08/07/2023 | ISO-NE WEBEX

ISO new england

New England T & D Technical Forum

Evolving light load, high voltage transmission system problems and distribution system interaction

Dean LaForest

MANAGER – REAL TIME STUDIES

Meeting agenda

- Introductions
- Forum Concept – discussion
- Presentation on New England load power factor, evolving load trends and growing transmission high voltage problems
- Q & A
- Next steps

FORUM CONCEPT

Rationale for the group's need

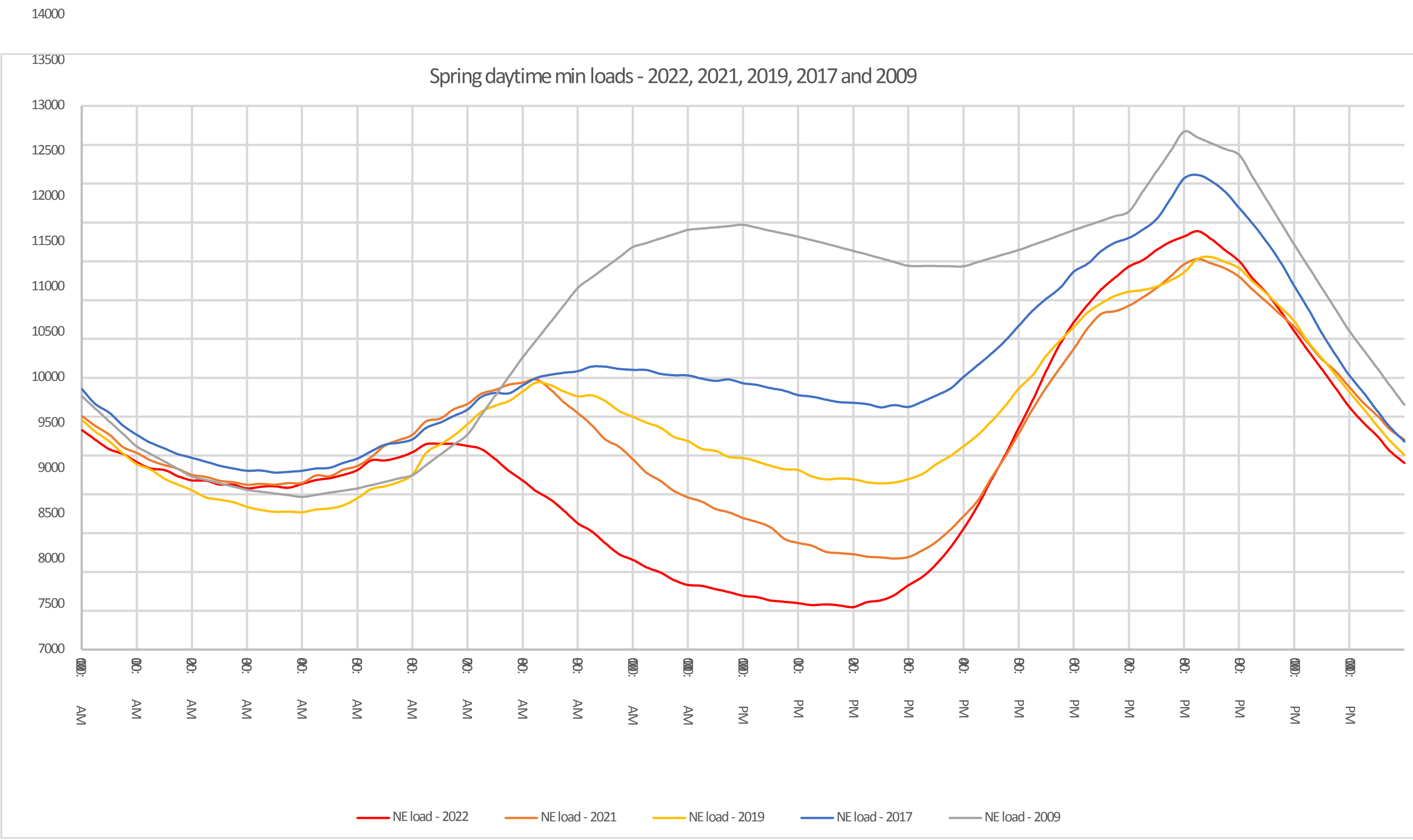
- New England's transmission and distribution systems are going through their most significant function transition in decades
  - A significant portion of energy production for the system is moving from fewer power production facilities on the transmission system to more numerous power production facilities on the distribution system
  - Fossil fueled power production is being minimized / eliminated and being replaced by renewable / non-polluting power production with energy storage
  - The redistribution of supply is changing some long-standing functions supplied / supported by the transmission system, and will significantly change use of the transmission system
  - This evolution is changing how the transmission system and distribution system may interact, so active discussion and improved understanding of how these changes are impacting both transmission and distribution seems a prudent course to take as these changes take place
  - This forum is an attempt to do just that

THE EVOLVING IMPACT OF ENERGY PRODUCTION CHANGES ON NET LOAD, LOAD POWER FACTOR AND TRANSMISSION VOLTAGE CONTROL

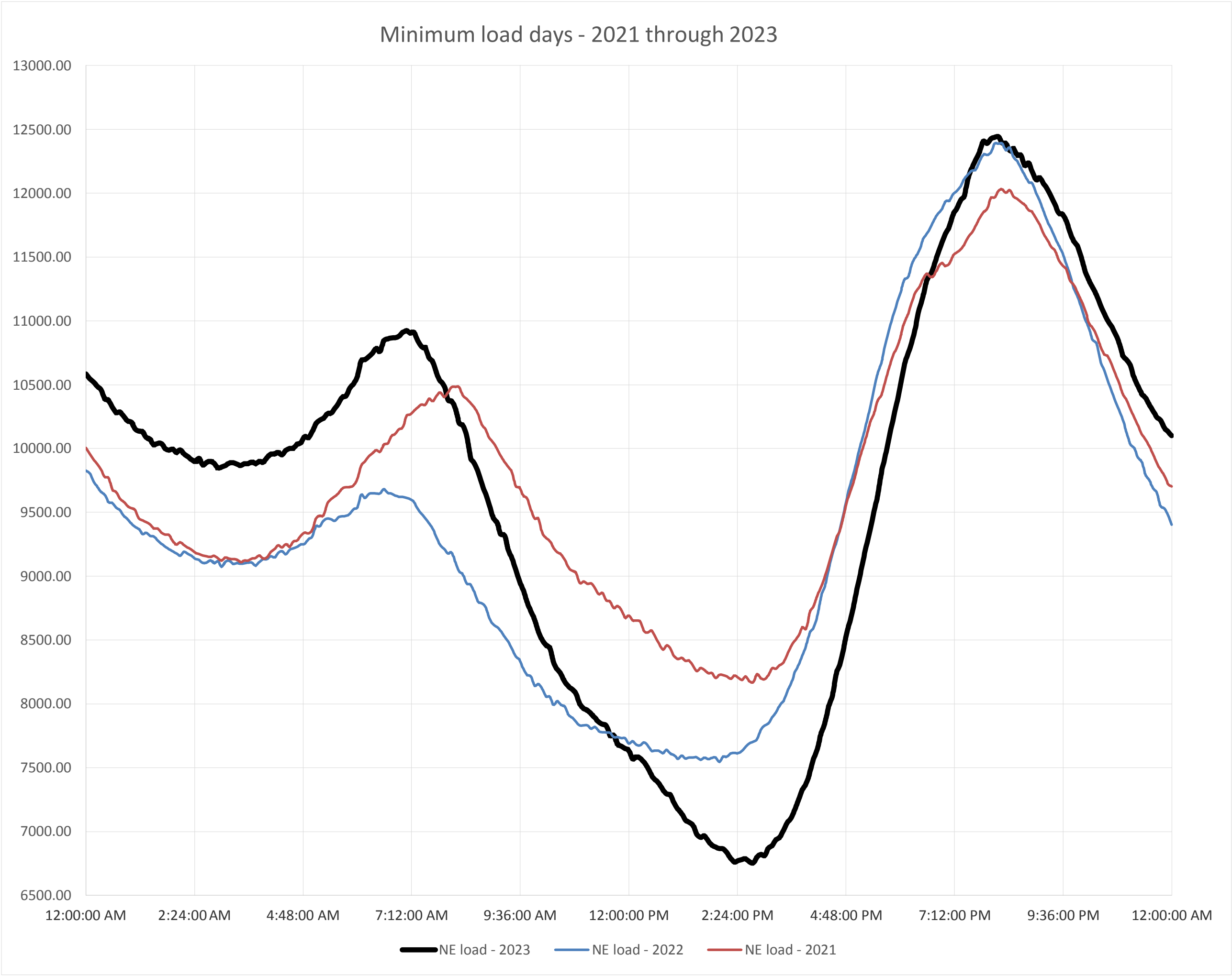
The "Duck Curve" – New England style

- New England has been working on reducing energy demand and transitioning to more renewable energy for many years
- The impacts of these changes have altered the overall demand, net load and the daily load shape in New England
- The two most significant changes have been on peak and minimum loads
  - Peak loads have not surpassed the all time peak set in the mid 2000s
    - System planning efforts in New England have largely managed the "peak issues"
  - Minimum load levels, especially during daylight hours, have steadily reduced over time, such that day time min loads on spring weekends are the new minimum load levels in New England

