1 INTRODUCTION AND BACKGROUND INFORMATION

1.1 STUDY OBJECTIVE

The 2009 Transmission System Analysis is an update of the 2006 Vermont transmission system 10-year long-range plan analysis. The update incorporates several changes in approach required by the Docket 7081 Memorandum of Understanding (MOU), which was approved by the Vermont Public Service Board subsequent to the 2006 analysis, on June 20, 2007. The changes include: increasing the planning horizon from 10 to 20 years; testing the sub-transmission system; screening non-transmission alternatives to each proposed conceptual solution; and incorporating the comments of the Vermont System Planning Committee (VSPC).

As the Regional Transmission Organization for New England, the New England independent system operator (ISO-NE) manages the New England region's bulk electric power system, administers and operates the wholesale electricity market, administers the region's Open Access Transmission Tariff ("OATT"), and conducts regional transmission planning. More specifically, the ISO's responsibilities include operating and maintaining a highly reliable bulk transmission system, promoting efficient wholesale electricity markets, and working collaboratively and proactively with state and federal regulators, New England Power Pool ("NEPOOL") Participants, and other stakeholders in the pursuit of these goals.

As part of its collaboration, ISO-NE seeks the input of the market participants and the public through the Planning Advisory Committee (PAC) in its efforts to create the 2009 Regional System Plan (RSP), which identifies regional system deficiencies, and the transmission reinforcements that address these deficiencies. Through participation in the PAC, the public stakeholders and other interested parties can influence the ISO-NE transmission plan, have advance knowledge of deficiencies, and are able to propose alternative solutions that may include demand reduction and supply measures.

A study group, including representatives from National Grid (NGRID) NY, NGRID NE, Public Service of New Hampshire (PSNH), ISO-NE, and VELCO, was formed to conduct the 10-yr analysis of the Vermont transmission system. The study scope was developed by this study group, and reviewed by the PAC. As required by the Vermont planning process, VELCO expanded the analysis to study a 20-yr horizon and assess the Vermont sub-transmission system.

1.2 ANALYSIS DESCRIPTION

The analysis of the Vermont electrical system consisted of the following:

- Create load flow base cases with multiple dispatch scenarios as required to reasonably stress the system in and around Vermont
- Conduct a comprehensive steady state analysis of the current system with planned upgrades to determine system reliability performance under several system conditions and operating scenarios
- Identify potential system reinforcements needed to meet the requirements of the NERC planning standards:
  1) all-lines-in service (N-0) – Category A/TPL 001
  2) Contingency analysis (N-1) of design contingencies – Category B/TPL 002
  3) Contingency analysis (N-1-1) of design contingencies – Category C/TPL 003

1.3 STUDY ASSUMPTIONS

1.3.1 LOAD

The load flow base cases originated from the New Hampshire 10-yr study, which originated from the New England 2003 set of library cases. Cases representing year 2018 conditions were developed. The New England load level examined was approximately 33,200 MW, which represents an estimated extreme weather 90/10[1] load. The New England 2018 load level was estimated from the most recent Capacity, Energy, Load, Transmission (CELT) Report by growing the 2017 load to 2018. The Vermont 2018 load was modeled at approximately 1275 MW, which represents projected 2018 extreme weather summer peak load based the 2008 load forecast prepared by ITRON. For the 2028 cases, the Vermont load was increased to approximately 1425 MW according to the load forecast provided by ITRON. This resulted in an approximate increase of Vermont station loads of about 10.6% over the 10 year period from 2018 to 2028. Losses increased due to no additions to the network or generation in Vermont. While Vermont is now a summer peaking system, some of the load zones are still winter peaking, and where voltage is a concern, more deficiencies may arise during winter conditions. A winter peak analysis was beyond the scope of this report.

The Vermont load power factor at the distribution level was approximately 0.96. The procedure for calculating power factor at the transmission system level, based on ISO operating procedure OP 17, considers step-down transformer flows including transformer losses, reactive dispatch and generation dispatch. That calculation yielded a power factor of approximately 0.97. However, due to the poor voltage performance in some areas of Vermont, individual step-down transformer power factor is strongly recommended to be at 0.98 or better.

The load outside of Vermont was kept constant because a New England 20-yr forecast does not exist, and future reinforcements and generation to support this additional load is unknown at this time. Assuming a constant load is representative of the fact that the system outside of Vermont will be reinforced to support the additional load. The NY load was also kept constant at all load levels for the same reasons.

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[1] The extreme weather load forecast is higher than a normal weather load forecast (50/50) due the effects of temperature and humidity. The percentage increase over the 50/50 forecast depends on how sensitive the load is to temperature and humidity. The 90/10 figure signifies that the actual load level has a 90% chance of being below the forecast, and there is a 10% chance that the forecast will be exceeded.

The Energy Efficiency Utility of Vermont is responsible for demand side management (DSM) programs in Vermont, and is presently forecasting DSM amounts out to 20 years. These DSM amounts can be superimposed on the load forecast to determine the load level at which transmission reinforcements may be needed. The load forecast includes the effects of expected changes to efficiency due to new regulations, such as the increased use of compact fluorescent lighting in the near future. The load forecast includes the effects of ongoing DSM because historical load levels include the effects of past DSM. However, the effects of additional DSM due to an increased budget were not included in the load forecast, which makes it possible for a simple subtraction of the DSM forecast from the load forecast.

For the purpose of forecasting electrical load and DSM, the state was divided into sixteen zones. A geographical map showing the sixteen zones can be found in Figure 1. The zones were assigned a letter designation as suggested by the VSPC. The zones were also assigned a number designation for use by the power flow program.

