Draft 2021 Vermont Long-Range Transmission Plan

Senate Natural Resources & Energy Committee

April 6, 2021

Roles & responsibilities

VELCO's vision is to create a sustainable Vermont through our people, assets, relationships and operating model.

VELCO's role is to ensure transmission system reliability by planning, constructing and maintaining the state's high-voltage electric grid.

Related responsibilities

- Serve as Local Control Center for Vermont grid operations
- Manage the Vermont System Planning Committee
- Develop and submit Vermont's Long-Range Transmission Plan

2021 VT Long-Range Transmission Plan

- Plan and associated public outreach required by Vermont statute and Public Utility Commission order
- To support full, fair and timely consideration of all cost-effective non-wires solutions to growth-related issues
- To inform utilities, regulators, generation/storage developers and other stakeholders in development of projects and policy

Collaborative process

- 18-month process before publication of public draft
- Load forecast with VSPC participation
  - Input from the Department, utilities and other VSPC members
  - EV forecast by VEIC
  - CCHP forecast by EVT
- Scope review and input by the VSPC and utilities
- Consultation with ISO-NE and VT utilities during study
- Congestion analysis by Daymark Energy Advisors
  - Risk-based scenario planning
- Two VSPC reviews of draft plan
- Feedback from Renewable Energy Vermont
- Planned conversations with regional planning commissions and other key statkeholders

What's important to remember

- System reliability will be maintained
- Vermont is a transmission-dependent state
- Significant load growth expected – winter peaking
- No major upgrades needed to serve load within the 10-year horizon
  - Presumes additional load management capability
  - Does not resolve all local concerns
- Incremental solar does not reduce load at peak hour
  - Efficiency and solar PV have provided great value
- VT utilities continue to implement innovative programs
- Further collaboration and innovation needed to achieve renewable and climate-driven requirements

What's new in the 2021 Plan?

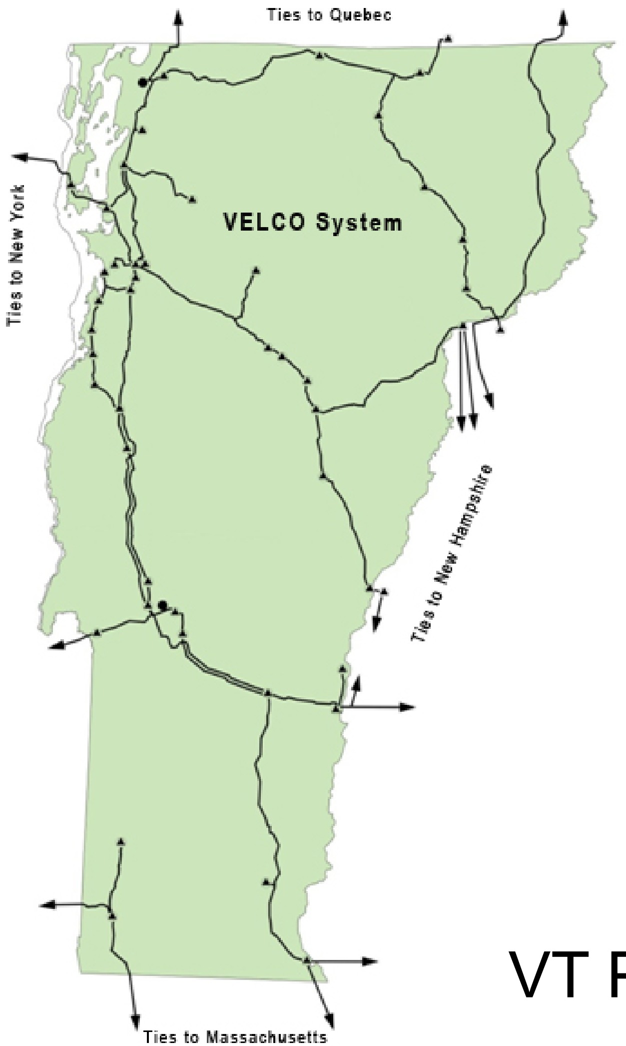
- In-depth scenario analyses with greater collaboration
- Inclusion of climate trends in load forecast and consideration of long-term climate impacts to grid
- High-load scenario analysis assuming EV load control
- Use of collaboratively developed scenario planning tool
- Ground-tested high-generation scenario analysis with more realistic assumptions
  - Allow some import amount from our controllable tie lines
  - Model larger (20 MW) FERC-jurisdictional generation projects
  - Consider distribution transformer limits
  - Assess station level effectiveness of solar PV and storage

Recommendations

- Give greater weight to grid impacts when siting generation
- Bring to scale flexible load management
  - Enable inverter grid support functionality, i.e., voltage control and ride through capability
  - Enable utility management of distributed generation
  - Continue to evolve with storage
  - Establish data organizational architecture
  - Deepen/broaden fiber communications network
- Grid reinforcements (e.g., transmission, subtransmission and distribution investments)

TODAY'S SYSTEM

Generation mostly renewable and intermittent

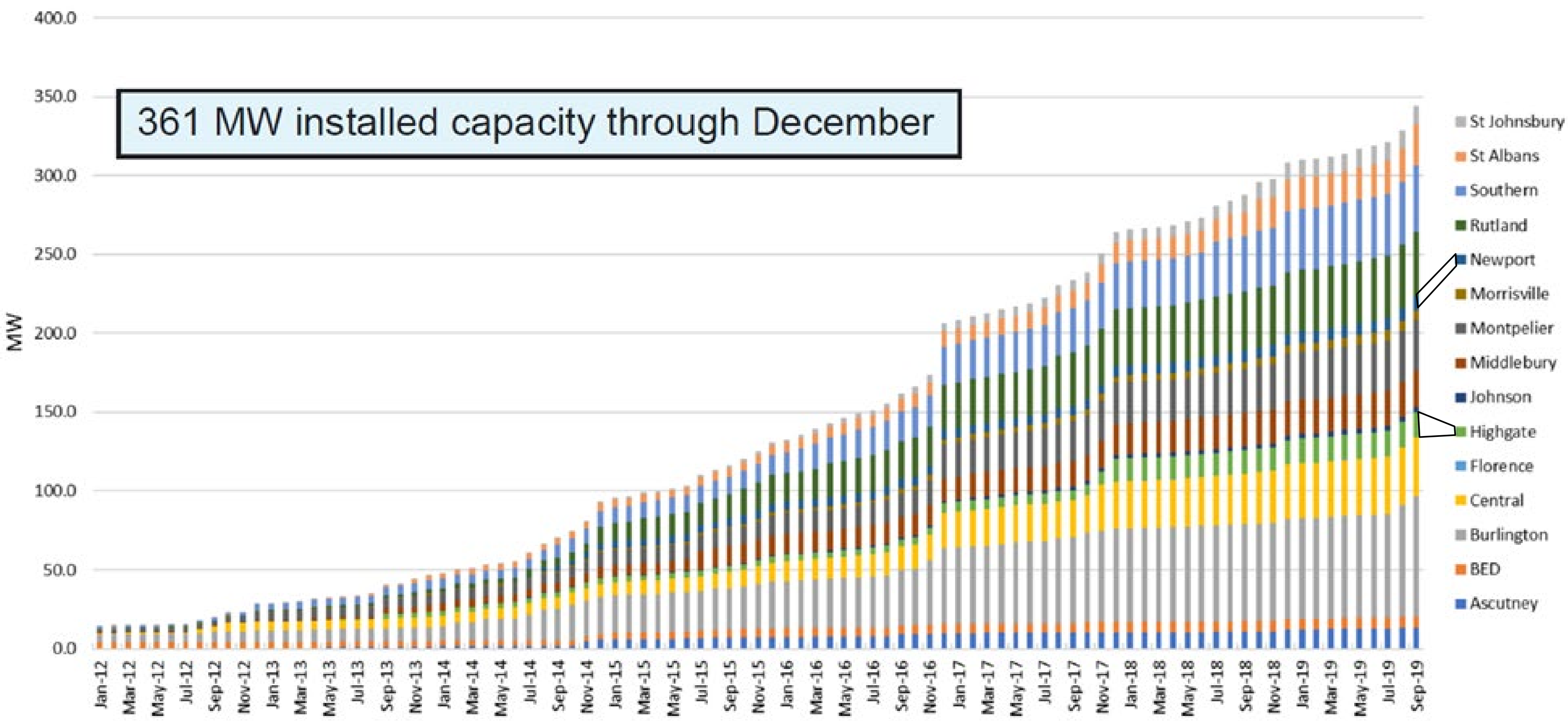


Type		MW
Fossil (fast start units)	Winter	188
	Summer	138
Hydro		152
Wind		151
Landfill gas		9
Biomass (wood)		72
Utility scale solar PV		20
Small scale solar PV		400 and growing
Small scale farm methane, wind, hydro		63 and growing
TOTAL IN-STATE GENERATION SUMMER NAMEPLATE CAPACITY		**~ 1005**