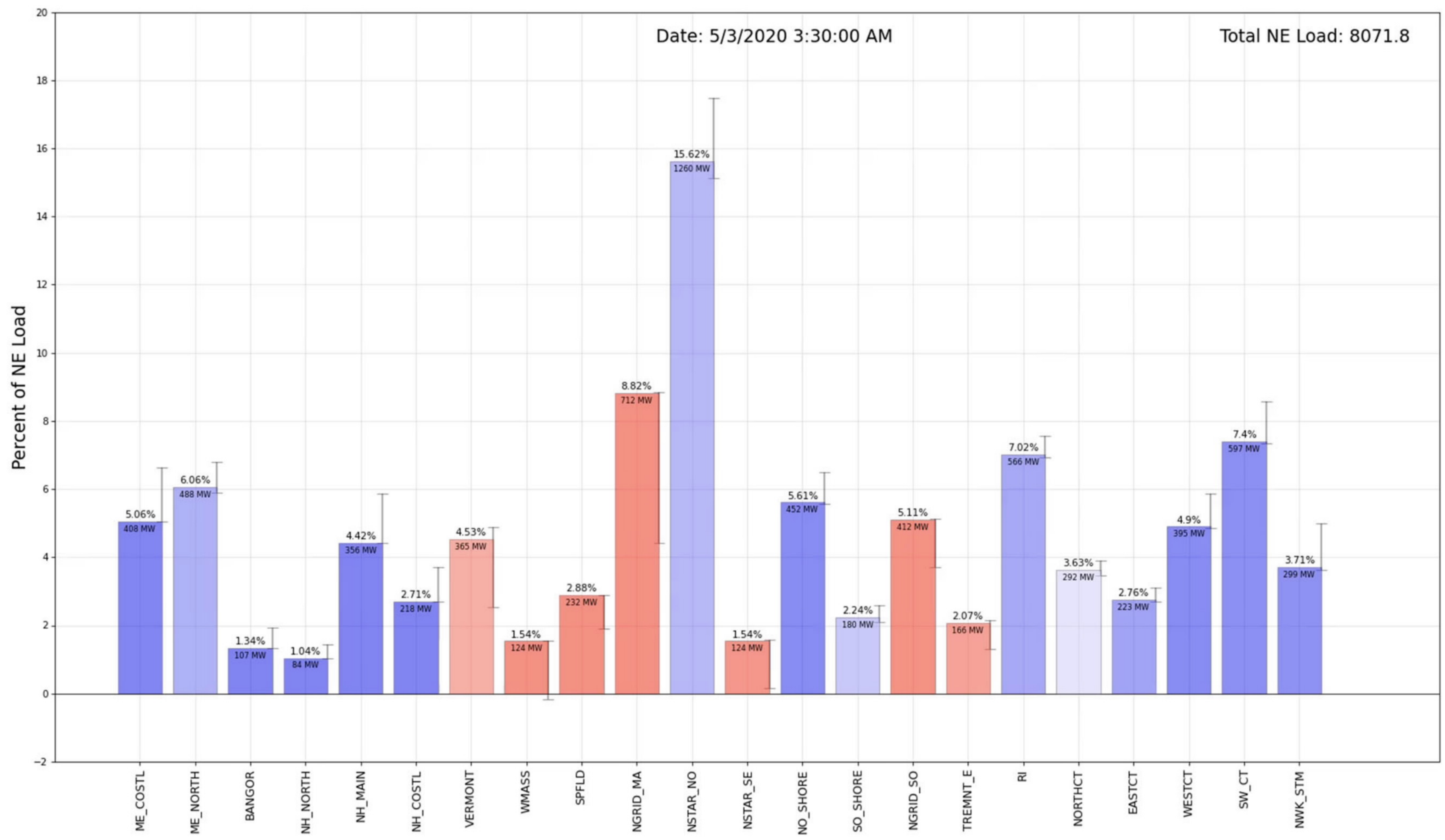
Daytime Min Loads over the past decade plus



Daytime Min Loads over the past three years



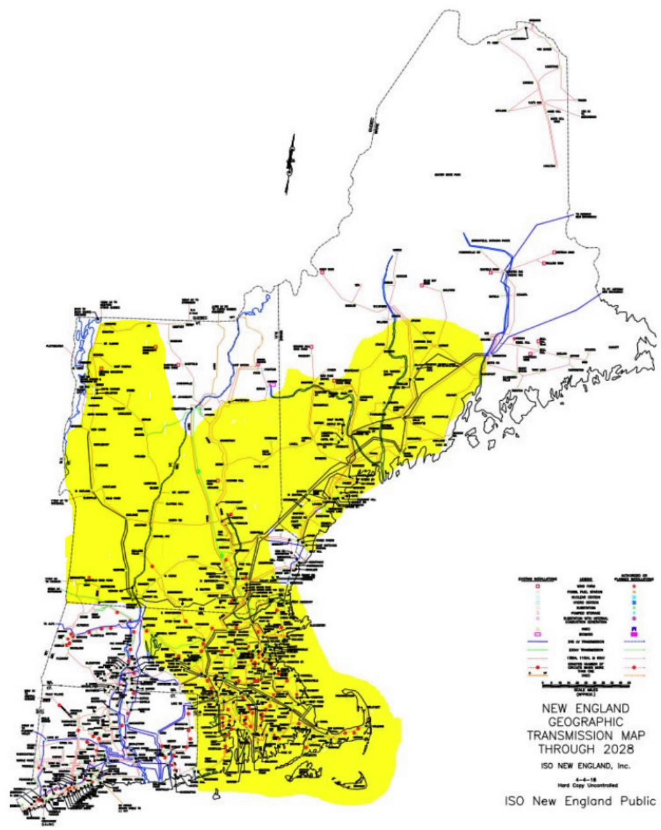
Animation showing Daytime Loads on 5/3/22



Impact on unit commitment due to new low daytime loads

- Unit in New England is driven by economics and need
  - Load and export / import from adjoining areas drives internal commitment
  - Reliability commitment is made afterward
- Lower minimum loads drives down commitment of in market generation
  - Generation not in the market (such as DER) is not impacted

Potential area without transmission connected generation for current lightest loads



LOAD POWER FACTOR IN NEW ENGLAND

Load Power Factor – Why We Monitor It

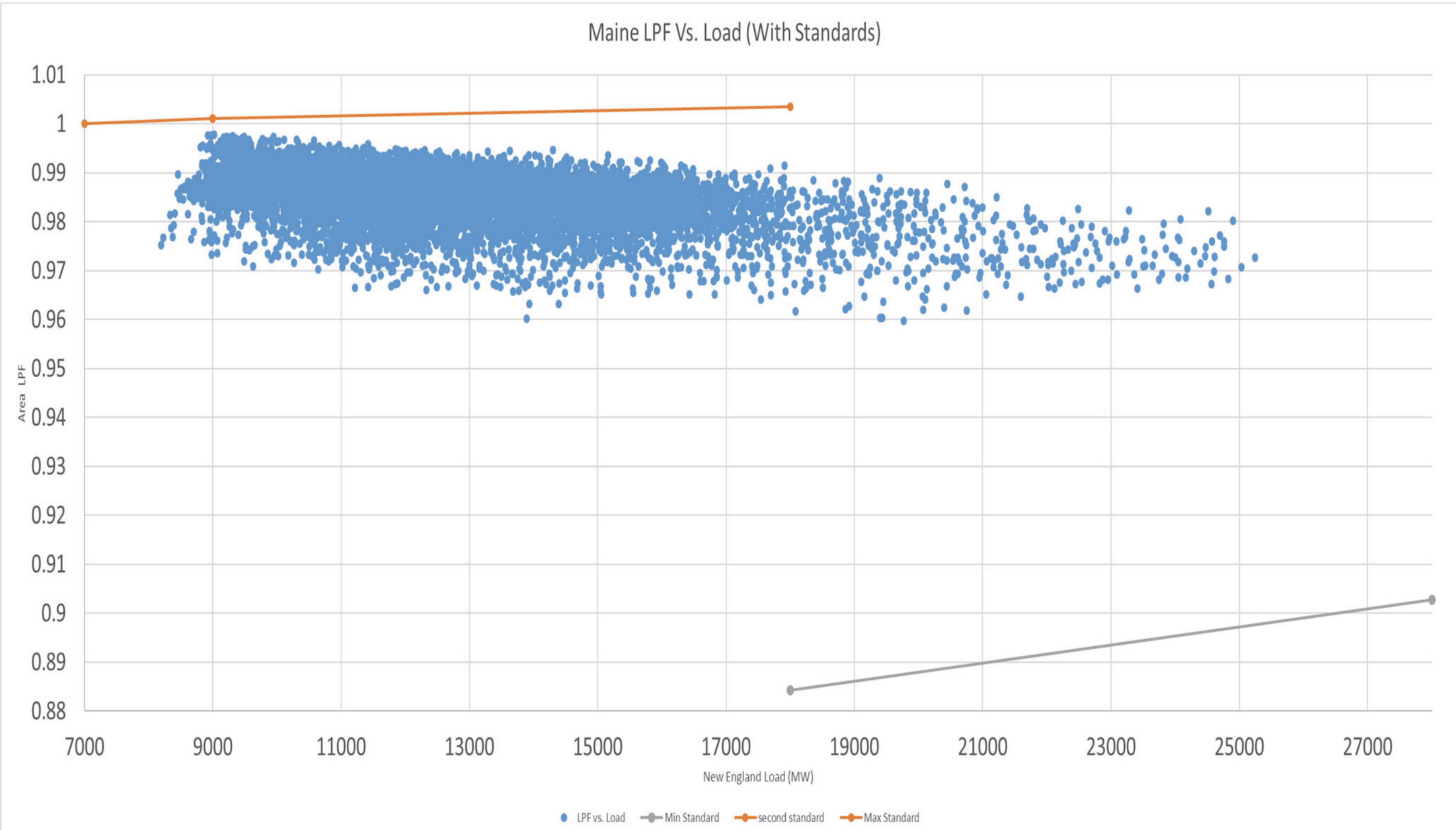
- ISO NE began monitoring back in the 1990s
  - At the time, peak load / low voltage was the operating concern
  - Concerns have morphed into light load / high voltage operating concerns (“all lines in” and “facility out”)
- Monitoring included reporting for each area (determined by local voltage performance and TO operating footprint)
- Operating studies were performed to determine what load power factor each area could support reliably
- The “LPF survey” examined 6 selected points to represent the whole year – TOs provided the data
- ISO recently transitioned to examining hourly data for each area using our archived SCADA data to get a more complete picture of performance