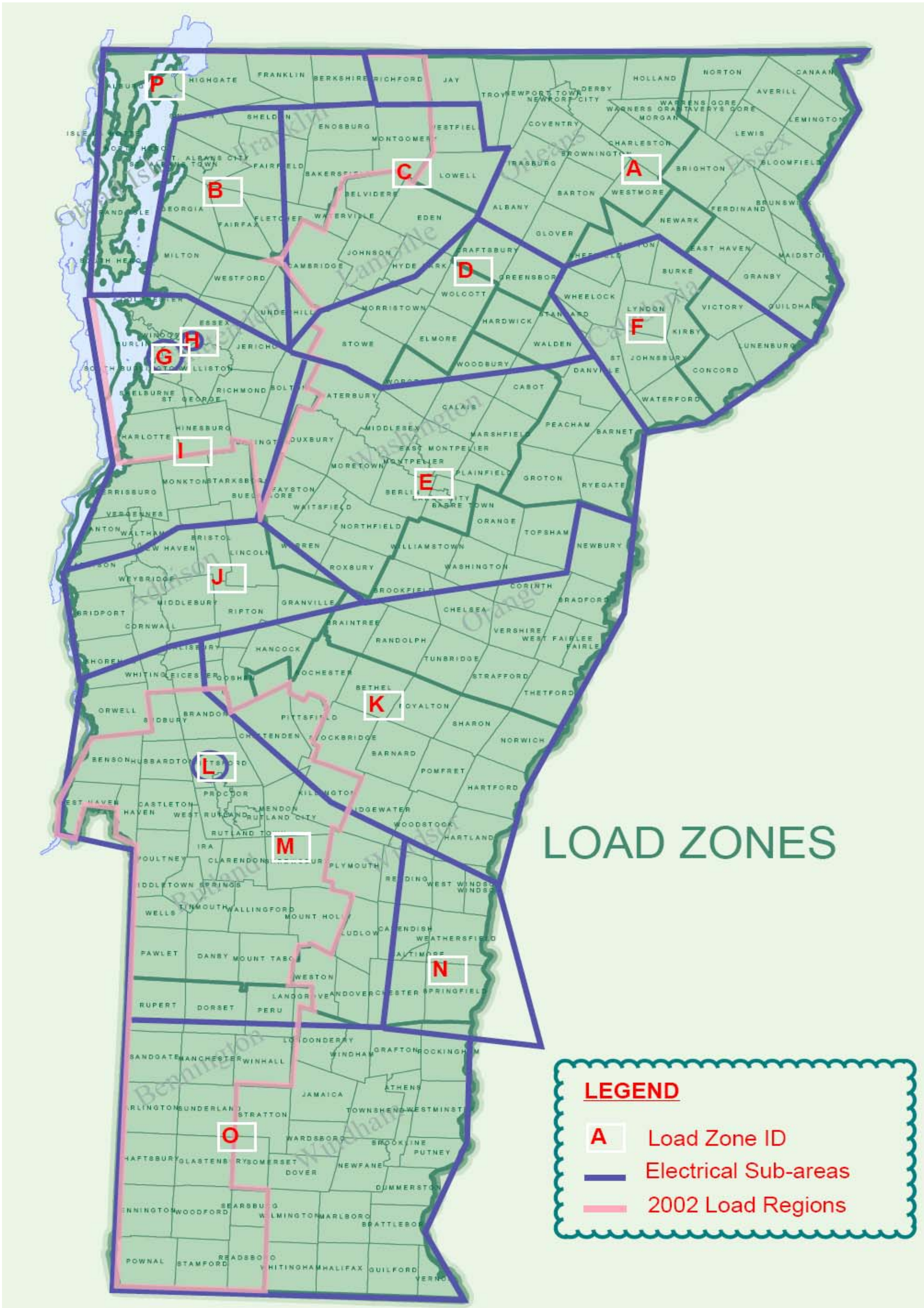

Figure 1: Vermont Load Zones

Zone O – Southern #11: Load is supplied by transformers at Bennington, Newfane, Vernon Road, Harriman, Vernon, and Bellows Falls. This zone includes the Searsburg Wind units.

Zone N – Ascutney #12: Load is supplied by transformers at Ascutney, Windsor, and Bellows Falls. This zone includes generation at Ascutney GT and Cavendish hydro.

Zone M – Rutland #14: Load is supplied by transformers at Cold River, North Rutland and Blissville. This zone includes generation at Rutland GT, and hydro units at Glen, Patch, Pittsford, and Carver Falls.

Zone L – Florence #15: Load is supplied by a transformer at Florence. This zone includes generation at Florence GT and hydro units at Proctor, Belden and Huntington.

Zone K – Central VT #13: Load is supplied by transformers at Chelsea and Hartford. This zone includes hydro units at Dewey Mills, Taftsville, Smith, and Silverlake.

Zone J – Middlebury/New Haven #16: Load is supplied by transformers at Middlebury and New Haven. This zone includes hydro generation at Salisbury, Middlebury and Weybridge.

Zone I – Burlington GMP #17: Load is supplied by transformers at Essex, Gorge, East Avenue, Tafts Corner, Queen City, Shelburne, Charlotte, North Ferrisburg, and Vergennes. This zone include generation at Essex diesels, Gorge GT, McNeil wood, Vergennes GT, and hydro units at Essex, Gorge, and Vergennes.

