Transmission Planning for the Clean Energy Transition

Pilot Study Preliminary Results

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TRANSMISSION PLANNING

Objectives of Today's Presentation

- Share progress on Transmission Planning for the Clean Energy Transition (TPCET) Pilot Study
- Share qualitative trends observed in preliminary steady-state and stability results
- Discuss future work and schedule for completion of the TPCET Pilot Study

Presentation Outline

- Overview of TPCET Pilot Study
- Preliminary Steady-State Results
- Preliminary Stability Results
- Next Steps & Tentative Schedule for TPCET Conclusion

Note: in order to maximize stakeholder involvement, this presentation does not contain Critical Energy Infrastructure Information (CEII). As a result, information about the exact contingencies causing concerns is not being shared at this time.

OVERVIEW OF TPCET PILOT STUDY

Overview of the TPCET Pilot Study

- New England continues to lead many industry trends
  - Development of Distributed Energy Resources (DER)
  - Integration of renewable resources, including offshore wind
  - Increasing imports via HVDC interconnections
  - Integration of battery energy storage resources
- To quantify trade-offs between cost and ability of the transmission system to accommodate high amounts of renewable resources, ISO-NE is conducting a “pilot” study of certain key system conditions
- The pilot study will aid in developing assumptions for use in future Needs Assessments, and will explore reliability concerns that may arise under these system conditions

Past PAC Presentations on TPCET Efforts

- Sept. 2020: Introductory Presentation
- Nov. 2020: Updated Assumptions and Pilot Study Proposal
- Dec. 2020: System Conditions and Dispatch Assumptions
- Jan. 2021: Generation Dispatch Details

Review of Study Assumptions

The TPCET Pilot Study examines six scenarios that capture future system conditions most critical to transmission system reliability:

Scenario	Scenario (Base Case) Name	Power Consumption (before reductions due to behind-the-meter solar)	Wind Level (1,270 MW onshore, 3,260 MW offshore nameplate*)	Solar Level (7,900 MW nameplate*)
1	Spring Weekend Nighttime Minimum Load (High Renewables)	8,000 MW	65% Onshore 90% Offshore	0%
2	Spring Weekend Nighttime Minimum Load (Low Renewables)	8,000 MW	5% Onshore 15% Offshore	0%
3	Spring Weekend Mid-Day Minimum Load	12,000 MW	55% Onshore 60% Offshore	90%
4	Summer Weekday Mid-Day Peak Load (High Renewables)	100% of 90/10 Peak Load (27,462 MW)	30% Onshore 90% Offshore	65%
5	Summer Weekday Mid-Day Peak Load (Low Renewables)	100% of 90/10 Peak Load (27,462 MW)	5% Onshore 5% Offshore	40%
6	Summer Weekday Evening Peak Load	95% of 90/10 Peak Load (26,089 MW)	5% Onshore 5% Offshore	10%

*Solar/wind values represent nameplate capacity, without reductions for losses within the projects' collector systems. The total offshore wind capacity includes the four future projects listed on the following slide as well as Block Island Wind.

Future Transmission and Generation Included

- All PPA-approved transmission projects through May 1, 2020
- Preferred solutions for Boston (2028), New Hampshire, Maine, and Eastern Connecticut
- All future generation projects with Forward Capacity Market commitments as of FCA14, or with financially binding contracts in place or under negotiation, including the following:
  - NECEC HVDC (1090 MW interconnecting at Larrabee Road 345 kV)
  - Vineyard Wind (800 MW interconnecting at Barnstable 115 kV)
  - Revolution Wind (704 MW interconnecting at Davisville 115 kV)
  - Mayflower Wind (804 MW interconnecting at Bourne 345 kV)
  - Park City Wind (804 MW interconnecting at West Barnstable 345 kV)
  - Three Corners Solar (112 MW interconnecting at Albion Road 115 kV)
- All known generation retirements and permanent delists through FCA14, including Mystic