LATEST LPF CURVES

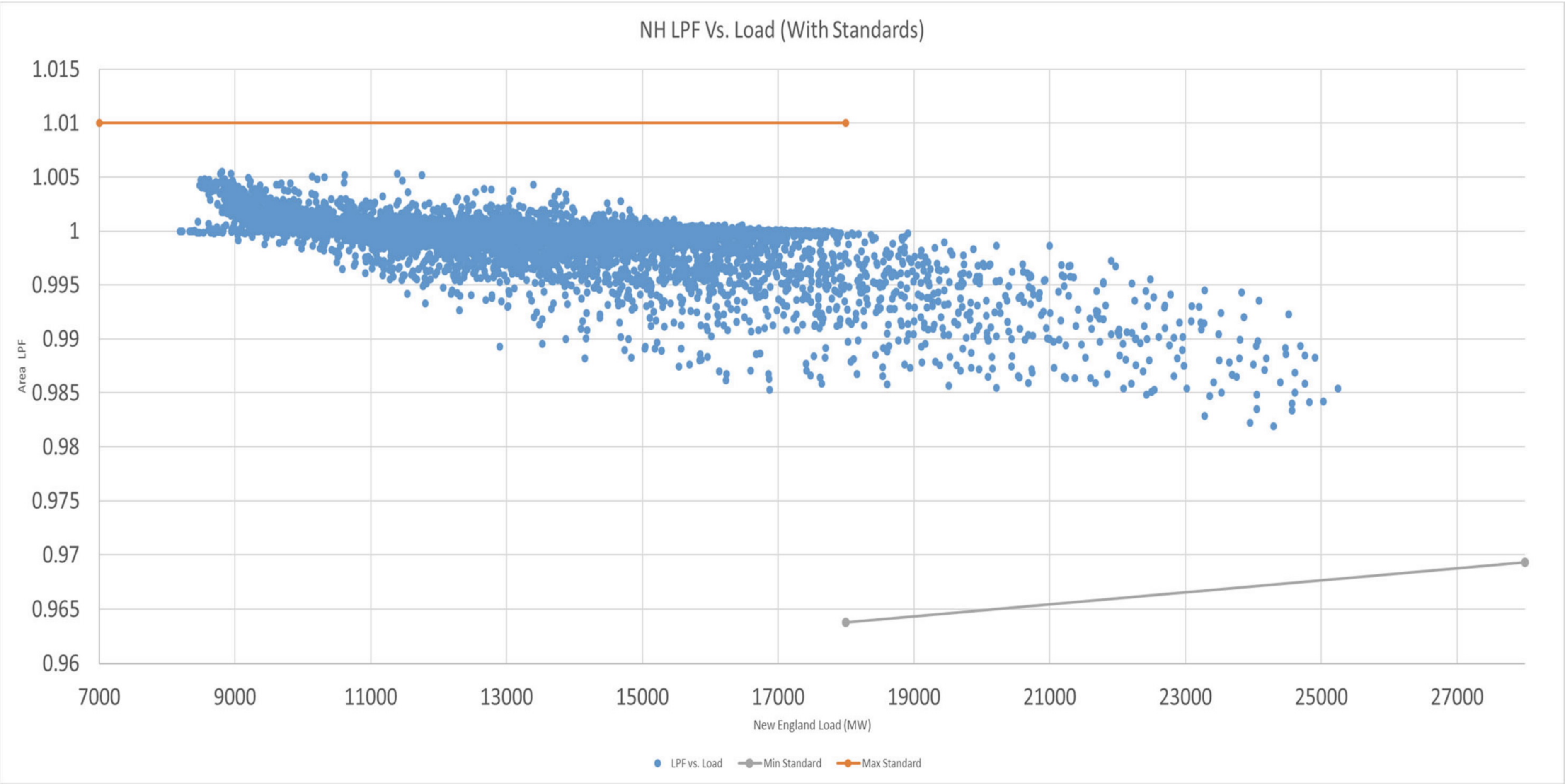
Load Power Factor Curve background info

- Curves created for each area
- Hourly load power factor monitored at high side load distribution transformer
  - So 115 kV side for a 115 / 34.5 kV transformer
- LPF plotted against two curves
  - Orange curve on the upper left shows allowable “light load / high voltage” curve
    - Points above that line have the potential to cause post-contingent transmission high voltage without added generation commitment or other operating actions
  - Gray curve to the lower right shows allowable “high load / low voltage” curve
    - Points below that line have the potential to cause post-contingent transmission low voltage without added generation commitment or other operating actions