Zone G – Burlington BED #24: Load is supplied by transformers at East Avenue, Queen City, and McNeil. This zone includes generation at Burlington GT, and hydro at Winooski.

Zone H – IBM #18: Load is supplied by transformers at IBM. There is no generation in this zone

Zone C – Johnson, Zone D Morrisville, Zone E Montpelier #19: Load is supplied by transformers at Barre, Berlin, Middlesex, and Irasburg. This zone includes methane units at Moretown and Coventry, a wood unit at Ryegate, Berlin GT, and hydro generation at Dodge Falls, Marshfield, West Danville, Middlesex, Little River, Bolton Falls, Barnet, and Morrisville.

Zone J – Middlebury/New Haven: Load is supplied by transformers at Middlebury and New Haven. This zone includes hydro generation at Salisbury, Middlebury and Weybridge.

Zone F – St Johsnbury #20: Load is supplied by the St Johnsbury transformer. This zone includes hydro generation at Arnold Falls, Gilman, Gage, Passumpsic, East Barnet, and Pierce Mills.

Zone B – St Albans #21: Load is supplied by transformers at St Albans and East Fairfax. This zone includes hydro generation at East Fairfax and lower Lamoille.

Zone A – Newport #22: Load is supplied by a transformer at Newport. This zone includes generation at Newport diesels, Barton diesels, and hydro generation at Newport and Barton.

Zone P – Highgate #23: Load is supplied by transformers at Highgate. This zone includes generation at Swanton GT, Enosburg GT, and hydro units at Sheldon, Highgate Falls, and Enosburg.

The zones were initially assumed to behave differently in terms of load growth and load shape. Certainly, the availability of DSM should be different by zone due to the makeup of the load (proportion of residential, commercial and industrial customers) and its density. The zones were divided along electrical boundaries so that historical data could be gathered and tracked. The zonal historical data were utilized to then allocate the state wide forecast to each zone. Based on historical data, the amount of load within each zone as a percentage of the state wide load is relatively constant, which suggests that no one zonal load has been growing so much more than the rest of the state that its load ratio share of the state load has been growing significantly from year to year. Below is a listing of zonal loads as a percentage of the state load from 2002 to 2007. Because these loads are samplings of the summer peak hour, these loads represent coincident peak load levels, and yearly differences may be due to variations in temperature and humidity from peak to peak. For example, in the case of the Florence load, the OMYA industrial load is a large portion of the zonal load and its status during the peak has not been predictable. Therefore, it is difficult to establish a trend of the Florence zonal load. In the case of IBM, the load has been constant. Therefore, as a percentage of the state wide load, it has been decreasing.

Table 1: Historical load ratio shares of the load zones

Zone name-letter-number	2002	2003	2004	2005	2006	2007
Southern – O – 11	12.6%	12.5%	11.9%	11.6%	12.7%	12.5%
Ascutney – N – 12	6.3%	6.3%	6.4%	6.7%	6.6%	6.6%
Rutland – M – 14	10.0%	9.5%	9.8%	9.5%	9.9%	9.6%
Florence – L – 15	2.2%	2.6%	2.1%	2.5%	1.9%	2.9%
Central – K – 13	6.7%	6.4%	6.6%	6.6%	6.0%	6.0%
Middlebury-J – 16	3.6%	3.6%	3.8%	3.6%	3.8%	3.5%
BurlgtnGMP-I – 17	16.1%	16.5%	16.3%	15.8%	16.2%	16.2%
BED-G – 24	6.2%	6.5%	6.4%	6.4%	6.2%	6.2%
IBM - H – 18	6.7%	6.6%	6.6%	6.2%	6.0%	5.9%
Johnson - C – 19	1.4%	1.3%	1.4%	1.4%	1.5%	1.6%
Morrisville - D – 19	3.2%	3.2%	3.3%	3.4%	3.4%	3.5%
Montpelier - E – 19	9.6%	9.6%	9.9%	10.2%	9.7%	9.8%
St Johnsbury - F – 20	2.9%	2.9%	2.8%	3.0%	2.8%	2.9%
St Albans - B – 21	5.4%	5.6%	5.7%	5.6%	5.7%	5.9%
Highgate - P – 22	3.9%	3.7%	4.0%	4.6%	4.3%	3.5%
Newport - A – 23	3.2%	3.1%	3.0%	3.0%	3.3%	3.4%

Figure 2 below shows the historical summer peak loads (blue diamond), the load forecast prepared by ITRON for VELCO (red circle) and the load forecast prepared by ISO-NE (green triangle). The ITRON forecast was used to grow the Vermont load. Three trend lines were added to the graph. The first trend line (purple) was based on the highest historical peaks; the second trend line (red) was based on the moderate historical peaks; and the third trend line (orange) was based on the lowest historical peaks. It can be seen that both forecasts start higher in the beginning years but approach the moderate peak trend line near 2016. This, albeit, simple analysis suggests that the 2023 peak could occur as early as 2017 if the high trend is followed, or as late as 2028 if the low trend is followed. Primarily, this graph reflects that load forecasting is not an exact science. The forecast was prepared before the economic downturn that started in late 2008. While the short-term forecast may turn out to be lower than shown in the following figure, the load is expected to grow at a lower rate in the short term based on ISO-NE analysis in preparation of the 2009 regional forecast. Further, the expected economic recovery is expected to remove near-term economic effects from the long-term forecast. The level of accuracy of a forecast decreases the farther out the horizon for which it is prepared. When the load uncertainty is superimposed on other changeable factors, such as generation, system topology, system operation, regulatory requirements, and so on, a study beyond the 10-yr time frame should be taken as one that provides additional data to better inform decisions made for the system within the 10-yr time frame. Although expressed as an extreme weather forecast, the ITRON forecast appears to be a middle of the road forecast because it is closer to the average summer peak trend line. The results for the 2028 load level may well be relevant because the 2028 load level may be reached earlier than suggested by the ITRON forecast, and the system should be designed with enough margin to serve higher load levels should they occur earlier than projected.