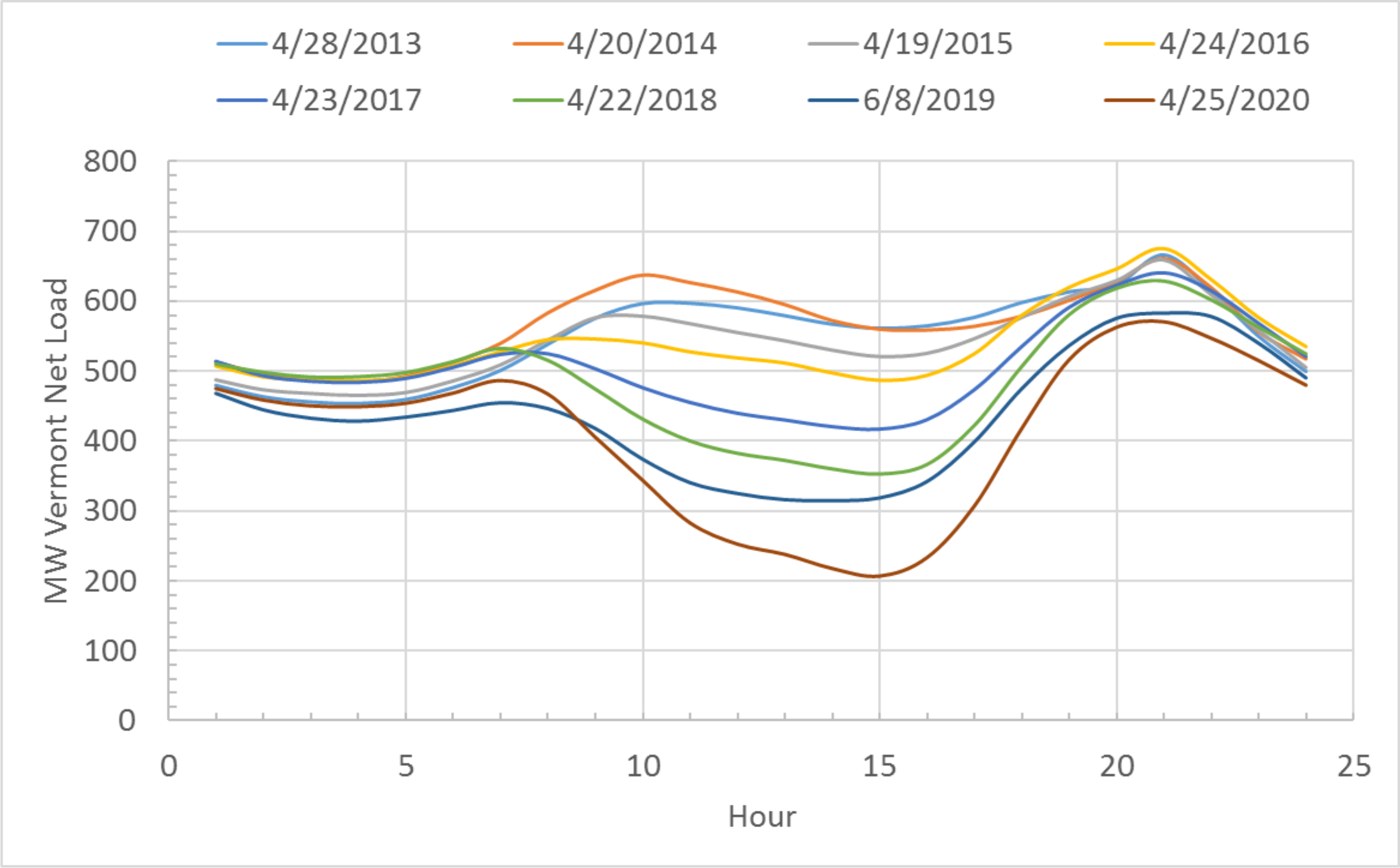
VT Peak load 1000 MW (winter and summer)

