Attendee	Organization
J. Truswell - Chair	ISO New England Inc.
K. Sreenivasachar - Secretary	ISO New England Inc.
S. Adams	ISO New England Inc.
Z. Ahmed	ISO New England Inc.
S. Ali	PPL Energy Plus
B. Andrew	Eversource Energy
J. Babu	Eversource Energy
N. Baldenko	Eversource Energy
D. Bergeron	Maine Public Utilities Commission
P. Bernard	ISO New England Inc.
M. Berninger	Con Edison Transmission, Inc
D. Beron	New England Power Company
P. Boughan	ISO New England Inc.
J. Breard	ISO New England Inc.
J. Burlew	ISO New England Inc.
D. Burnham	Eversource Energy
D. Capra	NESCOE
D. Cavanaugh	Energy New England
S. Chen	RLC Engineering
D. Conroy	RLC Engineering
F. Dallorto	ISO New England Inc.
B. D’Antonio	Eversource Energy
B. Deonarine	Con Edison Transmission, Inc
J. Dobiac	New England Power Company
J. Dong	Eversource Energy
M. Drzewianowski	ISO New England Inc.
F. Ettori	VELCO
J. Fenn	Versant Power
B. Forshaw	Connecticut Municipal Electric Energy Cooperative
B. Fowler	Wheelabrator North Andover Inc.; Exelon Generating Company LLC; Nautilus Power; Dynegy Power Marketing, LLC; Entergy Nuclear Power

Item 1.0 – Chairs Remarks
Ms. Jody Truswell welcomed the committee and reviewed the days' agenda.

Item 2.0 – New England Bulk Power System List Updates
Mr. Dan Schwarting provided an overview of performance-based Bulk Power System (BPS) classification of transmission elements. Key changes to NPCC Document A-10, which drove the need for this re-analysis, included changes in assumptions regarding protection systems and system transfers. Adjustments to system transfers resulted in less stressed generator dispatches used to determine BPS elements.

The 2022 BPS analysis showed 19 buses that tested as non-BPS and have been removed from the BPS list. Of the 19 buses, four of them are at the 345 kV voltage level, one bus is at the 230 kV voltage level, and 14 buses are at the 115 kV voltage level. Two buses were added to the BPS list due to a change in remote fault clearing times and the energization of the new substation.

The 2027 BPS analysis showed five additional buses could become BPS in the future. Three of the buses are at the 345 kV voltage level, and two of the buses are at the 115 kV voltage level.

Eighteen buses that are on the BPS list today, tested as non-BPS in the current year (2022) analysis, but tested as BPS in 2027. Four of the buses are at the 345 kV voltage level, one bus is at the 230 kV voltage level, and thirteen buses are at the 115 kV voltage level.

One bus at the 115 kV voltage level, which was a future addition to the BPS list as per a past analysis, has tested non-BPS in 2027 analysis. That bus will no longer be added to the BPS list once constructed.

The BPS list will become official after NPCC's Task Force on System Studies and Reliability Coordinating Committee (RCC) approve it. The RCC vote will likely occur in February 2023.

In response to stakeholder questions, ISO-NE provided the following statements:

- Phase II was dispatched off in the East to West (E-W) cases because E-W flow was near its target due to the other conditions in the model, such as high Maine to New Hampshire flows. Dispatching Phase II on would have caused E-W flow to exceed the target.
- The dispatch in the BPS analysis is used only for BPS classification purposes, and should not be compared to generation dispatches used in a Needs Assessment analysis. The requirements are different for these two types of studies.
- There is a possibility of BPS buses being excluded from the list after they have tested as BPS in a previous year's analysis. However, there are benefits to these upgrades beyond

compliance with NPCC standards. The protection systems that were required as a result of having been classified as BPS provide for more operational flexibility for protection system maintenance and improve system reliability. In addition, the upgrades would help to ensure acceptable system performance under the new requirements in NERC Standard TPL-001-5.
- ISO-NE did not apply the exclusion test for Directory 1 applicability for the 2022 BPS analysis. If the exclusion test were to be performed, the testing would not occur until late 2023.