Load Power Factor Assumptions

- Load power factor (LPF) significantly affects transmission system voltage, especially under minimum load conditions
  - Lagging LPF: load consumes VARs, lower transmission voltages
  - Leading LPF: load produces VARs, higher transmission voltages
- For most load zones, New England currently assumes a 0.998 leading LPF* for minimum load conditions
  - This assumption continues to be used in nighttime minimum load cases
  - Operational experience to date shows that LPF tends to be less leading during daylight hours
- Most loads in the daytime minimum case have been modeled assuming a unity (1.000) LPF* (no VARs consumed/produced by load)
  - In order for this assumption to remain valid, distribution companies will need to continue to maintain LPF at unity or lagging during daylight hours as PV penetration increases

*LPF is measured at the low side of the distribution transformer. Loads in the Boston area are an exception to the rules stated here.

Pilot Study Results

- The TPCET pilot study is intended only to give a rough approximation of a sample of the needs likely to be observed in future Needs Assessments
- This presentation will give a conceptual overview and qualitative summary of the needs, without any specific numerical results
- Further precision and detail will be provided in future TPCET presentations and reports, but likely not at the level of a typical Needs Assessment

Differences Between Pilot Study and Future Needs Assessments

- DER location data: TPCET pilot study is using a geographical estimate based on town lines and substation locations, future Needs Assessments are expected to use actual data from distribution companies
- Study assumptions: TPCET is using 2020 CELT, while 2021 CELT includes about 2000 MW (nameplate) of additional PV development
- Generator outages: Results presented today do not exactly match generator outages that would be used in Needs Assessments (further work on TPCET pilot study will examine dispatches similar to those used in Needs Assessments at peak load)
- Level of detail: due to the scope and schedule for the TPCET pilot study, detailed investigation into operational actions to mitigate some violations will not be conducted

PRELIMINARY STEADY-STATE RESULTS

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Steady State N-1 Qualitative Results

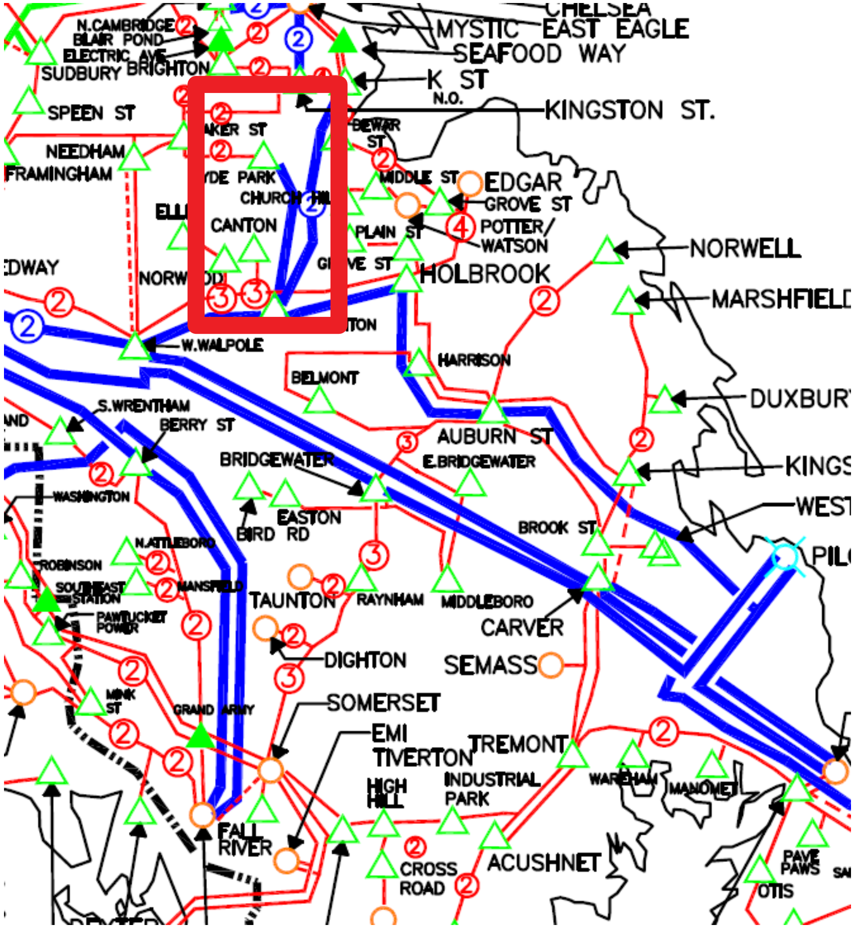
- Marginally high voltages in Maine attributable to proposed assumptions (as shown on slide 7)
  - Increased wind in Scenario 1 and increased PV in Scenario 3 lead to lower amounts of synchronous generation online, reducing the ability to control voltage
  - Today, voltage on the power system is controlled with the help of synchronous generators; wind and PV resources may be less effective due to their location or operating characteristics

