entities are Western Area Power Administration, Basin Electric Power Cooperative, and Heartland Consumers Power District. Also, SPP Staff has also reached out to North Western Energy, Corn Belt Power Cooperative, and Missouri River Energy Services.

Gayle Nansel stated that it is planned for SPP to assume RC responsibilities June 2015, and full integration October 2015.

MOD 32 & 33 Gap Analysis
Derek Brown requested SPP Staff to develop a gap analysis for MOD 32 R1 and point to how it is being fulfilled.

AI: Staff to develop gap analysis for MOD 32 R1 compliance. Due by November, 2014 MDWG meeting.

MOD Training
This item has been tabled for a future meeting.

<u>Agenda Item 5 – Summary of Action Items:</u>

- **Members are to submit their discussion notes to Anthony by September 26, 2014.**
- **Anthony to ask Brandon if both sets of Short Circuit models are needed.**
- **Staff to post approve 2015 Series schedule.**
- **Anthony to make changes to manual and post updated manual.**
- **Staff to provide outage report of facilities for TPL-001-4 R2.3.**
- **Add to manual the 3 types of short circuit models.**
- **Members need to review TPL-007-1.**
- **Staff to compile a list of transformers with Y-connection, High-side 200kV or greater. Due September 30, 2014.**
- **Staff to develop gap analysis for MOD 32 R1 compliance. Due by November, 2014 MDWG meeting.**

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<u>Agenda Item 6 – Future Meetings:</u>
The group suggested sending out a Doodle Poll to try and schedule a meeting in October.

AI: Staff to send out a Doodle Poll for an October, 2014 meeting.

Adjourn Meeting

Scott Schichtl motioned to adjourn the meeting, Reené Miranda seconded the motion. The motion passed unopposed.

Respectfully submitted,
Anthony Cook
SPP Staff Secretary

Southwest Power Pool, Inc.

MODEL DEVELOPMENT WORKING GROUP

September 17, 2014

Conference Call

1:00 P.M. – 4:00 P.M.

• A G E N D A •

1. Administrative Items .... Joe Fultz (20 min)
    a. Call to Order
    b. Introductions
    c. Proxies
    d. Agenda Review (Action Item)
    e. Previous Meeting Minutes (Action Item)
        i. July 1, 2014 Conference Call
        ii. August 14, 2014 Conference Call
    f. Meeting Materials

2. MDWG Model Building Activities .... Staff (1 hr)
    a. 2014 Series
        i. Dynamic Update
    b. 2015 Series
        i. Schedule (Action Item)
            1. Short Circuit
            2. Dynamics

3. Model Development Procedure Manual .... All (45 min)
    a. General Updates

4. Other .... All (45 min)
    a. TPL TF Updates
        i. TPL-001-4 R2.3
    b. TPL 007-1
    c. Addition of IS and others to 2015 Series
    d. MOD 32 & 33 Gap Analysis
    e. MOD Training

5. Summary of Action Items .... Anthony Cook (5 min)

6. Little Rock Meeting .... Joe Fultz (5 min)
    a. MDWG Call: TBD
    b. MDWG Face-to-Face: November 12
    c. Model Update Meeting 13 and 14

ID	WBS	Task Name	Duration	Start	Finish	Resource Names
1	1	**2015 MDWG Powerflow, Short Circuit and Dynamics Models**	**299 days**	**Fri 6/20/14**	**Thu 8/20/15**	
2	**1.1**	**2015 MDWG Powerflow Models**	**299 days**	**Fri 6/20/14**	**Thu 8/20/15**	
3	1.1.1	Post Preliminary Models	1 day	Fri 6/20/14	Fri 6/20/14	
4	**1.1.2**	**Kick-off**	**21 days**	**Tue 7/1/14**	**Wed 7/30/14**	
5	**1.1.2.1**	**Kick-off - Review MOD Projects**	**10 days**	**Tue 7/1/14**	**Tue 7/15/14**	
6	1.1.2.1.1	Kick-off - Review MOD Projects	10 days	Tue 7/1/14	Tue 7/15/14	SPP
7	1.1.2.2	Kick-off - Lock Down MOD	18 days	Mon 7/7/14	Wed 7/30/14	SPP
8	1.1.2.3	Kick-off - MOD Model Extraction	1 day	Wed 7/16/14	Wed 7/16/14	SPP
9	**1.1.3**	**Kick-off - Build Pass 1 Powerflow**	**10 days**	**Thu 7/17/14**	**Wed 7/30/14**	
10	1.1.3.1	Kick-off - Build Pass 1 Powerflow	10 days	Thu 7/17/14	Wed 7/30/14	SPP
11	1.1.4	Kick-off - Post Pass 1 Powerflow	0 days	Wed 7/30/14	Wed 7/30/14	SPP
12	1.1.5	Kick-off - Initial Data Request (Contingency List Updates, Transactions, MTL)	0 days	Wed 7/30/14	Wed 7/30/14	SPP
13	**1.1.6**	**Pass 1**	**27 days**	**Thu 7/31/14**	**Mon 9/8/14**	
14	1.1.6.1	Pass 1 - Members Review/Submit Changes to Pass 1 Models	10 days	Thu 7/31/14	Wed 8/13/14	Members
15	1.1.6.2	Pass 1 - Member Review/Changes Due (Projects, Transactions, MTL, Contingency List)	0 days	Wed 8/13/14	Wed 8/13/14	Members
16	**1.1.6.3**	**Pass 1 - Review MOD Projects**	**15 days**	**Thu 7/31/14**	**Wed 8/20/14**	
17	1.1.6.3.1	Pass 1 - Review MOD Projects	15 days	Thu 7/31/14	Wed 8/20/14	SPP
18	1.1.6.4	Pass 1 - Lock Down MOD	16 days	Thu 8/14/14	Fri 9/5/14	SPP
19	1.1.6.5	Pass 1 - MOD Model Extraction	1 day	Thu 8/21/14	Thu 8/21/14	SPP
20	**1.1.6.6**	**Pass 1 - Build Pass 2 Powerflow Models**	**10 days**	**Fri 8/22/14**	**Fri 9/5/14**	
21	1.1.6.6.1	Pass 1 - Build Pass 2 Powerflow Models	10 days	Fri 8/22/14	Fri 9/5/14	SPP
22	1.1.6.7	Pass 1 - Post Pass 2 Powerflow Models	0 days	Fri 9/5/14	Fri 9/5/14	SPP
23	1.1.6.8	Pass 1 - Pass 2 ACCC Analysis (if models solved)	1 day	Mon 9/8/14	Mon 9/8/14	SPP
24	**1.1.7**	**Pass 2**	**27 days**	**Mon 9/8/14**	**Wed 10/15/14**	
25	1.1.7.1	Pass 2 - Members Review/Submit Changes to Pass 2 Powerflow Models	10 days	Mon 9/8/14	Fri 9/19/14	Members
26	1.1.7.2	Pass 2 - Status Conference Call	1 day	Mon 9/15/14	Mon 9/15/14	
27	1.1.7.3	Pass 2 - Member Review/Changes Due	0 days	Fri 9/19/14	Fri 9/19/14	Members
28	1.1.7.4	Request First Tier external Short Circuit sequence data	0 days	Wed 10/15/14	Wed 10/15/14	SPP
29	**1.1.7.5**	**Pass 2 - Review MOD Projects**	**15 days**	**Mon 9/8/14**	**Fri 9/26/14**	
30	1.1.7.5.1	Pass 2 - Review MOD Projects	15 days	Mon 9/8/14	Fri 9/26/14	SPP
31	1.1.7.6	Pass 2 - Lock Down MOD	16 days	Mon 9/22/14	Mon 10/13/14	SPP
32	1.1.7.7	Pass 2 - MOD Model Extraction	1 day	Mon 9/29/14	Mon 9/29/14	SPP
33	**1.1.7.8**	**Pass 2 - Build Pass 3 Powerflow Models**	**10 days**	**Tue 9/30/14**	**Mon 10/13/14**	
34	1.1.7.8.1	Pass 2 - Build Pass 3 Powerflow Models	10 days	Tue 9/30/14	Mon 10/13/14	SPP
35	1.1.7.9	Pass 2 - Post Pass 3 Powerflow Models	0 days	Mon 10/13/14	Mon 10/13/14	SPP
36	1.1.7.10	Pass 2 - Pass 3 ACCC Analysis (if models solved)	1 day	Tue 10/14/14	Tue 10/14/14	SPP
37	**1.1.8**	**Pass 3**	**32 days**	**Tue 10/14/14**	**Wed 11/26/14**	
38	1.1.8.1	Pass 3 - Request Review of 2014 ITP IDEVS	0 days	Fri 11/14/14	Fri 11/14/14	SPP
39	1.1.8.2	Pass 3 - Members Review/Submit Changes to Pass 3 Powerflow Models	24 days	Tue 10/14/14	Fri 11/14/14	Members
40	1.1.8.3	Pass 3 - Status Conference Call	1 day	Wed 10/29/14	Wed 10/29/14	
41	1.1.8.4	Pass 3 - Member Review/Changes Due	0 days	Fri 11/14/14	Fri 11/14/14	Members
42	**1.1.8.5**	**Pass 3 - Review MOD Projects**	**24 days**	**Tue 10/14/14**	**Fri 11/14/14**	
43	1.1.8.5.1	Pass 3 - Review MOD Projects	24 days	Tue 10/14/14	Fri 11/14/14	SPP
44	1.1.8.6	Pass 3 - Lock Down MOD	7 days	Mon 11/17/14	Tue 11/25/14	SPP
45	1.1.8.7	Pass 3 - Model Update Meeting	2 days	Thu 11/13/14	Fri 11/14/14	
46	1.1.8.8	Pass 3 - MOD Model Extraction	1 day	Mon 11/17/14	Mon 11/17/14	SPP
47	**1.1.8.9**	**Pass 3 - Build Pass 4 Powerflow Models**	**6 days**	**Tue 11/18/14**	**Tue 11/25/14**	
48	1.1.8.9.1	Pass 3 - Build Pass 4 Powerflow Models - Merge with 2014 MMWG Series	6 days	Tue 11/18/14	Tue 11/25/14	SPP
49	1.1.8.10	Pass 3 - Post Pass 4 Powerflow Models	0 days	Tue 11/25/14	Tue 11/25/14	SPP
50	1.1.8.11	Pass 3 - Pass 4 ACCC Analysis	1 day	Wed 11/26/14	Wed 11/26/14	SPP
51	**1.1.9**	**Pass 4**	**45 days**	**Wed 11/26/14**	**Mon 2/2/15**	
52	1.1.9.1	Pass 4 - Members Review/Submit Changes to Pass 4 Powerflow Models	22 days	Wed 11/26/14	Wed 12/31/14	Members
53	1.1.9.2	Pass 4 - Status Conference Call	1 day	Fri 12/12/14	Fri 12/12/14	
54	1.1.9.3	Pass 4 - Member Review/Changes Due	0 days	Wed 12/31/14	Wed 12/31/14	Members
55	**1.1.9.4**	**Pass 4 - Review MOD Projects**	**33 days**	**Wed 11/26/14**	**Thu 1/15/15**	
56	1.1.9.4.1	Pass 4 - Review MOD Projects	33 days	Wed 11/26/14	Thu 1/15/15	SPP
57	1.1.9.5	Pass 4 - Lock Down MOD	22 days	Thu 1/1/15	Fri 1/30/15	SPP
58	1.1.9.6	Pass 4 - MOD Model Extraction	1 day	Fri 1/16/15	Fri 1/16/15	SPP
59	**1.1.9.7**	**Pass 4 - Build Final Powerflow Models**	**10 days**	**Mon 1/19/15**	**Fri 1/30/15**	