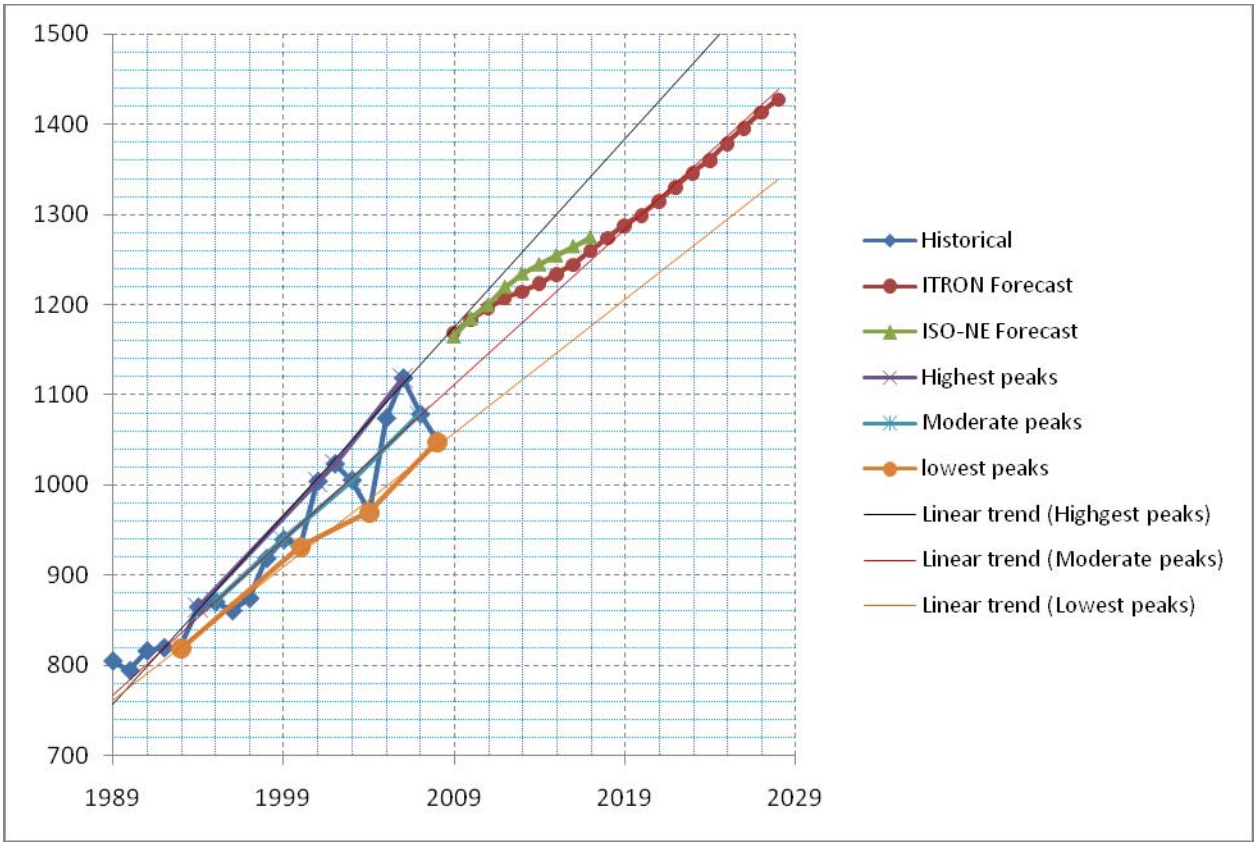

Figure 2: Vermont Load 90/10 Forecasts

1.3.2 NETWORK TOPOLOGY

Below is a listing of future projects that were modeled in the cases. These projects have ISO-NE Proposed Plan Application (PPA) approval. The critical projects are located in VT, NH and MA near the Vermont border.

In Vermont,

- Northwest Vermont Reliability Projects
- Lamoille County Project
- Coolidge Connector Project
- East Avenue Loop Project
- Tafts Corner Project
- Gorge Area Reliability Project
- Stratton 46 kV synchronous condenser (no PPA approval required)

In New Hampshire,

- 115 kV Y138 Line Closing Project
- Monadnock Region Reliability Project (excluding the Coolidge Dynamic Var Device)
- 115 kV X116 (including Z119) Line Reinforcement Project
- 115 kV Weare Project
- 3rd 345/115 kV Scobie Autotransformer Project
- Relocate Comerford HVDC caps/reactors to Comerford AC Station
- Comerford Repowering Project

In Maine,

- 115 kV Maguire Road Project
- 115 kV Kennebunk Light and Power Project
- 345 kV Buxton Breaker Project
- 115 kV Rumford-Woodstock-Kimball Road Project
- 115 kV Benton Project
- 345 kV Northeast Reliability Interconnect Project
- 115 kV Hancock County Project
- 115 kV Downeast Project

The New Hampshire 2018 needs assessment determined that the Maine Power Reliability Program (MPRP) had little effect on results outside of the Seacoast area of New Hampshire. Since Vermont is further away from Maine, the MPRP was not be modeled in this analysis.