Steady State N-1-1 Qualitative Results

- Scenarios 1 – 3 (minimum load scenarios)
  - High voltages in Connecticut and Maine were observed
    - Connecticut high voltages were observed in both Scenario 1 and 3
    - Maine high voltages were observed in all minimum load scenarios
  - High voltages attributable to assumptions changes
    - Increased wind in Scenario 1 and increased PV in Scenario 3 lead to lower amounts of synchronous generation online, reducing the ability to control voltage
- Scenarios 4 – 6 (peak load scenarios)
  - Stoughton – K St. 345 kV overloads
    - Overload attributable to proposed assumptions (as shown on slide 7) in Scenario 4

Stoughton – K St. 345 kV Cable Loading

- Stoughton – K Street cables connect SEMA (with lots of wind generation) with Boston (a major load center)
- Further analysis will be done to capture the relationship between generation in SEMA and the Stoughton – K Street constraint



Mitigation of Steady-State Voltage Violations

- Results of stability simulations indicate the need for additional dynamic devices (likely synchronous condensers)
  - More details on this need will be provided in the next section of this presentation
  - These added devices will also provide steady-state voltage control, and could address the violations described here
- Steady-state voltage performance will be re-examined once these representative solutions to stability concerns have been developed

PRELIMINARY STABILITY RESULTS

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IEEE Standard for Interconnection of DERs

- Characteristics of DERs installed before December 31, 2018 – IEEE Std 1547-2003 [estimated to be 33% of DERs by 2030]
  – The DERs were allowed to trip at any time during a disturbance, with no mandatory operation or voltage ride through requirements
  – Exact/most common trip settings in the field not known to ISO, and distribution companies were not able to provide “typical” settings
- Characteristics of DERs installed after December 31, 2018 – IEEE Std 1547-2018 [estimated to be 67% of DERs by 2030]
  – Has mandatory operation and voltage ride-through requirements
  – Intended to keep DERs online during faults far from the DER POI

DERs installed based on IEEE standard 1547-2003 are referred to as ‘2003 DERs’ and DERs installed based on IEEE standard 1547-2018 are called ‘2018 DERs’ throughout this presentation