ID	WBS	Task Name	Duration	Start	Finish	Resource Names
60	1.1.9.7.1	Pass 4 - Build Final Powerflow Models - with ITP NTC IDEVS	10 days	Mon 1/19/15	Fri 1/30/15	
61	1.1.9.8	Pass 4 - Post MDWG 2015 Series Build Final Powerflow Models	0 days	Fri 1/30/15	Fri 1/30/15	SPP
62	1.1.9.9	Pass 4 - Final ACCC Analysis	1 day	Mon 2/2/15	Mon 2/2/15	SPP
63	**1.1.10**	**Final**	**6 days**	**Mon 2/2/15**	**Mon 2/9/15**	
64	1.1.10.1	Final - Members Review for Finalization of Powerflow Models	5 days	Mon 2/2/15	Fri 2/6/15	Members
65	1.1.10.2	Finalization - Conference Call Vote	1 day	Mon 2/9/15	Mon 2/9/15	
66	**1.1.11**	**2015 MDWG Short Circuit Models - Build Pass 1 Short Circuit Models**	**56 days**	**Tue 11/18/14**	**Mon 2/9/15**	
67	1.1.11.1	Kick-off - Build Pass 1 Short Circuit Models	6 days	Tue 11/18/14	Tue 11/25/14	SPP
68	1.1.11.2	Kick-off - Post Pass 1 Short Circuit Models	0 days	Tue 11/25/14	Tue 11/25/14	SPP
69	1.1.11.3	Pass 1 - Members Review/Submit Changes to Pass 1 Short Circuit Models	22 days	Wed 11/26/14	Wed 12/31/14	Members
70	1.1.11.4	Pass 1 - Member Review/Changes Due	0 days	Wed 12/31/14	Wed 12/31/14	Members
71	1.1.11.5	Pass 1 - Build Final Short Circuit Models	22 days	Thu 1/1/15	Fri 1/30/15	SPP
72	1.1.11.6	Pass 1 - Post MDWG 2015 Series Final Short Circuit Models	0 days	Fri 1/30/15	Fri 1/30/15	SPP
73	1.1.11.7	Final - Member Review for Finalization of Short Circuit Models	5 days	Mon 2/2/15	Fri 2/6/15	Members
74	1.1.11.8	Finalization - Conference Call Vote	1 day	Mon 2/9/15	Mon 2/9/15	
75	**1.1.12**	**2015 MDWG DYNAMICS MODELS**	**188 days**	**Wed 11/26/14**	**Thu 8/20/15**	
76	**1.1.12.1**	**MMWG 2014 Series Dynamic Models**	**1 day**	**Mon 1/19/15**	**Mon 1/19/15**	
77	1.1.12.1.1	Receive ERAG MMWG SDDB (Dynamics Database)	1 day	Mon 1/19/15	Mon 1/19/15	
78	**1.1.12.2**	**Initial Data Update**	**54 days**	**Wed 11/26/14**	**Fri 2/13/15**	
79	**1.1.12.2.1**	**Initial Data Update - Build and Post DYRE Files, Wind Farm Data, and Docureport**	**10 days**	**Wed 11/26/14**	**Thu 12/11/14**	
80	1.1.12.2.1.1	Initial Data Update - Build and Post DYRE Files, Wind Farm Data, and Docureport	10 days	Wed 11/26/14	Thu 12/11/14	SPP
81	1.1.12.2.2	Initial Data Update - Members Submit Data Updates	44 days	Fri 12/12/14	Fri 2/13/15	Members
82	1.1.12.2.3	Initial Data Update - Member Data Due	0 days	Fri 2/13/15	Fri 2/13/15	Members
83	**1.1.12.3**	**Powerflow Adjustments**	**20 days**	**Tue 2/10/15**	**Mon 3/9/15**	
84	1.1.12.3.1	Powerflow Updates	10 days	Tue 2/10/15	Mon 2/23/15	SPP
85	1.1.12.3.2	Wind Farm Topology and GI Updates	10 days	Tue 2/24/15	Mon 3/9/15	SPP
86	**1.1.12.4**	**Dynamic Case Adjustments**	**37 days**	**Tue 2/24/15**	**Wed 4/15/15**	
87	1.1.12.4.1	Update SDDB (ERAG/MMWG Dynamic Database)	4 days	Tue 2/24/15	Fri 2/27/15	SPP
88	1.1.12.4.2	Duplicate Models	2 days	Mon 3/2/15	Tue 3/3/15	SPP
89	1.1.12.4.3	Generator Data Checks	2 days	Wed 3/4/15	Thu 3/5/15	SPP
90	1.1.12.4.4	SDDB Governor Limits and Small Time Constant Reset	2 days	Fri 3/6/15	Mon 3/9/15	SPP
91	1.1.12.4.5	WMOD/Generic WTG Checks	2 days	Tue 3/10/15	Wed 3/11/15	SPP
92	1.1.12.4.6	CONL & GNET Files Updates	4 days	Thu 3/12/15	Tue 3/17/15	SPP
93	1.1.12.4.7	Post Member Feedback for Dynamic Data & Case Issues	1 day	Wed 3/18/15	Wed 3/18/15	SPP
94	1.1.12.4.8	Members Submit Data Updates	15 days	Thu 3/19/15	Wed 4/8/15	Members
95	1.1.12.4.9	Member Data Due	0 days	Wed 4/8/15	Wed 4/8/15	Members
96	1.1.12.4.10	Process SPP Member Updates	5 days	Thu 4/9/15	Wed 4/15/15	SPP
97	**1.1.12.5**	**Dynamic Case Initialization**	**15 days**	**Thu 4/16/15**	**Wed 5/6/15**	
98	1.1.12.5.1	Case & Dyre File Corrections based on Initialization Messages	15 days	Thu 4/16/15	Wed 5/6/15	SPP
99	**1.1.12.6**	**Build Final Models**	**35 days**	**Thu 5/7/15**	**Wed 6/24/15**	
100	1.1.12.6.1	20 Second No-fault Test & Case Adjustment	10 days	Thu 5/7/15	Wed 5/20/15	SPP
101	1.1.12.6.2	60 Second Ring-Down Test & Case Adjustment	10 days	Thu 5/21/15	Wed 6/3/15	SPP
102	1.1.12.6.3	NERC B&C Faults Test & Case Adjustment	5 days	Thu 6/4/15	Wed 6/10/15	SPP
103	1.1.12.6.4	Dynamic Case Reduction	10 days	Thu 6/11/15	Wed 6/24/15	SPP
104	**1.1.12.7**	**Dynamic Case Review and Finalization**	**41 days**	**Thu 6/25/15**	**Thu 8/20/15**	
105	1.1.12.7.1	Post Initial Models	5 days	Thu 6/25/15	Wed 7/1/15	SPP
106	1.1.12.7.2	Member Review of Initial Models	10 days	Thu 7/2/15	Wed 7/15/15	Members
107	1.1.12.7.3	Member Data Due	0 days	Wed 7/15/15	Wed 7/15/15	Members
108	1.1.12.7.4	Final Data Update - Build Final Models	10 days	Thu 7/16/15	Wed 7/29/15	SPP
109	1.1.12.7.5	Post Final Models	1 day	Thu 7/30/15	Thu 7/30/15	SPP
110	1.1.12.7.6	Member Review for Finalization of Dynamic Models	10 days	Fri 7/31/15	Thu 8/13/15	Members
111	1.1.12.7.7	MDWG Vote	5 days	Fri 8/14/15	Thu 8/20/15	Members

Southwest Power Pool

Southwest Power Pool, Inc.

~~POWER FLOW~~ MODEL DEVELOPMENT

PROCEDURE MANUAL

Comment [AC1]: – If this manual is to be publicly posted on the SPP website with unrestricted access, as was the prior version, it will need to be PUBLIC.

If this manual is not to be publicly posted, but will be shared with all or a subset of SPP members, it will need to be SPP RESTRICTED.

SPP Confidential information is for internal SPP use only and cannot be released out of SPP without executive approval and/or a non-disclosure agreement.

MAINTAINED BY
SOUTHWEST POWER POOL
MODEL DEVELOPMENT WORKING GROUP

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Version History

Original: September 1985

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TABLE OF CONTENTS

SECTION **PAGE**

TABLE OF CONTENTS (Continued)

SECTION **PAGE**

TABLE OF CONTENTS (Continued)

SECTION **PAGE**

TABLE OF CONTENTS (Continued)

SECTION **PAGE**

MODEL DEVELOPMENT WORKING GROUP

Joe Fultz, Chairman
Grand River and Dam Authority, OK (GRDA)

Nate Morris, Vice Chairman
Empire District Electric Company, MO (EMDE)

Scott Rainbolt, Member
American Electric Power, OK (AEPW)

Derek Brown, Member
Westar Energy, KS (WERE)

Dustin Betz, Member
Nebraska Public Power District, NE (NPPD)

John Boshears, Member
City Utilities of Springfield, MO (SPRM)

Mike Clifton, Member
OG+E Electric Services, OK (OGE)

Rene Miranda, Member
Xcel Energy, Inc., TX (SWPS)

Scott Schichtl, Member
Arkansas Electric Cooperative Co, AR (AECC)

Jason Shook, Member
GDS Associates, GA (ETEC Representation)

Brian Wilson, Member
Kansas City Power & Light Company, MO (KCPL)

Nathan McNeil, Member
Midwest Energy, Inc., KS (MIDW)

Anthony Cook, Secretary
Southwest Power Pool, Inc., AR (SPP)

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1. GENERAL INFORMATION

A. Purpose

This manual provides concise written guidelines and procedures for use by the system representatives in building and updating the Southwest Power Pool, Inc. (SPP)∗ Power Flow Models. Proper use of this document should aid in the coordination between systems, consistency in reporting of data, and realism of the model developed. As the responsibility of model development shifts from one person to another within the SPP systems, it is important that this document be used as the basis for instruction in order that the details are kept from deteriorating through word-of-mouth transfer.

B. SPP Background

SPP was formed in the early summer of 1941 when 11 companies voluntarily joined together in order to serve a large industrial load and meet critical national defense needs during World War II. These 11 electric utilities joined together to form a major "Pool." This pooling of resources became known as the Southwest Power Pool. At the conclusion of World War II, the Executive Committee of SPP decided to retain the organization. This retention of SPP was due in part to the vast experience gained in power pooling and coordination.

In mid-1968, SPP became part of the North American Electric Reliability Council (NERC), one of nine regional reliability councils, and in late 1969, member systems signed a new Coordination Agreement, which reorganized SPP into a regional reliability organization as envisioned by a special task force of the Federal Power Commission (FPC) that studied the northeast blackout of 1965. Achieving reliability (adequacy and security) and economics of operations requires close coordination and communication between SPP Member Systems as well as with our neighboring councils of Southeastern Electric Reliability Council (SERC), Mid-Continent Area Power Pool (MAPP), Electric Reliability Council of Texas (ERCOT) and Western Electricity Coordinating Council (WECC).

Some of the data models developed in SPP are used in the development of the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) models. The ERAG MMWG was formerly under the NERC and is now under the ERAG Management Committee (MC). These models represent the

Multiregional electrical configuration of the entire eastern interconnected region, and are used primarily by the various regions to develop external equivalents.

C. General Data Reporting Responsibilities

The SPP ~~member transmission planners~~data reporting entities are responsible for the following categories of system modeling data:

1) Power Flow,
2) Short Circuit,
3) Dynamics

Power Flow models are developed for an annual series of SPP cases, including an annual series of ERAG MMWG cases. Specific models are prepared and modified for use in SPP designated studies as required by SPP Regional Tariff and Criteria.

Short Circuit models are developed annually using a subset of the Reliability Power Flow models.

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The Dynamics Model is also updated annually with current generator unit information. Power Flow models are used in conjunction with stability data to run dynamic simulation.

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 Power Flow 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 Criteria.

For the purpose of building planning models it is recognized that unplanned generation

∗ See Section 8 - ACRONYMS

may be required to meet local load demands. Members submitting exploratory type generation to meet local load demands are required to submit Model On Demand (MOD) Projects with the appropriate Project Type (Reliability), Status (NERC Standard Compliance), and unit ID of Zx (where x is any second ID designation appropriate in PSS/E).