In Massachusetts,

- Central Massachusetts Transmission Upgrades
- West Amesbury 345/115 kV Autotransformer
- NSTAR 345 kV Transmission Reliability Project (3 cables in-service)
- Ward Hill Autotransformer Additions
- Wakefield Junction
- Western Massachusetts Transmission Upgrades
- Bellows Falls Station Upgrades

In Connecticut,

- Norwalk Harbor, CT to Northport, NY (1385) Cable Upgrade
- Killingly 345/115 kV Autotransformer Addition
- Barbour Hill 345/115 kV Autotransformer Addition
- Bethel-Norwalk 345 kV Transmission Project
- Middletown-Norwalk 345 kV Transmission Project
- Glenbrook-Norwalk 115 kV Cables Addition Project

The New England East West Solution (NEEWS) project was not modeled because it is located in the southern portion of the New England system and components of the project have continued to be re-evaluated and modified.

1.3.3 GENERATION AND INTERFACE TRANSFERS

The planning standards in New England require that the transmission system be planned assuming stressed conditions. In order to model stressed conditions in the load flow cases, high transfers were modeled. Specifically, the East to West (EW) transfer across New England was modeled at approximately 2,400 MW, and the New England to New York (NE-NY) transfer was modeled at approximately 1,200 MW. To achieve these transfer levels, the 1400 MW Maine-New Hampshire transfer limit was exceeded by 200 MW, and essentially all generators on the east side of the EW interface had to be turned on. Likewise, very little generation was out of service on the west side of the EW interface to achieve a high NE-NY transfer. To simultaneously serve the 2018 projected peak load level and stress relevant interfaces, representative new resources (dummy generation) were added to the cases at Brayton Point, and/or Canal, which are electrically distant from Vermont. These locations were selected since they would not impact the performance of the Vermont transmission system. A West to East (WE) transfer condition was also modeled, with the WE transfer at approximately 1,000 MW and the NY-NE transfer at approximately 1,200 MW.

Vermont Yankee (VY) is not considered one of the Vermont generation resources because it is located electrically outside of the Vermont load pocket. VY was dispatched in service in all of the cases, except where the generator was taken out of service as the initial outage as required by NERC, ISO-NE, and NPCC standards, or when assumed retired.

The Highgate 200 MW HVdc converter was dispatched in service in all of the cases, except where the converter was taken out of service as the initial outage as required by NERC, ISO-NE, and NPCC standards, or when assumed decommissioned.

The next largest Vermont resource after Highgate is McNeil, which is a 50 MW wood burning generator in Burlington. Based on ISO-NE standards, this plant was dispatched out of service in all base cases. Ryegate, which is a 20 MW wood burning plant in northeastern Vermont, was dispatched on-line. Coventry, a recently constructed methane plant with a present capacity of approximately 5 MW, and future capacity of 8 MW, was dispatched on-line at its future capacity. In general, at least 50% of the new units were dispatched in service. In addition, 25% or 50% or the remaining units were dispatched in service between the first and the second contingency, depending on whether the first contingency is a longer-term outage or an overhead line, the latter typically being a short-term outage.

The generation dispatch is based on regional guidelines developed by ISO-NE and the transmission owners to comply with NERC and regional standards, and ensure consistency among regional studies. In general, the guidelines require that two critical units be modeled out of service in the base case before any contingencies are tested. The guidelines also require minimal reliance on peaking units. Therefore, the units that were selected to be in service in the base case were newly installed or proposed to be installed in the ISO-NE generation interconnection queue, such as Essex, Swanton, Newport, Coventry, and Moretown. Following the first contingency but before the second contingency, NERC standards allow use of generation in preparation for the second contingency. Therefore, additional generation was dispatched in service. The units selected first were those that had a somewhat greater chance of remaining in service due to recent repairs or the fact that there are multiple units at that location, such as Burlington and Vergennes. As a result, locations where there is a single thermal unit were not utilized, such as Gorge, Rutland, and Ascutney.

With all lines in, 68 MW out of 183 MW of the thermal units, not counting McNeil, were dispatched in service. For a longer term outage, an additional 31 MW were dispatched in service. For the outage of an overhead line, which is typically considered a short-term outage, an additional 62 MW were dispatched in service. In other words, nearly 64% of the thermal units were dispatched in service with an overhead line out of service. Below is a listing of Vermont generation dispatched in the cases tested.

With all lines in, the following dispatch was modeled:

- Highgate importing 200 MW
- PV20 flow at approximately 100 MW into Vermont
- Hydro at 10% rated capacity (approximately 15 MW)
- Total Vermont Wind at 10% rated capacity (approximately 5 MW)
- McNeil 51 MW Wood Plant off
- Coventry landfill methane at 8 MW (4.8 existing)
- Ryegate Wood Plant at 20 MW
- All existing gas turbines and diesels off
- Proposed 42 MW Swanton gas turbines at 50% capability
- Vermont Yankee at 667 MW
- Proposed Newport 10 MW diesels at 8 MW
- Proposed Moretown methane at 4.8 MW
- New 8 MW Essex Diesels at 6 MW

With a longer term outage as the first contingency (Highgate, PV-20, VY G1, 345/115 kV or 230/115 kV autotransformers), an additional 31 MW (approximately 25% of the remaining total generation capacity of Vermont's peaking thermal units) was considered between first and second contingencies as follows:

- Vergennes diesels at 2 MW (+2 MW)
- Proposed Swanton gas turbines at 42 MW (+21 MW)
- New Newport diesels at 10 MW (+2 MW)

- New Essex diesels at 8 MW (+2 MW)
- Florence gas turbines at 4 MW (+4 MW)

With a short term outage as the first contingency (K-65 Queen City-Shelburne, and all overhead 230 kV and 345 kV lines), an additional 62 MW (approximately 50% of the remaining total generation capacity of Vermont's thermal units) was considered between first and second contingencies as follows.