IEEE Standard for Interconnection of DERs

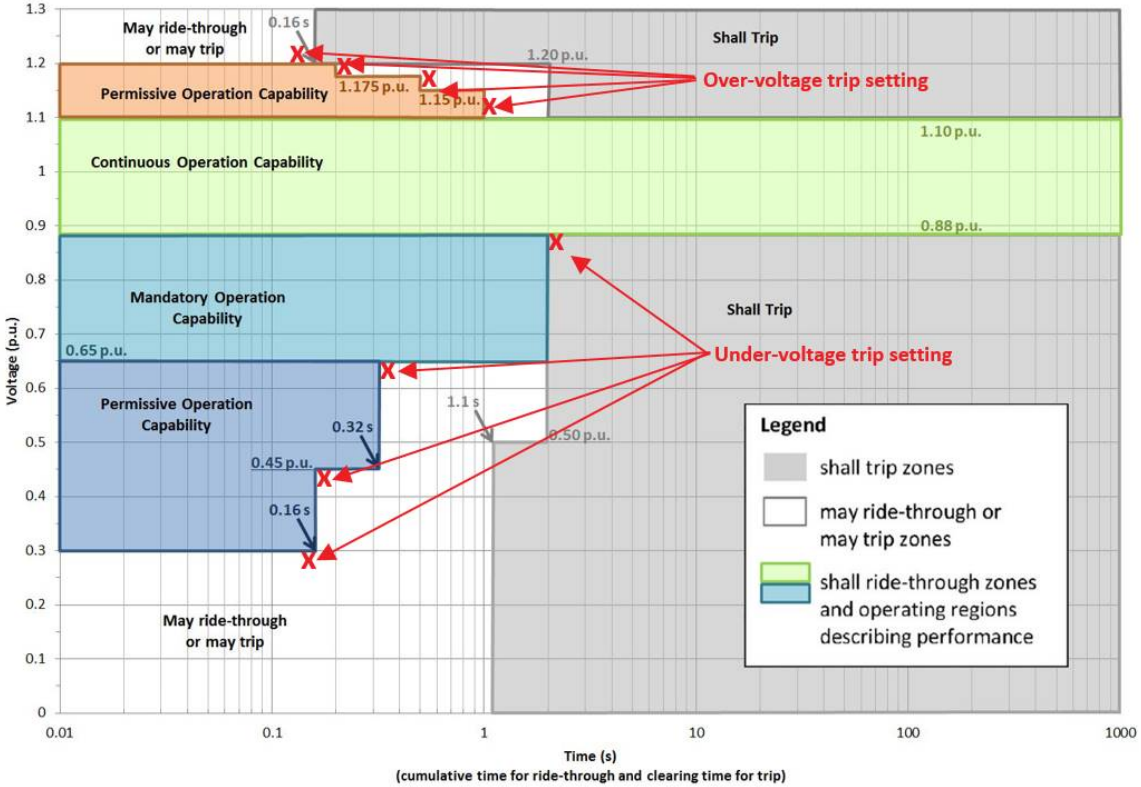
Voltage Trip Settings – IEEE Std 1547-2003

Voltage (p.u)	Maximum Time (sec) IEEE Std 1547-2003	Time (sec) Assumption for 2003 DERs
<0.5	0.16	0.1
0.5-0.88	2	0.1
0.88-1.1	NR	N/A
1.1-1.2	1	0.1
>1.2	0.16	0.1

- In reality, the DERs may be set to trip anywhere in the “may or may not trip zones”
- If we assume a time longer than what might be implemented in reality, we could fail to see a problem that exists
- ISO’s assumptions for the IEEE Std 2003 DERs are based on previous work by EPRI

IEEE Standard for Interconnection of DERs

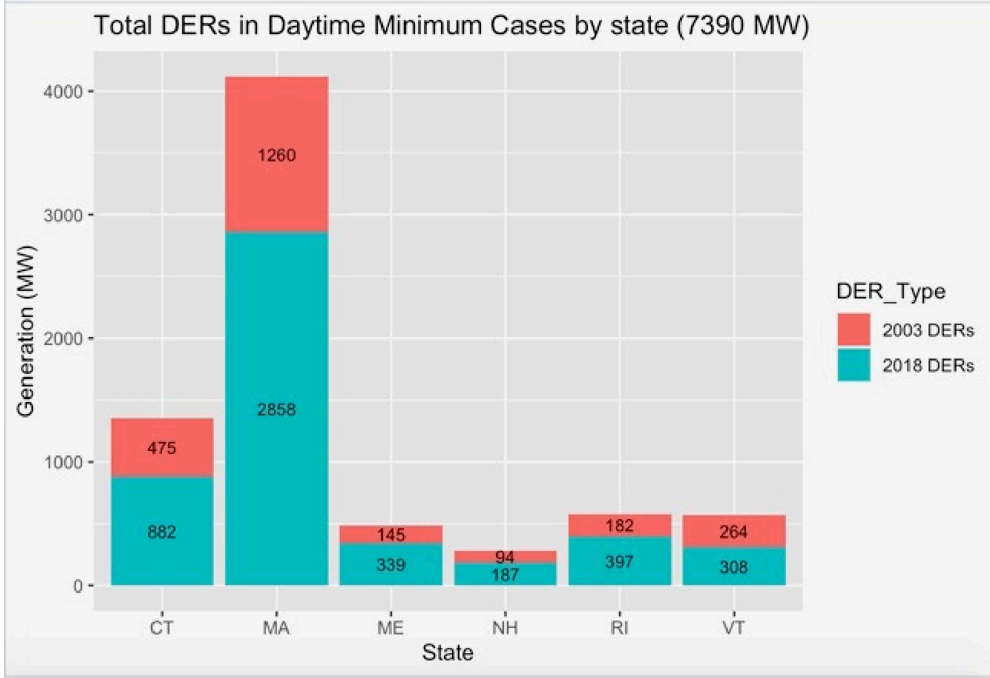
Voltage Trip and Ride-Through Settings – IEEE Std 1547-2018