Entities in the SPP region that are not members of the SPP but required to submit data (i.e. IPPs, Municipalities) will submit data directly to the Transmission Owner or Balancing Authority in which their system resides. Upon review (i.e. data accuracy, quality) by the Transmission Owner or Balancing Authority the data will then be provided to the SPP during the annual MDWG model update process. The data submitted will be in the standard PTI format as specified in the MDWG Powerflow Development manual. All non-SPP members that are responsible for submitting this data should directly coordinate with the Transmission Owner or Balancing Authority on timing for sending data, as well as any special requirements in data formatting.

D. 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.

E. Power Flow Development Manual Changes

- Section 2.A.1 ---- Power Flow Model Development, Introduction
- Section 2.B.1 ---- Dynamic Model Development, Introduction
- Section 3.A.5 ---- Load Data
- Section 3.A.7 ---- Remote Generation Modeling Procedure
- Section 3.A.10 ---- Owner Data and Line Mileage Data (SAS-70 Control)
- Section 3.C.5.C ---- Wind generation modeling
- Section 4.C ---- MDWG Updates
- Section 6.C ---- SPP Members

- Section 9 ---- MDWG Contact List
- Section 10.B ---- Request an SPP Map / Model
- Section 11 ---- MDWG Model set
- Section 12 ---- MMWG Compliance Checks
- Section 13. MMWG Appendices for Reference
- Section 15 Compliance

2. SCHEDULE

As with all schedules, the meeting of deadlines is most critical. All system representatives must familiarize themselves with the schedule well in advance of all deadlines. This will alleviate any problems with the timing of data submittal and data reviews. The schedule for model development will be sent with the first data request and posted with the starting models. An introduction to the power flow, dynamic, and short circuit model types is below.

A. Power Flow Model Development

1. Introduction

SPP planning model data is contained in the SPP database which is MOD and the Data Submittal Workbook. MOD data is divided into three parts a Base Case, Projects, and Profiles (Bus, Loads, Generation, Device Control, and Net Schedule Interchange). MOD also contains seasonal ratings for branches, two winding transformers, and three winding transformers, and short circuit model sequence data. The Data Submittal Workbook includes: Transactions, Generator Data, Owner Mapping, Load Mapping, Expanded Bus Names & Translation, Non-Scalable Load, Area Summary Report, and Regional Ties. The Data Submittal Workbook is posted on the SPP File Sharing site.

SPP MDWG Power Flow Models are published according to the schedule in Section 15 A.

2. AC Contingency Analysis

SPP will perform AC Contingency Analysis ~~of the current year Summer Peak model and the farthest out Summer Peak model after the final models are posted~~on all models contained in the power flow model set. ~~Members' AC Contingency Mitigation Plans are due to SPP per the model building schedule.~~ The purpose of this contingency analysis is to validate the models. Member updates for errors found due to contingency analysis are due per the latest MDWG schedule.

B. Stability Model Development

1. Introduction

The MDWG Stability Models include full MMWG cases and machine reduced cases. The initialized no-fault models can be solved with quarter-cycle and half-cycle time

~~step~~ steps. The MDWG Stability Model Update is used to support SPP reliability studies and ERAG MMWG Dynamic model requirements. It is important for all generating entities that interconnect to the SPP transmission to support the Regional Transmission Organization with current detailed dynamics data in the proper SPP model format. The current MDWG Stability Model Format is PSS/E dynamics DYRE and RAWD formats.

The Dynamics Model data includes:

a. Power Flow models
b. Dynamics model data in Siemens PTI PSS/E DYRE format
c. User written model source and object code (includes wind farms)
d. ERAG MMWG System Dynamics Database (SDDB)
e. SDDB data update worksheet

SPP MDWG Dynamic Models are published according to the schedule in Section 15 B.

3. POWER FLOW MODEL DEVELOPMENT

A. Data Preparation

The following section describes important items to be considered in the development of a Power Flow model. These guidelines must be followed in preparing the data for publishing new models or updating existing models. ~~Each system must keep MOD data current or updated for the MDWG model builds. The transactions workbook will be updated for the MDWG models. The Data Submittal Workbooks will be updated annually. The MMWG Regional Tie data must be current for all models.~~

1. ~~---~~MOD data ~~must~~ should be kept current for each pass during the MDWG model~~s~~ build.
2. The Data Submittal Workbook tabs should be kept current for each pass during the MDWG model build including the items below.
   a. Transactions and tie line modifications shall be coordinated with neighboring systems
   a. Known outage(s) of Generation or Transmission Facility(ies) with a duration of at least six months

~~--- Data Submittal Workbooks updated annually for the MDWG B1 series models~~

~~--- MMWG Regional Tie Data must be current for MDWG models~~

~~Modifications to tie line data shall be made in MOD through a Project. Tie line modifications shall be coordinated with neighboring systems. Generator ratings must also be updated in the generator worksheet in the Data Submittal Workbook~~

All changes to the SPP Power Flow models are made through the Siemens PTI MOD, ~~and~~ PSS/E software, and Data Submittal Workbook.

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Annual Models

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

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

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

The list of MDWG Power Flow models is in Section 11

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 dependant 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.

The ERAG MMWG Procedure Manual (May 07, 2009) states: "The power flow model will be based on a load forecast which assumes a statistical probability of one occurrence in two years (50/50)."

Loads should be derived using the 50/50 probability forecast as a minimum.

Various seasonal models are presently developed by SPP systems. They are: a Summer Peak condition, a Winter Peak condition, a Spring Peak condition, and a Fall Peak condition. These four seasonal peak conditions are defined to represent the one-hour system peak and should **not** consider coincidence between member systems' load.

Spring Peak:	April & May
Summer Peak:	June thru September
Fall Peak:	October & November
Winter Peak:	December thru March

The definition of the **April minimum** load level pinpoints a condition such as a **Sunday morning in April, hour ending 5:00 a.m**. The intent is to represent a system's minimum annual load. This, of course, would occur at different times for each system.

The seasonal on-peak average model is prepared primarily to calculate incremental losses for the SPP Regional Tariff. The on-peak average model, or shoulder, is defined to be 85% of the total seasonal peak load level.

1. **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 Power Flow 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 listed in Section 6-B should be used on the Area Summary Report and in the Power Flow input data of area interchange and transactions. The following sequence of steps is to be used in completing this report:

a. 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.

b. 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 <u>not</u> 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.

c. 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.

d. The case year and season should be entered in the appropriate locations in chronological order.

e. The current system official load forecast should be entered as net load (Item 6).

f. The estimated losses should be entered (Item 5). The reference cases can be used as a starting point to estimate system losses.

g. Load equals net load minus estimated losses (Item 4).

h. 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.

i. Net power (Item 3) must equal net load (Item 6). Generation (Item 1) is equal to the net power plus interchange.

2. 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 **<u>must</u>** coordinate with its neighbors on the tie line representation in the models being developed.
This coordination should consist of:

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

SPP Member Tie data is maintained in a MOD Project file. The majority owner of the tie is responsible for maintaining the tie's Power Flow, Sequence, and Ratings data.

SPP uses the MMWG Regional Tie line list as the first database for tie line information for NERC/SPP inter-region ties. 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.

3. 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 line and transformer data formats are found in Section 5.

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

a. 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 <u>bus</u> will require a similar record to delete all associated or connected devices with the bus (lines, generators, loads, transformers, etc.) from the base case.

b. 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.

c. The impedance data should be specified on a 100 MVA base. The smallest allowable reactance is 0.00011 P.U. on a 100 MVA base. Reactance values less than minimum will cause the Power Flow program to treat the line as a zero impedance line to reduce solution time.

d. Line charging data will be divided in the appropriate units depending on the specific format being utilized. Accuracy is needed to ensure a proper voltage profile in the model.

e. Each SPP member shall rate transmission circuits in accordance with the SPP Criteria (Section 12.2). This criteria calls for each member to compute, at a minimum, summer and winter seasonal ratings for each circuit element. Each Base Case (Network) and Project branch, two-winding and three-winding transformer must have a specified rate A (normal) and rate B (long-term emergency) for spring, summer, fall, and winter. The ratings data format is in the MOD Procedure Manual.

f. The transformer tap and tap limits shall be specified. The use of LTC transformers should be kept to a minimum to help reduce the case solution time. Using LTC transformers for local area voltage control where no such transformer exists should be avoided. Regulating transformers **should not** be located at a bus with a regulating generator or other voltage regulating device.

g. 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 SPP Regional Tariff. Circuit mileages should be coordinated on all jointly owned lines. Invalid line lengths result in inaccurate revenue allocations.

h. 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 power flow 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.

4. Bus Data

For all SPP Power Flow models, systems will model buses within their SPP allocated bus range (see Section 6-B). For the sake of consistency, the bus names and numbers should remain constant from case to case and year to year. All bus shunts will be modeled as switched shunt. The Switch Shunt may be locked. Any changes to bus names or numbers will be documented on the SPP Expanded bus name list. This will include renumbering buses as well as adding new or removing old buses from the models. 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. The SPP Expanded bus name list can be used as a quick reference for new names. 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:

a. 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, ect.) must also be deleted or removed from the power flow model within the Project.

b. As previously mentioned, the bus names and numbers should remain constant unless there is a particular reason for changing them. This will aid the consistency of the models developed. Bus names may be up to 12 characters with the first character, preferably, alphabetic rather than numeric. The name should be left justified. The eighth character field of the bus name should be the SPP voltage code described as follows:

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

The ninth through twelfth character fields of the bus name are reserved for the base kV designation (right justified). As associated with the voltage code, the generally used kV values are: 69.0, 115, 138, 161, 230, 345, 500 and 765.

c. For generator regulated buses, a desired voltage magnitude will be given with reactive power limits also specified. 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 Criteria Section 12.1. Generators should model the net output of the generating facility while taking auxiliary load into account. The net generator output is usually modeled with an explicit auxiliary load (fans, motors, etc.) at the generator bus and the generator PMAX & PGEN set to a gross output level – OR – the generator PMAX & PGEN is simply set to the net power output (i.e., gross output – motor load – fan load, etc.) with the auxiliary load already accounted for. 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.

d. Bus loads should be specified with the real and reactive values provided **as a pair** in all entries.

e. 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.

f. Capacitors and reactors 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.

   Do not model existing or planned shunts on the Bus record. Shunts should be modeled in the Switched Shunt Record unless they are line shunts and trip when the line is opened. Bus shunt voltage bandwidth must be wide enough to prevent "hunting" of shunt value during power flow solution of base case or contingency analysis. The switched shunts can be modeled as fixed shunts with specified B initial value.

5. Load Data

Load data is maintained in models via an IDEV file which is applied to the model. Profiles, Loads can belong to an Area that is not the same as the Bus Area. Refer to Section 5-A-3 for load data formats. 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 Data Submittal Workbook. 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 Data Submittal Workbook.

6. **Generator Data**

Check Generator MW and Mvar output to ensure the unit is within the PMAX, PMIN, QMAX, QMIN and Mbase limits and that the output of the generator accounts for auxiliary load. Generator MW should be set to “gross” level if auxiliary load is modeled explicitly – OR – “net” level if auxiliary loads are not modeled. Qmax and Qmin values in the models should be based on unit test data. Intermittent resources (e.g., wind and run-of-river hydro) should not normally be dispatched beyond their net capability as established by SPP Rating of Generating Equipment Criteria 12. Ensure accurate values of ZR and ZX. This data is not needed in normal power flow and equivalent construction work, but is required for switching studies, fault analysis and dynamic simulation. For dynamic simulation, **this complex impedance must be set equal to the sub unsaturated transient impedance for those generators modeled by sub transient level machine models**, and to transient impedance for those modeled by classical or transient level models. Machine Base (MBASE) and Zero Impedance (ZSOURCE) values for the Power Flow models must match stability data. The MDWG powerflow models will use the unsaturated subtransient impedance data for generators (X’’di). Future Generators that are in the models but are not budgeted for construction need to be identified in the Generator Data worksheet of the Data Submittal Workbook.