VELCO

Vermont has been very successful in installing PV

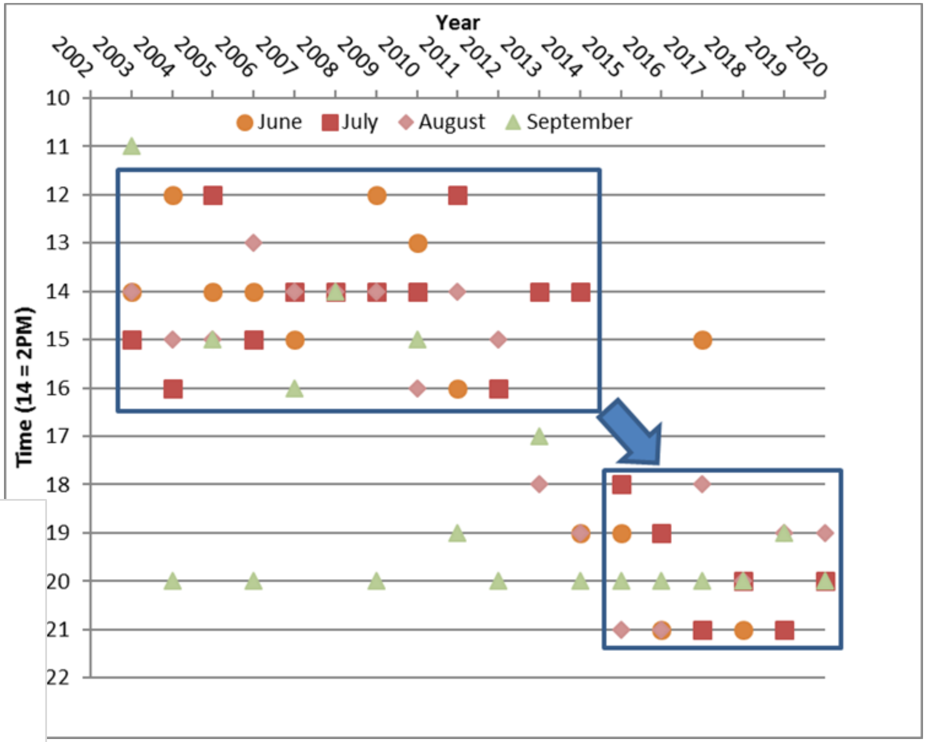


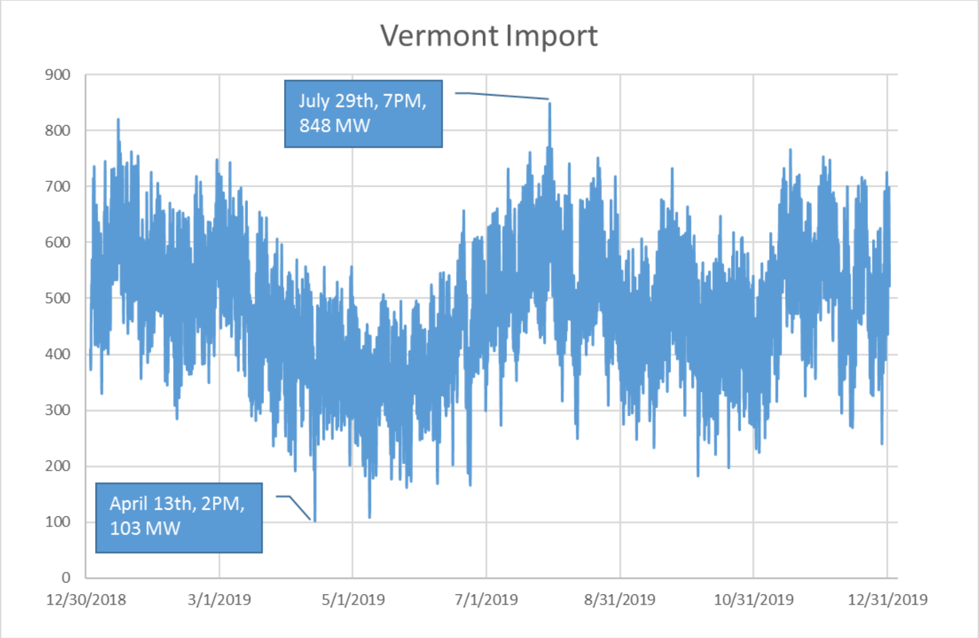
Solar PV impacts on net loads



No incremental benefit of solar PV at peak hour

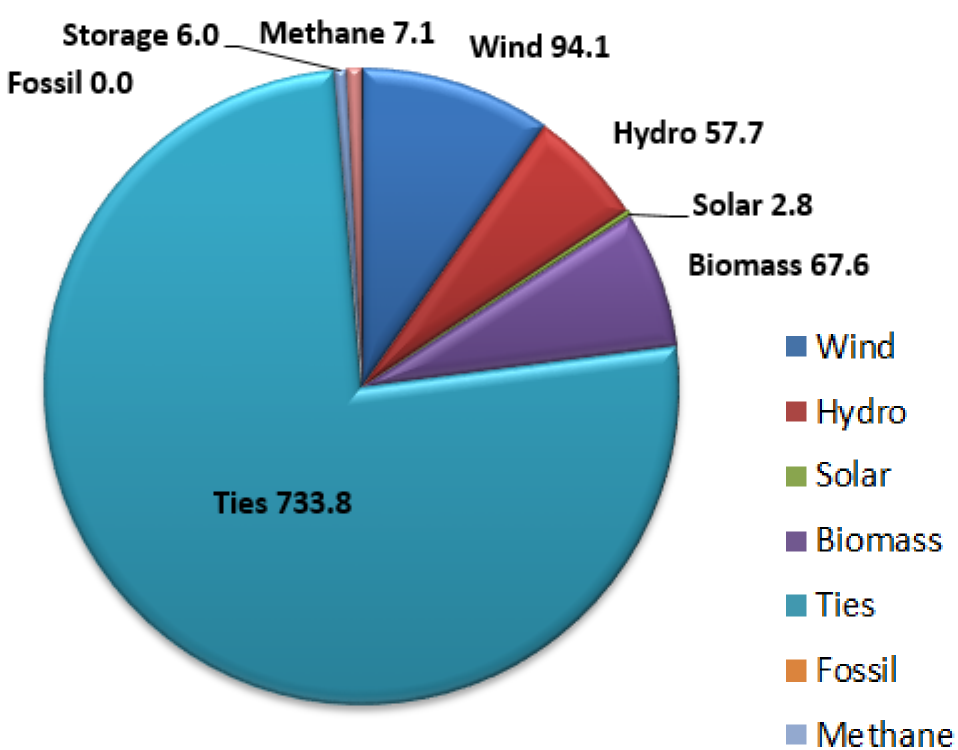
- Summer months are peaking in the evening
- Imminent spring excess generation
- High imports during summer and winter