- Voltage trip settings and voltage ride-through settings used for 2018 DERs align with IEEE Std 1547-2018 and ISO Source Requirement Document

Faults on Daytime Minimum Load Case

- Tested a limited number of faults dispersed all over New England
- Faults were tested on all cases. However, this presentation only concentrates on Daytime Minimum case for the following reasons:
  - Has the maximum amount of DERs online (7,390 MW DERs, which is 63% of total generation in the case)



  - Has very few synchronous generators online (2,600 MW of Nuclear units and about 100 MW of Hydro)

Summary of Faults

Summary
345/115 kV 3ph transformer fault in MA DERs tripped: 1,370 MW DERs with temporary power reduction: 215 MW Localized tripping/temporary power reduction
115 kV 3ph line fault in VT DERs tripped: 190 MW DERs with temporary power reduction: 180 MW Localized tripping/temporary power reduction
345 kV 3ph line fault in ME DERs tripped: 595 MW DERs with temporary power reduction: 680 MW Localized tripping/temporary power reduction
345 kV 3ph line fault in NH DERs tripped: 0 MW DERs with temporary power reduction: 3,345 MW Non-localized temporary power reduction
345 kV 3ph line fault in RI DERs tripped: 60 MW DERs with temporary power reduction: 235 MW Localized tripping/temporary power reduction

Summary of Faults Cont..

Summary
345 kV 3ph line fault in SEMA/RI DERs tripped: 0 MW DERs with temporary power reduction: 5,295 MW Non-localized temporary power reduction
345 kV 1LG line fault with BF in SEMA/RI DERs tripped: 1,855 MW DERs with temporary power reduction: 175 MW Non-localized tripping/temporary power reduction
345 kV 3ph line fault in SEMA DERs tripped: 0 MW DERs with temporary power reduction: 2,730 MW Non-localized temporary power reduction
345 kV 3ph line fault in WMA DERs tripped: 0 MW DERs with temporary power reduction: 2,635 MW Non-localized temporary power reduction
345 kV 3ph line fault in CT DERs tripped: 0 MW DERs with temporary power reduction: 2,700 MW Non-localized temporary power reduction

Observations Based on The Faults Studied

- The voltage trip settings for 2003 DERs were assumed to be 0.1 seconds or 6 cycles
  - This is close to the clearing time for faults on 345 kV system
  - This voltage trip assumption determines whether or not, and how much, of the 2003 DERs would trip in the simulations
  - For example, 'Fault 6' (shown on slide 23) has a clearing time of 5 cycles and hence none of the 2003 DERs trip. However, 'Fault 3' (shown on slide 22) has a clearing time of 6 cycles and hence some of the 2003 DERs trip
- Faults on the transformers generally have longer clearing times than line faults. Hence, there is a higher possibility of the DERs tripping for transformer faults
- Faults on the 345 kV system result in lower voltages over a larger area, leading to non-localized tripping/temporary power reduction of the DERs