When modeling mothballed and future retired units, the Pmax, Pmin, Qmax, and Qmin values should be modeled as zero. Decommissioned units should be removed from the models.

Rules for building +10 year model:

When building the +10 year model, a member may not have enough generation to supply their load. Therefore, members should follow these guidelines to compensate. The solutions are listed in order of preference.

a. Use existing IPP’s inside of a member’s footprint to supply the needed generation.
b. Create a transaction from a first tier control area that has generation available. Then add this transaction to the transaction workbook with an ID of ‘ z ‘ and not

checked as firm.

c. Create a new generator in the most likely spot for adding a generator to the members system and label it as an exploratory project. The location of the generator should consider transmission constraints for the area. In other words, can the power be pushed into the system at that location?

Note: The Generator Data worksheet data will be maintained to provide a convenient source of data for Member and SPP Staff use. Therefore accurate data in the Generation workbook is imperative. The official SPP generator data is in the MOD Base Case or Project.

7. Remote Generation Modeling Procedure

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

b. **Modeling Process**
If a member acquires remote generation outside their Control Area (Power Flow model numbered area), the following modeling process should be followed:

(1) All buses should be assigned numbers that are in the host's control area bus number range.
(2) Area Number/Name should be the host's control area number.
(3) Zone Number/Name should be in the host's control 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.

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

8. Power Flow Data Check List

The Power Flow Data Check List should be used as an aid for ensuring good model data. As the data and preliminary runs are reviewed for each model, the items should be checked off. A copy of this form can be found in **Section 7**.

9. Facilities Transferred to SPP's Functional Control

The SPP FERC "Docket No. RT04-01-00 Volume 1", ***In the July 2 Order, the Commission: …(7) ordered that SPP file a list of all transmission facilities that***

will be transferred to its operational control and revise the Operational Authority White Paper ("OA White Paper") or Membership Agreement, or provide some other binding document, to reflect SPP's clear authority to exercise day-to-day control over the appropriate transmission facilities within its footprint…

Attachment AI to the SPP Regional Tariff contains the criteria for inclusion of facilities that are considered "***Facilities Transferred to SPP's Functional Control***". Transmission facilities meeting the definition set forth in Attachment AI must be included in the SPP MDWG Power Flow Models.

10. Owner Data and Line Mileage Data (SAS-70 Control)

Per SAS-70 requirements (i.e. – Loss calculations) SPP Loss models must be updated every June and October with current Owner Data and Line Mileage data. To meet the SAS-70 requirement the SPP models must include owner data and line-mileage data. SPP Staff will obtain this data from the MOD Base Case and Projects; therefore; it is important that Members keep the data current in MOD.

11. Zone Range Assignments

a. MMWG Region

Region	Bus Numbers	Area Number	Zone Number	Owner Numbers
Entire System	100,000 to 899,999	100 to 899	100 to 1,899	100 to 1,199
NPCC	100,000 to 199,999	100 to 199	100 to 199 and 1,100 to 1,199	100 to 199
RFC	200,000 to 299,999	200 to 299	200 to 299 and 1,200 to 1,299 and 1,800 to 1,899	200 to 299
SERC	300,000 to 399,999	300 to 399	300 to 399 and 1,300 to 1,399	300 to 399
FRCC	400,000 to 499,999	400 to 499	400 to 499 and 1,400 to 1,499	400 to 499
SPP	500,000 to 599,999	500 to 599	500 to 599 and 1,500 to 1,599	500 to 599 and 800 to 899
MRO	600,000 to 699,999	600 to 699	600 to 699 and 1,600 to 1,699	600 to 699
ERCOT (future)	700,000 to 799,999	700 to 799	700 to 799 and 1,700 to 1,799	700 to 799

b. SPP Area

Refer to the most current SPP Area Zone Assignments.

B. Data Transmittal

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

(1) **ELECTRONIC** --- www.TrueShare.com

(2) **E-MAIL** --- planningmodeling@spp.org

The preferred method of submittal is through the "SPP MDWG File Sharing Site" www.TrueShare.com. 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. See Section 6-B for a sample file format. Case title lines should include the case title as in the following format examples: *04SP, *04FA, *04SH, *07SP (no spaces between characters).

C. 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 power flow detail report should be examined. If loads were scaled from a reference case, the scaling factor should be checked. The load power factor should also be checked as power factors change seasonally. Check Power-factor of loads. The load supplying entities for the MDWG models 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 Power Flow 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 Power Flow models and have since been delayed or cancelled should be removed entirely from the Power Flow model. These facilities cause solution problems for some power flow programs if left in the model with an off-line status. Planned projects, including reactive resources such as capacitor banks, are to be included in the models. These projects are to be added through MOD in accordance with the MOD Type/Status Matrix of the Web Based Power Flow Model Development Procedure Manual.

5. Review of Output

The power flow 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.

Three useful reports for locating problems include:

--- The voltage summary,

--- The overloaded branch summary, and

--- 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 power flow 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 power flow 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 number of taps should not be greater than 50.

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 Workbook. The generator workbook will be updated to include both the saturated and unsaturated impedance for each machine. Fuel types, especially wind farms, should be indentified in the appropriate column.

The reactive output limits (MAX and MIN) should be realistic values as defined in SPP Criteria 12.1.6 (see Section V.A.4). For generators, a general rule of thumb sets MVAR limits as:

QT --- MAX = one-half of MW rating

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.

Wind farm generation should be modeled at the machine voltage bus (i.e. 575 V) when applicable; this is primarily done for Generation Interconnection studies when determining the power factor of a wind farm at the point of interconnection. For the purpose of other planning studies, all machines should be aggregated on a single machine voltage bus. The rating of the resulting unit should be the total rating of the wind farm. The unit should be dispatched per SPP Criteria 12.1.5.3.

4. <u>PERIODIC MODEL UPDATES</u>

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.

A. 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.

B. MDWG Updates

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

Two of these methods are:

a. Using the power flow update procedure in Section 5 to update MOD.
b. 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 a 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.

5. <u>PROGRAM OPERATION</u>

The **SPP Power Flow** 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.

A. PTI-PSS/E Data Format

Power Flow 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 **comma** (**not** 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 Power Flow 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 modified.** Data currently in the model is used as the default value for data fields not specified in the format.

1. Power Flow Solution

The power flow solution will have “Area interchange control” with the “Tie Line and Loads” option selected to meet ERAG MMWG model building requirements.

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

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

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

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

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

B. TRANSMITTED DATA FILE EXAMPLES (Refer to MOD Procedure Manual)

C. PTI-PSS/E SHORT CIRCUIT DATA FORMAT

The SPP Short Circuit data is included in MOD Base Case (Network) and Project data. 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. Missing Project sequence data must be updated by applying a sequence file to the Project in MOD.

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.

6. SPP DATA

A. Typical Transmission Line or Transformer Impedance

These tables are only for the checking of reasonableness of line and transformer data and should not be used in data preparation for existing facilities.

TYPICAL TRANSMISSION LINE DATA

(100 MVA BASE)

kV	Amps	R/mile	X/mile	(Mvar/mile) Charging	MVA	X/R
69	600	0.00540	.0143	0.00030	71	2.6
115	1200	0.00064	.0050	0.00084	240	7.8
138	1200	0.00045	.0038	0.00120	286	8.4
161	2000	0.00020	.0019	0.00220	558	9.5
230	2000	0.00010	.0010	0.0040	796	10
345	2000	0.00004	.00048	0.0091	1195	12
500	2000	0.00002	.00026	0.0170	1732	13

A typical transmission transformer's impedance is approximately 8% on the OA rating base.

For example:

On a 345 kV Line that is 70 miles long –

R is: 70(0.00004) = 0.0028

X is: 70(0.00048) = 0.0336

Charging is: 70(0.0091) = 0.637

B. System Abbreviations & Area Number Assignments

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

C. SPP Members

The SPP Members are identified on the SPP Website. See the "Members" link under "About SPP" on www.SPP.org.

7. FORMS – Area Summary Report

SPP Southwest Power Pool

Area Name & Number: ____________________

Prepared By: ____________________

Telephone Number: ____________________

POWER FLOW DATA AREA SUMMARY REPORT

CASE															
1. Generation															
Purchases (-)/Sales (+) To/From Area Name	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
2. Total Interchange															
3. Net Power (1-2)															
4. Load															
5. Losses															
6. Net Load (4+5)															
7. Slack Bus Generation															
8.Slack Bus Number & Name															

Note:

7. FORMS – Power Flow Data Checklist

SPP Southwest Power Pool

Area Name & Number: _______
Prepared By: _______
Telephone Number: _______

POWER FLOW DATA CHECKLIST

CASE															
BUS DATA															
Names - 12 characters															
Voltage Codes															
Power Factor															
Load - Real															
Reactive Load															
Voltage															
Fixed Shunts - Reactors															
Capacitors															
Dynamic Shunts - SVC's															
Synchronous Condensors															
Generation - Dispatch/Net															
Reactive Output															
Reactive Limits															
Regulated Voltages															
Generator Rating															
Slack Bus															
LINE DATA															
Ratings - Normal															
Emergency															
Impedance - Resistance															
Reactance															
Charging															
Flows															
Transformers - Taps															
Tap Ranges															
Regulated Bus															
OTHER DATA															
Net Area Interchange															
Area Transactions															

Note:

8. ACRONYMS

ATC – Available Transfer Capability

CAP – Capacitor

EIA – Energy Information Act

ERAG – Eastern Interconnection Reliability Assessment Group

ERCOT – Electric Reliability Council of Texas

FPC – Federal Power Commission

IDEV – Input Device (PSS/E Dialog Input Device Selection Activity)

LTC – Load Tap Changing

MAPP – Mid-Continent Area Power Pool

MAIN – Mid-American Interpool Network

MBASE – Machine Base

MDWG – Model Development Working Group

MMWG – Multiregional Modeling Working Group

Mvar – Megavar

MW – Megawatt

NERC – North American Electric Reliability Corporation

PSS/E – Power System Simulator for Engineers

PTI – Power Technologies, Inc.

pu – Per-unit

RAWD – Raw Data

RDCH – Read Change (Command to read in and change data in PSS/E)

REAC – Reactor

SERC – Southeastern Electric Reliability Council

SPP – Southwest Power Pool, Inc.

STEP - SPP Transmission Expansion Plan

TWG – Transmission Working Group

WSCC – Western Systems Coordinating Council

ZSOURCE – Zero Impedance

*** NOTE** – A complete listing of other SPP acronyms can be found on the SPP website at www.spp.org. See the “Glossary and Acronyms” link under “Training”

9. MDWG Contact List

The MDWG Contact List can be found on SPP's website, spp.org, under the documents section of the Model Development Working Group.

10. SPP Model Release Guidelines

A. SPP Model Release Guidelines

1. Power Flow and Short Circuit Models

SPP Base Case Power Flow 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 Power Flow models or reduced network equivalents of those models to government agencies. The public may receive models through the FERC Critical Energy Infrastructure Information (CEII) formal request process. For more information on requesting Base Case Power Flow models, contact the SPP Model Contact.

Base case power flow 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 equivalized, such external models must be disclaimed, as equivalent representations not intended for study of the transmission systems in those external areas.

2. System Dynamic Data Base and Dynamic Simulation Cases

SPP Stability 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 written 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.

3. SPP Model contact:

Please send all general modeling questions and concerns to planningmodeling@spp.org.

B. Request an SPP Map / Model

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

If you are an SPP member, interconnection customer, transmission service customer (or their consultant) and would like to request an SPP Transmission Map or Model, please complete the appropriate forms below. (Requests for Joint & Interregional System Planning Models are addressed on this page.) If you are requesting access on behalf of an organization other than your employer, a Consultant Authorization Form must also be submitted on your behalf.