- Vergennes diesels at 4 MW (+4)
- Proposed Swanton gas turbines at 42 MW (+21 MW)
- New Newport diesels at 10 MW (+2MW)
- New Essex diesels at 8 MW (+2 MW)
- Florence gas turbines at 6 MW (+6 MW)
- Burlington gas turbines at 12 MW (+12 MW)
- Berlin gas turbine at 15 MW (+15 MW)

1.3.3.1 Other generation assumptions - REDACTED

Hydro generation along the Connecticut River was dispatched at a low level, due to the uncertainty of water/hydro availability during the hot summer peak days. Specifically, Comerford and Moore generation was modeled at a total of 20 MW. The Wilder and Bellows Falls units were off. All base cases were created with Merrimack 2 off.

Three other dispatch scenarios were tested.

- Merrimack 2 was dispatched in service, and the AES Granite Ridge units were dispatched off
- The Comerford and Moore units were dispatched at full output
- Vermont Yankee was dispatched off

  Vermont Yankee (VY) was dispatched out of service as a base condition, i.e. not considered as the first contingency but eliminated from consideration in the generation mix such that VY is unavailable due to retirement or a permanent failure, then the first contingency was simulated followed by the second contingency. The performance criteria were applied whether VY was available or not. Any difference in reinforcement needs would be a measure of the support of VY to the system

Table 1 lists the cases tested. Tables 2 and 3 describe the main cases briefly. More detailed case summaries can be found in **appendix F on page 166.**

Table 2: List of cases tested

Case #	Case names	Transfer Condition	Vermont Load levels	Note
1	LRP18EW	East-West	1275 MW	All-lines-in
2	LRP18EW-AES	East-West	1275 MW	AES Off, Merrimack 2 ON
3	LRP18EW-VY	East-West	1275 MW	Vermont Yankee OFF
4	LRP18EWCMF	East-West	1275 MW	Comerford and Moore ON
5	LRP18EW-HG	East-West	1275 MW	Highgate OUT
6	LRP18EW-PV	East-West	1275 MW	PV-20 OUT (Plattsburgh-Sand Bar 115kV)
7	LRP18EW-K65	East-West	1275 MW	K65 OUT (Q City-Shelburne 115kV cable)
8	LRP18EW-F206	East-West	1275 MW	F206 OUT (Comerford-Granite 230 kV)
9	LRP18EW-370	East-West	1275 MW	370 OUT (W Rutland-N Haven 345)
10	LRP18EW-350	East-West	1275 MW	350 OUT (Coolidge-W Rutland 345 kV)
11	LRP18EW-340	East-West	1275 MW	340 OUT (VY-Coolidge 345 kV)
12	LRP18EW-3320	East-West	1275 MW	3320 OUT (Vernon-Newfane 345 kV)
13	LRP18EW-3321	East-West	1275 MW	3321 OUT (Newfane-Coolidge 345 kV)
14	LRP18EW-379	East-West	1275 MW	379 OUT (Vernon-Fitzwilliam 345 kV)
15	LRP18EW-381	East-West	1275 MW	381 OUT (Vernon-Northfield 345 kV)
16	LRP18EW-LIT	East-West	1275 MW	Littleton 230/115 kV auto OUT
17	LRP18EW-WRT	East-West	1275 MW	West Rutland 345/115 kV auto OUT
18	LRP18EW-CLT	East-West	1275 MW	Coolidge 345/115 kV auto OUT
19	LRP18EW-VRT	East-West	1275 MW	Vernon 345/115 kV auto OUT
20	LRP18EW-VYT	East-West	1275 MW	Vermont Yankee 345/115 kV auto UT
21	LRP18WE	West-East	1275 MW	All-lines-in
22	LRP18WE-AES	West-East	1275 MW	AES Off, Merrimack 2 ON
23	LRP18WE-VY	West-East	1275 MW	Vermont Yankee OFF
24	LRP18WECMF	West-East	1275 MW	Comerford and Moore ON
25	LRP18WE-HG	West-East	1275 MW	Highgate OUT
26	LRP18WE-PV	West-East	1275 MW	PV-20 OUT (Plattsburgh-Sand Bar 115)
27	LRP18WE-K65	West-East	1275 MW	K65 OUT (Q City-Shelburne 115 cable)
28	LRP18WE-F206	West-East	1275 MW	F206 OUT (Comerford-Granite 230 kV)
29	LRP18WE-370	West-East	1275 MW	370 OUT (W Rutland-N Haven 345)
30	LRP18WE-350	West-East	1275 MW	350 OUT (Coolidge-W Rutland 345 kV)
31	LRP18WE-340	West-East	1275 MW	340 OUT (VY-Coolidge 345 kV)
32	LRP18WE-3320	West-East	1275 MW	3320 OUT (Vernon-Newfane 345 kV)
33	LRP18WE-3321	West-East	1275 MW	3321 OUT (Newfane-Coolidge 345 kV)
34	LRP18WE-379	West-East	1275 MW	379 OUT (Vernon-Fitzwilliam 345 kV)
35	LRP18WE-381	West-East	1275 MW	381 OUT (Vernon-Northfield 345 kV)
36	LRP18WE-LIT	West-East	1275 MW	Littleton 230/115 kV auto OUT
37	LRP18WE-WRT	West-East	1275 MW	West Rutland 345/115 kV auto OUT
38	LRP18WE-CLT	West-East	1275 MW	Coolidge 345/115 kV auto OUT
39	LRP18WE-VRT	West-East	1275 MW	Vernon 345/115 kV auto OUT
40	LRP18WE-VYT	West-East	1275 MW	Vermont Yankee 345/115 kV auto UT