Item 3.0 – Greggs Substation Rebuild

Mr. Paul Melzen provided some background about the Greggs Substation rebuild project. This 115 kV Substation was built in 1945. Due to substantial number of asset condition issues, this substation was proposed to be rebuilt. Three alternatives were proposed:

1. New air insulated breaker-and-a-half substation at an estimated cost of $72.19M (-25 / +50%)
2. Replace or repair all known asset condition items at an estimated cost of $81.44M (-25 / +50%)
3. Convert existing substation to breaker-and-a-half scheme within existing fence line using gas insulated substation (GIS) technology at an estimated cost of $78.51M (-25 / +50%)

Alternative 1 was the preferred solution based on cost as it addresses all project drivers and increases overall system reliability at the lowest cost. It meets all current ISO PP9 requirements and guidelines for major substation design, provides room for future expansion, and has less costly ongoing maintenance.

In response to stakeholder questions, Eversource provided the following statements:

- Eversource agreed with a stakeholder comment that time line for completing the work is aggressive.
- Eversource will explore the need for the line reactor due to the rebuild of the station and the associated change in topology.
- Eversource is not proposing to use any new circuit breaker designs based on new technology for this project.
- Eversource will investigate if all lines emanating from the Greggs substation are BPS.

Item 4.0 – Economic Planning for the Clean Energy Transition (EPCET) Pilot Study: Reference Scenario and Market Efficiency Scenario, Assumptions & Preliminary Results

Mr. Ben Wilson provided the EPCET pilot study overview and assumptions for the Market Efficiency Needs scenario. The overall goal of the EPCET study is to prepare the models, tools, and processes such that informative and actionable results can be more readily produced in future Economic Study cycles. Three main scenarios have been proposed in the Economic study process: Benchmark scenario, Market Efficiency Needs scenario, and Policy scenario.

The 2021 hydroelectric profiles and historical large generator outages were included into the Benchmark scenario. Reserve model assumptions were also included in the Benchmark scenario. In addition, the transmission system has been modeled in detail. The New York area was not extensively modeled.

Nodal N-0 results showed minimal congestion. Nodal N-1 results did not show much congestion due to N-1 security constrained dispatches. Most binding contingencies happened along the East-West interface, and were binding during summer peak load hours or cold winter days. For N-1, only 345 and 230 kV contingencies were included. Including 115 kV contingencies and wind profiles would likely show additional congestion, but ISO-NE is still in the process of reviewing methods to implement this increased complexity in the model. A sample simulation run with the wind profile and 115 kV contingencies included for Northern New England showed additional congestion with increased curtailments of exports and wind generation. Future studies will include all OP-19 contingencies.

Market Efficiency Needs Scenario assumptions were provided.

Future studies will continue to investigate reserve and energy co-optimization model and methods to incorporate all 115 kV contingencies. For the Policy scenario, the goal is to develop a methodology and assumptions for capacity expansion model.

In response to stakeholder questions, ISO-NE provided the following statements:

- Since the presentation includes description of contingencies and their impact, the presentation is considered as CEII.
- The pricing of operating reserve is based on opportunity costs.
- ISO-NE will conduct 8760 hour simulations to study wind curtailment using DNV data.
- The idea of this presentation is to benchmark against historical data and provide a basis for future studies.

Item 5.0 – East Devon 345/115 kV Relay Upgrades

Mr. John Babu provided the background about the East Devon relay upgrade project. Due to lack of support for older GE and SEL relays, the relays at the East Devon Substation are being upgraded with newer and more reliable SEL relays. The work includes the replacement of 21 relays and the removal of three PLC communication devices.

The estimated PTF Cost is $6.72 Million (-25% / +50%) and the projected in-service date is Q4 2023.

In response to stakeholder questions, Eversource provided the following statements:

- The relays are not being replaced to comply with IEC 61850.
- Both A and B protection systems will be SEL relays but with different models and protection philosophies.

Item 6.0 – 3041/362 Line Structure Replacements & OPGW Installation

Mr. Chris Soderman provided the background and the need to replace the 3041/362 line structures. The primary reason for replacement is due to line structure deterioration. Details about Line 3014 and 362 line structure replacements are given below.