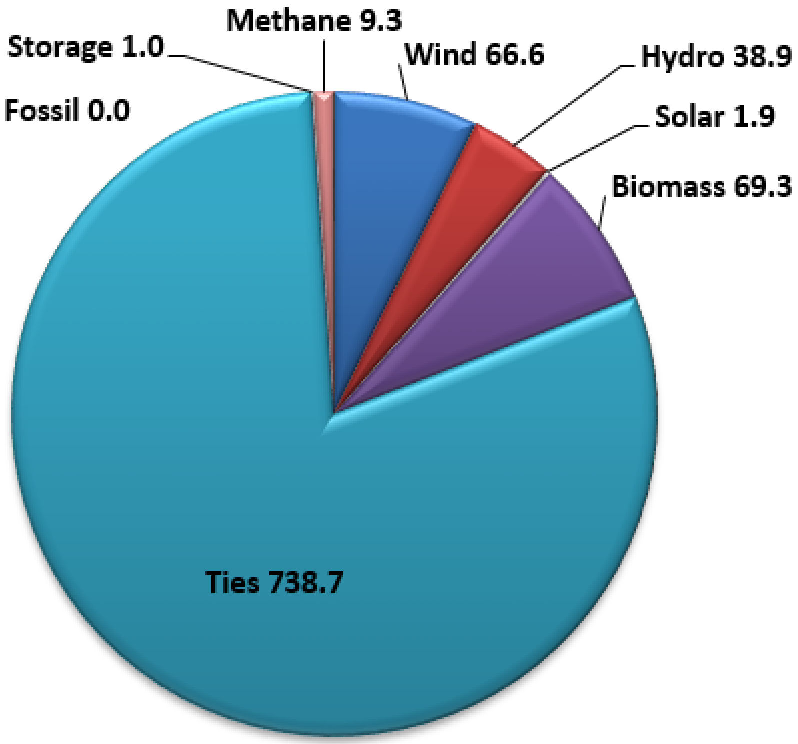


2019 Vermont peak days

- **2018/2019 winter peak day (1/21/19, 6:00 PM)**
- **Load was 969.2 MW**

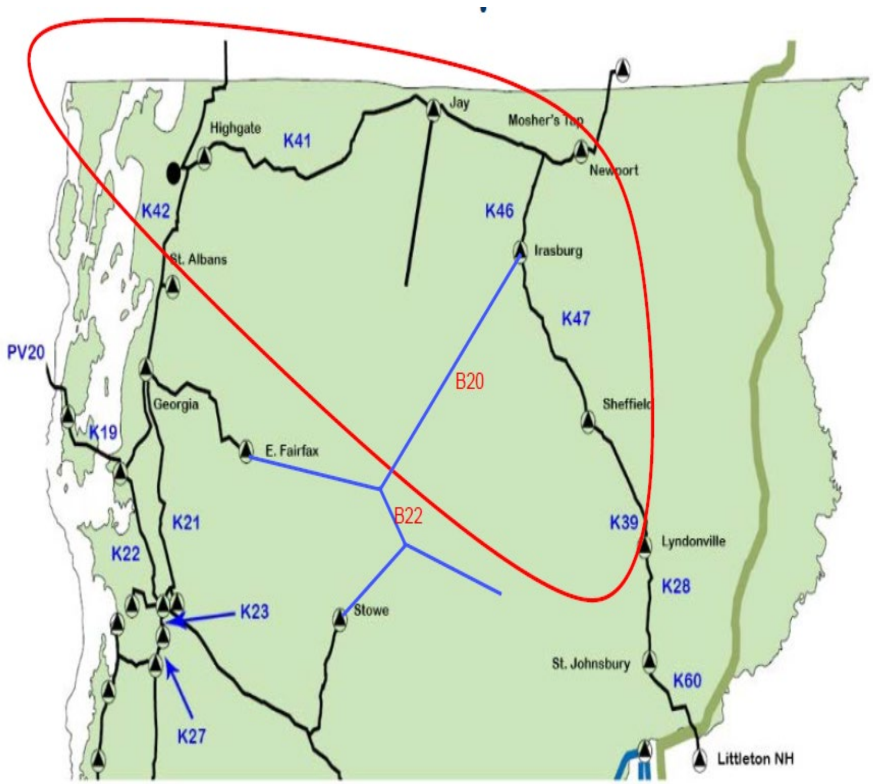


- **2019 summer peak day (7/20/19, 9:00 PM)**
- **Load was 925.7 MW**

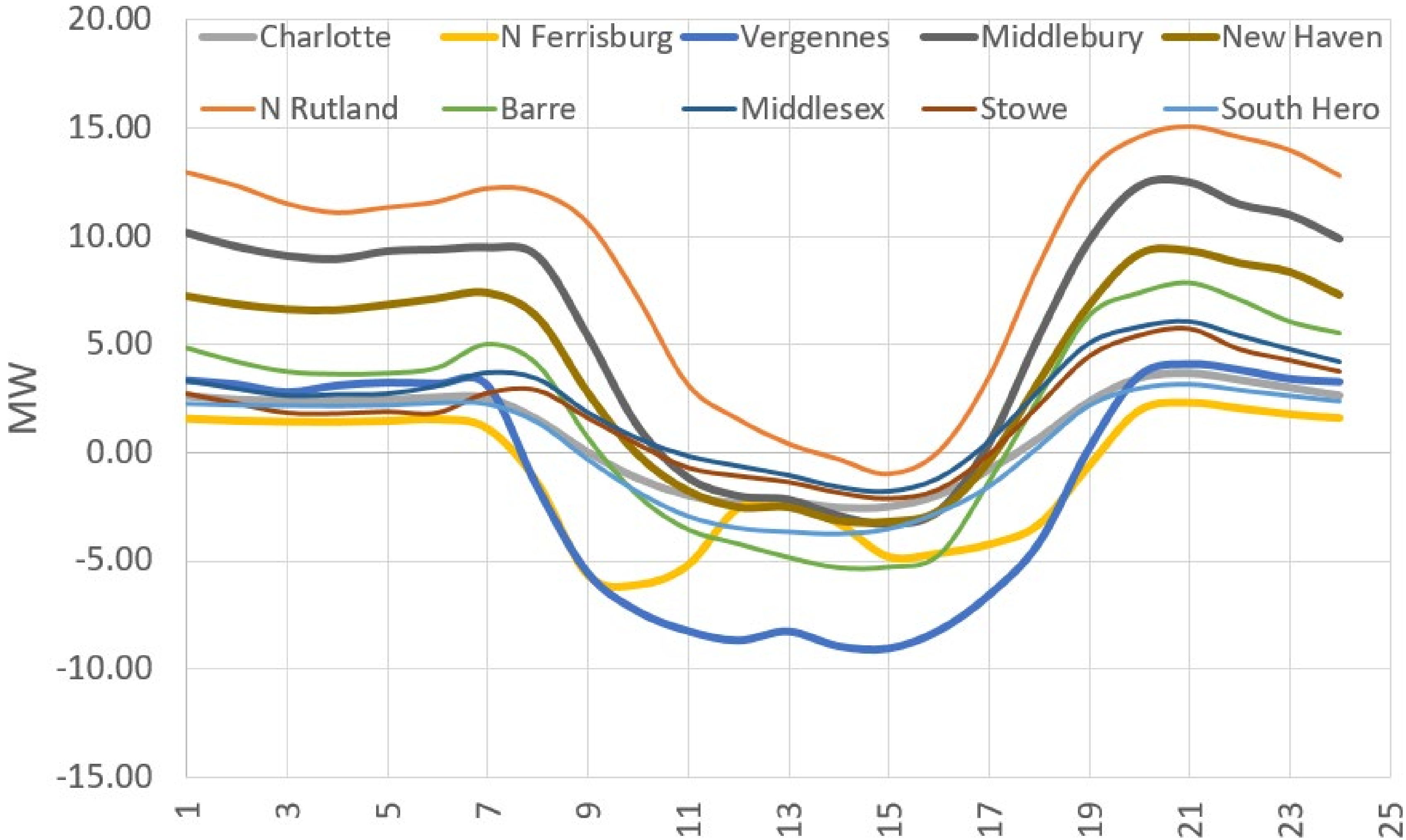


Growing DER is contributing to curtailments

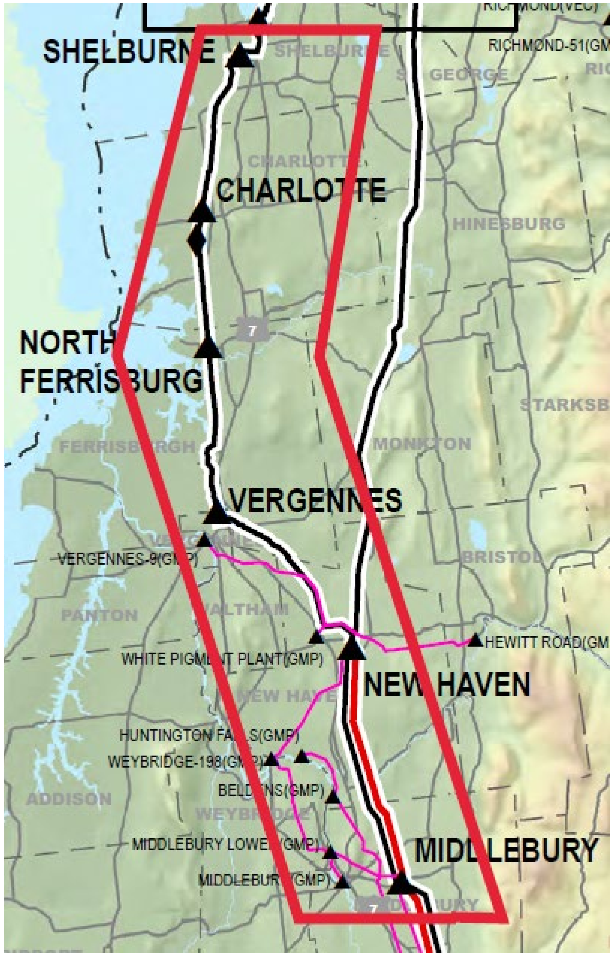
- Sheffield-Highgate Export Interface (SHEI)
  - Voltage constraint is binding
  - Thermal and stability follow
  - ISO-NE limits generation in real time using market rules