SPP Transmission Map Order Form
SPP Model Order Form
SPP Confidentiality Agreement
Consultant Authorization Form

All other requesters should file a Critical Energy Infrastructure Information (CEII) request with the Federal Energy Regulatory Commission (FERC). Detailed instructions on how to file a FERC CEII request are available at www.ferc.gov/help/filing-guide/ceii-request.asp. You may file your CEII request online at www.ferc.gov/legal/ceii-foia/ceii/eceii.asp.

If you have obtained FERC CEII approval and would like to request additional CEII, please submit the appropriate SPP Form(s) and SPP Confidentiality Agreement, **providing the requester's FERC CEII ID Number and attaching a copy of the FERC Authorization Letter (i.e., FERC Notice of Intent to Release)**.

Completed SPP Forms and the SPP Confidentiality Agreement should be e-mailed to SPP Customer Relations. The original, signed hardcopy of the SPP Confidentiality Agreement should be mailed to the attention of **Susan Polk, 415 North McKinley, Suite 140, Little Rock, Arkansas 72205**.

If you have questions or would like additional assistance, please contact SPP Customer Relations at (501) 614-3309.

Last Updated April 20, 2009

11. MDWG Model Set

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

12. <u>MMWG Compliance Checks</u>

ERAG MMWG Procedural Manual May 7, 2009 - Appendix VI

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

- 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. *
- All CNTB <u>errors</u> shall be corrected. (Exceptions will be documented.)
- All instances of mode=1 switched shunts with VHI – VLO < .005 per unit shall be corrected.
- 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.
- All instances of TCUL transformers with more than 50 tap steps shall be corrected.
- All instances of voltage controlling bandwidth less than twice the transformer tap step size shall be corrected.

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

13. MMWG Appendices for Reference

Appendix II
Dynamics Data Submittal Requirements and Guidelines

A. Power Flow Modeling Requirements

1) All power flow 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 MMWG power flow cases, the step-up transformer shall be represented in the power flow generator data record. Where the step-up transformer of the generator or condenser is represented as a branch in the MMWG power flow cases, the step-up transformer impedance data fields in the power flow generator data record shall be zero and the tap ratio unity. The mode of step-up transformer representation, whether in the power flow 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 power flow 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^{TM}E requirements, the Xsource value in the power flow generator data record shall be as follows:

   a) Xsource = X''_d for detailed synchronous machine modeling

   b) Xsource = X'_d for non-detailed synchronous machine modeling

   c) Xsource = should be equal to locked rotor impedance for an induction machine

   d) Xsource = 1.0 per unit or larger for all other devices

5) Generally, SVCs should be represented in power flows as continuously variable switched shunts rather than as generators. In iterative power flow solutions, a generator which hits 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^{TM}E dynamic library models compatible with either representation are available. If a user model representing particular SVC and control features is to be used and that model assumes generator representation, the SVC should be represented as a generator in the power flow.

B. Dynamic Modeling Requirements

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 PSS^{TM}E dynamic model types classified as detailed are GENROU, GENSAL, GENROE, GENSAE, and GENDCO.

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 modeled in detail per Requirement II.1 shall also include representations of the 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, and static compensators (STATCOM), shall be represented by the appropriate PSS™E dynamic models.

4) 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.

5) When user-defined modeling is used in the MMWG cases, written documentation shall be supplied explaining the dynamic device performance characteristics. The documentation for all MMWG user-defined models shall be posted on the MMWG Internet site as a separate document. 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^{TM}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.

6) 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.)

7) 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.

8) 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 power flow 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^{TM}E model IEEEG1 conventions.

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

C. Dynamics Data Validation Requirements

1) All dynamics modeling data shall be screened according to the SDDB data screening checks.

   All data items not passing these screening tests shall be resolved with the generator or dynamic device owner and corrected.

2) 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.

D. 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 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^{TM}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.

APPENDIX III

Procedures for Submission of Dynamics Data

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

A. 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 power flows 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	

B. Complete Set of Dynamics Data

The regional dynamics data must be in the format of a PSS^{TM}E DYRE file. The data must be compatible and consistent with the MMWG power flows selected for the dynamics cases that are being developed. One file for all cases is preferable.

APPENDIX IV
Deliverables

A. Regional Coordinators

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

1. Power Flow Cases
   A. Data as needed to create the MMWG power flow cases in RAWD or Saved Case format, regional representation shall be within an entire solved MMWG power flow model in the proper PSS^{TM}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

B. MMWG Coordinator(s)

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

1. Power Flow Cases
   Initialized steady state and regional contingency cases.
   A. Power Flow 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

APPENDIX V

Power Flow Modeling Guidelines

1. **Modeling Detail** – 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 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 power flow output.
3. **Islanded Buses** – Islanded buses shall not be modeled in MMWG cases.
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 power flow 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 power flow solution techniques and should be avoided.
8. **Transformers** – Effective with Revision 28 of PSS™E, off-nominal turns ratios may not be specified for branches; a block of four or five data records must be entered for each transformer. The off-nominal turns ratio in per unit, or the actual winding voltage in kilovolts, and the phase shift in degrees shall be specified for each winding. The measured impedance (resistive and inductive) between each pair of windings shall be specified: data entry options permit these to be entered in (1) per unit on system (100 MVA) base, (2) per unit on winding MVA base, or (3) load loss in watts and impedance on winding MVA base and base voltage.

9. **Transformers Controlling Voltage or 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 voltage or reactive power flow. Default values of 1.1, 0.9 and 33 are representative of U.S. practice. The upper and lower voltage limits are entered for transformers controlling voltage and the difference, in per unit, should be at least twice the tap step size. 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.
10. **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.
11. **Phase Angle Regulating Transformers** – For phase angle regulating (PAR) transformers, 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.
12. **Branch and Transformer Ratings** – Normal is defined as continuous ratings for system intact conditions and emergency is defined as limited duration ratings used until the system is returned to normal. Accurate normal and emergency seasonal ratings of facilities are necessary to permit proper assessment of facility loading in regional and interregional studies. Three rating fields are provided for each branch and each transformer winding. Normal and emergency ratings should be entered in the first two fields (RATEA and RATEB, respectively); use of the third rating field (RATEC) is optional. Ratings should be omitted for model elements which are part of an electrical equivalent. The rating of a branch or transformer winding should not exceed the rating of the most limiting series element in the circuit, including terminal connections and associated equipment. The emergency rating should be greater than or equal to the normal rating.
13. **Generator Step-Up Transformers** – Generator step-up transformers 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.
14. **Out-of-Service Generator Modeling** – Out-of-service generators should be modeled with a STATUS equal to zero.
15. **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.
16. **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.

17. **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.

18. **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.

19. **Over and Under Voltage Regulation** – Regulation of voltage schedules exceeding 1.10 per unit, or below 0.90 per unit should be avoided.

20. **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.

21. **Fixed Shunts** – All fixed shunt elements at buses modeled in the power flow should be modeled explicitly (not as loads or included with load). The status should be set to zero if the shunt is not in service. Fixed shunt elements that are directly connected to a bus should be represented as bus shunts. Fixed shunt elements that are directly connected to and switch with a branch should be represented as line shunts.

22. **Switched Shunts** – Switched shunt elements at buses modeled in the power flow should be modeled explicitly. Continuous mode modeling using a switched shunt should not be used unless it represents actual equipment (e.g. SVC or induction regulator). The number and size of switched admittance blocks should represent field conditions. The bandwidth (difference between VSWHI and VSWLO) of switched shunt devices should be wide enough that switching one block of admittance does not move the voltage at the bus completely through the bandwidth, thus causing solution problems at the bus. It is recommended that the minimum voltage bandwidth be 4% if only switched shunts are used to regulate voltage. Switched shunts should not regulate voltage at a generator bus, nor should they be connected to the network with a zero impedance tie.

23. **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.)

24. **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.

APPENDIX VII

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

A. 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.
      (Solution: Do not regulate a radial bus; hold MVAR output of a radial bus constant at the value obtained in last iteration.)
   c. Conflicting voltage regulation.
   d. Unreasonably small voltage range for switched shunts.
   e. 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.

<u>B. Problems</u>

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

Note: The PTI PSS™E power flow 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.

APPENDIX VIII
Procedures 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
      i. Branch flows exceeding normal ratings. [RATE or OLTL and OLTR]
      ii. 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]
      iii. Overloaded generators. [GEOL]. Note that this activity checks machine output against the machine MVA base, MBASE, not against PMAX, PMIN, QMAX, and QMIN.
      iv. Branches with extreme impedances or tap ratios [BRCH]. Suggested options are:
         1. 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.
         2. 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.
         3. 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.
         4. Parallel transformers. Minor tap ratio differences may simply reflect field conditions, but differences exceeding one step should be checked to guard against inadvertent errors.
         5. High tap ratios.
         6. 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 loads (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
         1. Generators in the load flow for which there is no active machine model.
         2. Models, usually of excitation systems or governors, initialized out of limits.
         3. The number of iterations required to initialize the initial-conditions power flow.
      ii. A tabulation of conditions at each online machine
         1. Terminal voltage
         2. Exciter output voltage
         3. Real and reactive power output
         4. Power factor
         5. Machine angle in degrees
         6. Direct and quadrature axis currents on machine base.
      iii. A diagnosis of initial conditions, either
         1. “Initial conditions check OK”, or
         2. 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 powerflow 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.

APPENDIX IX
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

MASTER TIE LINE FILE DATA FIELDS continued

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,

MASTER TIE LINE FILE DATA FIELDS
continued

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

MASTER TIE LINE FILE DATA FIELDS
continued

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,

MASTER TIE LINE FILE DATA FIELDS
continued

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,

MASTER TIE LINE FILE DATA FIELDS
continued

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

MASTER TIE LINE FILE DATA FIELDS
continued

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#,

MASTER TIE LINE FILE DATA FIELDS (continued)

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^{TM}E input requirements.
(2) The in-service and out-of-service dates will be expressed as mm/dd/yyyy.

Appendix X
Number Range Assignments for
ERAG MMWG Power Flow Data

Region	Bus Numbers	Area Numbers	Zone Numbers	Owner Numbers
Entire System	100,000 – 899,999	100 to 899	100 to 1,899	100 to 1,199
NPCC	100,000 to 199,999	100 to 199	100 to 199 and 1,100 to 1,199	100 to 199
RFC	200,000 to 299,999	200 to 299	200 to 299 and 1,200 to 1,299 and 1,800 to 1,899	200 to 299
SERC	300,000 to 399,999	300 to 399	300 to 399 and 1,300 to 1,399	300 to 399
FRCC	400,000 – 499,999	400 to 499	400 to 499 and 1,400 to 1,499	400 to 499
SPP	50,000 to 599,999	500 to 599	500 to 599 and 1,500 to 1,599	500 to 599 and 800 to 899
MRO	600,000 to 699,999	600 to 699	600 to 699 and 1,600 to 1,699	600 to 699
ERCOT (future)	700,000 to 799,999	700 to 799	700 to 799 and 1,700 to 1,799	700 to 799

1 Area or zone number 1 is sometimes used as a default when the number is omitted by mistake.
Its use to number an actual area should be avoided.