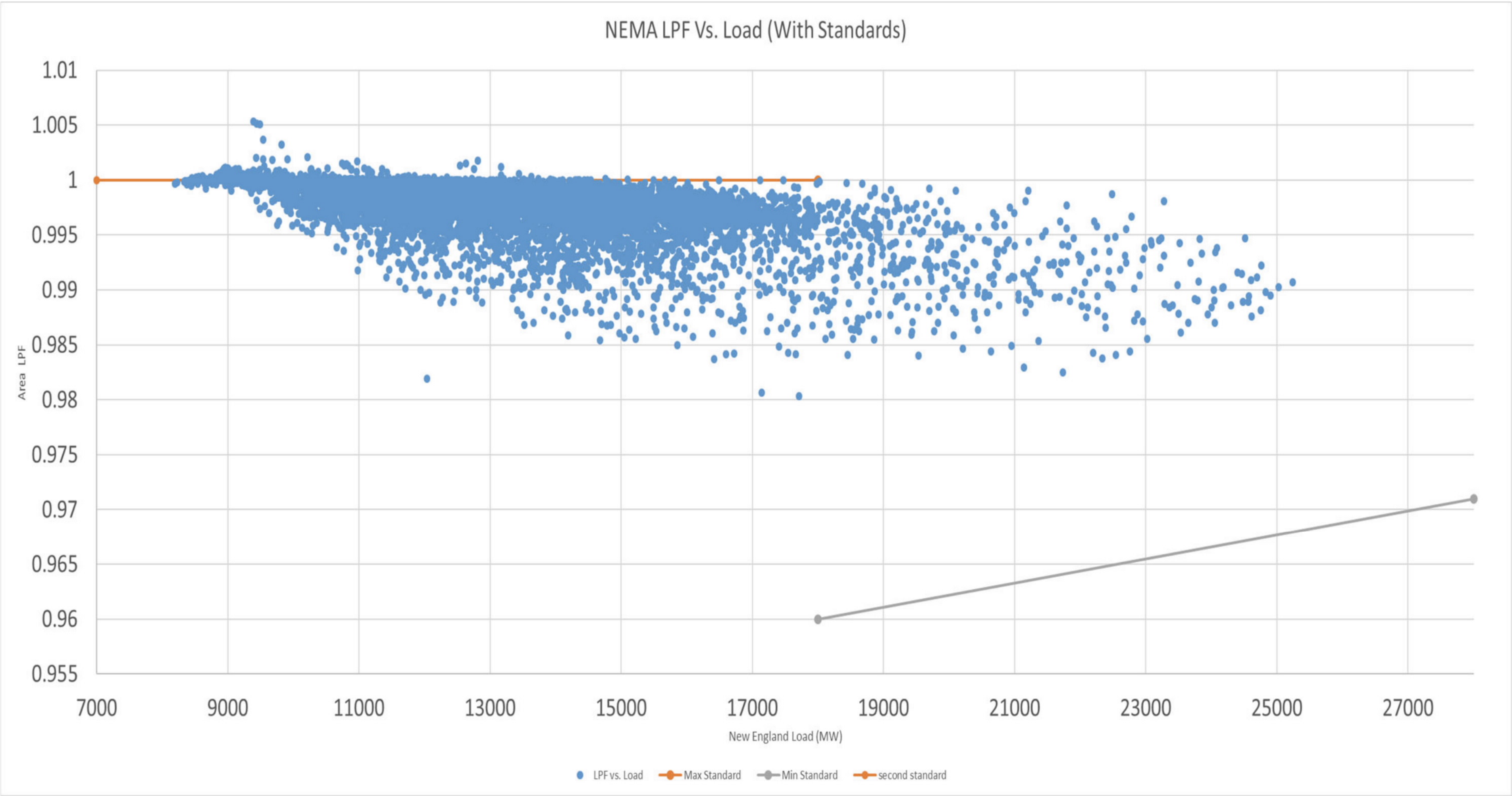
Maine LPF 2021



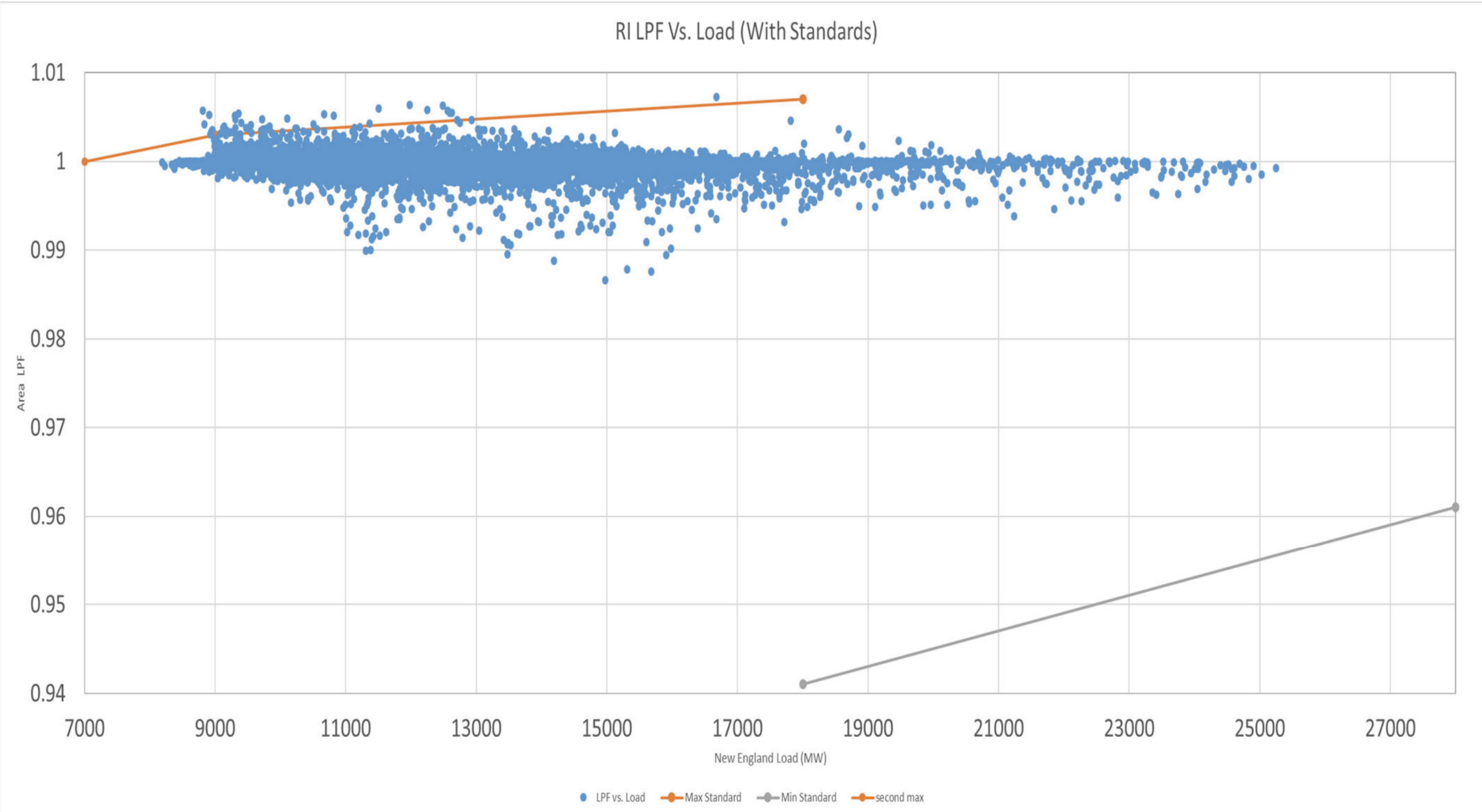
New Hampshire LPF 2021



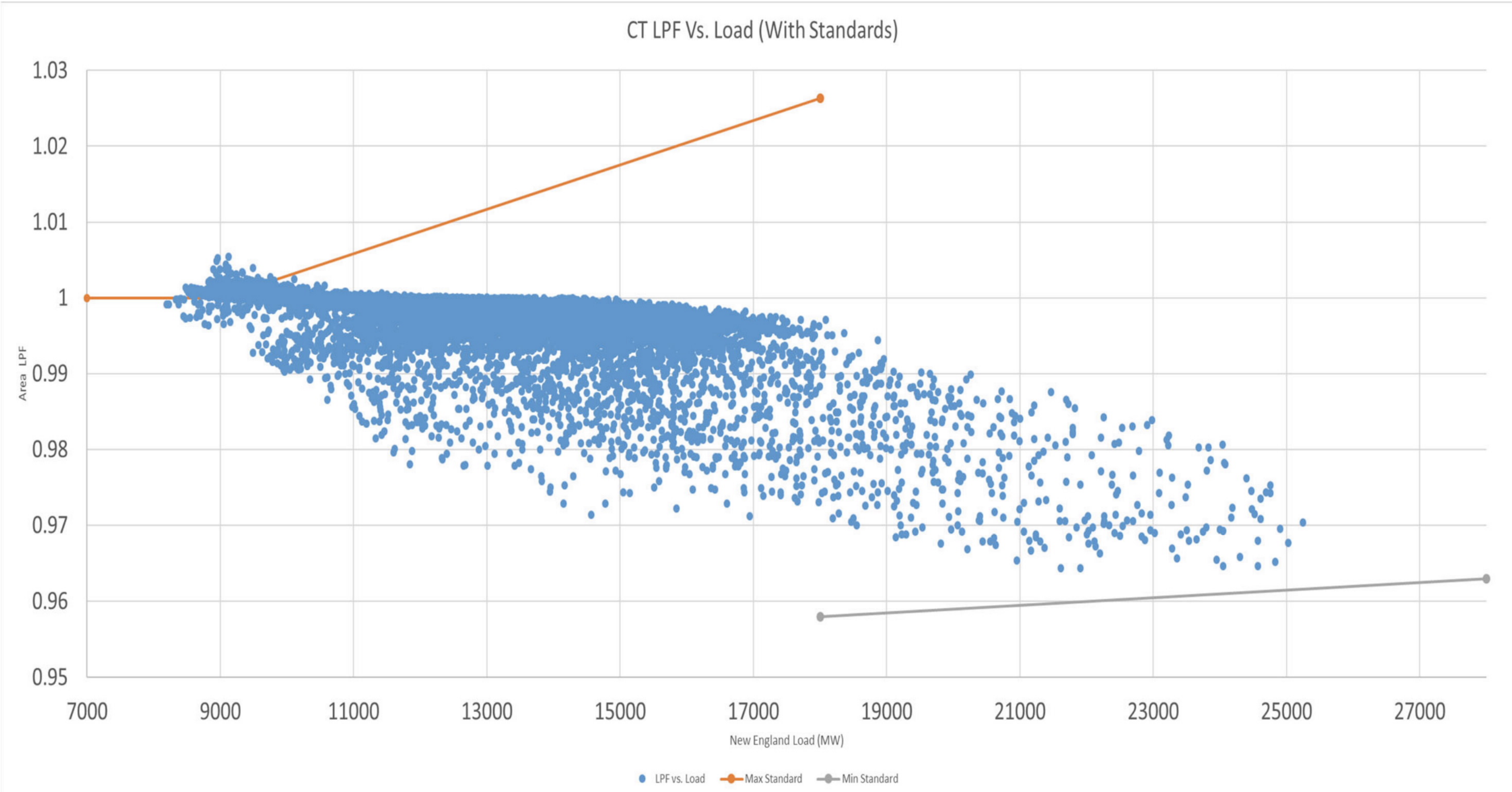
Northeast MA LPF 2021



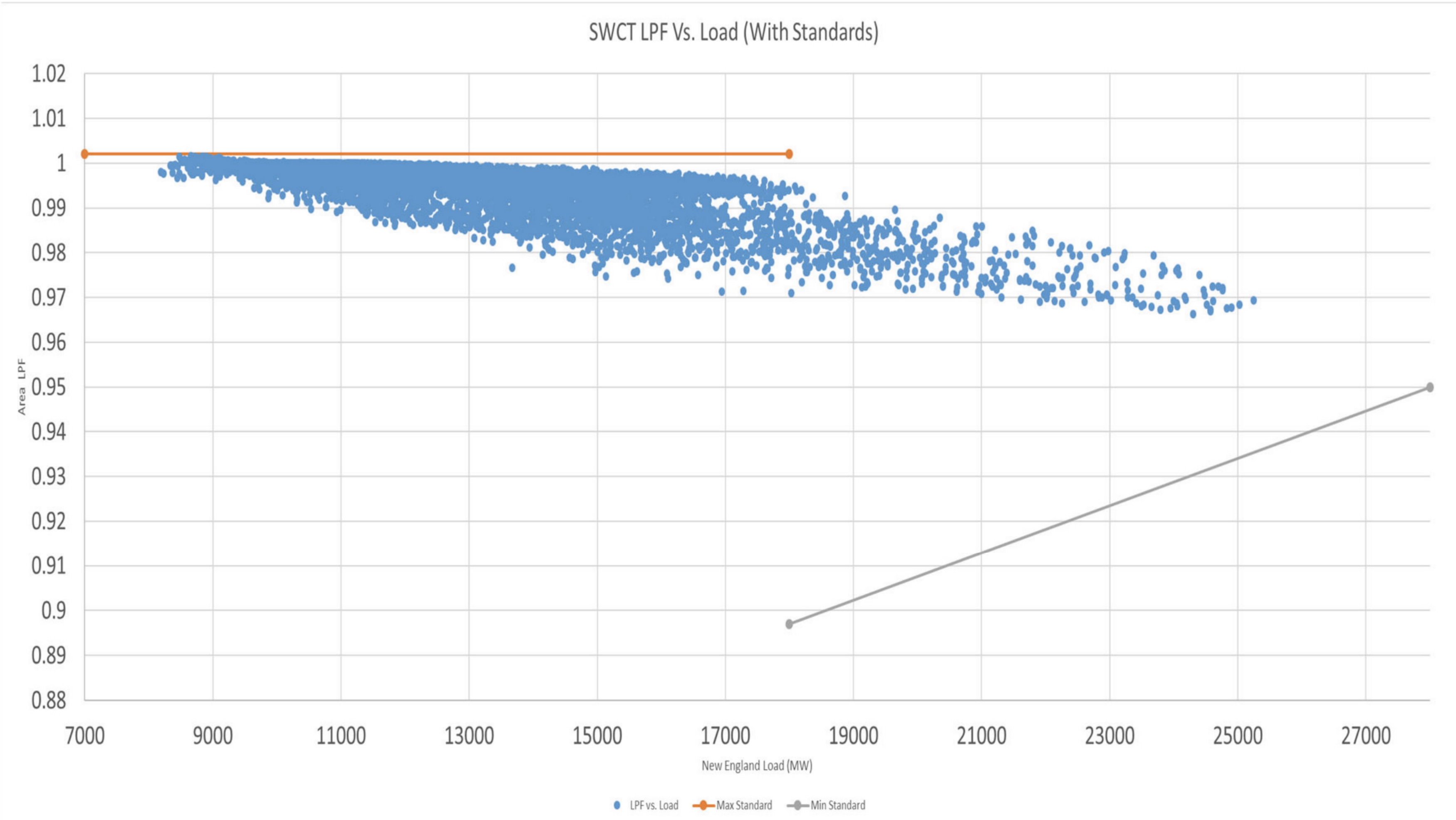
Rhode Island LPF 2021



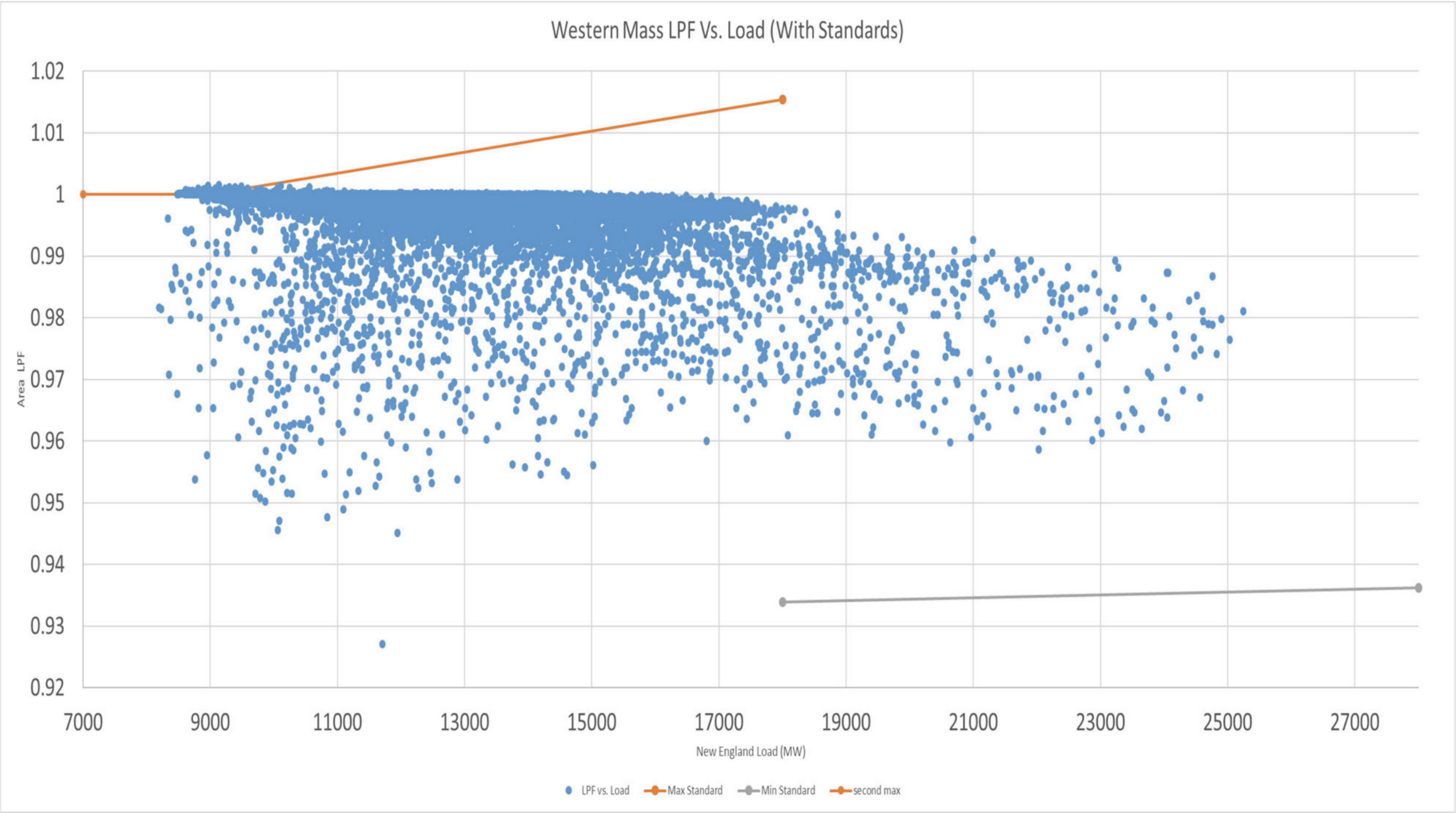
Connecticut LPF 2021



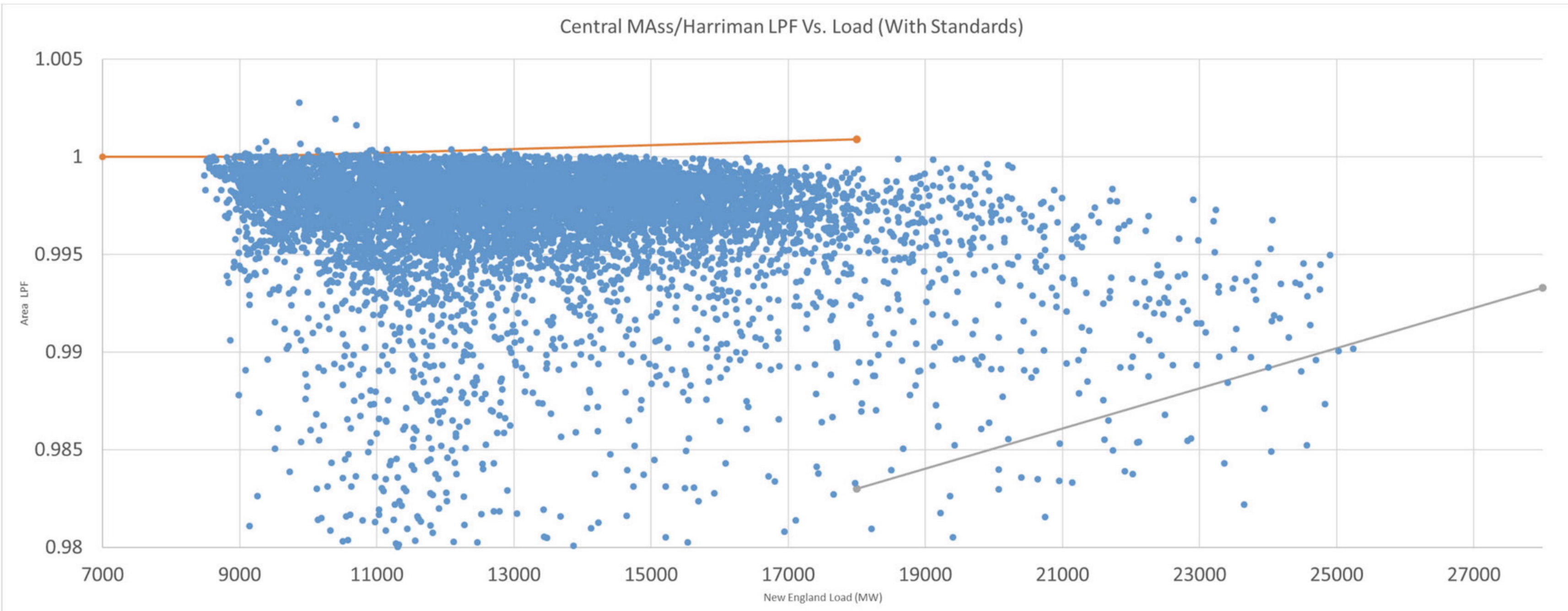
Southwest Connecticut LPF 2021

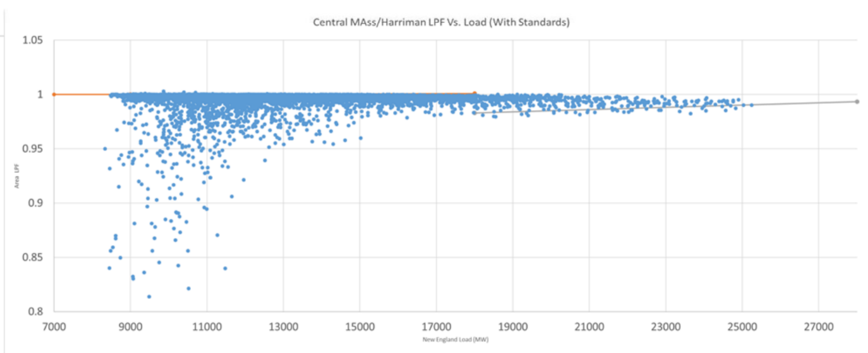


Western Masachusetts LPF 2021

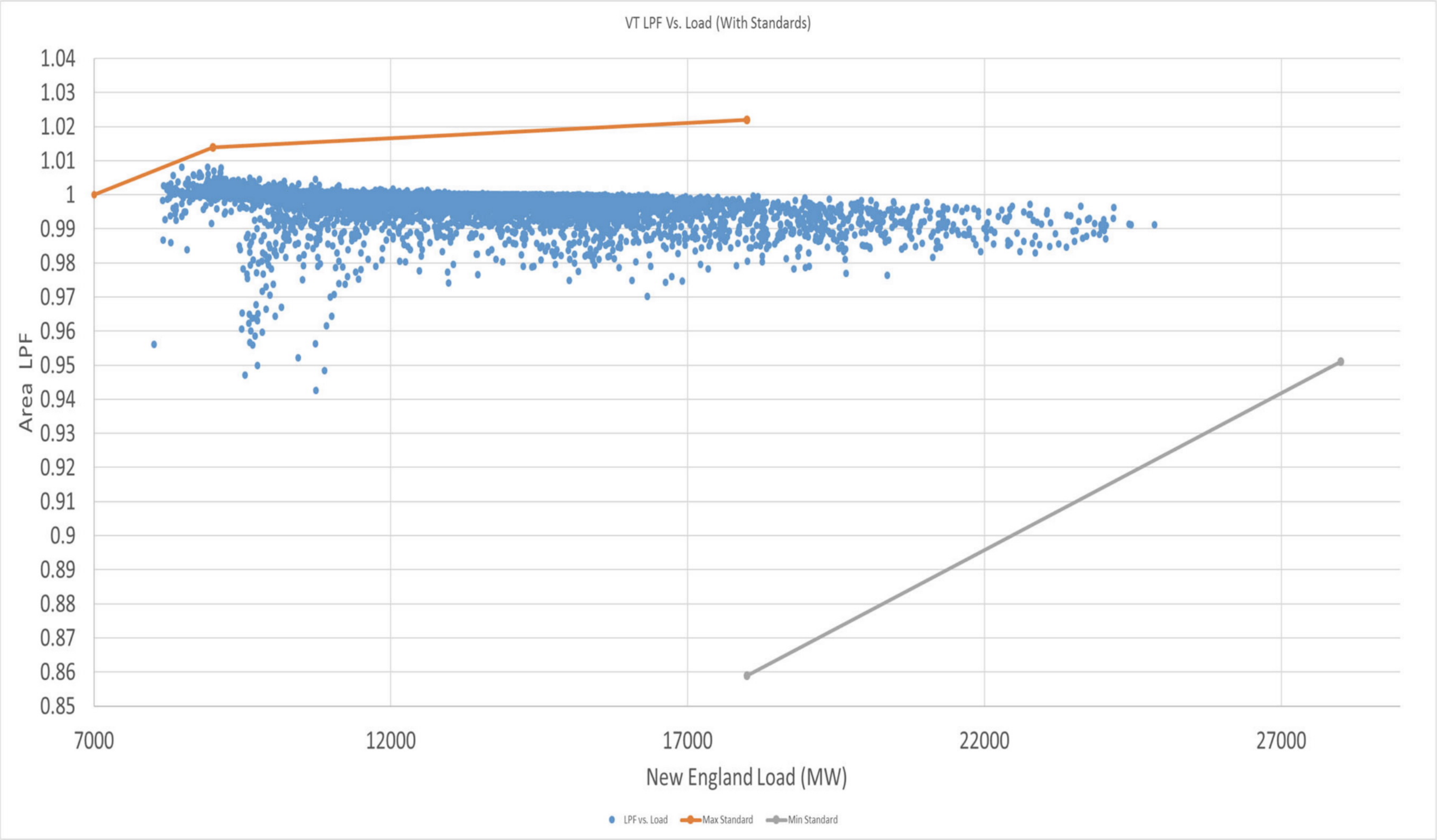


Central MA / Harriman LPF 2021





Vermont LPF 2021



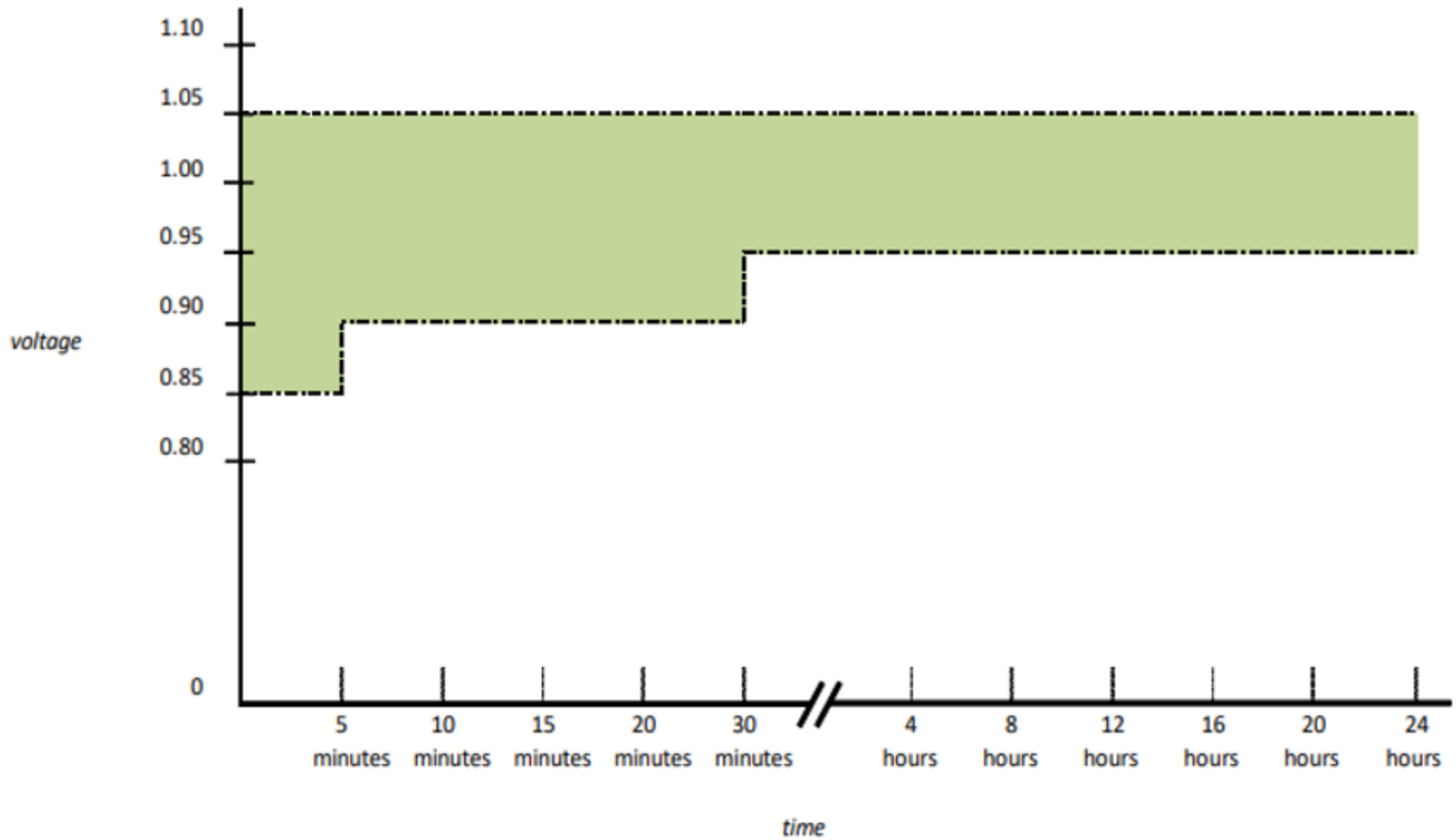
Transmission Voltage Limits

- Provided by the transmission owners (TOs)
- For high voltage, very few of the TOs allow ANY time above 105% of nominal voltage
- Example table below (take from OP 19, appendix K)

Table 2 - Long Time Emergency Voltage Limits (LTEVL)

Long Time Emergency Voltage Limits (LTEVL) [1, 2, 3, 4, 8, 9]									
	115 kV			230 kV			345 kV		