- Cases 5 to 20 and 25 to 40 were tested with VY out of service. For example, a Highgate OUT case was named LRP18EW-**VY**HG.
- To determine the timing of deficiencies, other load levels were tested. For example, a 2013 West-East all-lines-in case was named LRP**13**WE.
- All cases with a facility out as the first contingency were also tested with additional generation in Vermont, 31 MW for longer term outages, or 62 MW for short-term outages, including the K65 cable. For example, a Highgate OUT case was named LRP18EW**G**-HG

Table 3: Base case dispatch and interface flow summaries - REDACTED

Generators	Capacity	18EW	18EW-HG	18EW-VY	18EW-AES	18EWCMF	18WE	18WE-HG	18WE-VY	18WE-AES	18WECMF
Maine											
MIS											
Bucksport											
AEC											
RPA											
Westbrook											
WF Wyman											
New Hampshire											
Newington											
ConEd Newington											
Seabrook											
Schiller											
Merrimack											
Comerford											
Moore											
AES Granite Ridge											
NEMA/Boston											
Sithe Mystic											
Mystic											
Salem Harbor											
Kendall											
SEMA/RI											
Milford Power											
ANP Blackstone											
ANP Bellingham											
NEA											
Ocean State Power											
Brayton Point											
Manchester/FRSQ											
FPL Rise											
Sithe Fore River											
Potter											
Dighton											
Tiverton											
Brockton											
Canal+Braytn Pt dummy											
Canal											
Pilgrim											
W. Mass/VT											
Vermont Yankee											
McNeil											
Ryegate/Deckgen											
Vermont hydro & wind											
Other Vermont thermal											
Bear Swamp											
Northfield											
Stony Brook											
Berkshire Power											
Millennium											
CT/UI											
Lake Road											
Millstone											
Middletown											
Montville											
Meriden											
Milford											
Kleen											
Wallingford											
NH Harbor											
Bridgeport Harbor											
Bridgeport Energy											
Norwalk											
Interfaces											
NB-NE											
Highgate											
Phase II											
Me-NH											
NNE-Scobie											
North-South											
East-West											
NY-NE											
PV-20											
Boston Import											
Conn. Import											
SEMA/RI Export											

Table 4: Base case dispatch and interface flow summaries with VY OUT - REDACTED

Generators	Capacity	EW-VY	EW-VYHG	EW-VYAES	EWCMF-VY	WE-VY	WE-VYHG	WE-VYAES	WECMF-VY
Maine									
MIS									
Bucksport									
AEC									
RPA									
Westbrook									
WF Wyman									
New Hampshire									
Newington									
ConEd Newington									
Seabrook									
Schiller									
Merrimack									
Comerford									
Moore									
AES Granite Ridge									
NEMA/Boston									
Sithe Mystic									
Mystic									
Salem Harbor									
Kendall									
SEMA/RI									
Milford Power									
ANP Blackstone									
ANP Bellingham									
NEA									
Ocean State Power									
Brayton Point									
Manchester/FRSQ									
FPL Rise									
Sithe Fore River									
Potter									
Dighton									
Tiverton									
Brockton									
Canal+Braytn Pt dummy									
Canal									
Pilgrim									
W. Mass/VT									
Vermont Yankee									
McNeil									
Ryegate/Deckgen									
Vermont hydro & wind									
Other Vermont thermal									
Bear Swamp									
Northfield									
Stony Brook									
Berkshire Power									
Millennium									
CT/UI									
Lake Road									
Millstone									
Middletown									
Montville									
Meriden									
Milford									
Kleen									
Wallingford									
NH Harbor									
Bridgeport Harbor									
Bridgeport Energy									
Norwalk									
Interfaces									
NB-NE									
Highgate									
Phase II									
Me-NH									
NNE-Scobie									
North-South									
East-West									
NY-NE									
PV-20									
Boston Import									
Conn. Import									
SEMA/RI Export									

1.4 ANALYSIS METHODOLOGY

Predicting the load level, generation, the topology of the system, changes to planning standards and to the manner in which the transmission system will be utilized, is increasingly uncertain the farther out the horizon. Therefore, although a 20-yr horizon was examined, the bulk of the analysis was conducted for the 10-yr horizon. Once identified, the limiting cases for the 10-yr analysis were tested up to the 2028 load level. The results from the 2028 load level were utilized to examine system performance trends, evolving system needs, solution robustness with increased demand and longer term solution possibilities.

1.4.1 PLANNING STANDARDS AND CRITERIA

The study of the transmission system was performed in accordance with the North American Electric Reliability Corporation (NERC) planning standards TPL-001 to TPL-003; the Northeast Power Coordinating Council (NPCC) Document A-2, *"Basic Criteria for Design and Operation of Interconnected Power Systems";* and the ISO New England Planning Procedure 3, "*Reliability Standards for the New England Area Bulk Power Supply System*".

For the sub-transmission, the N-1 standard was applied as a consistent yardstick to measure the sub-transmission system's performance across the state, recognizing that the Vermont distribution utilities may have used varying planning standards.