Appendix XI
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

Appendix XII
Utilized DC Lines

DC Line Number	Region	Name		DC Line Number	Region	Name
1	MRO			**26**	NPCC	
2	MRO			**27**	NPCC	
3	MRO			**28**	NPCC	
4	MRO			**29**	NPCC	
5	MRO			**30**	RFC	
6	MRO			**31**	RFC	
7	MRO			**32**	Unused	
8	MRO			**33**	Unused	
9	MRO			**34**	Unused	
10	MRO			**35**	Unused	
11	NPCC			**36**	NPCC	
12	NPCC			**37**	NPCC	
13	NPCC			**38**	NPCC	
14	NPCC			**39**	NPCC	
15	NPCC			**40**	Unused	
16	NPCC			**41**	SPP	
17	NPCC			**42**	SPP	
18	NPCC			**43**	SPP	
19	NPCC			**44**	SPP	
20	NPCC			**45**	SPP	
21	NPCC			**46**	MRO	
22	NPCC			**47**	MRO	
23	NPCC			**48**	MRO	
24	NPCC			**49**	MRO	
25	NPCC			**50**	Unused	

APPENDIX XIII
System Codes for Use in ERAG MMWG Power Flow Data

NPCC – Northeast Power Coordination Council

Area #	ID	System
101	ISO-NE	ISO New England
102	NYISO	New York ISO
103	IESO	Independent Electric System Operator
104	TE	TransEnergie
105	NB	New Brunswick Power
106	NS	Nova Scotia Power
107	CORNWALL	Cornwall

RFC – Reliability First Corporation

Area #	ID	System
201	AP	Allegheny Power
202	FE	FirstEnergy
205	AEP	American Electric Power
206	OVEC	Ohio Valley Electric Corporation
207	HE	Hoosier Energy Rural Electric Cooperative, Inc.
208	DEM	Duke Energy Midwest
209	DAY	Dayton Power & Light Company
210	SIGE	Southern Indiana Gas & Electric Company
215	DLCO	Duquesne Light Company
216	IPL	Indianapolis Power & Light Company
217	NIPS	Northern Indiana Public Service Company
218	METC	Michigan Electric Transmission Co., LLC
219	ITCT	International Transmission Company
220	IPRV	Illinois Power- Riverside Plant
222	CE	Commonwealth Edison
225	PJM	PJM 500 kV System
226	PENELEC	Pennsylvania Electric Company
227	METED	Metropolitan Edison Company
228	JCP&L	Jersey Central Power & Light Company
229	PPL	PPL Electric Utilities
230	PECO	PECO Energy Company
231	PSE&G	Public Service Electric & Gas Company
232	BG&E	Baltimore Gas & Electric Company
233	PEPCO	Potomac Electric Power Company
234	AE	Atlantic Electric
235	DP&L	Delmarva Power & Light Company
236	UGI	UGE Utilities, Inc.
237	RECO	Rockland Electric Company
295	WEC	Wisconsin Electric Power Company (ATC)
	ESE	Edison Sault Electric (American Transmission Company - ATC)

SERC – SERC Reliability Corporation

Area #	ID	System
314	BREC	Big Rivers Electric Corporation
320	EKPC	East Kentucky Power Cooperative
330	AECI	Associated Electric Cooperative Inc.
331	BCA	Batesville
332	LAGN	Louisiana Generating Company
333	CWLD	Columbia, MO Water and Light
334	WESTMEMP	West Memphis
335	CONWAY	Conway
336	BUBA	Benton Utilities Balancing Authority
337	PUPP	Panda Union Power Partners
338	DERS	City of Ruston
339	DENL	City of North Little Rock
340	CPLE	Carolina Power & Light Company – East
341	CPLW	Carolina Power & Light Company – West
342	DUKE	Duke Energy Carolinas
343	SCEG	South Carolina Electric & Gas Company
344	SCPSA	South Carolina Public Service Authority
345	DVP	Dominion Virginia Power
346	SOUTHERN	Southern Company
347	TVA	Tennessee Valley Authority
349	SMEPA	South Mississippi Electric Power Association
350	AEC	Alabama Electric Cooperative
351	EES	Entergy Electric System
352	YAD	APGI – Yadkin Division
353	SEHA	Hartwell - SEPA
354	SERU	Russell - SEPA
355	SETH	Thurmond – SEPA
356	AMMO	Ameren Missouri
357	AMIL	Ameren Illinois
360	CWLP	City of Springfield (IL) Water Light & Power
361	SIPC	Southern Illinois Power Cooperative
362	EEI	Electric Energy Incorporated
363	LGEE	E.ON.US

FRCC Florida Reliability Coordination Council

Area #	ID	System
401	FPL	Florida Power & Light
402	PEF	Progress Energy Florida
403	FTP	Fort Pierce Utility Authority
404	GVL	Gainesville Regional Utility
405	HST	City of Homestead
406	JEA	Jacksonville Electric Authority
407	KEY	City of Key West
409	LWU	City of Lake Worth Utility
410	NSB	Utilities Commission of New Smyrna Beach
411	FMPP	Florida Municipal Power Pool
412	SEC	Seminole Electric Cooperative
414	STK	City of Starke
415	TAL	City of Tallahassee
416	TECO	Tampa Electric Company
417	FMP	FMPA / City of Vero Beach
418	NUG	Non-Utility Generators
419	RCU	Reedy Creek Energy Services, INC.
421	TCEC	Treasure Coast Energy Center
426	OSC	Osceola at Holopaw (PEF)
427	OLEANDER	Oleander IPP at Brevard (FPL)
428	CALPINE	Calpine at Recker (TECO)
431	VAN	IPS Avon Park at Vandolah (PEF)
433	HPS	Hardee Power Station (TECO)
436	DESOTOGEN	Desoto Generation IPP at Whidden (FPL)
438	IPP-REL	Reliant at Indian River (FMPP)

SPP – Southwest Power Pool, Inc.

Area #	ID	System
502	CELE	Central Louisiana Electric Company
503	LAFA	Lafayette Utilities
504	LEPA	Louisiana Energy and Power Authority
505	ALEX	City of Alexandria
507	RAYB	Rayburn Country Electric Cooperative
508	NTEC	North Texas Electric Cooperative
509	SRGT	Sam Rayburn G&T
511	AREC	Arkansas Electric Cooperative
513	CLWL	City of Clarksdale
514	MEAM	Municipal Energy Agency of Mississippi
515	SWPA	Southwestern Power Administration
520	AEPW	American Electric Power
522	KAMO	Kamo Electric Cooperative
523	GRDA	Grand River Dam Authority
524	OKGE	Oklahoma Gas and Electric Company
525	WFEC	Western Farmers Electric Cooperative
526	SPS	Southwestern Public Service
527	OMPA	Oklahoma Municipal Power Authority
531	MIDW	Midwest Energy
534	SUNC	Sunflower Electric Cooperative
536	WERE	Westar
537	SIKE	City of Sikeston, Missouri
539	WEPL	Westplains Energy
540	MIPU	Missouri Public Service Company
541	KAPL	Kansas City Power and Light Company
542	KACY	Board of Public Utilities
544	EMDE	Empire District Electric Company
545	INDN	City of Independence
546	SPRM	City Utilities of Springfield

MRO – Midwest Reliability Organization

Area #	ID	System
600	XEL	Xcel Energy North
	MUNI	Municipal data from Xcel Energy
	MMPA	MMPA Municipal data from Xcel Energy
	CMMPA	CMMPA Municipal data from Xcel Energy
608	MP	Minnesota Power & Light
613	SMMPA	Southern Minnesota Municipal Power Association
615	GRE	Great River Energy
620	OTP	Otter Tail Power Company
627	ALTW	Alliant Energy West
633	MPW	Muscatine Power & Water
635	MEC	MidAmerican Energy
	CBPC	CBPC Municipal data from MEC
	RPGI	RPGI Municipal data from MEC
	IAMU	IAMU Municipal data from MEC
	MMEC	MEC Municipal data from MEC (AMES,CFU, etc.)
640	NPPD	Nebraska Public Power District
	MEAN	Municipal Energy Agency of Nebraska (NPPD)
	GRIS	Grand Island (NPPD)
645	OPPD	Omaha Public Power District
650	LES	Lincoln Electric System, NE
652	WAPA	Western Area Power Administration
	MPC	Minnkota Power Cooperative, Inc.
	BEPC	Basin Electric Power Cooperative
	NWPS	Northwestern Public Service
	MRES	Missouri River Energy Services
661	MDU	Montana-Dakota Utilities Co.
667	MHEB	Manitoba Hydro
672	SPC	Saskatchewan Power Co.
680	DPC	Dairyland Power Cooperative
	WPPI	Wisconsin Public Power Inc.
694	ALTE	Alliant Energy East (ATC)
696	WPS	Wisconsin Public Service Corporation (ATC)
	CWP	Consolidated Water Power Company (ATC)
	MEWD	Marshfield Electric and Water Company (ATC)
	MPU	Manitowoc Public Utilities (ATC)
697	MGE	Madison Gas and Electric Company (ATC)
698	UPPC	Upper Peninsula Power Company (ATC)

ERCOT & WECC

Area #	ID	System
700	ERCOT	Electric Reliability Council of Texas, Inc.
800	WECC	Western Electricity Coordinating Council

14. NERC Reliability Standards for Modeling, Data, and Analysis, MOD-010-0 through MOD-015-0

Standard MOD-010-0 — Steady-State Data for Transmission System Modeling and Simulation

Adopted by NERC Board of Trustees: February 8, 2005 1 of 2
Effective Date: April 1, 2005

A. Introduction

1. Title: Steady-State Data for Modeling and Simulation of the Interconnected Transmission System

2. Number: MOD-010-0

3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.

4. Applicability:

4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1

4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1

5. Effective Date: April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

C. Measures

M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

D. Compliance

1.0 Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2 M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

1. None identified.

Version History

Version Date Action Change Tracking

0 April 1, 2005 Effective Date New

Standard MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures

Adopted by NERC Board of Trustees: February 8, 2005 1 of 3

Effective Date: April 1, 2005

A. Introduction

1. Title: Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures.

2. Number: MOD-011-0

3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. Applicability:

4.1. Regional Reliability Organization

5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:

R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location.

R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.

R1.3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations.

R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

R1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status.

R1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.

R1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.

R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection's steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.

C. Measures

M1. The Regional Reliability Organization shall have documentation of its Interconnection's steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in one of the seven areas defined in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Data requirements and reporting procedures for steady-state data were provided, but were incomplete in two of the seven areas defined in Reliability Standard MOD-011-0_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: Data requirements and reporting procedures for steady-state data were not provided, or the data requirements and reporting procedures provided were incomplete in three or more of the seven areas defined in Reliability Standard MOD-011-0_R1.

E. Regional Differences

1. None identified.

Version History

Version Date Action Change Tracking

0 April 1, 2005 Effective Date New

Standard MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation

Adopted by NERC Board of Trustees: February 8, 2005 1 of 2
Effective Date: April 1, 2005

A. Introduction

1. Title: Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.

2. Number: MOD-012-0

3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. Applicability:

4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R4

4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R4

4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R4

4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R4

5. Effective Date: April 1, 2005

B. Requirements

R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R4.

R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

C. Measures

M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R1.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

Version Date Action Change Tracking

0 April 1, 2005 Effective Date New

Standard MOD-013-0 — RRO Dynamics Data Requirements and Reporting Procedures
Adopted by NERC Board of Trustees: February 8, 2005 1 of 3
Effective Date: April 1, 2005

A. Introduction

1. Title: Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures

2. Number: MOD-013-0

3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. Applicability:

4.1. Regional Reliability Organization

5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements::

R1.1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

R1.1.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

R1.1.2. The Interconnection-wide requirements shall specify unit size thresholds for permitting:

- The use of non-detailed vs. detailed models,
- The netting of small generating units with bus load, and
- The combining of multiple generating units at one plant.

R1.2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

R1.3. Dynamics data representing electrical demand characteristics as a function of frequency and voltage.

R1.4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0_R1.

R2. The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).

C. Measures

M1. The Regional Reliability Organizations within each Interconnection shall have documentation of their Interconnection's dynamics data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-013-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Data requirements and reporting procedures: on request (5 business days).

Periodic review of data requirements and reporting procedures: at least every five years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Data requirements and reporting procedures for dynamics data were provided, but were incomplete in one of the four areas defined in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Data requirements and reporting procedures for dynamics data were not provided, or the data requirements and reporting procedures provided were incomplete in two or more of the four areas defined in Reliability Standard MOD-013-0_R1.

E. Regional Differences

1. None.

Version History

Version Date Action Change Tracking

0 April 1, 2005 Effective Date New

Standard MOD-014-0 — Development of Interconnection-Specific Steady State System Models
Adopted by NERC Board of Trustees: February 8, 2005 1 of 2
Effective Date: April 1, 2005

A. Introduction

1. Title: Development of Steady-State System Models

2. Number: MOD-014-0

3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. Applicability:

4.1. Regional Reliability Organization

5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-specific steadystate system models. The Interconnection-specific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels.