LCC / TO	Time applicable	Low voltage limits (kV)	High voltage limits (kV)	Time applicable	Low voltage limits (kV)	High voltage limits (kV)	Time applicable	Low voltage limits (kV)	High voltage limits (kV)
CONVEX (ES)	Infinite	105.0	121.0	N.A.	N.A.	N.A.	Use NORMVL		
CONVEX (UI)	Use NORMVL			N.A.	N.A.	N.A.	Use NORMVL		
Maine (CMP)	30 minutes	105.8	124.0	N.A.	N.A.	N.A.	Use NORMVL		
Maine (Versant Power)	30 minutes	105.8	124.0	N.A.	N.A.	N.A.	Use NORMVL		
New Hampshire	120 minutes	107.0	121.0	Use NORMVL			Use NORMVL		
NGRID (NGRID and RIE[10])	30 minutes	103.5	121.0	30 minutes	207.0	241.5	30 minutes	310.5	362.0
NSTAR	Load cycle[5]	103.5	121.0	Load cycle[5]	207.0	241.5	Load cycle[5]	310.5	362.0
VELCO	120 minutes	103.5	121.0	120 minutes	207.0	241.5	120 minutes	310.5	362.0

Transmission voltage limit example



LPF AND TRANSMISSION PLANNING

Load power factor assumptions in Transmission System Planning

- ISO New England has a set of agreed upon assumptions used by all regional planners