1.4.2 PERFORMANCE CRITERIA

The NERC Reliability Standards require that the Bulk Power system thermal and voltage limits remain within applicable limits after the events described in the following table, which was copied from NERC's Transmission Planning system performance criteria in TPL-001, TPL-002, and TPL-003. The specific criteria used for the transmission analysis are noted below in Tables 5 and 6.

For the sub-transmission system, the performance criteria associated with TPL-001 (N-0) and TPL-002 (N-1) were followed. In addition, loss of step-down transformers from the transmission system to the sub-transmission system should not result in loss of load except when the transformer is supplying an island, i.e. a portion of the system not normally connected to the remainder of the network except through the transformer in question.

Under the N-1 standard, the system is required to not exceed applicable emergency limits for a single outage event at the peak load level. The N-1 standard was used to test the entire sub-transmission system because it is a commonly used standard based on good utility practice. However, it is recognized that some parts of the sub-transmission system are not designed to the N-1 standard.

Table 5: NERC performance criteria

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

The following ratings and voltage limits are applicable for the conditions assessed as part of the NERC, NPCC, and ISO-NE standards. These criteria are based on common good utility practice and the current understanding by ISO-NE and the New England transmission owners. Vermont distribution utilities may have used different limits for the system below 115 kV. For example, the CVPS high voltage limit is 1.1 pu.

Table 6: Thermal and voltage criteria

System event	Thermal criteria	Voltage criteria		
	For all facilities	Below 115 kV	For 115 kV facilities	For 230 kV and above
Category A (All-lines-in) or N-0	At or below normal rating	At or above 0.95 pu and At or below 1.05 pu	At or above 0.95 pu and At or below 1.05 pu	At or above 0.98 pu and At or below 1.05 pu
Category B, C, & D (single or multi-element outages) or N-1 and N-1-1	At or below LTE rating	At or above 0.9 pu and At or below 1.05 pu Delta V no greater than 10%	At or above 0.95 pu and At or below 1.05 pu Delta V no greater than 10%	At or above 0.95 pu and At or below 1.05 pu Delta V no greater than 5%

1.4.2.1 Seabrook and Vermont Yankee voltages limits - REDACTED

1.4.2.2 Steady State Solution Parameters

Transformer taps, switched capacitor banks and phase shifter angles were not allowed to move during load flow simulations immediately after contingencies. Where needed, transformer taps and switched capacitor banks were allowed to move post-contingency to determine if low voltage violations could be removed. Where high post-contingency voltages occurred due to a capacitor bank being energized, it was assumed that this capacitor bank could be switched out of service to reduce the voltage below the high voltage limit. Voltage and thermal violations remote to Vermont were noted. However, no mitigating actions were proposed.

1.4.2.3 Phase shifter settings - REDACTED

Below is the approach utilized to set the Vermont phase shifters pre-contingency.

Sand Bar

Blissville

Granite

1.4.3 CONTINGENCIES TESTED

Contingencies include both Bulk Power System (BPS) and non-BPS facilities from 34.5 kV to 345 kV. Nearly 400 transmission contingencies were simulated in Vermont, and neighboring states, such as New Hampshire, Massachusetts, and New York. Nearly 170 contingencies were simulated on the sub-transmission system in Vermont. **See tables D-1 and D-2, in appendix D, page 91**. Contingencies include:

NERC Category B

- Single 34.5 kV and 46 kV line outages in VT
- Single 69 kV line outages in VT, NH, and MA
- Single 115 kV line outages in VT, NH, MA, and NY
- Single 230 kV and 345 kV line outages in VT, NH, MA, and NY
- Single 230 kV and 345 kV autotransformer outages in VT, NH, MA, and NY
- Single generator/HVDC outages, including loss of the Highgate HVDC facilities

NERC Category C

- 115 kV stuck breaker outages in VT and NH
- 115 kV double circuit tower outages in VT, NH, and MA
- 230 kV and 345 kV stuck breaker outages in VT, NH and MA
- 230 kV double circuit tower outages in NY
- Loss of Phase II and
- Category B contingencies with a facility already out of service. The initial contingencies include: **REDACTED**

ISO-NE PP3/NPCC A-2 (Extreme contingencies similar to NERC Category D)

- Category C contingencies with a facility already out of service. The initial contingencies include: **REDACTED**
- Loss of substations: **REDACTED**

Contingencies excluded:

NERC requires that the reasoning for not testing certain contingencies be provided. NERC defined Category D contingencies, e.g. loss of stations, loss of ROW, loss of load centers, etc, were excluded. However, loss of the West Rutland, Coolidge, and VY 345 kV stations and Category C contingencies in conjunction with a facility already out at extreme weather load levels were tested. Of the list of possible extreme contingencies, loss of substations is by far the most severe in Vermont, and some of the combinations of contingencies tested resulted in loss of the most significant 345 kV stations. The transmission system in Vermont is sparse. Transmission corridors do not include more than two transmission lines. The entire state load was modeled at 1275 MW. Therefore, there is no large load center that can be tripped. There is only one special protection system (SPS) on the Vermont transmission system. This type I SPS inserts a series reactor in the PV-20 line to reduce post contingency loading below the LTE rating. Inserting this series reactor when it is not required, which was included in the single contingency list, only reduces the flow on the line, which is less severe than tripping the line, which was also included in the single contingency list. The automatic insertion of the series reactor is only one of a number of actions that can be taken to reduce the flow on the PV-20 line. There is a phase shifter in series with the line, and the breaker that inserts the series reactor can be operated remotely via SCADA. These two actions can be taken in case the SPS does not operate as intended.