Observations Based on The Faults Studied

- Faults on the 115 kV or lower system result in lower voltages in a more localized area, leading to localized tripping/temporary power reduction of the DERs
- While low voltages are more localized on the 115 kV or lower system, longer clearing times lead to more DERs tripping overall
- Single line to ground faults with breaker failure conditions have longer clearing times and hence results in more DERs tripping

**Note that these observations are based on the selective faults studied. This may not be necessarily true for all faults in the system. More faults will be studied in the future to assess the impact of DERs.*

Further Investigation Required to Address These Concerns

- As much as 1,850 MW of DERs (which is 25% of DERs assumed online) were shown to trip for the tested conditions, which is greater than the 1,200 MW threshold where New England events could begin to impact the New York and PJM systems
  - In addition to the 1,200 MW limit based on New York and PJM's systems, are there other factors that would require the acceptable amount of DER tripped to be even smaller?
- Roughly 5,300 MW of DERs (which is 72% of DERs assumed online) could go into temporary power reduction and come back to full power output when the voltage is restored
- Ongoing coordination with New York will be required to accurately reflect daytime minimum load conditions on the New York system in New England studies

Further Investigation Required to Address These Concerns

- Assuming Daytime Minimum Load conditions occur for an average of 5 hours each weekend day during Spring (3 months) and some weekdays during Spring, up to 1.5%-5% of the hours of the year could resemble a low inertia scenario such as the Daytime Minimum load case studied. In addition, daytime minimum load conditions could occur during Fall too depending on the weather conditions
- 2021 CELT data has a higher PV forecast (10,000 MW nameplate) compared to the 2020 CELT forecast (7,800 MW nameplate) used for this pilot study. This would result in fewer synchronous generators online, possibly leading to more tripping/temporary power reduction or even system separation for design contingencies. Additionally, the number of hours with low inertia on the system would increase even further

Possible Mitigation for Loss of DER

- Modifications to 2003 DER trip settings are not practical
  - Tens of thousands of DERs were installed under this standard
  - Inverters and other equipment may not be physically capable of riding through transmission system faults
- Transmission system voltage must be better supported during faults to reduce the amount of DER tripped
  - Synchronous machines and power electronic devices with the ability to support voltage during a fault can limit the spread of low voltage

Possible Mitigation for Loss of DER

- Can existing synchronous generators be kept online during minimum load conditions?
  - Lower-load periods in the spring and fall are often used by existing generators for longer maintenance outages
  - Running generators out-of-merit would increase production cost and counteract emissions goals
  - Difficult for operators to determine in real time whether enough synchronous generation is online, or whether additional units are needed
  - Power from these generators must be used somewhere; transmission-connected renewable resources would likely need to be decreased, as load is low and DERs are largely not directly controllable
- Installation of additional dynamic voltage support devices is likely necessary to mitigate DER tripping
  - Synchronous condensers provide high levels of fault current, and limit the spread of low voltage during faults
  - Certain power electronic devices capable of supporting voltage during a fault may also be capable of addressing the need

NEXT STEPS & TENTATIVE TPCET SCHEDULE

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Further Analysis for TPCET Pilot Study

- Steady-State Analysis
  - Further analysis to capture the relationship between generation in SEMA and the Stoughton – K Street constraint
  - Variations on peak load cases, reflecting generator dispatches similar to those in recent Needs Assessments
  - Mitigating measures for steady state high-voltage conditions at minimum load, following the addition of any stability-related dynamic devices
- Stability Analysis
  - Further analysis of response to transmission system faults
  - Further investigation into acceptable megawatt limits on DER tripping
  - Mitigating measures for large amounts of DER tripping

Preliminary Plans for Future PAC Presentations

- July 2021: PAC presentation on additional steady-state and stability results
- August 2021: Final PAC presentation on steady-state and stability results, proposal for new study assumptions for load, solar generation, and wind generation
- September 2021: Finalize and document new study conditions for load, solar generation, and wind generation

Questions