R2. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steadystate models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

M1. Each Regional Reliability Organization shall have Interconnection-specific steady-state system models as specified in MOD-014-0_R1 and MOD-014-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Development of steady-state system models: annually, as determined by each Interconnection's schedule. Most recent steady-state system models: 30 calendar days.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization's cases either was not submitted by each Interconnection's data submission deadlines, or was submitted by the data submission deadline but was not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

2.2. Level 2: Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.3. Level 3: Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.4. Level 4: Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

E. Regional Differences

1. None identified.

Version History

Version Date Action Change Tracking

0 April 1, 2005 Effective Date New

Standard MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
Adopted by NERC Board of Trustees: February 8, 2005 1 of 2
Effective Date: April 1, 2005

A. Introduction

1. Title: Development of Dynamics System Models

2. Number: MOD-015-0

3. Purpose: To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.

4. Applicability:

4.1. Regional Reliability Organization

5. Effective Date: April 1, 2005

B. Requirements

R1. The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R1.

R1.1. The Regional Reliability Organization(s) shall develop Interconnection-specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of that Interconnection.

R2. The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.

C. Measures

M1. The Regional Reliability Organization shall have Interconnection-specific dynamics system models in accordance with Reliability Standard MOD-015-0_R1, MOD-015-0_R2 and MOD-015-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

Development of dynamics system models: annually in accordance with each Interconnection's schedule.

Most recent dynamics system models: 30 calendar days.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: One of a Regional Reliability Organization's cases was either not submitted by each Interconnection's data submission deadlines, or was submitted by the data submission deadline but was not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

2.2. Level 2: Two of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.3. Level 3: Three of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

2.4. Level 4: Four or more of a Regional Reliability Organization's cases were either not submitted by each Interconnection's data submission deadlines, or were submitted by the data submission deadline but were not fully solved/initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

E. Regional Differences

1. None.

Version History

Version Date Action Change Tracking

0 April 1, 2005 Effective Date New

15. Compliance

A. MDWG Power flow model schedule

Note: The latest document can be found on SPP.org

B. MDWG Dynamic model schedule (Continued)

Note: The latest document can be found on SPP.org

C. Data Submittal Forms (This is a separate document)

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

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
    a. Loss of a tower line with three or more circuits.[11]
    b. Loss of all Transmission lines on a common Right-of-Way[11].
    c. Loss of a switching station or substation (loss of one voltage level plus transformers).
    d. Loss of all generating units at a generating station.
    e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
    a. Loss of two generating stations resulting from conditions such as:
        i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
        ii. Loss of the use of a large body of water as the cooling source for generation.
        iii. Wildfires.
        iv. Severe weather, e.g., hurricanes, tornadoes, etc.
        v. A successful cyber attack.
        vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
    b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
    e. 3Ø internal breaker fault.
    f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
   c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The Standards Committee accepted the Standard Authorization Request (SAR) submitted by the Geomagnetic Disturbance Task Force (GMD TF) and approved Project 2013-03 (Geomagnetic Disturbance Mitigation) on June 5, 2013.
2. The SAR was posted for informal comment from June 26, 2013 through August 12, 2013.

Description of Current Draft

This draft is the first posting of the proposed standard. It is posted for a 30-day informal comment.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Initial Ballot	June 2014
45-day Formal Comment Period with Additional Ballot	August 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

The definition shall become effective on the first day of the first calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

The Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the Requirements shall become effective as described in the Implementation Plan beginning on the first day of the first calendar quarter that is 12 months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance shall be implemented over a 4-year period as described in the Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2013-03 (Phase 2)	N/A

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment: Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.

A. Introduction

1. **Title: Transmission System Planned Performance for Geomagnetic Disturbance Events**

2. **Number:** TPL-007-1

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events within the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a Planning Coordinator area that includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher

   4.1.2 Transmission Planner with a Transmission Planning area that includes a power transformer with a high side, wye-grounded winding connected at 200 kV or higher

   4.1.3 Transmission Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher

   4.1.4 Generation Owner who owns a power transformer(s) with a high side, wye-grounded winding connected at 200 kV or higher

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation, the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator and Transmission Planner shall maintain ac System models and geomagnetically-induced current (GIC) System models within its respective area for performing the studies needed to complete its GMD Vulnerability Assessment. The models shall use data consistent with that provided in accordance with the MOD standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P8 as the normal System condition for GMD planning in Table 1. The System models shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

   1.1. Existing Facilities

   1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.3. New planned Facilities and changes to existing Facilities

1.4. Real and reactive Load forecasts

1.5. Known commitments for Firm Transmission Service and Interchange

1.6. Resources (supply or demand side) required for Load

M1. Each Planning Coordinator and Transmission Planner shall have evidence in either electronic or hard copy format that it is maintaining ac System models and geomagnetically-induced current (GIC) System models within its respective area, using data consistent with MOD standards including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

Rationale for Requirement R1:

A GMD Vulnerability Assessment requires a dc GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The ac System model is used in conducting steady-state power flow analysis that accounts for the Reactive Power absorption of transformers due to GIC in the System.

The projected System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. These adjustments could include recalling or postponing maintenance outages, for example.

R2. Each Planning Coordinator and Transmission Planner shall complete a GMD Vulnerability Assessment of the Near Term Transmission Planning Horizon for its respective area once every 60 months. This GMD Vulnerability Assessment shall use studies, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Studies shall include the following conditions:

2.1.1. System peak Load for one year within the Near-term Transmission Planning Horizon.

2.1.2. System Off-Peak Load for one year within the Near-term Transmission Planning Horizon.

2.2 Studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the system meets the performance requirements in Table 1.

M2. Each Planning Coordinator and Transmission Planner shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R2.

Rationale for Requirement R2:

GMD Vulnerability Assessment includes steady-state power flow analysis and supporting studies that account for the effects of GIC. Performance criteria are specified in Table 1.

System peak Load and Off-peak Load must be examined in the analysis.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

R3. Each Planning Coordinator and Transmission Planner that determines through the GMD Vulnerability Assessment conducted in Requirement R2 that its System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of Demand-Side Management, new technologies, or other initiatives.

3.2. Be reviewed in subsequent GMD Vulnerability Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M3. Each Planning Coordinator and Transmission Planner shall have evidence such as electronic or hard copies of its Corrective Action Plan as specified in Requirement R3.

R4. Each Planning Coordinator and Transmission Planner shall have criteria for acceptable System steady state voltage limits for its System during the GMD conditions described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator and Transmission Planner shall have evidence such as electronic or hard copies of the criteria for acceptable System steady state voltage limits for its System in accordance with Requirement R4.

Rationale for Requirement R4:

System steady state voltage limits for GMD Vulnerability Assessment may by different from the limits used in the TPL-001 Planning Assessment. The planner must adhere to established limits that ensure the planned System achieves the performance requirements in Table 1.

R5. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify the individual and joint responsibilities of entities in the Planning Coordinator's area for performing the required studies for the GMD Vulnerability Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the GMD Vulnerability Assessment in accordance with Requirement R5.

R6. Each Planning Coordinator and Transmission Planner shall distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 within 90 calendar days of completion, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1 If a recipient of the GMD Vulnerability Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M6. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of completion, and to any functional entity who has indicated a reliability related need within 30 days of a written request. Each Planning Coordinator and Transmission Planner shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R5.

Rationale for Requirement R6:

Distribution of GMD Vulnerability Assessment results and Corrective Action Plans provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies and planned mitigation measures may affect neighboring systems and should be taken into account by planners. Additionally, this GIC information is essential for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment.

R7. Each Transmission Owner and Generator Owner shall conduct an assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher. The assessment shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. Be based on the benchmark GMD event described in Attachment 1 with peak geomagnetically-induced current (GIC) flows as modeled in the steady-state analysis conducted in Requirement R2

7.2. Document assumptions used in the analysis

7.3. Describe suggested actions and supporting analysis to mitigate the impact of geomagnetically-induced currents, if any.

M7. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher as specified in Requirement R7.

Rationale for Requirement R7:
The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the whitepaper posted on the project page. http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

R8. Each Transmission Owner and Generator Owner shall provide its assessment of thermal impact specified in Requirement R7 for all of its solely and jointly owned power transformers with high-side, wye-grounded windings connected at 200 kV or higher within 90 days of completion to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M8. Each Transmission Owner and Generator Owner shall have dated evidence such as postal receipts or email confirmation that it has provided a copy of its assessment of thermal impact for all of its solely and jointly owned power transformers with high-side, wye-grounded wye windings connected at 200 kV or higher as specified in Requirement R7 to the Planning Coordinator and Transmission Planner with responsibility for the area in which the associated power transformer is located within the timeframe prescribed in Requirement R8.

Table 1 –Steady State Planning Events				
Steady State: a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Consequential Load Loss as well as generation loss is acceptable as a consequence of P8 planning event. c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. d. System steady state voltages shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner in accordance with Requirement R4.				
Category	**Initial Condition**	**Event**	**Interruption of Firm Transmission Service Allowed**	**Non-Consequential Load Loss Allowed**
P8 GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation during the GMD event[3]	Yes[4]	Yes[4]

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for planning event P8 are described in Attachment 1 (Benchmark GMD Event).
3. Protection Systems may trip due to the effects of harmonics. P8 planning analysis shall consider removal of equipment that the planner determines may be susceptible.
4. The objective of the GMD Vulnerability Assessment is to prevent instability, uncontrolled separation, Cascading and uncontrolled islanding of the System during a GMD event. Non-Consequential Load Loss and/or curtailment of Firm Transmission Service may be needed to meet BES performance requirements during studied GMD conditions but should not be used as the primary method of achieving required performance. GMD Operating Procedures should be based on predetermined triggers from studied GMD conditions so that the likelihood and magnitude of Non-Consequential Load Loss or curtailment of Firm Transmission Service is minimized during a GMD event.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude to be used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 1-1 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α can be computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)}$$

where L is the geomagnetic latitude in degrees

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[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Table 1-1: Geomagnetic Field Scaling Factors	
Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
55	0.6
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 1-3. The peak geoelectric field, E_{peak}, to be used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide[2]; or
- Using the earth conductivity scaling factor β from Table 1-2 that correlates to the ground conductivity map in Figure 1-1 or Figure 1-2. Along with the scaling factor α, β is applied to the reference geolectric field using the following equation to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment.

$$E_{peak} = 8 \times \alpha \times \beta \text{ (V/km)}$$

The earth models used to calculate Table 1-2 for the United States were obtained from publicly available magnetotelluric data that is published on the U. S. Geological Survey website[3]. The models used to calculate Table 1-2 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. NRCan also has developed some models for sub-regions which should be used when available. Because all models in Table 1-2 are approximations, a planner can substitute a technically justified earth model for its planning area when available.