- Line 3041:
  - Replacement of 6 lattice structures and 13 wood structures with a combination of 10 light duty structures and 9 engineered structures
  - Install strut insulators on 4 existing structures to mitigate conductor swing
  - The cost is $11.6M (-25% / +50%)
  - The projected in-service date is Q2 2024

- Line 362
  - Replacement of 11 lattice tower structures with a combination of steel monopole structures and light duty steel H-frame structures
  - Replacement of 1 wood structure with one light duty three pole structure
  - Removal of 15.3 miles of 19#10 and 3/8" Alumoweld shield wire
  - Installation of 15.3 miles of 96 Fiber OPGW
  - The cost is $13.0M (-25% / +50%)
  - The projected in-service date is Q4 2023

In response to stakeholder questions, Eversource provided the following statements:

- Both dedicated fiber and multiplex are used, depending on the availability of equipment.

Item 7.0 – SEMA – RI Project Updates

Mr. Joe Dobiac provided information about the increase in PTF costs for RSP projects 1720, 1721 and 1722.

- RSP 1720 – Separate N12/M13 DCT & reconductor N12 & M13 between Somerset and Bell Rock.
- RSP 1721 – Reconfigure Bell Rock to breaker and half station, and upgrade to BPS standards. Split M13 line at Bell Rock and make Bell Rock ready to terminate 114 line. Install new breaker in series with N12/D21 tie breaker, upgrade D21 line switch and install 37.5 MVAR capacitor.
- RSP 1722 - Extend Line 114 - Dartmouth town line (Eversource- NGRID border) to Bell Rock (~4.2 miles)

The March 2017 cost estimate for RSP 1720, 1721 and 1722 was $82.1M. The September 2022 cost estimate for the same projects is $129.444M.

In response to stakeholder questions, National Grid provided the following statements:

- This presentation addresses the same projects as the presentation given at the September 2022 RC meeting.

Item 8.0 – Project Updates at the Planning Advisory Committee

Mr. Brent Oberlin proposed modifying the Transmission Planning Process Guide (TPPG) to define when project related changes are to be discussed with the Planning Advisory Committee (PAC).

Proposed changes in the TPTG manual are in Section 6.4, "Inclusion and Update of Projects in the Regional System Project List and Asset Condition Project List." A number of changes were proposed.

- If the price increase is greater than 50% and the increase is more than $5M, there are significant changes to scope, or something of importance occurs where that PAC needs to know, then an update should be presented to the PAC one month prior to the RSP update.
- Projects that do not meet the above thresholds will continue to be included in the RSP project and asset condition list and those will continue to be presented three times a year.
- In addition, typographical and updates to footnotes in other sections of the TPPG were also proposed. PP4 will be revisited once changes are made to TPPG manual.

In response to stakeholder questions, ISO-NE provided the following statements:

- The RSP ID number will be used for tracking projects.

Item 9.0 – Regional System Plan Transmission Projects and Asset October 2022 Update

Ms. Sarah Lamotte presented the October 2022 RSP Transmission Projects and Asset Condition Update.

Two projects had cost estimate changes greater than $5M that occurred between the June and October 2022 Project List. The details are as given below.

- The cost increased by $23.6M for the L190-4 and L190-5 line sections. The increase is due to increase in material costs and outage limitations that impacts construction sequencing.
- The cost also increased by $11.3M for the 400-1 line section rebuild due to increase in estimated pricing as a result of larger matting than anticipated for wetland and other sensitive environmental areas mitigation

There was one new project in Eastern CT. The project is to convert the 69 kV equipment at Buddington to 115 kV. The cost of the project is $5.5M.

Four upgrades were placed in-service since the June 2022 update. One in Connecticut, two in Boston and one in Rhode Island. No project was cancelled since the June 2022 update. Twenty new asset condition projects were included in the October 2022 update. Eighteen asset condition projects are in-service since the June 2022 update.

In response to stakeholder questions, ISO-NE provided the following statements:

- The cumulative investment is as of year 2002.

<u>Item 10.0 – Closing Remarks</u>

The next scheduled PAC meeting will be conducted virtually on Tuesday, November 15, 2022.

Meeting Adjourned at 12:00 PM

Respectively submitted,
Kannan Sreenivasachar
Technical Manager, Transmission Planning