- Included among those is the set of load power factors, supplied by each TO, for regional planning
- Light load conditions used an almost universal load power factor assumption
  - For all but the Boston area, a 0.998 leading load power factor is assumed
  - The 0.998 leading power factor yields approximately unity power factor on the high side of distribution transformers

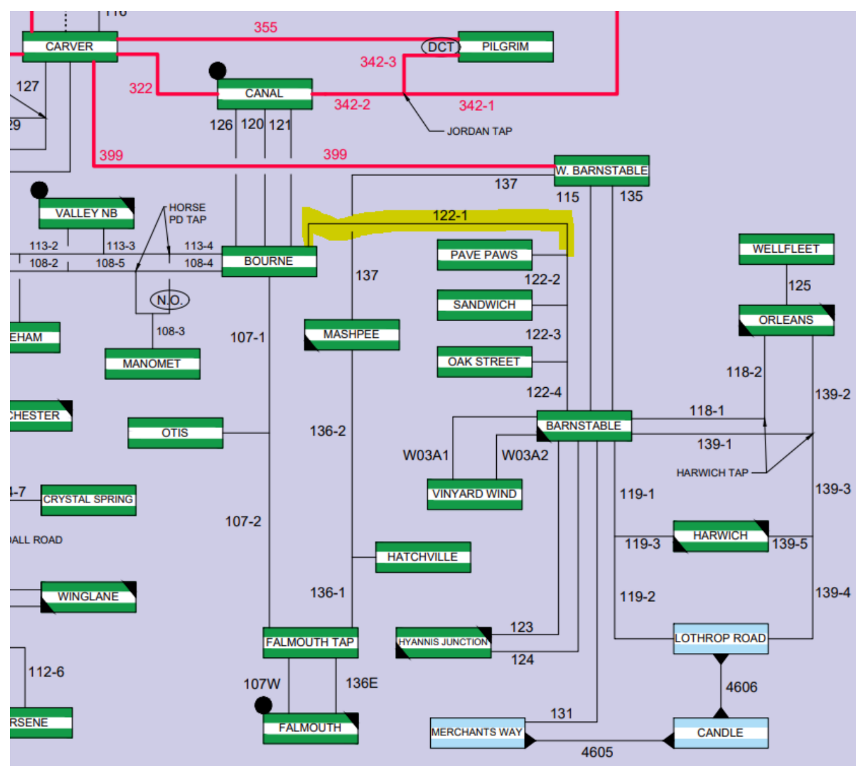
Regional planning and cost

- New England still supports regionalized cost support for meeting regional transmission needs
- Meeting these needs is premised, in part, on the assumed load power factor in the planning cases
- Actual load power factor in the region (at light loads) can be worse than that assumed in planning cases
- ISO NE is exploring if Operating Procedure 17 (Load Power Factor and System Assessment) should be based upon a reasonable set of load power factors and not what the system as currently designed can support

EXAMPLE OF CURRENT OPERATIONAL CONCERNS DUE TO POOR LOAD POWER FACTOR

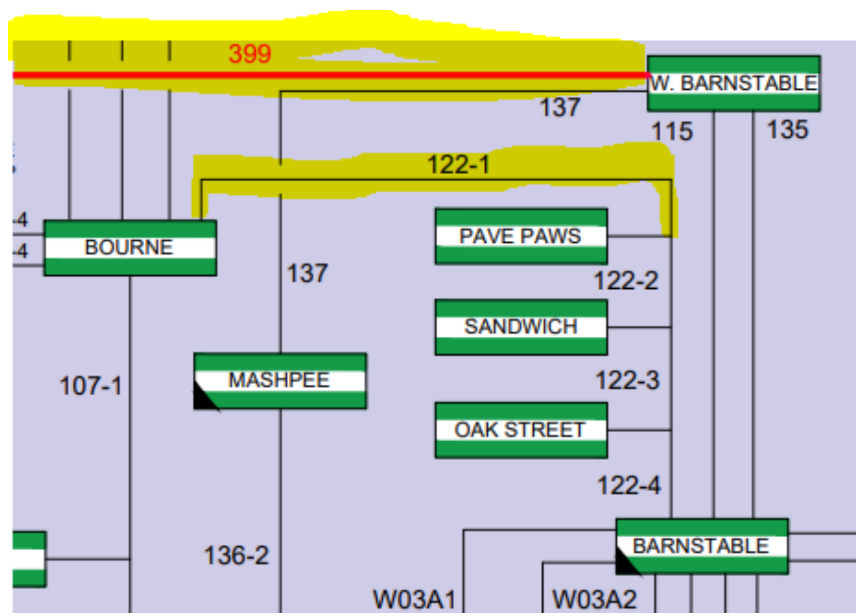
The system is continuously changing

- Planned maintenance work (transmission and generation) largely is performed in the spring and fall, during lighter system loads
- New generation often requires transmission work to integrate the new generation
- Work is underway to connect Vineyard Wind
  - 122 line outage in April (two weeks)



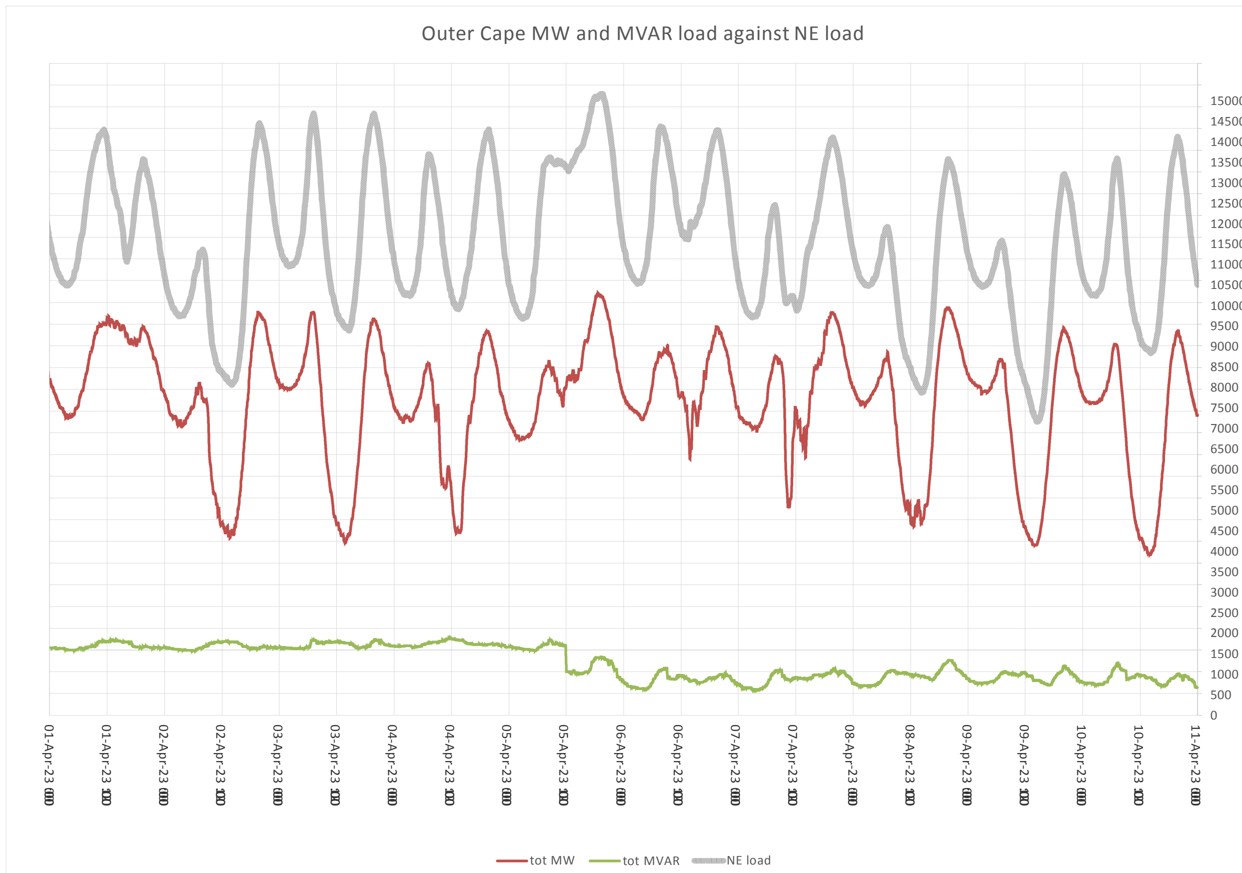
Operational concerns arose . . .

- Operating studies indicated when loads were at their daytime min loss of the 399 line was causing post-contingent high voltage on the Cape
- The 122 line was out for planned work
- The 137 line was carrying all load on the outer Cape

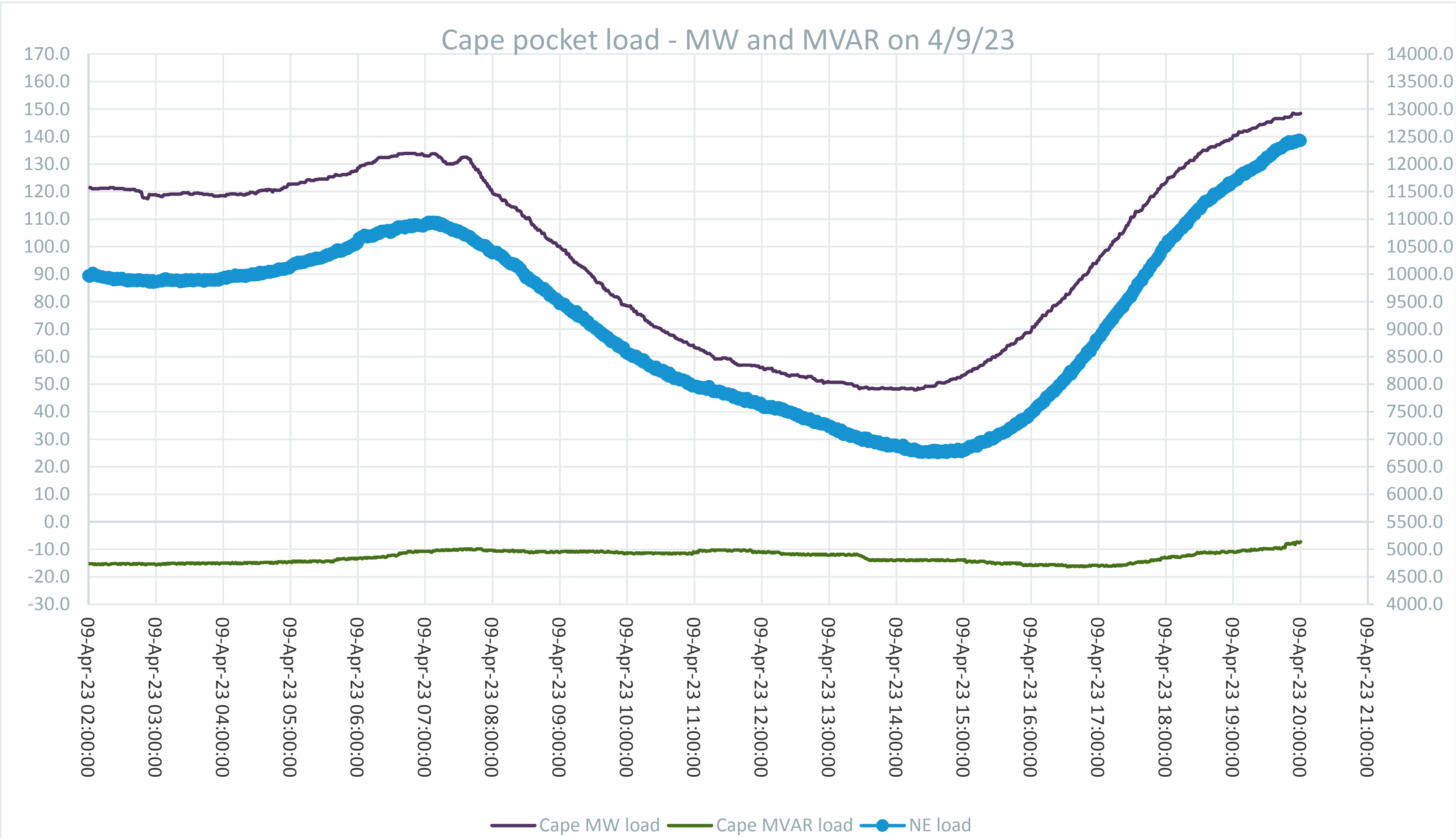


Loads on the Outer Cape (MW and MVARs)

- MW and MVAR loads plotted for the Outer Cape (on the 135 and 115 lines)
- Problem appeared with the reactive demand change (from positive to negative) before Easter (4/9/23)



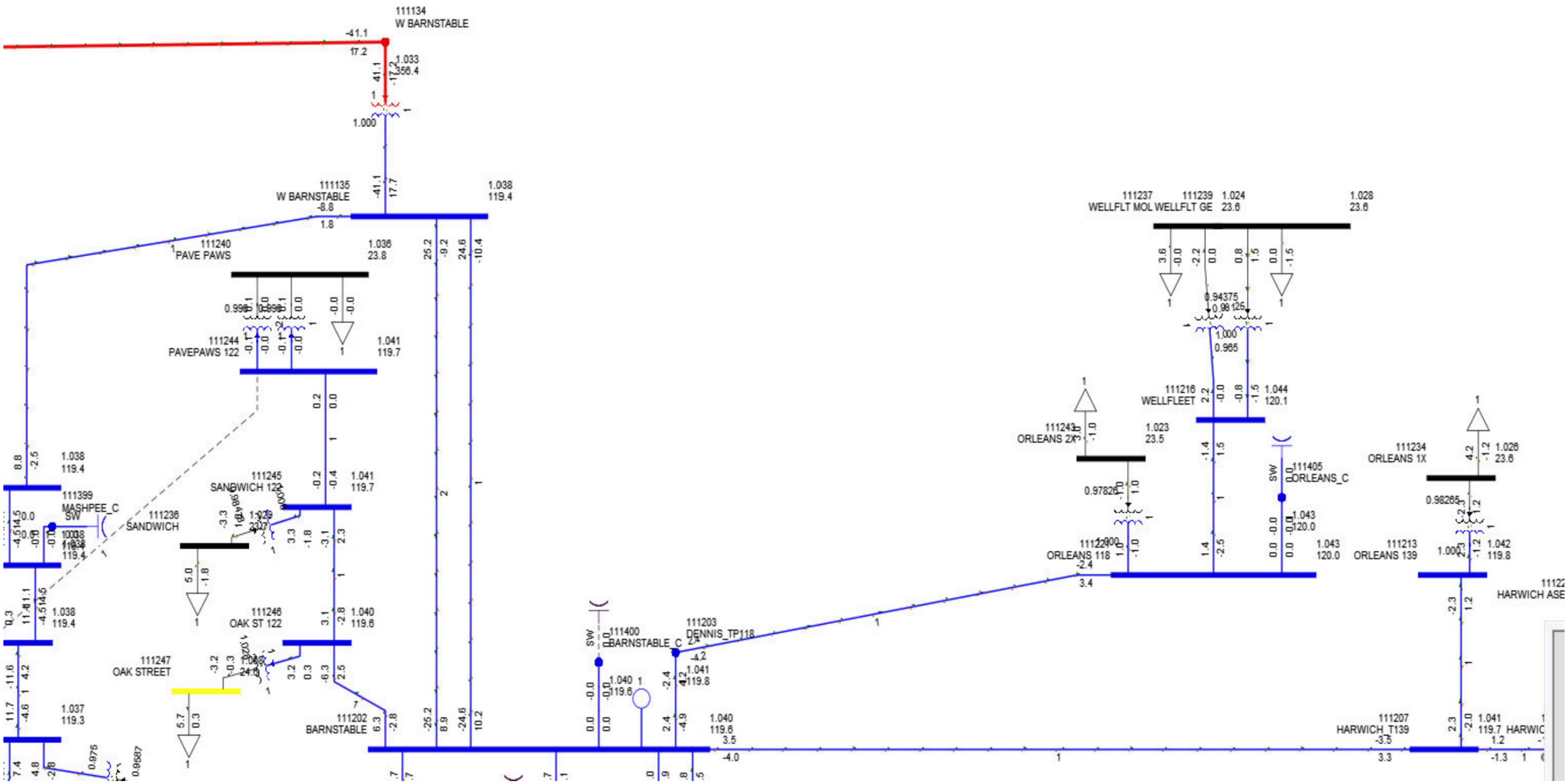
Loads on the Outer Cape on Easter (4/9/23)



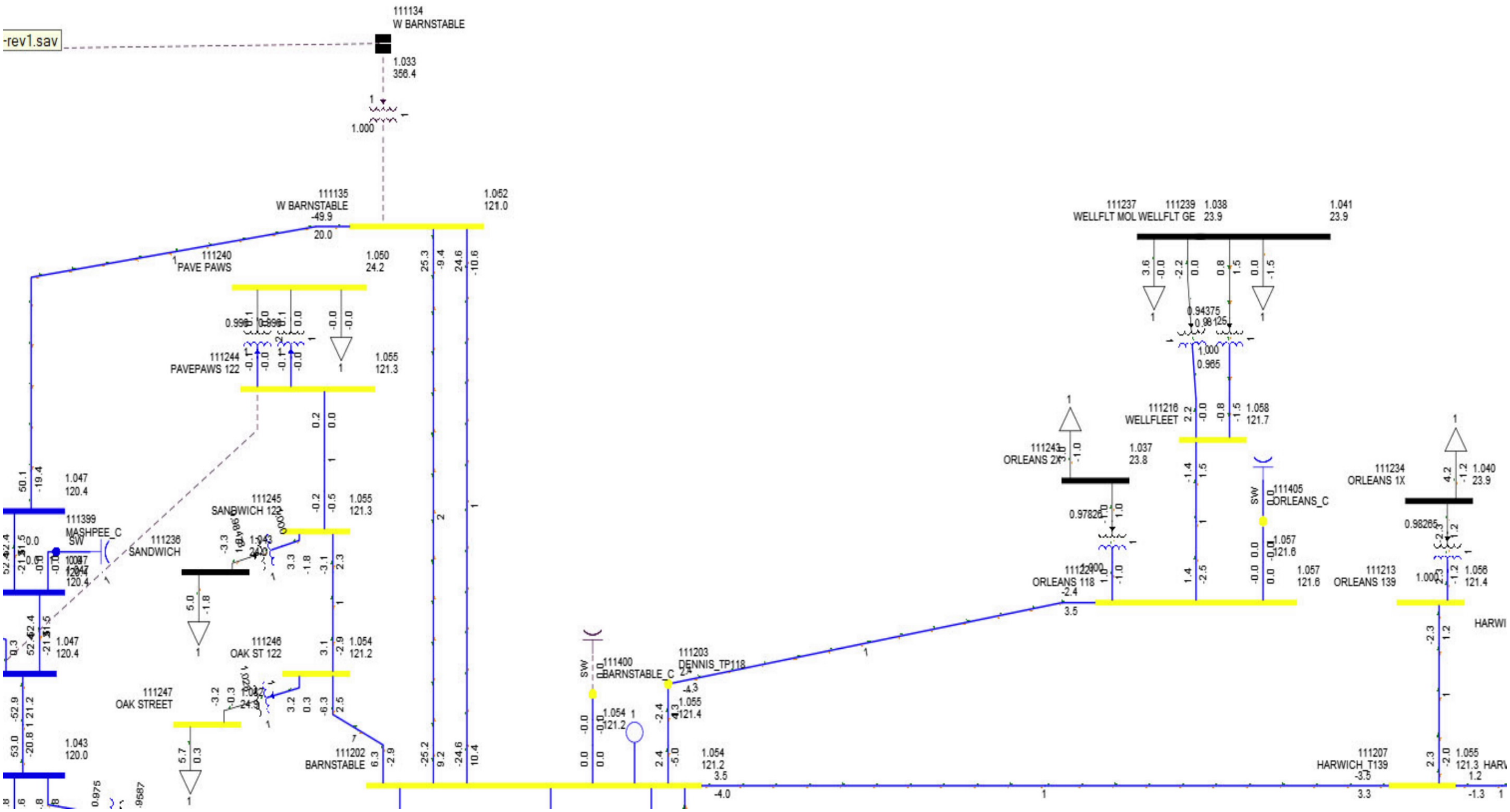
ISO NE control room saw post-contingent high voltage

- ISO NE's real time contingency analysis identified the issue
  - Loss of the 399 line placed the Outer Cape on only the 137 line
  - The impact of DER reduced local load from 120 MW at 3 AM to less than 50 MW at 2 PM
  - Local generation was unavailable to turn on to mitigate the issue
  - All local transmission caps were off
  - There were no local reactors
  - Remote reactors were maxed out
  - Luckily, planned generation outages in New England resulted in some somewhat remote generation being on-line (in central MA, Rhode Island and eastern CT) which had a very limited impact on voltage in the Cape
    - To make these units effective, significant deviations from normal voltage schedule were required
    - If these were not committed in economics, the cost to run these units were have been paid for by the local area with the high voltage issue

Pre-contingent power flow model



Post-contingent power flow model



How was this managed in real time

- Multiple remote, transmission connected generators were moved to their low voltage limit, going leading pre-contingency to decrease voltage on the Cape by less than 0.5 kV (less than 0.5 %)
- Worked with the local distribution company to first turn off manually switched and then time clock switched caps (6.5 MVARs of the latter found)
- Removing 5 MVAR of the time clock switched caps (manual were already all off) removed the problem
  - Reduced post-contingent transmission voltage on the Cape over 1 kV

Realizations from this event

- DER impacts on portions of the 115 kV system are starting to impact BES operations during maintenance / construction seasons
- This impact will increase over time as additional DER is installed
- The impact will worsen in areas currently impacted, and will become evident in other areas as they accrue DER
- DER voltage control (or lack thereof) is impacting transmission system performance
- Distribution voltage control and load power factor control is significantly increasing in importance to system reliability

Questions?