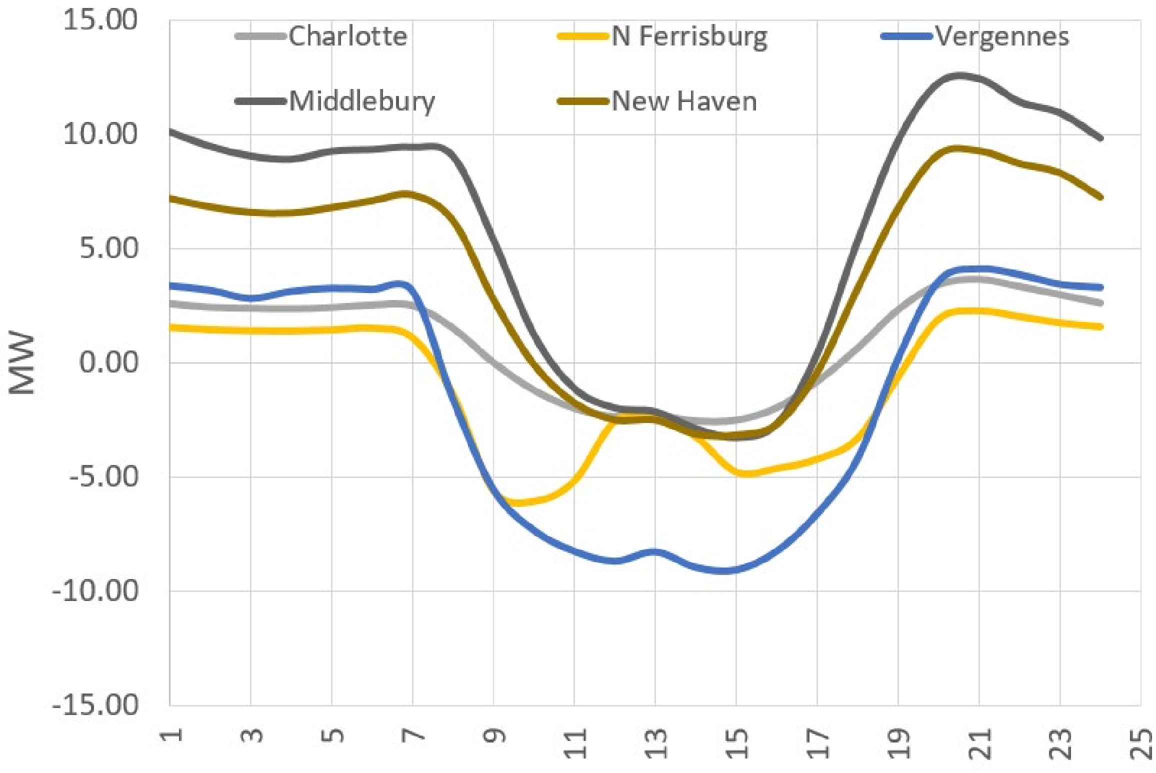


Top 10 reverse power transmission substations



DER affecting substation clusters





STUDY APPROACH

Study approach

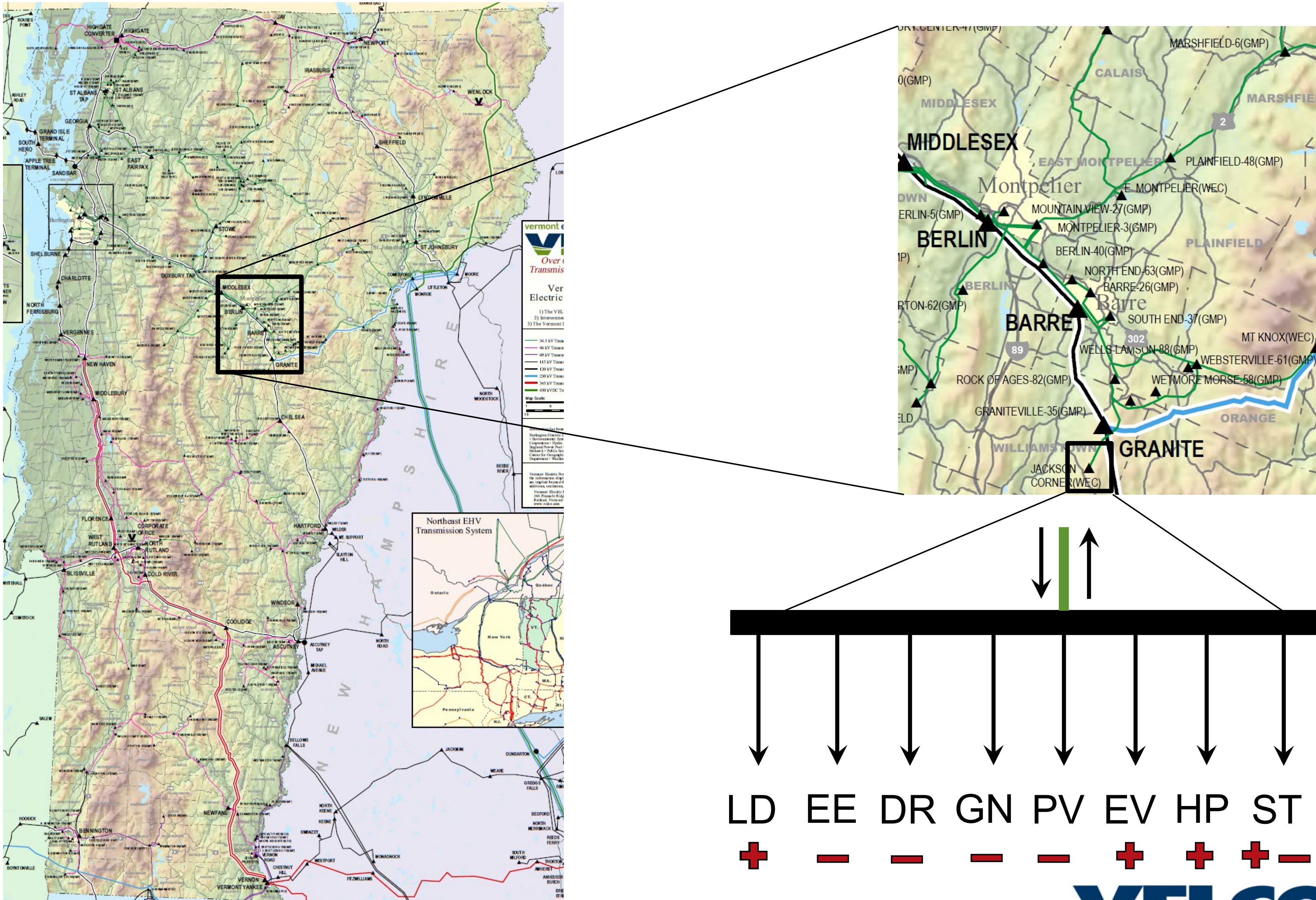
- Study results more critical for years 1-10
- Analyzed years 11-20 to examine risks and trends
  - – High load scenario
    - On track to meet 90% by 2050 renewable energy goal
  - – High distributed generation scenario
    - Potential doubling of the RES Tier II DG requirement
- Additional investigations
  - – Generation and storage charging hosting capacity of VELCO subs
  - – System impacts of retiring diesels/GTs
  - – Additional impacts of DU renewable energy goals
- Did not utilize previous ISO-NE study results
  - – Latest ISO-NE study did not include EV and HP loads
  - – ISO-NE studies model loads and generation at the NE peak hour
    - ISO-NE studies overstate solar PV in Vermont (5PM at ISO versus 8PM in VT)
    - ISO-NE has not tested winter peak loads (summer peak ISO, winter peak VT)

ETUs, generation, ties, and storage

- No Elective Transmission Upgrades included, e.g.:
  - 1000 MW HVdc at Coolidge substation, postponed twice
  - 400 MW HVdc at New Haven substation, withdrawn from ISO queue
- Generation dispatched at the peak hour according to season
  - Summer: 10% Hydro, 5% Wind, 0% Solar
  - Winter: 50% Hydro, 25% Wind, 0% Solar
  - McNeil out of service
  - Most other thermal units online to mitigate potential reliability issues
- Fixed pre-contingency imports on controlled ties
  - New York: no pre-contingency imports
  - New Hampshire: 100 MW imported
- Battery energy storage not modeled
  - Forecast of battery energy storage uncertain
  - Insufficient model detail, primarily location
  - Consider energy storage as potential solution to reliability issues

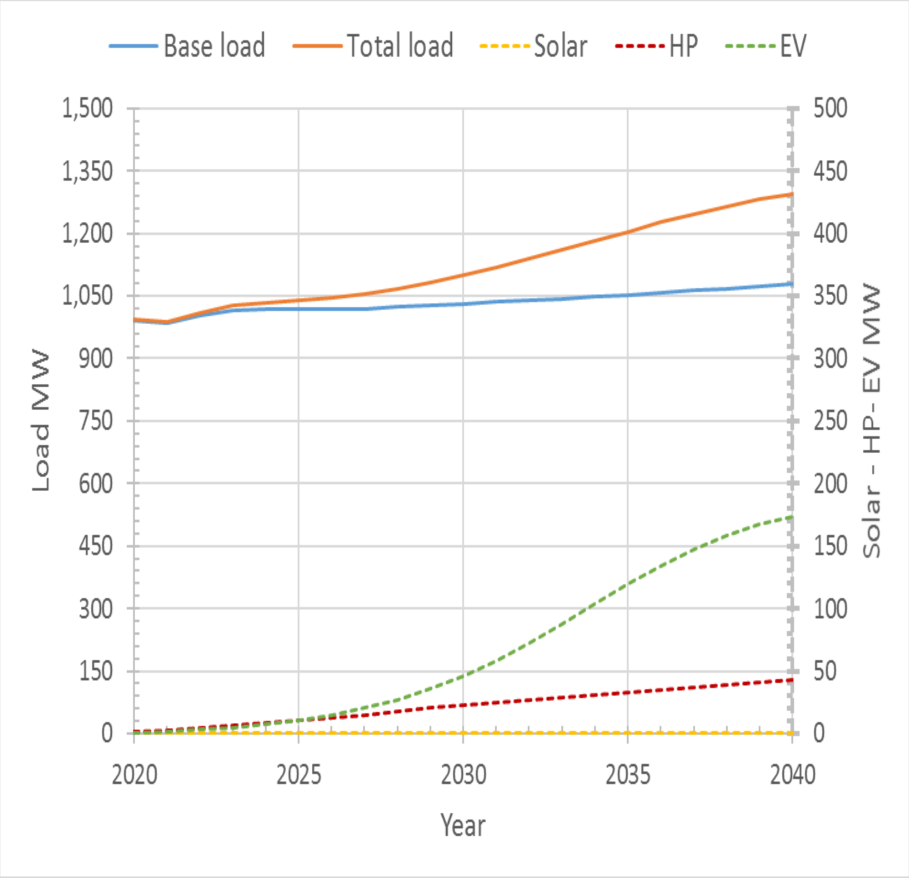
THE FORECASTS

Load modeling (state, zone, substation)

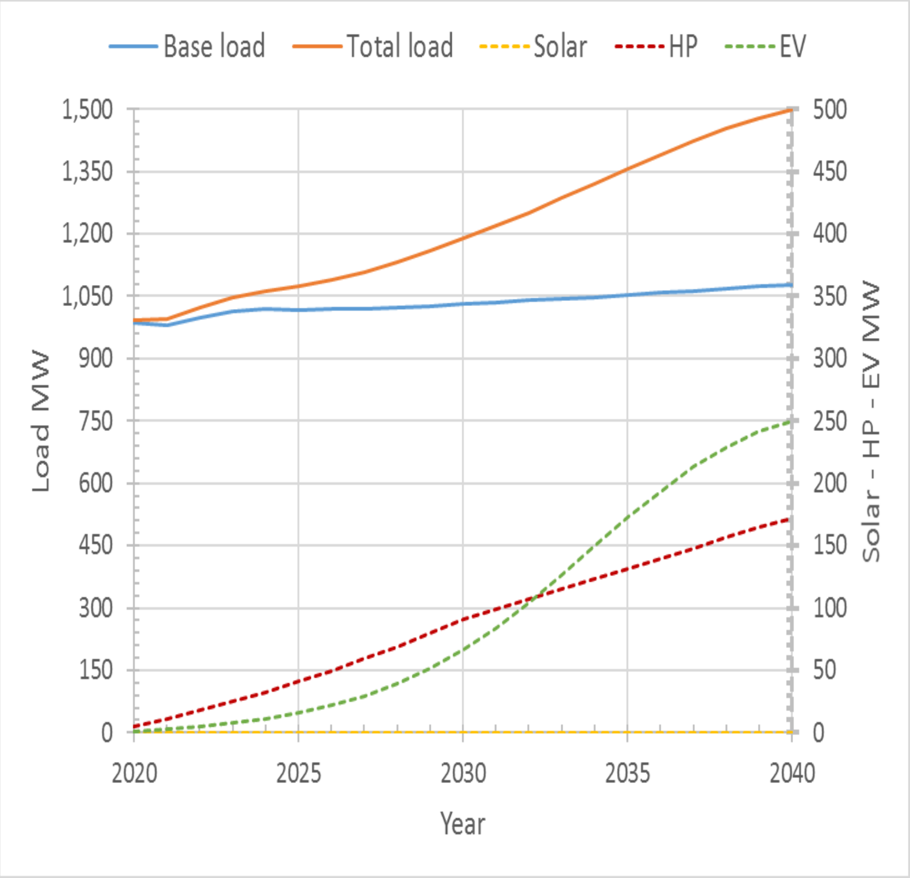


Summer and Winter Medium Peak Load Forecast Components

Summer Peak Load Forecast

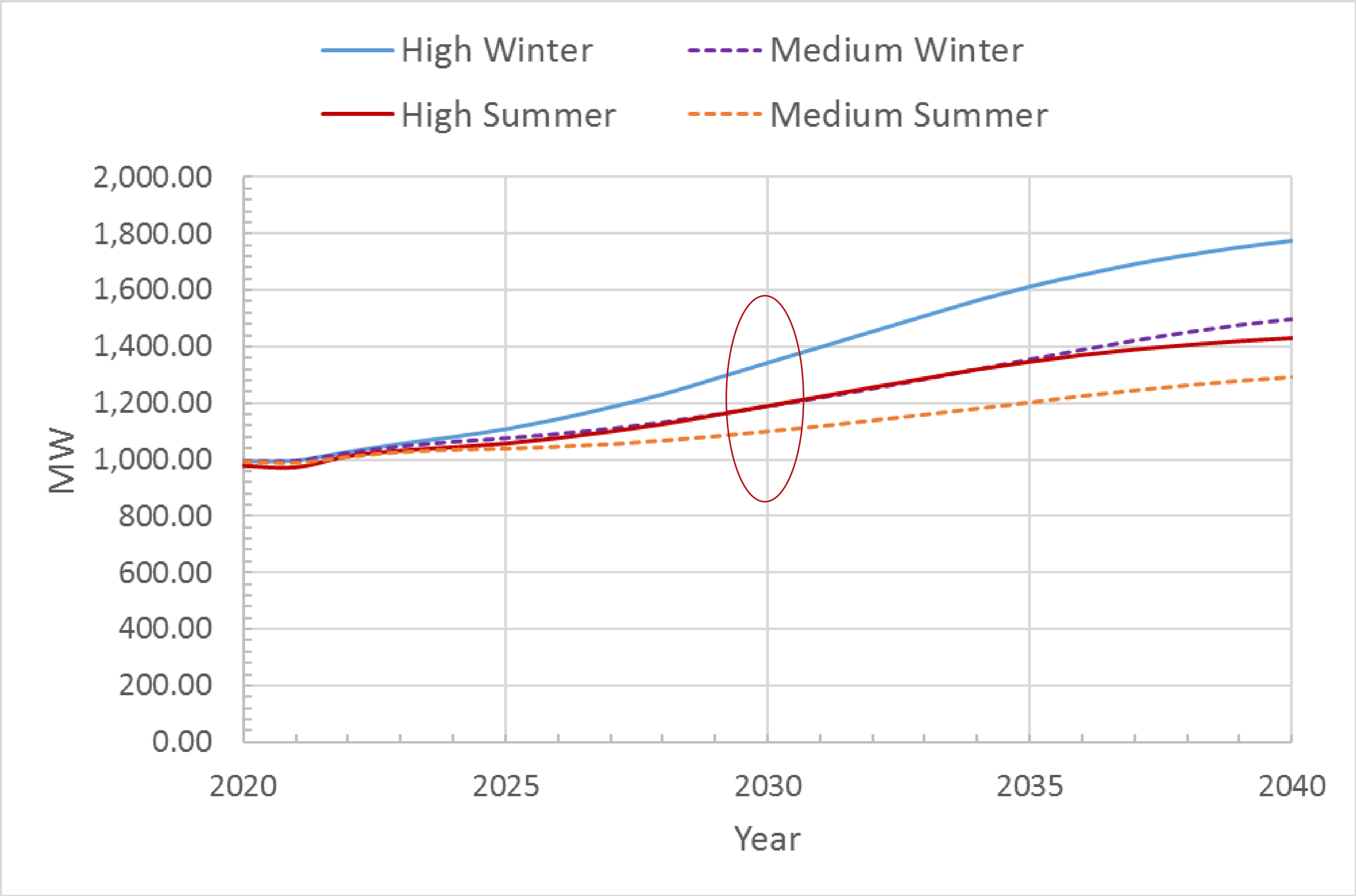


Winter Peak Load Forecast



Technology forecasts do not include effect of load control

Load forecast scenarios



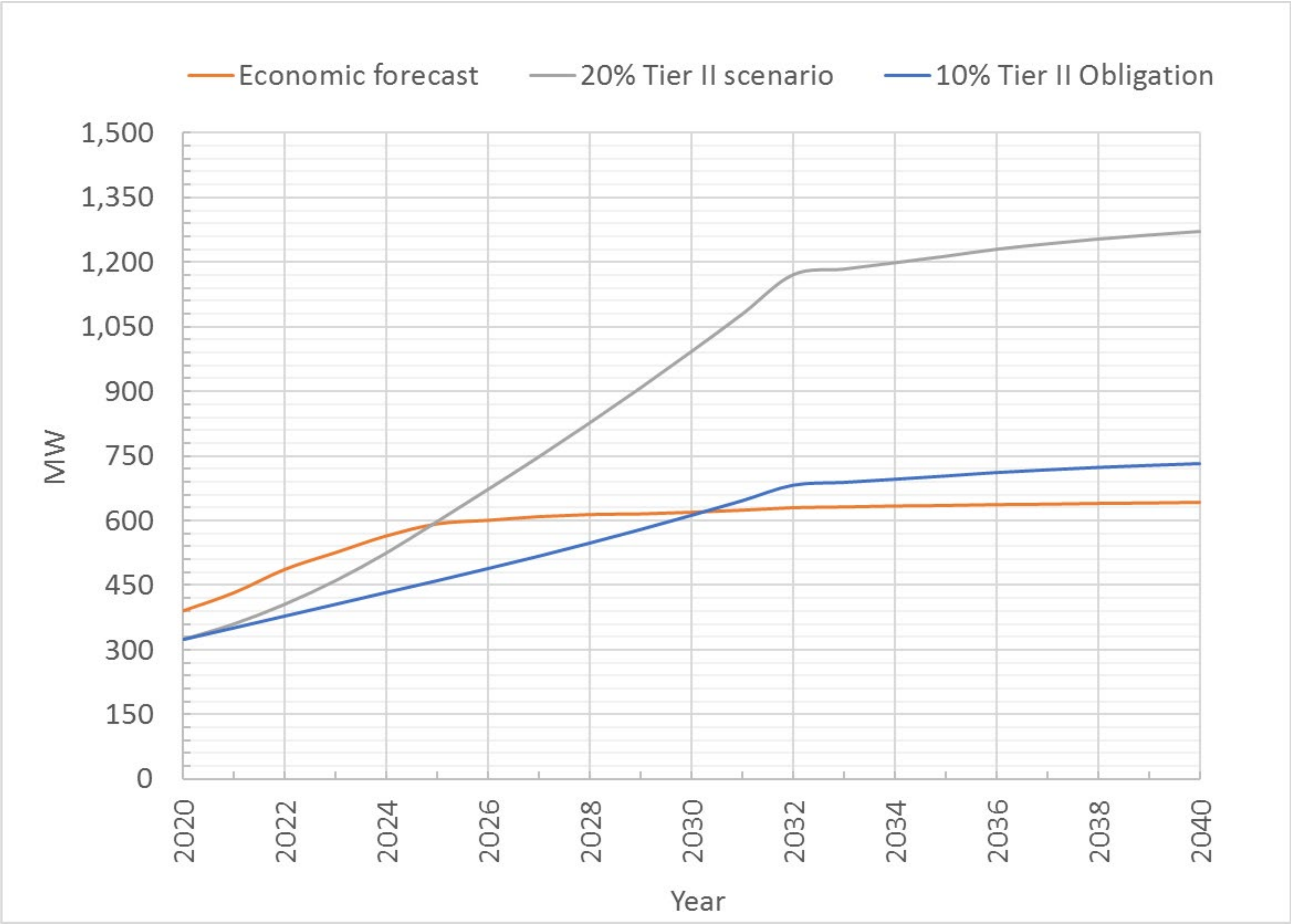
Load forecast scenarios

	Low forecast scenario		Medium forecast scenario		High forecast scenario		All-time peak (year)	Historical 5-yr average
Year	2030	2040	2030	2040	2030	2040		
Summer	1071 MW	1185 MW	1119 MW	1294 MW	1189 MW	1430 MW	1118 MW (2006)	950 MW
Winter	1135 MW	1292 MW	1219 MW	1499 MW	1342 MW	1774 MW	1086 MW (2004/05)	970 MW

	Actual	Low forecast scenario		Medium forecast scenario		High forecast scenario	
Year	2020	2030	2040	2030	2040	2030	2040
Electric Vehicles	3912	36080	126184	71624	256417	190125	412689
Heat Pumps	4611	61185	80141	77685	149141	110185	254141

450,000 light-duty vehicles today – did not forecast trucks, buses, etc.
320,000 residential customers today

Solar PV growth scenarios



RESULTS

ABILITY TO SERVE PEAK LOADS

No major upgrades needed to serve load within the 10-year horizon

Bulk system	• No peak load concerns. Issues addressed with tie line adjustments
Predominantly bulk system	• No peak load concerns. Issues addressed by tie line adjustments and operator actions • Acceptable loss of load (5-150 MW). As a direct consequence of outage and operator actions.
Subtransmission issues	• Flagged some issues to be evaluated by distribution utilities
High-load scenario	• Minimal effect within 10 years • After 10 years, requires non-transmission solutions to avoid transmission upgrades: load management, energy efficiency, storage, generation, …

RESULTS

ABILITY TO ACCOMMODATE DISTRIBUTED GENERATION (DG)

Location matters

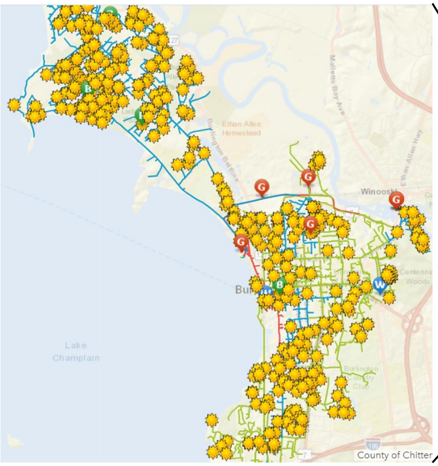
- Current geographical distribution will cause additional overloads and voltage concerns
- Optimizing DG distribution avoids major upgrades
  - New information from sensitivity analysis
    - DG hosting capacity affected by controllable tie lines
      - Additional PV20 flows decrease hosting capacity by nearly 1-to-1
      - F206 flows have similar impacts but less than 1-to-1
    - Queued Projects (20 MW or greater) may alter the limiting elements, restricting DG locally and changing an optimized solution
    - Distribution transformer ratings not particularly restrictive

Tier II Doubled

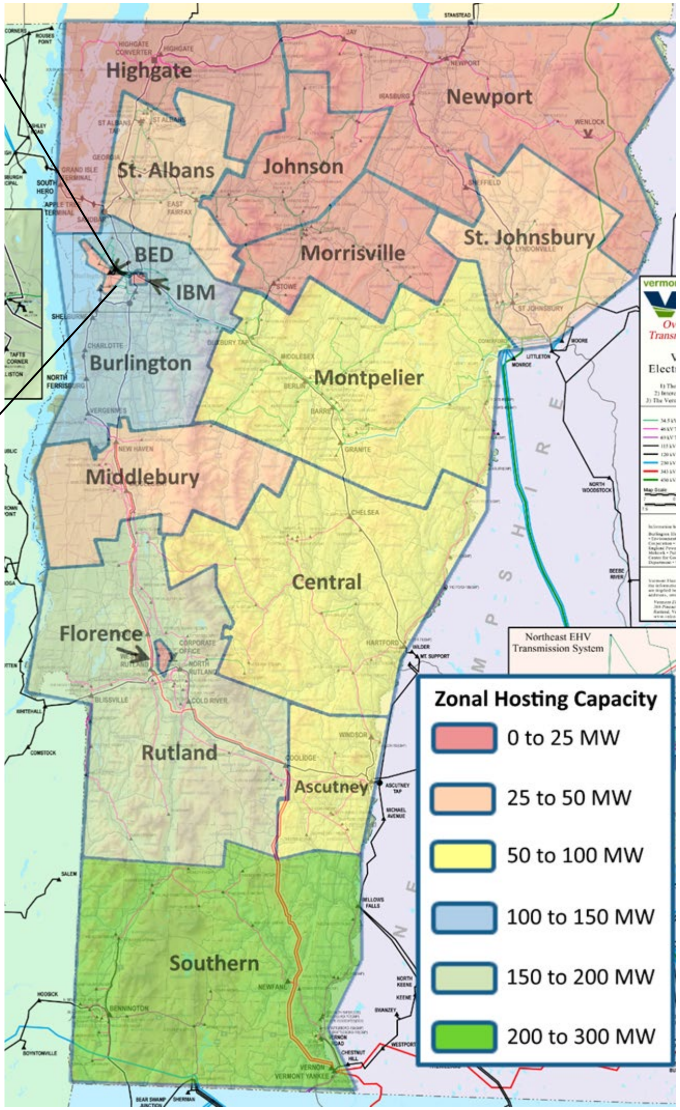
- Transmission overloads
- No optimization

Represents newly observed overloads in 2021 analysis

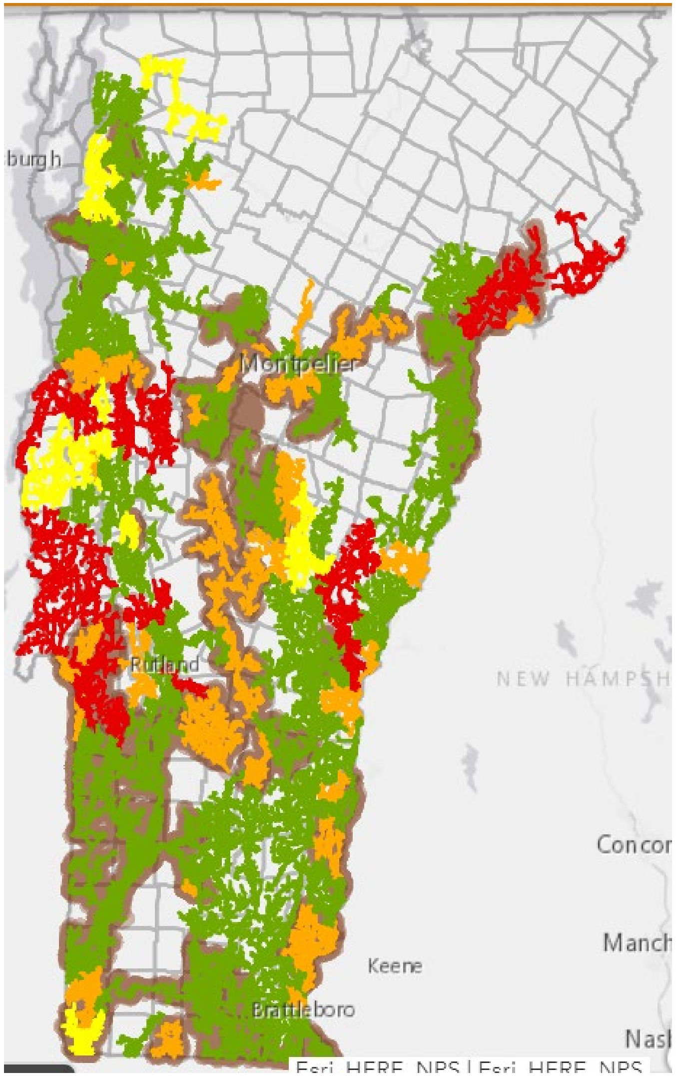
BED additional solar PV Map



Transmission total DG zonal limits



GMP additional solar PV Map



System reliability will be maintained

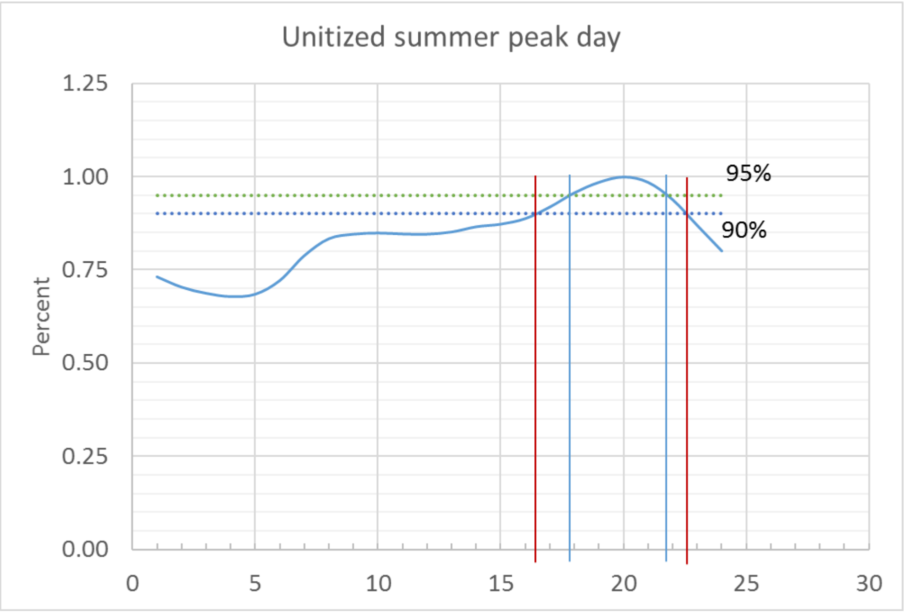
- Distribution limits result in interconnection request rejections
- ISO-NE conducts cluster studies – minimum interconnection standard
- Transmission limits result in real-time curtailment of dispatchable generators
- If generation curtailment is not sufficient:
  - Reduce tie line flows
  - Disconnect stations with net reverse flows
    - Load and generation are disconnected
- Grid reinforcement when cost-effective
  - Grid-only option estimated over $500M
  - Storage is not less costly

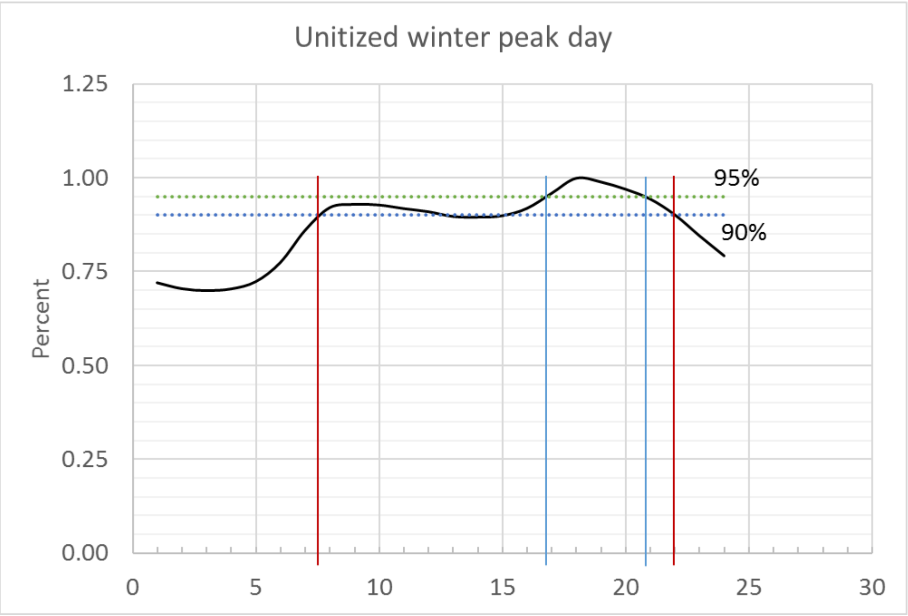
Controls to address non-optimized system concerns

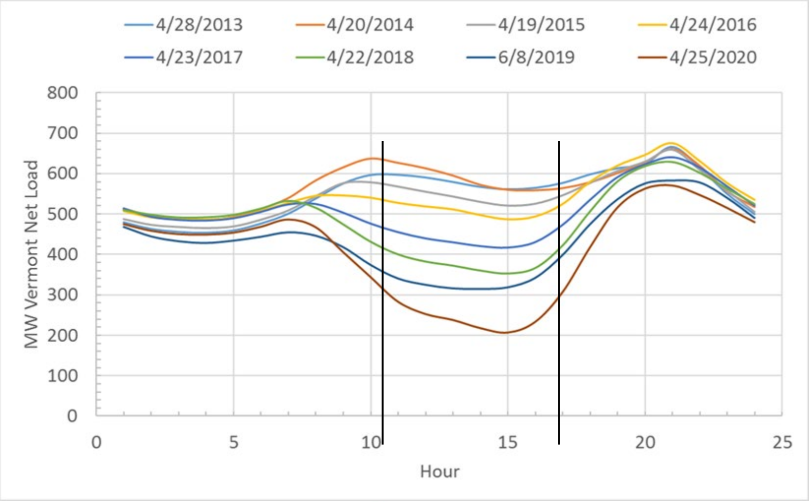
Names	Non-optimized	Optimized, no FERC projects	Excess
St Johnsbury	35.6	30	5.6
Newport	17.2	5.4	11.8
Highgate	57.9	19.8	38.1
Johnson	12.2	20	
Burlington	247.8	126.2	121.6
BED	23.7	7.5	16.2
Montpelier	90.3	76.8	13.5
Morrisville	39.9	25	14.9
Middlebury	91	50	41
Rutland	134.6	151.9	
Ascutney	59.8	73	
Southern	148.6	251.5	
St Albans	95.9	40	55.9
Central	126.9	98.7	28.2
Florence	0.6	20	
IBM	0	0	
Zonal Totals	1182	995.8	**346.8**

- Estimate of storage, curtailment or load management
  - 350MW for at least 4 hours (1400 MWh)

Load shape affects storage MWh need







Next outreach steps

- Continue direct, key stakeholder discussions
- Two virtual public meetings
  - Wednesday, April 28, 11am – 1pm
  - Wednesday, May 5, 5pm – 7pm
- Incorporate public comments in report
- Submit report to VT Public Utility Commission by July 1, 2021