[2] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[3] Available at http://geomag.usgs.gov/conductivity/

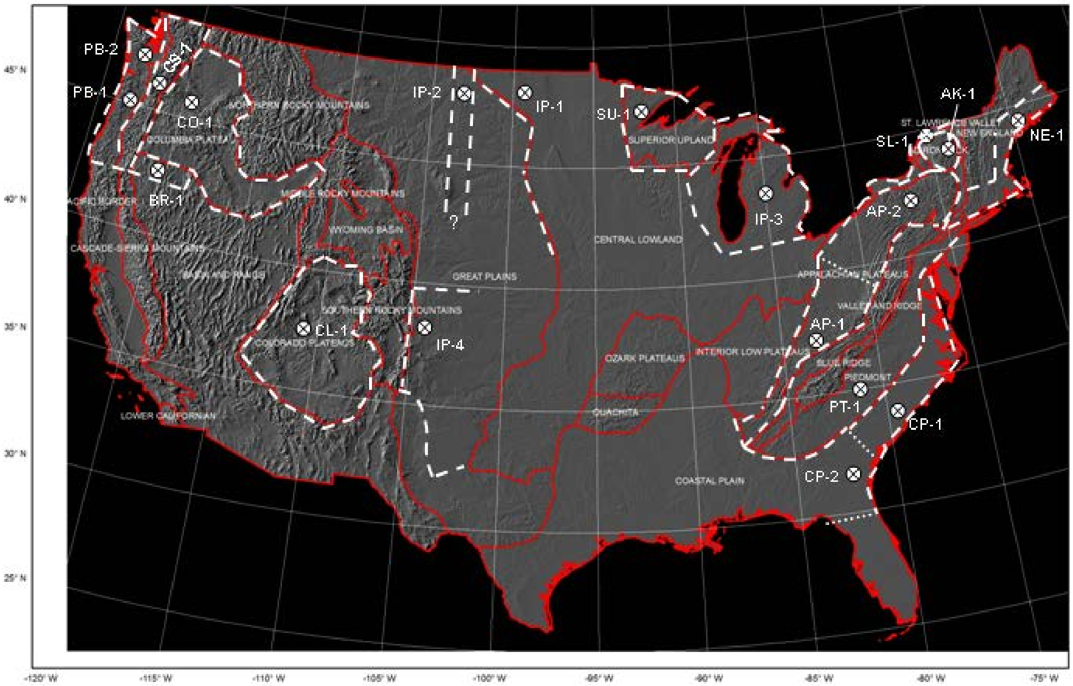

Figure 1-1: Physiographic Regions of the Continental United States[4]

Figure 1-2: Physiographic Regions of Canada

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4 Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 1-2 Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	.0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 1-3: Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape[5]
The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveshape to be used when performing thermal analysis of power transformers.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 1-3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figs. 1-4 and 1-5). Sampling rate for the geomagnetic field waveshape is 10 seconds.[6]

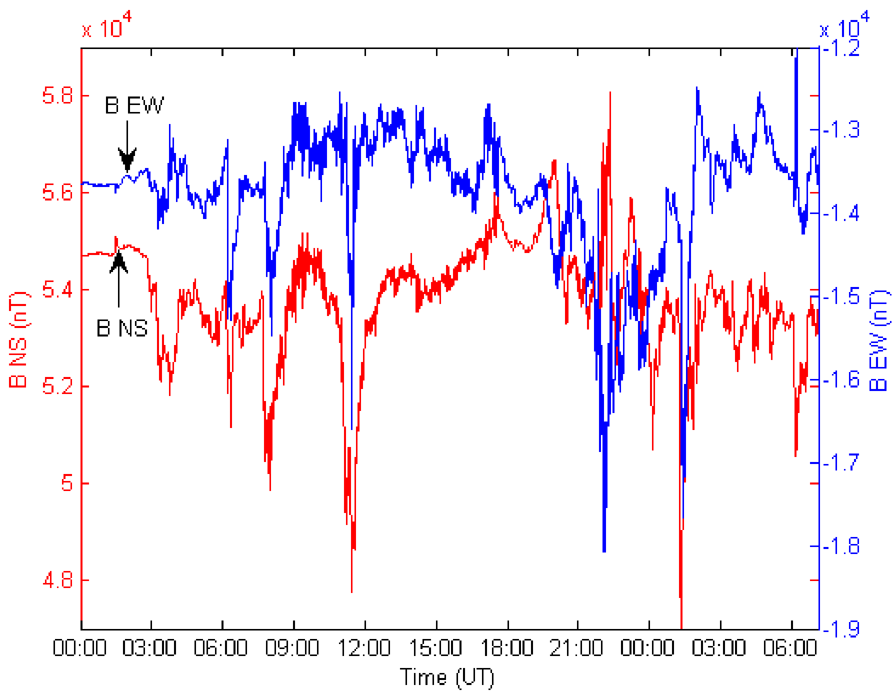

Figure 1-3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

[5] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[6] The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

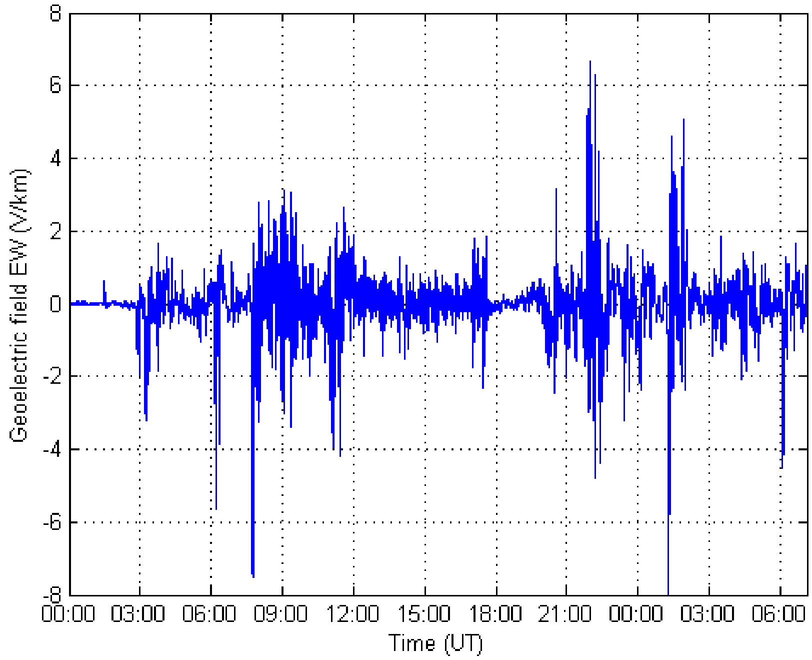

Figure 1-4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

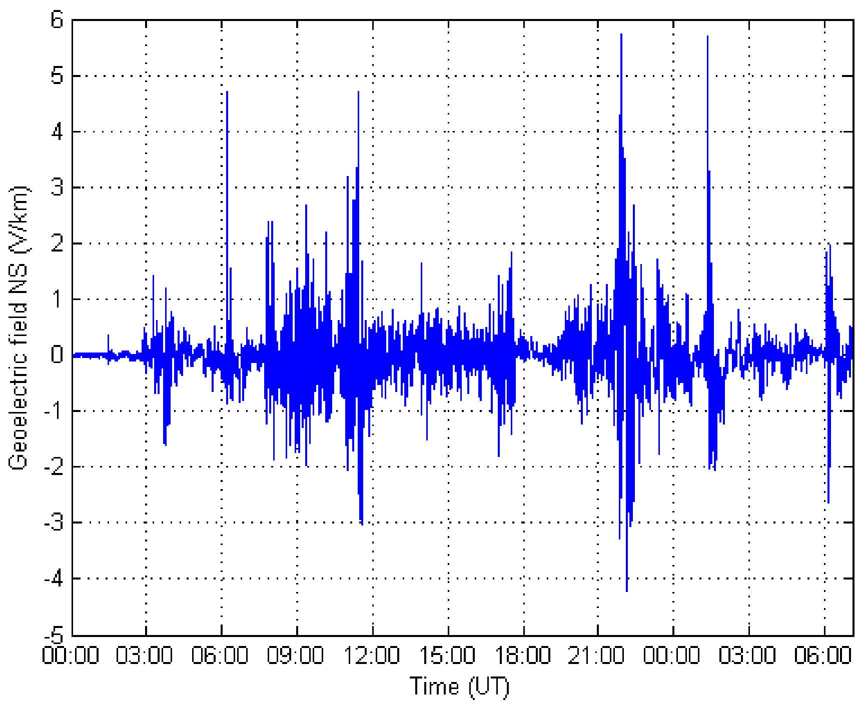

Figure 1-5: Benchmark Geoelectric Field Waveshape – E_N (Northward)

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for five years.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include one of the elements in Requirement R1, Parts 1.1 through 1.6.	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include two of the elements in Requirement R1, Parts 1.1 through 1.6.	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include three of the elements in Requirement R1, Parts 1.1 through 1.6.	The responsible entity's ac System model and geomagnetically-induced current (GIC) model failed to include four or more of the elements in Requirement R1, Parts 1.1 through 1.6; OR The responsible entity's ac System model and geomagnetically-induced current (GIC) model did not represent projected System conditions as described in Requirement R1; OR The responsible entity's ac System model and geomagnetically-induced current (GIC) model did not use data consistent with the MOD standards including items represented in the Corrective Action Plan.

R2	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity completed a GMD Vulnerability Assessment but it was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to include one of the following Parts of Requirement R2: Part 2.1 or 2.2; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to include two of the following Parts of Requirement R2: Part 2.1 or 2.2; OR The responsible entity completed a GMD Vulnerability Assessment but it was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.
R3	Long-term Planning	High	N/A	N/A	The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R3 parts 3.1 and 3.2.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R3 parts 3.1 and 3.2; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R3.

R4	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits for its System during the GMD conditions as required.
R5	Long-term Planning	Low	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R6	Long-term Planning	Medium	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 90 days but less than or equal to 120 days following completion;	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 120 days but less than or equal to 130 days following its completion;	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 130 days but less than or equal to 140 days following its completion;	The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4 but it was more than 140 days following its completion; OR

			OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 30 days but less than or equal to 40 days following the request; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 30 days but less than or equal to 40 days following the receipt as specified in Part 6.1.	OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 40 days but less than or equal to 50 days following the request; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 40 days but less than or equal to 50 days following the receipt as specified in Part 6.1.	OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 50 days but less than or equal to 60 days following the request; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 50 days but less than or equal to 60 days following the receipt as specified in Part 6.1.	The responsible entity did not distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to adjacent Planning Coordinators, adjacent Transmission Planners, and Transmission Owners and Generator Owners in its respective planning area as specified in the Applicability Section 4.1.3 and 4.1.4; OR The responsible entity distributed its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional entities having a reliability related need who requested the information in writing but it was more than 60 days following the request; OR The responsible entity did not distribute its GMD Vulnerability Assessment results and Corrective Action Plan, if any, to functional

						entities having a reliability related need who requested the information in writing; OR The responsible entity provided a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan, but it was more than 60 days following the receipt as specified in Part 6.1; OR The responsible entity did not provide a documented response to documented comments received from a recipient of its GMD Vulnerability Assessment results and Corrective Action Plan as specified in Part 6.1.
R7	Long-term Planning	High	The responsible entity failed to conduct an assessment of thermal impact for 5% or less of its solely owned and jointly owned power transformers with high-side, wye-grounded	The responsible entity failed to include one of the required elements as listed in Requirement R7 parts 7.1 through 7.3; OR The responsible entity failed to conduct an assessment of thermal	The responsible entity failed to include two or more of the required elements as listed in Requirement R7 parts 7.1 through 7.3; OR The responsible entity failed to conduct an	The responsible entity failed to conduct an assessment of thermal impact for more than15% of its solely owned and jointly owned power transformers with high-side, wye-grounded

			windings rated 200 kV or higher.	impact for more than 5% up to (and including) 10% of its solely owned and jointly owned power transformers with high-side, wye-grounded windings rated 200 kV or higher.	assessment of thermal impact for more than 10% up to (and including) 15% of its solely owned and jointly owned power transformers with high-side, wye-grounded windings rated 200 kV or higher.	windings rated 200 kV or higher.
R8	Long-term Planning	Medium	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 90 days but less than or equal to 120 days following its completion.	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 120 days but less than or equal to 130 days following its completion.	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 130 days but less than or equal to 140 days following its completion.	The responsible entity provided a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner but it was more than 140 days following its completion. OR The responsible entity did not provide a copy of its assessment of thermal impact to the Planning Coordinator and Transmission Planner.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R1

A GMD Vulnerability Assessment requires a dc GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System. The guide is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Requirement R2

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

Requirement R3

Technical considerations for GMD mitigation planning are available in Chapter 5 of the GMD Planning Guide. Additional information is available in the 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Requirement R7

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, or other technically justified means. A process for conducting the assessment is presented in the whitepaper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx