AGENDA
JOINT MEETING
NEPOOL MARKETS & RELIABILITY COMMITTEES
Wednesday, March 31, 2021

Location: Teleconference
Call-in Number: 1-866-711-7475 / Access Code: 8562734
WebEx: WebExLink
WebEx Password: nepool

Item	Description	Time Allotted
1*	CHAIRS' OPENING REMARKS ***(A) Approval of Minutes [66.67% MC vote] [66.67% RC vote]*** • Joint MC/RC Meeting Date: February 26, 2021	9:30 – 9:45
2*	FUTURE GRID RELIABILITY STUDY (Project Administrator: Peter Flynn) (11th Joint MC/RC Mtg) Report on latest developments and 2021 Economic Study request	9:45 – 12:00
	LUNCH	12:00 – 12:30
3*	ADDITIONAL FEEDBACK ON FUTURE GRID RELIABILITY STUDY FRAMEWORK DOCUMENT (ISO-NE: Carissa Sedlacek) (11th Joint MC/RC Mtg) ISO's assumption recommendations, following up from the February 26, 2021 meeting presentation, on Production Cost Simulation (GridView) and Ancillary Service Simulations (EPECS) and presentation on the Resource Adequacy Screen and Probabilistic Resource Availability Analysis work plan (ISO-NE: Patrick Boughan and Fei Zeng)	12:30 – 2:30
4	OTHER BUSINESS	2:30 – 2:35

* Material distributed for this agenda item
AGENDA ITEMS with BOLD & ITALICIZED FONT: MC ACTION and RC ACTION Requested
WMPP: Wholesale Markets Project Plan

MINUTES OF THE
JOINT MARKETS COMMITTEE (MC) AND RELIABILITY COMMITTEE (RC) MEETING
HELD ON FEBRUARY 26, 2021
VIA WEBEX TELECONFERENCE

Attendee	Member/ Alternate	Market Participant
M. Winkler	MC Chair	ISO New England Inc.
E. Laine	RC Chair	ISO New England Inc.
R. Stein	RC Vice-Chair	
	Member	Generation Group Member; NRG Power Marketing; PSEG Energy Resources
	Alternate	H.Q. Energy Services (U.S.) Inc.
	Temporary Alternate	Footprint Power Salem Harbor Development LP
W. Fowler	MC Vice-Chair	Wheelabrator North Andover Inc.
		Exelon Generating Company LLC
		Dynegy Power Marketing, LLC
		Great River Hydro, LLC
		Nautilus Power
M. Lyons	RC Secretary	ISO New England Inc.
C. Belew	Member	Commonwealth of Massachusetts Office of Attorney General
D. Burnham	Member	Eversource Energy

D. Cavanaugh	Alternate	Braintree Electric Light Dept., Belmont Municipal Light Dept., Block Island Power Company, Chester Municipal Electric Light Dept., Concord Municipal Light Plant, Danvers Electric Division, Georgetown Municipal Light Dept., Groveland Municipal Electric Department, Hingham Municipal Lighting Plant, Littleton Electric Light & Water Dept., Massachusetts Bay Transportation Authority, Merrimac Municipal Light Dept., Middleborough Gas & Electric Department, Middleton Municipal Light Dept., North Attleborough Electric Department, Pascoag Utility District, Reading Municipal Light Department; Rowley Municipal Lighting Plant, Stowe Electric Dept., Taunton Municipal Lighting Plant, Town of Wallingford, Village of Hyde Park Electric Department, Wellesley Municipal Light Plant, Westfield Gas & Electric Dept.
D. Donovan	Alternate	Acadia Center
D. Errichetti	Member	Eversource Energy
F. Ettori	Member	VELCO
J. Fenn	Member	Versant Power
B. Forshaw	Member	Connecticut Municipal Electric Energy Cooperative
	Temporary Alternate	Vermont Public Power Supply Authority; MMWEC
P. Gandbhir	Alternate	Conservation Law Foundation
M. Gardner	Member	NextEra Energy Resources
J. Gordon	Alternate	CPV Towantic
B. Griffiths	Alternate	Commonwealth of Massachusetts Office of Attorney General
L. Guilbault	Member	H.Q. Energy Services
H. Healy	Temporary Alternate	Jericho Power
B. Ho	Member	Natural Resources Defense Council, Inc.
D. Hurley	Member	Small DG Group Member, Vermont Energy Investment Corp, New Hampshire Office of Consumer Advocate

B. Jagolinzer	Member	Central Maine Power
S. Kaminski	Member	NH Electric Cooperative
T. Kaslow	Member	FirstLight Power Management
S. Kirk	Member	Exelon Generation Company
A. Krich	Member	Generation Group Member/Boreas Renewables
P. Littlehale	Temporary Alternate	Eversource
N. Mah	Member	Consolidated Edison Energy
J. Martin	Member	New England Power Company
L. Martin	Member	Versant Power
T. Martin	Member	New England Power Company
H. Presume	Alternate	VELCO
J. Rotger	Member	Cross-Sound Cable, Galt Power
	Temporary Alternate	BP Energy, DTE Energy Trading, Mercuria
M. Smith	Alternate	The Energy Consortium
B. Thomson	Member	MMWEC
A. Trotta	Member	Avangrid
J. Westbrook	Alternate	Environmental Defense Fund
A. Worsley	Member	AR RG Large Group Member
J. York	Alternate	RTO Insider
Guest		**Affiliation**

E. Annes		Connecticut Department of Public Utilities
P. Asarese		ISO New England Inc.
N. Baldenko		Eversource Energy
D. Bergeron		Maine Public Utilities Commission
P. Boughan		ISO New England Inc.
P. Bernard		ISO New England Inc.
D. Capra		NESCOE
Q. Chen		ISO New England Inc.
W. Coste		ISO New England Inc.
B. D'Antonio		NESCOE
A. DiGrande		ISO New England Inc.
D. Donovan		Acadia Center
R. Ethier		ISO New England Inc.
P. Flynn		Consultant
A. George		ISO New England Inc.
J. Grasse		New England Power Company
K. Haag		ISO New England Inc.
P. Holloway		Massachusetts Public Utilities Commission
N. Hutchings		ISO New England Inc.
S. Judd		ISO New England Inc.
M. Kotha		ISO New England Inc.

R. Kowalski		ISO New England Inc.
M. Krowlewski		Vermont Public Utilities Commission
P. Lopes		Mass DOER
X. Luo		ISO New England Inc.
A. Mills		Maine Public Utilities Commission
D. Nelson		Massachusetts Public Utilities Commission
B. Oberlin		ISO New England Inc.
L. Ortiz		Anbaric Development Partners
M. Perben		National Grid
D. Phelan		NH PUC
P. Powers		American Petroleum Institute
L. Raber		Maine Public Utilities Commission
T. Reppucci		Mass. Attorney General's Office
E. Runge		Day Pitney
K. Schlichting		ISO New England Inc.
K. Scully		ISO New England Inc.
C. Sedlacek		ISO New England Inc.
J. Slocum		Exelon Generation Company
P. Wong		ISO New England Inc.
F. Zeng		ISO New England Inc.

Agenda Item No.1 – Chair's Remarks

The Chairs welcomed committee members and guests and reviewed the day's agenda.

There was a quorum in all sectors for the Markets Committee and Reliability Committee.

Agenda Item No.1A – Meeting Minutes

Markets Committee (MC) – Meeting Minutes

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee approves the minutes for the January 19, 2021 joint meeting of the Markets and Reliability Committees, as circulated for the joint MC and RC February 26, 2021 meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

Reliability Committee (RC) – Meeting Minutes

The following motion was moved and seconded by the Reliability Committee:

RESOLVED, that the Reliability Committee approves the minutes for the January 19, 2021 joint meeting of the Markets and Reliability Committees, as circulated for the joint MC and RC February 26, 2021 meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

Agenda Item No.2 – Future Grid Reliability Study

Mr. Flynn asked the presenters to review the changes made to their scenario's Assumptions since the last meeting.

Julia Grasse on behalf of National Grid delivered an overview of the changes made to the Scenario 1 assumptions and described the changes to Alternate Scenario A. Key highlights from the presentation included:

- Clarifying that within the transportation category, electric vehicle (EV) load will not push back energy to the grid.

- The location and interconnection points of all new resources will be consistent with the 2020 Economic Study.

- The demand reductions for EE (Energy Efficiency), and BTM (Behind-the-Meter) PV will stay consistent with the 2021 CELT Report.

- The battery storage characteristics modeled will start at $3/MWh one-way at 86% efficiency and the BESS are expected to be aggregated by Zone.

- With respect to topology this scenario will use, the existing system plus RSP planned projects, including: Boston RFP, NECEC, and the Cape Cod Cluster.

- Alternative Scenario A analyzes the impact of bi-directional transmission to Quebec for long-term storage and as a balancing resource. It now includes a 2400 MW bi-directional HVDC tie injecting to NEMA.

No questions were presented to National Grid.

Nic Baldenko, on behalf of Eversource, reviewed the changes made to the Scenario 2 assumptions. Key highlights from the presentation include:

- For in-market versus out-of-market storage, Scenario 2 proposes approximately 4 GWs of new battery storage. It proposes modeling all storage as in-market resources responding to LMPs.

- Scenario 2 calculates EV by miles traveled to calculate emissions, the EV Assumptions in this scenario represent a 66% emissions reduction compared to 1990 levels.

- The demand reduction for EE and BTM PV would be built off of the 2021 CELT.

- There are 3940 MWs of new battery storage at 90% efficiency in this scenario. The storage is distributed to zones based on system needs. Additional storage will be added, as necessary, during model development.

- With respect to resource adequacy proxy units, this scenario will use battery storage as the proxy unit. National Grid, Anbaric and NESCOE agree on using battery storage as the initial proxy unit.

- Eversource noted that they will further discuss how to model availability within MARS to assume that the battery energy will be there to meet the seasonal peaks.

In response to stakeholder questions, Eversource:

- Noted that the storage capability break down is in 2-hour, 4-hour, and 8-hour increments based on the resource technologies.
- The time of use for vehicle miles is coming from state transportation data. Eversource does not have the exact values available now but will work to obtain them.
- Some concern was expressed in using batteries as the proxy units to cover reliability. Mr. Flynn rephrased what he heard to confirm his understanding of the committees' consensus regarding the use of proxy units. The committees are comfortable with the use of modest amounts of battery storage as proxy units. If this path indicates that a large number of batteries are needed, they will be supplemented with gas-fired units. The project coordinator suggested that Carissa Sedlacek work with the MARS team to think on battery modeling in MARS and fold in ISO's feedback for later discussions.

Ben D'Antonio, on behalf of NESCOE, reviewed the changes made to Scenario 3 assumptions. Key highlights from the presentation include:

- This scenario uses load assumptions derived from the Massachusetts 2050 Decarbonization Roadmap study and those loads have been transposed onto the ISO's Regional System Plan (RSP) zones.
- An overview was given on the interconnection locations by resource type, MWs, and state.
- A review of the Load Growth Rate for Scenario 3; projecting a 4.19% load growth from 2030 to 2040 and a review of load reduction for EE and BTM resources and flexible load for EVs.
- With respect to battery storage, Scenario 3 assumptions use the roadmap results of aggregate pumped and energy storage, then deducts existing pumped storage facilities. Market facing battery storage in this scenario will also use $3/MWh variable O&M assumption to start.
- With respect to network topology for the modeling assumptions, The RIO model results were mapped onto the system topology used in this study.

No questions were raised for NESCOE.

Mr. Doug Hurley, on behalf of the multi-sector group, reviewed the changes made to the Alternative Scenario B. Key highlights from the presentation include:

- This alternative scenario starts with Scenario 3 assumptions, and will model the EVs as offering 25% of their battery capacity, which results in larger amounts of storage on the system between 100 GWs and 200 GWh's. This will impact the market studies and transmission assessment throughout the system.

- Mr. Hurley reviewed the interconnection locations for battery storage. Locations are adjusted for population density and urban centers. Market facing batteries will be modeled with a $0/MWh variable O&M assumption.

In response to stakeholder questions:

- Mr. Hurley confirmed that 8 million additional EVs will account for the increased storage on the system.
- Mr. Hurley noted that there is a reasonable chance EVs can be a paid as a capacity resource for the system. This would be possible through businesses that could aggregate the EVs and then make payments to the EV owners for their battery capacity.

Stakeholder comments included:

- Curiosity about the ability to predict EV owner behavior and when they would be willing to not drive their vehicles in order to be available to provide grid capacity in time of low solar and/or wind lulls.
- One member objected to the idea that a market facing battery resource will have a $0/MWh O&M cost.

Mr. Luis Ortiz, on behalf of Anbaric, reviewed the changes made to the Alternative Scenario D and E. Key highlights from the presentation include:

- Scenario D is based on a grid with zero emissions.
- Scenario E a variant of Scenario D with offshore wind interconnection points evenly distributed between SEMA/Boston and CT.
- Anbaric proposed as the assumptions for new and retiring resources to match Scenario 3, except to retire all fossil units. Storage will be assumed to be located where the fossil resources retire.
- With respect to storage, Anbaric proposed storage durations be dispatched under different paradigms. Shorter duration batteries should be dispatched based on market LMPs and longer duration units would be used for grid balancing on a longer timescale.

In response to stakeholder questions, Mr. Ortiz agreed that it may not be practical to retire all fossil fuel resources, but Anbaric would like to see the results of that modeled scenario to see the impact and compare reduced and zero emissions scenarios.

Mr. Flynn stated Alternative Scenario C would not be reviewed regarding the retirement of nuclear units as it was covered in the January 2021 presentation by Michelle Gardner.

Mr. Flynn reviewed the incremental changes to the Framework Document by stepping through the document redline changes. The framework document has been converted to a format to suit the 2021 Economic Study and limited to Phase 1. Stakeholders requested and Mr. Flynn agreed to put together a companion document regarding the existing Phase 2 work as part of the initial Framework document for the Chairs and Vice Chairs to hold for future use.

For production cost simulation, the New England transmission system will be modeled in an unconstrained system using a "pipe and bubble" configuration. The unconstrained transmission system will be built out with no costs provided as part of the Production Cost Simulation.

In response to stakeholder feedback, the ISO:

- Will consider adding to the study by noting all transmission constraints that arise for further review.
- Suggested that to model long periods of time when there are wind and solar lulls, the DNV-GL stochastic weather data can be used as a sensitivity to test very unlikely weather scenarios and see how the system performs.

Agenda Item No.3 – Additional Feedback on Future Grid Reliability Study Framework Document

Ms. Carissa Sedlacek (ISO-NE) reviewed ISO-NE's revised stakeholder schedule assuming the 2021 Economic Study path. She also provided additional feedback to the draft framework document sent to ISO-NE for review on December 29, 2020.

In response to the stakeholder feedback, the following topics were discussed where stakeholders will be providing feedback to the ISO:

- If nuclear, municipal solid waste, and landfill gas resources are utilized in production cost modeling runs, they should also be included in MARS runs. If they are not utilized in the production cost modeling, we may consider not including them in MARS runs.
- Regarding varying the amount of reserves, the ISO was looking for confirmation that the study should follow the first and second contingencies for the procurement of reserves in both GridView and EPECS or otherwise seek synergy between the models.

- Should EPECS simulations be different from past Economic Studies where emphasis is solely on the shoulder months or do stakeholders prefer to analyses to span the entire year?

- Gridview does model operating reserves but rather EPECS; it assumes the requirements based on the increase in load. In EPECS, only regulation reserves are available in real time to respond to system imbalances. If participants want a real-time proxy for how battery storage could respond, they should specify it as regulation reserves.

- Some modeling assumptions are unique to the MARS analysis and need to be defined. Next month, the ISO will provide recommendations for missing assumptions.

Carissa and Mr. Flynn will work on clarifying the order in which the matrix scenarios will be run with the alternative scenarios. Feedback or questions on Phase 1 of the Future Grid Reliability Study may be provided by e-mail to Peter Flynn and Carissa Sedlacek. The 2021 Economic Study requests are due by April 1st.

Mr. Steven Judd (ISO-NE) provided a review of the DNV-GL data for modeling wind/solar resources. The following are key points from the presentation along with the presented data:

- The runs will be benchmarked from 2 datasets of existing onshore and offshore as well as future offshore wind speed profiles.

- The dataset has been expanded from 8 years to 20 years. There was also an expansion of solar and load profiles for 20-years, which was explained to provide co-dependencies.

- Mr. Judd clarified that the simulation of lulls in wind were based on historical records, which had shown cold snaps and heatwaves to be consistent with the data produced. He confirmed that there is correlation within the draws for cold spells that last up to 24 days.

Mr. Wayne Coste (ISO-NE) led a discussion regarding electric vehicle modeling. He delivered an overview of current proposals received from proponents and reviewed load demands and charging profiles. In regards to stakeholder feedback, the following clarifications were made:

- The current proposed model is an average daily profile for Scenario 1 EVs that was submitted. The data used for this model also contributed to the National Grid 2020 Economic Study.
- An assumption was made that there will be an incentive for consumers to charge their vehicles during a certain time of day to compensate for peak hours.

Agenda Item No.4 – Determine if there is Consensus to Request Phase 1 as the 2021 Economic Study

The Chair asked the committee whether there were any thoughts or feedback on whether to submit Phase 1 of the Future Grid Reliability Study as the 2021 Economic Study. There were no comments. There were no objections raised to this approach and a consensus was reached for NEPOOL to request the Framework Document and assumptions, as amended following this meeting, to be sent ISO as a 2021 Economic Study request.

<u>Agenda Item No.5 – Reflection and Next Steps on Phase 2 of the Project</u>

Ms. Allison DiGrande (ISO) provided a high-level overview of Vamsi Chadalavada's "ISO New England's Approach to Future Grid Studies - Supporting New England's Transition to a Clean Energy Future" presentation given to the PC on February 18, 2021 that was provided for today's meeting. At the PC meeting, Vamsi put forward a number of compelling reasons why we NEPOOL might pause proceeding with Phase 2 at this time.

Mr. Flynn asked the stakeholders if pausing Phase 2 is the correct step. An agreement was achieved that the committee should pause Phase 2 Revenue Sufficiency at least until the production cost modeling analysis of Phase 1 is complete. The committee also indicated that transmission security pieces could be put on hold until the 2050 Transmission Study takes place. A member noted that the review on whether to proceed with the Revenue Sufficiency aspect of Phase 2 could commence in Q1 2022 based on the current schedule. That schedule could change based on the progress is made on Phase 1.

The Chair thanked the committees and congratulated on reaching milestone of consensus on proposing the phase 1 FGRS as the 2021 Economic Study.

<u>Agenda Item No.6 – Other Business</u>

The next Joint MC/RC on the Future Grid will be Wednesday, March 31, 2021.

There was no further business before the committees.

Meeting Adjourned at 4:30 PM

Respectfully submitted,

_______/s/_____________

Marc Lyons
Secretary, Reliability Committee

FUTURE GRID RELIABILITY STUDY UPDATE

Peter Flynn
March 31, 2021

Overview and Background

- Over the last 7 months, the MC/RC scoped a study, determined its metrics, and considered assumptions for what the grid might look like in 2040 under a number of scenarios
- MC/RC reached consensus on 2/26 that NEPOOL should submit the FGRS Phase 1 Framework, with amendments to be made following the meeting, to ISO-NE as a 2021 Economic Study request

- NEPOOL submitted the study request on 3/12 to ISO-NE as a 2021 Economic Study

Agenda for Today

- This morning
  - Review the amendments that were made to the Phase 1 Framework following the 2/26 MC/RC meeting
  - Review the stakeholder process going forward
  - Report on Phase 2 documentation
- This afternoon
  - ISO will provide additional feedback on the Phase 1 Framework and address next steps

Study Framework for Phase 1

- Study Framework consists of 2 documents:
  - Framework Document (the Word document)
  - Assumptions Spreadsheet
- Documents reviewed at the 2/26 MC/RC meeting were revised following the meeting to:
  - Reflect feedback from the MC/RC at the 2/26 meeting
  - Clarify certain points as suggested by the MC/RC leadership, the ISO, or NESCOE

Production Cost Simulation

- Clarified how transmission will be modeled:
  - Simulations without constraints
  - Unconstrained flows will be monitored against current interface limits to inform where conceptual transmission could be added
  - For certain assessments, constrained conditions will also be modeled
    - Interface limits will be enforced causing the system to change the generation dispatch
    - Will show the benefit of increased transfers vs. the existing system

GE MARS Analyses

- Added a footnote
  - If certain resource types are not committed in GridView/EPECS, ISO may run sensitivities that examine the impact of removing those resources in the MARS simulations

GE MARS Analyses

- Clarified certain capacity assumptions
  - All new resources' capacity contributions will be modeled
  - Resource Adequacy Screen will model resources at their qualified capacity value based on current market rules
  - Probabilistic Resource Availability Analysis will model solar/wind resources under the DMV GL stochastic model set

GE MARS Analyses

- Clarified metrics
  - For Resource Adequacy Screen
    - Loss of load expectation (LOLE), expected unserved energy (EUE) and loss of load hours (LOLH)
  - For Probabilistic Resource Availability Analysis
    - LOLE, EUE, LOLH, loss of load events (LOLEv), EUE/LOLEv and LOLH/LOLEv

Resource Adequacy Screen

- Clarified proxy resources
  - Modest amount of batteries and, if additional resources are needed, new thermal units will be added
  - Exception: For Alternate Scenarios D and E, proxy units will consist entirely of batteries

Probabilistic Resource Availability Analysis

- Clarified objective
  - Analyze system reliability taking into consideration:
    - Uncertainties associated with the output of renewable resources due to weather risks
    - Interactions between different types of VERs
    - Correlation with loads during and outside of the summer and winter peak periods

Matrix Describes 34 Scenarios Reading "Down and Across"

	(Resource 1) OSW 8,000 MW DER 18,000 MW	(Resource 2) OSW 8,000 MW DER 25,000 MW	(Resource 3) OSW 17,000 MW DER 31,000 MW
(Load 1) Buildings 9,600 GWh Transport 7,300 GWh	**(5 Scenarios) Matrix Scenario 1 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 1) Scenario 2 (Resource 2 and Load 1) Scenario 3 (Resource 2 and Load 1)	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 1) Scenario 2 (Resource 3 and Load 1) Scenario 3 (Resource 3 and Load 1)
(Load 2) Buildings 6,600 GWh Transport 18,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 2) Scenario 2 (Resource 1 and Load 2) Scenario 3 (Resource 1 and Load 2	**(5 Scenarios) Matrix Scenario 2 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 2) Scenario 2 (Resource 3 and Load 2) Scenario 3 (Resource 3 and Load 2)
(Load 3) Buildings 38,900 GWh Transport 37,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 3) Scenario 2 (Resource 1 and Load 3) Scenario 3 (Resource 1 and Load 3	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 3) Scenario 2 (Resource 2 and Load 3) Scenario 3 (Resource 2 and Load 3)	**(6 Scenarios) Scenario 3 plus Alternatives A, B, C, D and E**

Stakeholder Process

- Study Framework will continue to be refined based on:
  - Continued consultation among the ISO, NEPOOL representatives and scenario proponents
  - Preliminary study results

- ISO intends to present at PAC on a monthly basis to discuss modeling progress and results

Stakeholder Process

- NEPOOL intends that the ISO will engage with the MC/RC to:
  - Provide periodic high-level reports on the study progress
  - Seek MC/RC determinations if there are *major* decision points about the direction and focus of the studies
  - Receive guidance from the MC/RC on the studies as they progress
- The ISO may receive feedback both from MC/RC and PAC
  - Material decisions on the study will remain NEPOOL's prerogative as the study proponent

Feedback Contacts Going Forward

- We are now entering the phase of interacting with the ISO and awaiting study results
- For stakeholder feedback, comments, and suggestions on RC/MC direction and oversight of the 2021 Economic study as we proceed, please contact:
  - Reliability Committee Chair, Emily Laine Elaine@iso-ne.com
- For stakeholder feedback pertaining to clarifications on the study modeling, results, and PAC presentations and materials, please send inquires to:
  - the attention of Carissa Sedlacek, Director, Planning Services, and Patrick Boughan, 2021 Economic Study Project Manager, at PACmatters@iso-ne.com

Questions on Phase 1

Phase 2

- Consensus achieved at the 2/26 MC/RC meeting to pause on Phase 2
- A paper has been submitted to MC/RC leadership and it will be posted shortly:
  - Documenting the work that has been done to develop a partial draft framework for Phase 2
  - Noting that the MC/RC believes that the timing and details of Phase 2 require further consideration
  - Intent is that the paper can serve as a refresher and starting point when the MC/RC recommences work on Phase 2

Conclusion

- Thanks to everyone for your engagement, input, commitment and collegiality
- Let the study begin!

NEPOOL Future Grid Reliability Study
Study Framework for Phase 1 Economic Study Request (March 12, 2021)

The New England Power Pool (NEPOOL) provides this document as the framework for Phase 1 of its studies related to the reliability of the future grid (collectively, the studies are referred to as the Future Grid Reliability Study).

The New England states have enacted energy and environmental laws that call for a significant reduction in greenhouse gas emissions. Compliance with these laws is expected to result in changes in the generation and use of electricity. Generators that do not emit carbon will likely produce a much greater percentage of the region's power supply. In addition, electricity will likely become more prevalent in heating buildings and powering vehicles, significantly changing load amounts, peaks and profiles.

NEPOOL is commissioning this Future Grid Reliability Study to understand better the implications of this substantially changed future grid. Specifically, the Future Grid Reliability Study (Phases 1 and 2 together) will examine whether revenues from the existing markets will likely be sufficient to attract and retain the new and existing resources that will be needed to continue to operate the system reliably. It will also identify what operational and reliability challenges will need to be addressed in the future grid and identify possible ways to meet those needs.

This document together with the assumptions spreadsheet (Assumptions Spreadsheet) constitute the "Study Framework" for Phase 1 of the Future Grid Reliability Study. The Study Framework has been developed through the stakeholder process at joint meetings[1] of the NEPOOL Markets and Reliability Committees (MC/RC) with support from the New England States Committee on Electricity (NESCOE) and Independent System Operator - New England, Inc. (ISO-NE). Although referred to as a Study Framework, the body of work will actually consist of several analyses using different computer models. No single model can address the range of issues that NEPOOL stakeholders desire to assess. The analyses will be conducted in a staggered iterative approach with the results from one analysis informing decisions about what to model or remodel in other analyses. The Study Framework is being presented to ISO-NE prior to April 1, 2021 as a 2021 Economic Study request. The Study Framework will continue to be refined after being provided to ISO-NE based on continued consultation among ISO-NE, NEPOOL representatives and scenario proponents and on preliminary study results.

I. Study Objective / Scope

NEPOOL approved the Future Grid Reliability Study objective and scope in a document commonly referred to as the "bubble chart."[2] The objective is to assess and discuss the future

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1 Joint meetings of NEPOOL's MC and RC were held beginning April 2020. Six past/ongoing studies were identified for examination: (1) 2016 NEPOOL Economic Study; (2) 2019 NESCOE Economic Study; (3) Massachusetts 2050 Roadmap Effort; (4) Eversource "Grid of the Future" Study; (5) E3/EFI "Electric Reliability under Deep Decarbonization" Study; and (6) 2019 Brattle Group "Achieving 80% GHG Reduction in New England by 2050" Study. For more information, see: http://nepool.com/Future_Grid.php.

2 See November 12, 2020 meeting materials, https://www.iso-ne.com/static-assets/documents/2020/11/a2_presentation_future_grid_reliability_study.pdf (slide 4)

state of the regional power system in light of state energy and environmental laws as of December 31, 2020. The scope is to define and assess the future state of the regional power system identifying: 1) a resource mix or mixes for future years; and 2) resource and operational/reliability needs. A gap analysis will determine whether, in the future state envisioned, the markets in effect on December 31, 2020 will likely provide sufficient market revenues to attract and retain the new and existing resources that will be needed to continue to operate the system reliably. The gap analysis will also identify any market deficits that may need to be addressed to assure operability and reliability in accordance with the standards of the North American Electric Reliability Corporation, Northeast Power Coordinating Council, Inc. and ISO-NE.

The Future Grid Reliability Study will therefore encompass both economic and engineering analyses. The economic analyses (production cost and ancillary services simulations, and the revenue sufficiency analysis) will seek to answer questions such as what are the forecasted market revenues, and will they likely be sufficient to attract and retain the different types of resources that will be needed to reliably operate the system in that future. The engineering analyses (ancillary services simulation, resource adequacy screen, and the probabilistic availability and system security analyses) will seek to answer questions about what conditions will likely present operational or reliability issues, the nature of those issues, and whether the system will be able to operate reliably when, for example, variable energy resources (VERs) are the predominant generation resources, when production from VERs exceeds load, and when there may be a sustained reduction in VER production.

The studies will be performed in two phases. Phase 1 will consist of the production cost simulation, ancillary services simulation, resource adequacy screen and probabilistic resource analysis. The Phase 1 work is described in detail below. NEPOOL expects that Phase 2 will consist of revenue sufficiency and system security analyses and any other analyses NEPOOL deems appropriate at the time of commencing Phase 2. The Phase 2 study framework will be further developed by the MC/RC in a separate document later.

II. Areas of Analysis

A. Production Cost Simulation: ABB GridView (ISO-NE)

Objectives: Show economic dispatches and energy market revenues for different scenarios. Provide useful information related to the operational/reliability analyses, and identify conditions upon which further operational/reliability analyses may focus.

Scope: New England only; external interfaces are assumed historic profiles unless otherwise specified in the scenario assumptions. A "pipe and bubble" configuration representing 13 planning sub-areas (or "bubbles") of supply-side resources within the New England control area connected by simplified transmission models (or "pipes") will be used. These "pipes" are a defined collection of specific transmission lines with assigned transfer limits.[3] Simulations will be performed without transmission constraints between RSP planning sub-areas. The unconstrained flows will be

[3] For additional information, see https://www.iso-ne.com/about/key-stats/maps-and-diagrams

monitored against current interface limits and will inform where conceptual transmission could be added to allow for the higher interface flows. For certain assessments, constrained conditions will be modeled to show the benefit of increased transfers versus the existing system where interface limits are enforced causing the system to change generation dispatch to maintain those limits.

Methods: Customary approach to economic studies – scenario analyses - with some flexibility to reflect the variable operation and maintenance costs of resources in the simulated dispatch. However, the variable operation and maintenance costs of battery storage will be assumed to be $3/megawatt-hour each way.[4] Sensitivities may be performed. Alternative scenarios may also be run that assume different cost amounts. Iterate model simulations with updated values informed by the results of other areas of analysis.[5]

Metrics: Using scenario analysis, perform energy market simulation studies that provide information on system performance, including production costs by resource type and fuel type, location marginal prices, load-serving entity energy expenses, uplift and environmental emission levels (CO_2, NO_X and SO_X) for all matrix and alternative scenarios

Learning points: High-level observations about transmission constraints between sub-areas in GridView and when during the year those conditions might occur; observations about whether the results suggest scenarios for further study; the results will feed into the probabilistic resource availability analysis.

B. Ancillary Services Simulation: EPECS (ISO-NE)

Objectives: Show if resources will provide the necessary amounts of regulation, reserves, ramping and load following. Provide insight to expected revenues from the existing ancillary services markets under the scenarios studied.

Scope: New England only; assume unconstrained internal transmission but interfaces at the RSP bubbles will be monitored. Some sensitivities that recognize constraints may be run. For the: (i) study year; and (ii) selected time periods within the study year

Methods: Using the same or complementary assumptions as the energy market simulations described above, use a methodology similar to what is used for those studies. Examine relationships between system imbalance estimates and: a) reserve

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[4] See the December 16, 2020 Modeling of Battery Storage in Economic Studies presentation available at: https://www.iso-ne.com/static-assets/documents/2020/12/a9_modeling_of_battery_storage_in_economic_studies.pdf

[5] For example, results of the Resource Adequacy Screen and Probabilistic Resource Availability Analysis may suggest that Production Cost Simulation(s) be re-run.

products, and b) other system parameters. Estimate quantities of ancillary services requirement gaps" indicated in the scenario analysis. There will be some flexibility to iterate model simulations with updated values informed by the results of other areas of analysis.

Metrics: For all matrix and alternative scenarios, analyze the regulation, reserves, ramping, and load following capability needed to maintain the supply/demand balance of the New England bulk electric power system with a significant VER penetration. (The EPECS model provides an integrated platform for assessing simulated operating reserves, interface flows, tie-line utilization, and regulation performance. The one-minute time increment used in the EPECS model augments the GridView model, which uses one-hour time-step increments to analyze: day-ahead resource scheduling as a security-constrained unit commitment; real-time resource scheduling as a real-time unit commitment; real-time balancing as a security-constrained economic dispatch; and real-time physical power flow with integrated regulation service.) Environmental emission rates (CO_2, NO_X and SO_X) will be provided for resources providing ancillary services.

Learning points: High-level observations about conditions that may stress the grid due to weather risks associated with various resource mixes, the timing of when those conditions might occur and any ancillary services gaps; observations about whether the results suggest scenarios for further study; the results will feed into the probabilistic resource availability analysis.

C. Resource Adequacy Screen and Probabilistic Resource Availability Analysis: GE MARS (ISO-NE)

The same modeling tool will be used to perform two different types of analyses as described below. There are some common elements:

Scope: New England only; assume unconstrained internal transmission but interfaces at the RSP bubbles will be monitored. Some sensitivities that recognize transmission constraints may be run.

Methods: Use a probabilistic approach (Monte Carlo simulations) that examines all 8760 hours of the study year.[6] All new resources' capacity contributions will be modeled. The Resource Adequacy Screen will model resources at their appropriate qualified capacity value based on current market rules. The Probabilistic Resource Availability Analysis will model solar/wind resources ~~under~~ using the DNV GL ~~stochastic~~ historical model set starting with the most recent year and work back in time to incorporate as many years as possible to the extent computation capability

[6] ISO-NE will identify if certain resources or resource types are not committed in the GridView/EPECS simulations for a given scenario. If that occurs, ISO-NE may run sensitivities that examine the impact of removing those resources in the MARS simulations.

allows.[7] This will form a recent 'stochastic' data set based on the most recent weather history.

The objectives and methods of the two analyses differ in the following respects.

1. Resource Adequacy Screen

Objective: Determine Installed Capacity Requirement (ICR) for each future scenario in preparation for potential energy market simulation(s) to ensure that loss of load expectation (LOLE) is met for expected system loads. Includes the creation of system-wide Marginal Reliability Impact (MRI) curves.

Methods: Determine ICR in accordance with the methodology described in Market Rule 1, Section 12, in preparation for energy market simulations; scenarios found to be resource inadequate will be identified and will add sufficient proxy resources for the case to solve. Proxy resources will consist of a modest amount of batteries and, if additional resources are needed, new thermal units will be added except in Alternative Scenarios D and E. For those two alternative scenarios, the proxy units will consist entirely of batteries. Some sensitivities could be performed for different proxy resources.

Metrics: Evaluate all matrix and alternative scenarios to determine system reliability during the peak hours of the study year. Produce MRI curves for select scenarios chosen by the MC/RC. LOLE of one day in ten years, expected unserved energy (EUE), loss of load hours (LOLH).

2. Probabilistic Resource Availability Analysis

Objective: Analyze system reliability taking into consideration the uncertainties associated with the output of renewable resources due to weather risks, the interactions between different types of VERs, and the correlation with loads during the summer and winter peak periods as well as *outside* of the summer and winter peak periods.

Methods: For select matrix and alternative scenarios chosen by the MC/RC, examine correlation of loss of load risk and the risk associated with VER availability estimates. Examine the frequency with which elevated risk events are projected to occur over time (e.g., number of times and for how long). Examine the occurrence of loss-of-load probability and identify risk trends (e.g., daily or seasonal instances of increased resource availability risk). Revise scenario assumptions to model other elevated risk events as chosen by the MC/RC. Include flexibility to iterate with updated values informed by the results of other areas of the Phase 1 analysis.

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[7] DNV GL ~~stochastically~~ modeled the historical 2~~0~~1-year dataset (2000-2020) of onshore and offshore wind generation, behind-the-meter distributed solar generation, gross load, and net load data, to assess the full spectrum of operating conditions within the ISO-NE service area. The ~~stochastic~~ historical modeling methodology is described in a report that is available at: ~~https://www.iso-ne.com/static-assets/documents/2021/03/a9_dnv_gl_report_analysis_of_stochastic_dataset_for_iso_ne_rev1.pdf~~https://www.iso-ne.com/static-assets/documents/2021/03/a9_stochastic_time_series_modeling_for_isone_rev_2.pdf

Metrics: LOLE of one day in ten years, loss of load probability (LOLP), EUE, LOLH, loss of load event (LOLEv) which counts the number of events, EUE/LOLEv, and LOLH/LOLEv

Learning points: Observations will be made about conditions in which there may not be sufficient resources to meet the LOLE criterion, the timing of when those conditions might occur, and whether there may be a need for certain categories of resources in some amounts in order to meet that criterion. Observations will be made about whether the results suggest scenarios for further study as part of the Phase 1 work or some iterations with the energy and ancillary services analyses. The results may inform the Phase 2 system security analysis.

III. Scenarios

Use a matrix approach with alternatives to represent a range of possible futures based on Future Grid Reliability Study proposals that stakeholders submitted to the MC/RC.

Matrix of Scenarios for Energy and Ancillary Services Market Simulations

	(Resource 1) OSW 8,000 MW DER 18,000 MW	(Resource 2) OSW 8,000 MW DER 25,000 MW	(Resource 3) OSW 17,000 MW DER 31,000 MW
(Load 1) Buildings 9,600 GWh Transport 7,300 GWh	**(5 Scenarios) Matrix Scenario1 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 1) Scenario 2 (Resource 2 and Load 1) Scenario 3 (Resource 2 and Load 1)	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 1) Scenario 2 (Resource 3 and Load 1) Scenario 3 (Resource 3 and Load 1)
(Load 2) Buildings 6,600 GWh Transport 18,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 2) Scenario 2 (Resource 1 and Load 2) Scenario 3 (Resource 1 and Load 2	**(5 Scenarios) Matrix Scenario 2 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 2) Scenario 2 (Resource 3 and Load 2) Scenario 3 (Resource 3 and Load 2)
(Load 3) Buildings 38,900 GWh Transport 37,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 3) Scenario 2 (Resource 1 and Load 3) Scenario 3 (Resource 1 and Load 3	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 3) Scenario 2 (Resource 2 and Load 3) Scenario 3 (Resource 2 and Load 3)	**(6 Scenarios) Scenario 3 plus Alternatives A, B, C, D and E**

OSW = Offshore wind
DER = Distributed energy resources (photovoltaics and electric storage)

Stakeholders also proposed some alternative scenarios..

Alternative Scenarios

A. Bi-Directional Transmission (see National Grid 2020 Economic Study[8])
B. Vehicle to Grid (see Multi-Sector A)
C. Nuclear Retirement (see NextEra/Dominion)
D. 100% decarbonization (see Anbaric)
E. On-shore and off-shore grids (see Anbaric)

[8] See https://www.iso-ne.com/static-assets/documents/2020/11/2020-economic-studies-preliminary-production-cost-results-revision-2-clean.pdg

ISO-NE will run the scenarios in the following sequence. First, it will run matrix Scenario 1 and the Scenario 1 sensitivities. The sensitivities will apply the different resource mixes and loads assumed in Scenarios 2 and 3 to Scenario 1. Next ISO-NE will run the alternative scenarios that go with Scenario 1.

ISO-NE will then proceed to run matrix Scenario 2, the Scenario 2 sensitivities and the alternative scenarios that go with Scenario 2, followed by matrix Scenario 3, the Scenario 3 sensitivities and the alternative scenarios that go with Scenario 3.

ISO-NE will assess as it proceeds through the sequence, based on the results obtained to date, whether any of the subsequent runs will likely be unrealistic, infeasible, incapable of being completed in a reasonable time or not likely to tell something new. Based on ISO-NE's assessment, the MC/RC could decide to drop certain subsequent scenarios or sensitivities. ISO-NE will present Production Cost Simulation (GridView) results first for all scenarios. Then proceed with presenting the Ancillary Services Simulation (EPECS) results, followed by the Resource Adequacy Screen (MARS) results. At that point, a discussion with the MC/RC will be required to determine the scenarios that will be included in the Probabilistic Resource Availability Analysis.

A. Matrix Scenario 1

Matrix Scenario 1 assumes significant growth in non-carbon emitting generators and electrified load. However, with respect to both the resource mix and load, it assumes a slower pace of change than the two other matrix scenarios. The resource mix in Scenario 1 assumes approximately 8,000 MW of offshore wind (about 17% of the resource mix) and 18,000 MW of distributed energy resources (about 33% of the resource mix). On the load side, it assumes approximately 16,900 gigawatt-hours (GWh) of electrified building and transportation load weighted towards buildings. The electrified building and transportation load accounts for about 11% of net load. The detailed assumptions for this and each of the scenarios are presented in the Assumptions Spreadsheet.

B. Matrix Scenario 2

Matrix Scenario 2 assumes greater growth in distributed energy resources and electrified load than Scenario 1. The resource mix in Scenario 2 assumes approximately 8,000 MW of offshore wind (about 15% of the resource mix) and 25,000 MW of distributed energy resources (about 41% of the resource mix). On the load side, it assumes approximately 25,100 GWh of electrified building and transportation load weighted towards transportation. The electrified building and transportation load accounts for about 18% of net load.

C. Matrix Scenario 3

Matrix Scenario 3 assumes significantly greater growth in offshore wind, distributed energy resources and electrified loads than Scenarios 1 or 2. The resource mix in Scenario 3 is comprised of approximately 17,000 MW of offshore wind (about 28% of the resource mix) and 31,000 MW of distributed energy resources (about 41% of the resource mix). With respect to load, Scenario 3 assumes approximately 76,400 GWh of electrified load roughly balanced between buildings and transportation. The electrified building and transportation load accounts for about 45% of net load. Matrix Scenario 3 is based upon the Massachusetts 2050 Roadmap Study results for the All Options Scenario in 2040.

D. Alternative Scenario A:

The objective is to analyze the impact of bi-directional controllable transmission to Quebec. It assumes the addition of as much as 2,400 MW of bi-directionally capable, controllable direct current ties injecting into Northeast Massachusetts. Alternative A to be applied to Scenarios 1, 2 and 3.

E. Alternative Scenario B:

The objective is to analyze the impact of vehicle to grid storage. It assumes that an additional 100 gigawatts/200 GWh of energy storage are available for a two-hour duration based on an estimated 25% of 8 million electric vehicles with 100 kilowatt batteries capable of providing electric storage and vehicle to grid services. Alternative B to be applied only to Scenario 3.

F. Alternative Scenario C:

The objective is to analyze the impact of the loss of the Seabrook and Millstone nuclear power plants. It assumes the retirement of both stations. Alternative C to be applied to Scenarios 1, 2 and 3.

G. Alternative Scenario D:

The objective is to analyze the impact of a power system that is carbon free in 2035 in line with the Biden July 2020 energy plan. It assumes the retirement of the current fossil fuel generation fleet. Alternative D to be applied to Scenarios 1, 2 and 3.

H. Alternative Scenario E

The objective is to analyze the different impacts of an on-shore and off-shore grid. It is a variant of Alternative D where higher proportions of off-shore wind are interconnected closer to load as suggested in the 2020 Brattle/GE/CHA study (e.g. more even split of offshore wind among Southeast Massachusetts, Boston and Connecticut). Alternative E to be applied to Scenarios 1, 2 and 3.

IV. Assumptions

The detailed assumptions for the different scenarios are shown in the Assumptions Spreadsheet which is part of this Study Framework.

V. Deliverables and Output Results

A. Resource Needs: For the resource mix proposed in each scenario studied, provide information related to resource financial viability in the current New England markets.

1. Show economic dispatches and energy market revenues for different scenarios from the GridView results.

2. Provide insight to expected revenues from the existing ancillary services markets under the scenarios studied from the GridView and EPECS results. Due to the GridView and EPECS model configuration, expected ancillary service market revenues may be a general approximation of revenues from current ancillary services markets, and not a direct reflection of estimated market revenues.[9]

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B. System Operational and Reliability Needs: Determine for different scenarios whether operational or reliability issues would arise.

1. Provide useful information related to the operational/reliability analyses, and identify conditions upon which further operational/reliability analyses may focus.

2. Show if resources will provide the necessary amounts of regulation, reserves, ramping and load following.

3. Determine the ICR for each future scenario in preparation for the energy market simulation to ensure that LOLE is met for expected summer and winter system peaks. Include the creation of MRI curves for selected scenarios.

4. Analyze the periods of time and system conditions during and outside of summer and winter system peaks that may not meet LOLE due to factors such as insufficient capacity or flexible demand, weather risk, operational risk, etc.

C. Carbon Emissions: Provide information on whether each scenario meets New England state law requirements and the resulting degree of grid decarbonization.

1. Estimate the power sector carbon emission / emission reduction levels in:

   a. The power sector through the GridView results; and

[9] Estimates of capacity market revenues and resource costs will be included in Phase 2.

b. Across the broader economy with reference to input assumptions related to heating and transportation electrification.

2. Estimate the energy production associated with renewable and clean energy resources through the GridView results.

D. Make non-confidential raw data used in the analyses available to interested persons

VI. Timing - Preliminary Schedule

This section illustrates the requested study schedule. Opportunities to overlap and expedite work should continue to be explored and pursued.

Assumptions development for matrix scenarios: February 2021 - March 2021

Assumptions development for alternative scenarios: February 2021- April 2021

Preliminary production cost simulations: April 2021 – August 2021

Preliminary production cost results discussed with the Planning Advisory Committee (PAC): June 2021 – August 2021

Final production cost simulations: July 2021 – December 2021

Ancillary services simulations: August 2021 – December 2021

Final production cost results discussed with the PAC: October 2021 --December 2021

MARS analyses: October 2021 – January 2022

Review/update assumptions: November 2021 – December 2021

Ancillary services results discussed with the PAC: November 2021 – December 2021

MARS results discussed with the PAC: December 2021- January 2022

Report writing: January 2022 – March 2022

NEPOOL Future Grid Reliability Study
Study Framework for Phase 1 Economic Study Request (March 12, 2021)

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<tr><td></td><td colspan="11">2021</td><td colspan="12">2022</td></tr>
<tr><td></td><td>Feb</td><td>Mar</td><td>Apr</td><td>May</td><td>June</td><td>Jul</td><td>Aug</td><td>Sept</td><td>Oct</td><td>Nov</td><td>Dec</td><td>Jan</td><td>Feb</td><td>Mar</td><td>Apr</td><td>May</td><td>June</td><td>Jul</td><td>Aug</td><td>Sept</td><td>Oct</td><td>Nov</td><td>Dec</td></tr>
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<tr><td></td><td colspan="3">Assumptions Development Alternative Scenarios</td><td colspan="20"></td></tr>
<tr><td></td><td colspan="9"></td><td colspan="2">Review / Update Assumptions</td><td colspan="12"></td></tr>
<tr><td></td><td colspan="2"></td><td colspan="5">Preliminary production cost simulations</td><td colspan="16"></td></tr>
<tr><td></td><td colspan="4"></td><td colspan="3">Preliminary production cost results discussed with PAC</td><td colspan="16"></td></tr>
<tr><td></td><td colspan="5"></td><td colspan="6">Final production cost simulations</td><td colspan="12"></td></tr>
<tr><td></td><td colspan="8"></td><td colspan="3">Final production cost results discussed with PAC</td><td colspan="12"></td></tr>
<tr><td></td><td colspan="6"></td><td colspan="5">Ancillary services simulations</td><td colspan="12"></td></tr>
<tr><td></td><td colspan="9"></td><td colspan="2">Ancillary services results discussed with PAC</td><td colspan="12"></td></tr>
<tr><td></td><td colspan="8"></td><td colspan="5">MARS analyses</td><td colspan="10"></td></tr>
<tr><td></td><td colspan="10"></td><td colspan="3">MARS results discussed with PAC</td><td colspan="10"></td></tr>
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VII. Deliverables

The deliverables will include: 1) periodic status updates and consultations; 2) periodic PowerPoint presentations on simulation and analysis results; and 3) a final PowerPoint presentation and written report on the Phase 1 results and key findings and observations.

VIII. Stakeholder Process

ISO-NE will conduct the Phase 1 studies as an Economic Study under the Tariff and, consequently, will engage the PAC on a regular basis to discuss the studies and the results; however, NEPOOL intends that ISO-NE will also engage with the MC/RC on a regular basis to: (i) provide high level reports to the MC/RC on the studies; (ii) seek MC/RC determinations on any major decision points about the direction and focus of the studies; and (iii) receive guidance from the MC/RC to ISO-NE on the studies as they progress.

NEPOOL Future Grid Reliability Study
Study Framework for Phase 1 Economic Study Request (March 12, 2021)

The New England Power Pool (NEPOOL) provides this document as the framework for Phase 1 of its studies related to the reliability of the future grid (collectively, the studies are referred to as the Future Grid Reliability Study).

The New England states have enacted energy and environmental laws that call for a significant reduction in greenhouse gas emissions. Compliance with these laws is expected to result in changes in the generation and use of electricity. Generators that do not emit carbon will likely produce a much greater percentage of the region's power supply. In addition, electricity will likely become more prevalent in heating buildings and powering vehicles, significantly changing load amounts, peaks and profiles.

NEPOOL is commissioning this Future Grid Reliability Study to understand better the implications of this substantially changed future grid. Specifically, the Future Grid Reliability Study (Phases 1 and 2 together) will examine whether revenues from the existing markets will likely be sufficient to attract and retain the new and existing resources that will be needed to continue to operate the system reliably. It will also identify what operational and reliability challenges will need to be addressed in the future grid and identify possible ways to meet those needs.

This document together with the assumptions spreadsheet (Assumptions Spreadsheet) constitute the "Study Framework" for Phase 1 of the Future Grid Reliability Study. The Study Framework has been developed through the stakeholder process at joint meetings[1] of the NEPOOL Markets and Reliability Committees (MC/RC) with support from the New England States Committee on Electricity (NESCOE) and Independent System Operator - New England, Inc. (ISO-NE). Although referred to as a Study Framework, the body of work will actually consist of several analyses using different computer models. No single model can address the range of issues that NEPOOL stakeholders desire to assess. The analyses will be conducted in a staggered iterative approach with the results from one analysis informing decisions about what to model or remodel in other analyses. The Study Framework is being presented to ISO-NE prior to April 1, 2021 as a 2021 Economic Study request. The Study Framework will continue to be refined after being provided to ISO-NE based on continued consultation among ISO-NE, NEPOOL representatives and scenario proponents and on preliminary study results.

I. Study Objective / Scope

NEPOOL approved the Future Grid Reliability Study objective and scope in a document commonly referred to as the "bubble chart."[2] The objective is to assess and discuss the future

[1] Joint meetings of NEPOOL's MC and RC were held beginning April 2020. Six past/ongoing studies were identified for examination: (1) 2016 NEPOOL Economic Study; (2) 2019 NESCOE Economic Study; (3) Massachusetts 2050 Roadmap Effort; (4) Eversource "Grid of the Future" Study; (5) E3/EFI "Electric Reliability under Deep Decarbonization" Study; and (6) 2019 Brattle Group "Achieving 80% GHG Reduction in New England by 2050" Study. For more information, see: http://nepool.com/Future_Grid.php.

[2] See November 12, 2020 meeting materials, https://www.iso-ne.com/static-assets/documents/2020/11/a2_presentation_future_grid_reliability_study.pdf (slide 4)

state of the regional power system in light of state energy and environmental laws as of December 31, 2020. The scope is to define and assess the future state of the regional power system identifying: 1) a resource mix or mixes for future years; and 2) resource and operational/reliability needs. A gap analysis will determine whether, in the future state envisioned, the markets in effect on December 31, 2020 will likely provide sufficient market revenues to attract and retain the new and existing resources that will be needed to continue to operate the system reliably. The gap analysis will also identify any market deficits that may need to be addressed to assure operability and reliability in accordance with the standards of the North American Electric Reliability Corporation, Northeast Power Coordinating Council, Inc. and ISO-NE.

The Future Grid Reliability Study will therefore encompass both economic and engineering analyses. The economic analyses (production cost and ancillary services simulations, and the revenue sufficiency analysis) will seek to answer questions such as what are the forecasted market revenues, and will they likely be sufficient to attract and retain the different types of resources that will be needed to reliably operate the system in that future. The engineering analyses (ancillary services simulation, resource adequacy screen, and the probabilistic availability and system security analyses) will seek to answer questions about what conditions will likely present operational or reliability issues, the nature of those issues, and whether the system will be able to operate reliably when, for example, variable energy resources (VERs) are the predominant generation resources, when production from VERs exceeds load, and when there may be a sustained reduction in VER production.

The studies will be performed in two phases. Phase 1 will consist of the production cost simulation, ancillary services simulation, resource adequacy screen and probabilistic resource analysis. The Phase 1 work is described in detail below. NEPOOL expects that Phase 2 will consist of revenue sufficiency and system security analyses and any other analyses NEPOOL deems appropriate at the time of commencing Phase 2. The Phase 2 study framework will be further developed by the MC/RC in a separate document later.

II. Areas of Analysis

A. Production Cost Simulation: ABB GridView (ISO-NE)

Objectives: Show economic dispatches and energy market revenues for different scenarios. Provide useful information related to the operational/reliability analyses, and identify conditions upon which further operational/reliability analyses may focus.

Scope: New England only; external interfaces are assumed historic profiles unless otherwise specified in the scenario assumptions. A "pipe and bubble" configuration representing 13 planning sub-areas (or "bubbles") of supply-side resources within the New England control area connected by simplified transmission models (or "pipes") will be used. These "pipes" are a defined collection of specific transmission lines with assigned transfer limits.[3] Simulations will be performed without transmission constraints between RSP planning sub-areas. The unconstrained flows will be

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monitored against current interface limits and will inform where conceptual transmission could be added to allow for the higher interface flows. For certain assessments, constrained conditions will be modeled to show the benefit of increased transfers versus the existing system where interface limits are enforced causing the system to change generation dispatch to maintain those limits.

Methods: Customary approach to economic studies – scenario analyses - with some flexibility to reflect the variable operation and maintenance costs of resources in the simulated dispatch. However, the variable operation and maintenance costs of battery storage will be assumed to be $3/megawatt-hour each way.[4] Sensitivities may be performed. Alternative scenarios may also be run that assume different cost amounts. Iterate model simulations with updated values informed by the results of other areas of analysis.[5]

Metrics: Using scenario analysis, perform energy market simulation studies that provide information on system performance, including production costs by resource type and fuel type, location marginal prices, load-serving entity energy expenses, uplift and environmental emission levels (CO_2, NO_X and SO_X) for all matrix and alternative scenarios

Learning points: High-level observations about transmission constraints between sub-areas in GridView and when during the year those conditions might occur; observations about whether the results suggest scenarios for further study; the results will feed into the probabilistic resource availability analysis.

B. Ancillary Services Simulation: EPECS (ISO-NE)

Objectives: Show if resources will provide the necessary amounts of regulation, reserves, ramping and load following. Provide insight to expected revenues from the existing ancillary services markets under the scenarios studied.

Scope: New England only; assume unconstrained internal transmission but interfaces at the RSP bubbles will be monitored. Some sensitivities that recognize constraints may be run. For the: (i) study year; and (ii) selected time periods within the study year

Methods: Using the same or complementary assumptions as the energy market simulations described above, use a methodology similar to what is used for those studies. Examine relationships between system imbalance estimates and: a) reserve

[4] See the December 16, 2020 Modeling of Battery Storage in Economic Studies presentation available at: https://www.iso-ne.com/static-assets/documents/2020/12/a9_modeling_of_battery_storage_in_economic_studies.pdf

[5] For example, results of the Resource Adequacy Screen and Probabilistic Resource Availability Analysis may suggest that Production Cost Simulation(s) be re-run.

products, and b) other system parameters. Estimate quantities of ancillary services requirement gaps" indicated in the scenario analysis. There will be some flexibility to iterate model simulations with updated values informed by the results of other areas of analysis.

Metrics: For all matrix and alternative scenarios, analyze the regulation, reserves, ramping, and load following capability needed to maintain the supply/demand balance of the New England bulk electric power system with a significant VER penetration. (The EPECS model provides an integrated platform for assessing simulated operating reserves, interface flows, tie-line utilization, and regulation performance. The one-minute time increment used in the EPECS model augments the GridView model, which uses one-hour time-step increments to analyze: day-ahead resource scheduling as a security-constrained unit commitment; real-time resource scheduling as a real-time unit commitment; real-time balancing as a security-constrained economic dispatch; and real-time physical power flow with integrated regulation service.) Environmental emission rates (CO_2, NO_X and SO_X) will be provided for resources providing ancillary services.

Learning points: High-level observations about conditions that may stress the grid due to weather risks associated with various resource mixes, the timing of when those conditions might occur and any ancillary services gaps; observations about whether the results suggest scenarios for further study; the results will feed into the probabilistic resource availability analysis.

C. Resource Adequacy Screen and Probabilistic Resource Availability Analysis: GE MARS (ISO-NE)

The same modeling tool will be used to perform two different types of analyses as described below. There are some common elements:

Scope: New England only; assume unconstrained internal transmission but interfaces at the RSP bubbles will be monitored. Some sensitivities that recognize transmission constraints may be run.

Methods: Use a probabilistic approach (Monte Carlo simulations) that examines all 8760 hours of the study year.[6] All new resources' capacity contributions will be modeled. The Resource Adequacy Screen will model resources at their appropriate qualified capacity value based on current market rules. The Probabilistic Resource Availability Analysis will model solar/wind resources ~~under~~ using the DNV GL ~~stochastic~~ historical model set starting with the most recent year and work back in time to incorporate as many years as possible to the extent computation capability

[6] ISO-NE will identify if certain resources or resource types are not committed in the GridView/EPECS simulations for a given scenario. If that occurs, ISO-NE may run sensitivities that examine the impact of removing those resources in the MARS simulations.

allows.[7] This will form a recent 'stochastic' data set based on the most recent weather history.

The objectives and methods of the two analyses differ in the following respects.

1. Resource Adequacy Screen

Objective: Determine Installed Capacity Requirement (ICR) for each future scenario in preparation for potential energy market simulation(s) to ensure that loss of load expectation (LOLE) is met for expected system loads. Includes the creation of system-wide Marginal Reliability Impact (MRI) curves.

Methods: Determine ICR in accordance with the methodology described in Market Rule 1, Section 12, in preparation for energy market simulations; scenarios found to be resource inadequate will be identified and will add sufficient proxy resources for the case to solve. Proxy resources will consist of a modest amount of batteries and, if additional resources are needed, new thermal units will be added except in Alternative Scenarios D and E. For those two alternative scenarios, the proxy units will consist entirely of batteries. Some sensitivities could be performed for different proxy resources.

Metrics: Evaluate all matrix and alternative scenarios to determine system reliability during the peak hours of the study year. Produce MRI curves for select scenarios chosen by the MC/RC. LOLE of one day in ten years, expected unserved energy (EUE), loss of load hours (LOLH).

2. Probabilistic Resource Availability Analysis

Objective: Analyze system reliability taking into consideration the uncertainties associated with the output of renewable resources due to weather risks, the interactions between different types of VERs, and the correlation with loads during the summer and winter peak periods as well as *outside* of the summer and winter peak periods.

Methods: For select matrix and alternative scenarios chosen by the MC/RC, examine correlation of loss of load risk and the risk associated with VER availability estimates. Examine the frequency with which elevated risk events are projected to occur over time (e.g., number of times and for how long). Examine the occurrence of loss-of-load probability and identify risk trends (e.g., daily or seasonal instances of increased resource availability risk). Revise scenario assumptions to model other elevated risk events as chosen by the MC/RC. Include flexibility to iterate with updated values informed by the results of other areas of the Phase 1 analysis.

[7] DNV GL ~~stochastically~~ modeled the historical 2~~0~~1-year dataset (2000-2020) of onshore and offshore wind generation, behind-the-meter distributed solar generation, gross load, and net load data, to assess the full spectrum of operating conditions within the ISO-NE service area. The ~~stochastic~~ historical modeling methodology is described in a report that is available at: ~~https://www.iso-ne.com/static-assets/documents/2021/03/a9_dnv_gl_report_analysis_of_stochastic_dataset_for_iso_ne_rev1.pdf~~https://www.iso-ne.com/static-assets/documents/2021/03/a9_stochastic_time_series_modeling_for_isone_rev_2.pdf

Metrics: LOLE of one day in ten years, loss of load probability (LOLP), EUE, LOLH, loss of load event (LOLEv) which counts the number of events, EUE/LOLEv, and LOLH/LOLEv

Learning points: Observations will be made about conditions in which there may not be sufficient resources to meet the LOLE criterion, the timing of when those conditions might occur, and whether there may be a need for certain categories of resources in some amounts in order to meet that criterion. Observations will be made about whether the results suggest scenarios for further study as part of the Phase 1 work or some iterations with the energy and ancillary services analyses. The results may inform the Phase 2 system security analysis.

NEPOOL Future Grid Reliability Study
Study Framework for Phase 1 Economic Study Request (March 12, 2021)

III. Scenarios

Use a matrix approach with alternatives to represent a range of possible futures based on Future Grid Reliability Study proposals that stakeholders submitted to the MC/RC.

Matrix of Scenarios for Energy and Ancillary Services Market Simulations

	(Resource 1) OSW 8,000 MW DER 18,000 MW	(Resource 2) OSW 8,000 MW DER 25,000 MW	(Resource 3) OSW 17,000 MW DER 31,000 MW
(Load 1) Buildings 9,600 GWh Transport 7,300 GWh	**(5 Scenarios) Matrix Scenario1 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 1) Scenario 2 (Resource 2 and Load 1) Scenario 3 (Resource 2 and Load 1)	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 1) Scenario 2 (Resource 3 and Load 1) Scenario 3 (Resource 3 and Load 1)
(Load 2) Buildings 6,600 GWh Transport 18,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 2) Scenario 2 (Resource 1 and Load 2) Scenario 3 (Resource 1 and Load 2	**(5 Scenarios) Matrix Scenario 2 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 2) Scenario 2 (Resource 3 and Load 2) Scenario 3 (Resource 3 and Load 2)
(Load 3) Buildings 38,900 GWh Transport 37,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 3) Scenario 2 (Resource 1 and Load 3) Scenario 3 (Resource 1 and Load 3	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 3) Scenario 2 (Resource 2 and Load 3) Scenario 3 (Resource 2 and Load 3)	**(6 Scenarios) Scenario 3 plus Alternatives A, B, C, D and E**

OSW = Offshore wind
DER = Distributed energy resources (photovoltaics and electric storage)

Stakeholders also proposed some alternative scenarios..

Alternative Scenarios

A. Bi-Directional Transmission (see National Grid 2020 Economic Study[8])
B. Vehicle to Grid (see Multi-Sector A)
C. Nuclear Retirement (see NextEra/Dominion)
D. 100% decarbonization (see Anbaric)
E. On-shore and off-shore grids (see Anbaric)

[8] See https://www.iso-ne.com/static-assets/documents/2020/11/2020-economic-studies-preliminary-production-cost-results-revision-2-clean.pdg

ISO-NE will run the scenarios in the following sequence. First, it will run matrix Scenario 1 and the Scenario 1 sensitivities. The sensitivities will apply the different resource mixes and loads assumed in Scenarios 2 and 3 to Scenario 1. Next ISO-NE will run the alternative scenarios that go with Scenario 1.

ISO-NE will then proceed to run matrix Scenario 2, the Scenario 2 sensitivities and the alternative scenarios that go with Scenario 2, followed by matrix Scenario 3, the Scenario 3 sensitivities and the alternative scenarios that go with Scenario 3.

ISO-NE will assess as it proceeds through the sequence, based on the results obtained to date, whether any of the subsequent runs will likely be unrealistic, infeasible, incapable of being completed in a reasonable time or not likely to tell something new. Based on ISO-NE's assessment, the MC/RC could decide to drop certain subsequent scenarios or sensitivities. ISO-NE will present Production Cost Simulation (GridView) results first for all scenarios. Then proceed with presenting the Ancillary Services Simulation (EPECS) results, followed by the Resource Adequacy Screen (MARS) results. At that point, a discussion with the MC/RC will be required to determine the scenarios that will be included in the Probabilistic Resource Availability Analysis.

A. Matrix Scenario 1

Matrix Scenario 1 assumes significant growth in non-carbon emitting generators and electrified load. However, with respect to both the resource mix and load, it assumes a slower pace of change than the two other matrix scenarios. The resource mix in Scenario 1 assumes approximately 8,000 MW of offshore wind (about 17% of the resource mix) and 18,000 MW of distributed energy resources (about 33% of the resource mix). On the load side, it assumes approximately 16,900 gigawatt-hours (GWh) of electrified building and transportation load weighted towards buildings. The electrified building and transportation load accounts for about 11% of net load. The detailed assumptions for this and each of the scenarios are presented in the Assumptions Spreadsheet.

B. Matrix Scenario 2

Matrix Scenario 2 assumes greater growth in distributed energy resources and electrified load than Scenario 1. The resource mix in Scenario 2 assumes approximately 8,000 MW of offshore wind (about 15% of the resource mix) and 25,000 MW of distributed energy resources (about 41% of the resource mix). On the load side, it assumes approximately 25,100 GWh of electrified building and transportation load weighted towards transportation. The electrified building and transportation load accounts for about 18% of net load.

C. Matrix Scenario 3

Matrix Scenario 3 assumes significantly greater growth in offshore wind, distributed energy resources and electrified loads than Scenarios 1 or 2. The resource mix in Scenario 3 is comprised of approximately 17,000 MW of offshore wind (about 28% of the resource mix) and 31,000 MW of distributed energy resources (about 41% of the resource mix). With respect to load, Scenario 3 assumes approximately 76,400 GWh of electrified load roughly balanced between buildings and transportation. The electrified building and transportation load accounts for about 45% of net load. Matrix Scenario 3 is based upon the Massachusetts 2050 Roadmap Study results for the All Options Scenario in 2040.

D. Alternative Scenario A:

The objective is to analyze the impact of bi-directional controllable transmission to Quebec. It assumes the addition of ~~as much as 2,400 MW~~an unlimited ~~of~~ bi-directionally capable, controllable direct current tie~~s~~ injecting into Northeast Massachusetts. Alternative A to be applied to Scenarios 1, 2 and 3.

E. Alternative Scenario B:

The objective is to analyze the impact of vehicle to grid storage. It assumes that an additional 100 gigawatts/200 GWh of energy storage are available for a two-hour duration based on an estimated 25% of 8 million electric vehicles with 100 kilowatt batteries capable of providing electric storage and vehicle to grid services. Alternative B to be applied only to Scenario 3.

F. Alternative Scenario C:

The objective is to analyze the impact of the loss of the Seabrook and Millstone nuclear power plants. It assumes the retirement of both stations. Alternative C to be applied to Scenarios 1, 2 and 3.

G. Alternative Scenario D:

The objective is to analyze the impact of a power system that is carbon free in 2035 in line with the Biden July 2020 energy plan. It assumes the retirement of the current fossil fuel generation fleet. Alternative D to be applied to Scenarios 1, 2 and 3.

H. Alternative Scenario E

The objective is to analyze the different impacts of an on-shore and off-shore grid. It is a variant of Alternative D where higher proportions of off-shore wind are interconnected closer to load as suggested in the 2020 Brattle/GE/CHA study (e.g. more even split of offshore wind among Southeast Massachusetts, Boston and Connecticut). Alternative E to be applied to Scenarios 1, 2 and 3.

IV. Assumptions

The detailed assumptions for the different scenarios are shown in the Assumptions Spreadsheet which is part of this Study Framework.

V. Deliverables and Output Results

A. Resource Needs: For the resource mix proposed in each scenario studied, provide information related to resource financial viability in the current New England markets.

1. Show economic dispatches and energy market revenues for different scenarios from the GridView results.

2. Provide insight to expected revenues from the existing ancillary services markets under the scenarios studied from the GridView and EPECS results. Due to the GridView and EPECS model configuration, expected ancillary service market revenues may be a general approximation of revenues from current ancillary services markets, and not a direct reflection of estimated market revenues.[9]

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B. System Operational and Reliability Needs: Determine for different scenarios whether operational or reliability issues would arise.

1. Provide useful information related to the operational/reliability analyses, and identify conditions upon which further operational/reliability analyses may focus.

2. Show if resources will provide the necessary amounts of regulation, reserves, ramping and load following.

3. Determine the ICR for each future scenario in preparation for the energy market simulation to ensure that LOLE is met for expected summer and winter system peaks. Include the creation of MRI curves for selected scenarios.

4. Analyze the periods of time and system conditions during and outside of summer and winter system peaks that may not meet LOLE due to factors such as insufficient capacity or flexible demand, weather risk, operational risk, etc.

C. Carbon Emissions: Provide information on whether each scenario meets New England state law requirements and the resulting degree of grid decarbonization.

1. Estimate the power sector carbon emission / emission reduction levels in:

   a. The power sector through the GridView results; and

[9] Estimates of capacity market revenues and resource costs will be included in Phase 2.

   b. Across the broader economy with reference to input assumptions related to heating and transportation electrification.

2. Estimate the energy production associated with renewable and clean energy resources through the GridView results.

D. Make non-confidential raw data used in the analyses available to interested persons

VI. Timing - Preliminary Schedule

This section illustrates the requested study schedule. Opportunities to overlap and expedite work should continue to be explored and pursued.

Assumptions development for matrix scenarios: February 2021 - March 2021

Assumptions development for alternative scenarios: February 2021- April 2021

Preliminary production cost simulations: April 2021 – August 2021

Preliminary production cost results discussed with the Planning Advisory Committee (PAC): June 2021 – August 2021

Final production cost simulations: July 2021 – December 2021

Ancillary services simulations: August 2021 – December 2021

Final production cost results discussed with the PAC: October 2021 --December 2021

MARS analyses: October 2021 – January 2022

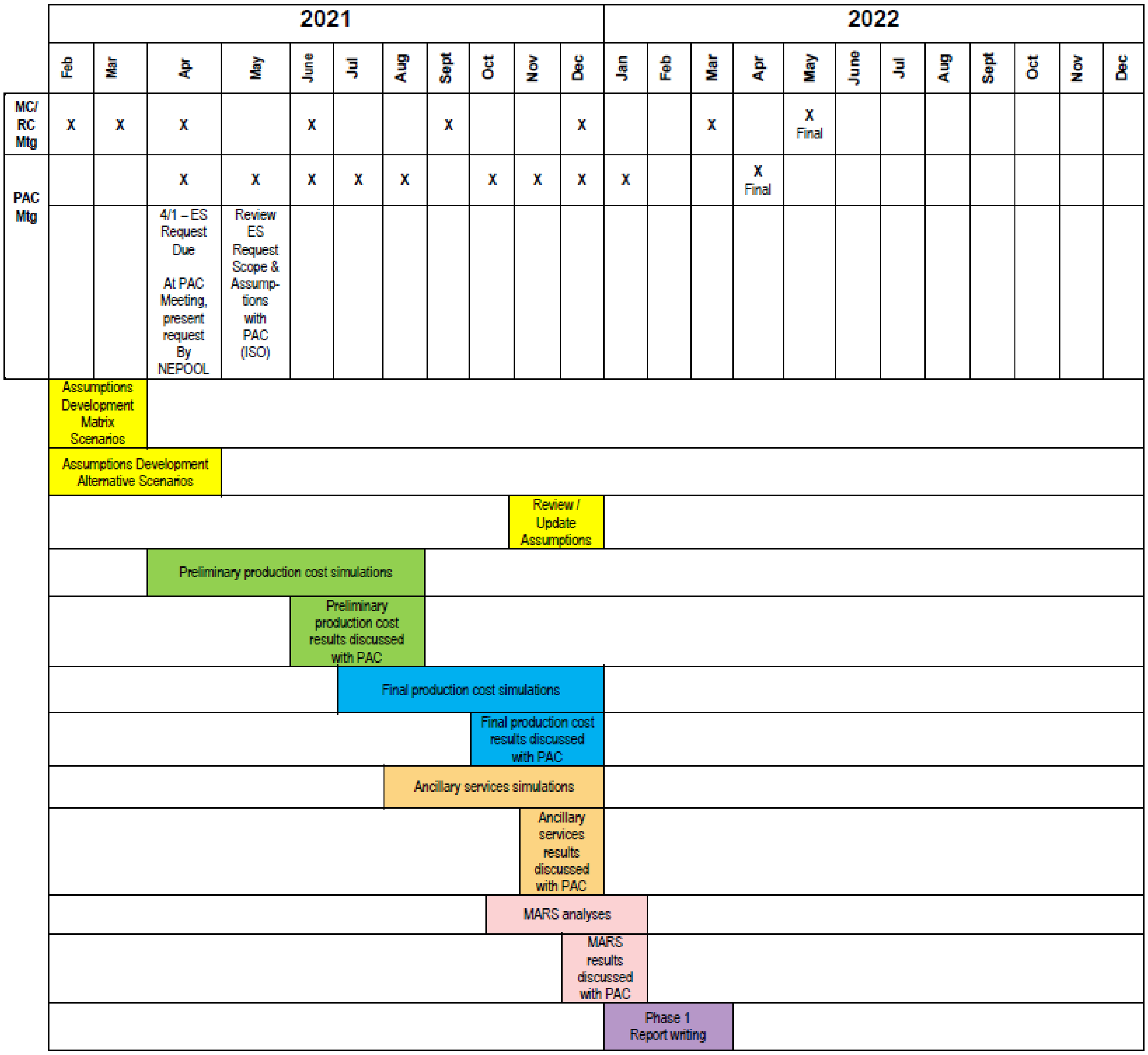
Review/update assumptions: November 2021 – December 2021

Ancillary services results discussed with the PAC: November 2021 – December 2021

MARS results discussed with the PAC: December 2021- January 2022

Report writing: January 2022 – March 2022

NEPOOL Future Grid Reliability Study
Study Framework for Phase 1 Economic Study Request (March 12, 2021)



VII. Deliverables

The deliverables will include: 1) periodic status updates and consultations; 2) periodic PowerPoint presentations on simulation and analysis results; and 3) a final PowerPoint presentation and written report on the Phase 1 results and key findings and observations.

VIII. Stakeholder Process

ISO-NE will conduct the Phase 1 studies as an Economic Study under the Tariff and, consequently, will engage the PAC on a regular basis to discuss the studies and the results; however, NEPOOL intends that ISO-NE will also engage with the MC/RC on a regular basis to: (i) provide high level reports to the MC/RC on the studies; (ii) seek MC/RC determinations on any major decision points about the direction and focus of the studies; and (iii) receive guidance from the MC/RC to ISO-NE on the studies as they progress.

	Load-Related					
Scenario	**Gross Load**	**Energy Efficiency**	**Behind-the-Meter Distributed Energy Resources**	**Storage**	**Heating**	**Transportation**
Matrix Scenario 1	Gross load to be calculated from 2021 CELT extrapolated with a 3-year CAGR to 2040 Net Load will be calculated after as: Gross – EE – BTM + transport + heat; Both subject to change according to profile used which is scaled using peak load value	Peak Reduction and MW Annual Energy Reduction to be calculated based on 2021 CELT	Peak Reduction and nameplate MW to be calculated based on 2021 CELT	Incremental Storage: 2000 MW Aggregated by RSP Zone based on grid-scale storage in the ISO-NE queue 4-hour duration 86% efficiency for battery storage Responds to LMP Provides System Capacity Provides regulation and reserves	Peak: 5,214 MW Demand: 9.6 TWh Projections by load zone Profile based on 2015 weather year but can be adjusted *2035 building heat electrification assumptions represent a top-down projection of primarily air-source heat pump (ASHP) adoption resulting in electrification of ~18% of non-electric building heat (compared to <1% today) and including a 14% decline in building heat demand due to efficiency gains.*	Peak: 1,817MW Demand: 7.3TWh Hourly shapes, broken down by subarea proportional to population; Generally charging is lowest in the morning and peaks at hour ending 18:00; Flex charing per ISO's proposed methodology, amount TBD *2035 EV assumptions represent a top-down projection of electric vehicle adoption. It focuses on light-duty vehicles and is absent of significant incremental policy support, including policies designed to impact EV charge timing. The EV load represents 2.2 million light-duty vehicles electrified by 2035 in ISONE (~19% of vehicle stock, 50% of new sales).*

	Load-Related					
Scenario	**Gross Load**	**Energy Efficiency**	**Behind-the-Meter Distributed Energy Resources**	**Storage**	**Heating**	**Transportation**
Matrix Scenario 2	Gross load to be calculated from 2021 CELT extrapolated with a 3-year CAGR to 2040 Net Load will be calculated after as: Gross – EE – BTM + transport + heat; Both subject to change according to profile used which is scaled using peak load value	Peak Reduction and MW Annual Energy Reduction to be calculated based on 2021 CELT	Peak Reduction and nameplate MW to be calculated based on 2021 CELT	New Storage Capacity: 3,940 MW Range of 1-hr to 8-hr discharge capability at 90% efficiency. All storage in-market, responds to LMP.	Heating Peak MW 2,991 MW Heating Demand: 6.6 TWh Heat pump forecasts based on heating sector emission targets combined with census population data kW peak and annual kWh per heat pump based on ISO "Final Draft 2020 Heating Electrification Forecast"	EV contribution to winter 8PM peak: 3,578 MW EV Demand: 18.5 TWh EV stock based on forecast total vehicle miles and transportation sector emission targets EV demand profiles based on ISO-NE "Final Draft 2020 Transportation Electrification Forecast", adjusted to account for more coordinated charging
Matrix Scenario 3	Net Summer Peak Load: 39,985 MW *(July at 6pm)* Net Winter Peak Load: 42,525 MW *(January at 6pm)* Annual Net Load: 182.5 TWh *(including Energy Efficiency,* ***Rooftop Solar PV*** **, and new Heating and Transportation loads) (Total energy 198.5 TWh less Rooftop Solar PV 16 TWh = 182.5 TWh)* Hourly, zonal load forecast for 2040 from EnergyPATHWAYS model output from MA EEA 80x50 – adjusted to move rooftop solar PV to load side. EnergyPATHWAYS is a scenario analysis tool that is used to develop economy-wide energy demand scenarios. It is used to determine the demand for fuels (electricity, pipeline gas, diesel, etc.) over time, subject to economy-wide emissions constraints. also produces an hourly (8760) electricity load shape for each of the six New England states.	n/a Energy Efficiency is already reflected in the net load forecast discussed above (estimated amounts are unavailable)	Rooftop Solar PV: 12,671 MW Nameplate *Total* (~16.1 TWh Annual Gen) (8,870 MW Nameplate *Incremental Rooftop Solar PV*) Both Rooftop PV and Ground Mounted PV modeled as supply in capacity expansion model. However, Rooftop PV is included in Net Demand calculation.	*Flexible Load representing approximately 50% of EVs with capability to delay charging by up to 8 hours. Values provided in data file with month-hour average flexible load impacts for each state. Values should be added to the 8760 load profile.*	38.9 TWh (embedded in load forecast from EnergyPATHWAYS) (Primary fuel type emissions reduced by approximately two-thirds relative to 2020)	Transportation 40.0 TWh (embedded in load forecast from EnergyPATHWAYS) (Primary fuel type emissions reduced by approximately two-thirds relative to 2020)

	Load-Related					
Scenario	**Gross Load**	**Energy Efficiency**	**Behind-the-Meter Distributed Energy Resources**	**Storage**	**Heating**	**Transportation**
Alternative Scenario A Bi-Directional Transmission (National Grid)						
Alternative Scenario B Vehicle to Grid (Multi Sector A)	*Same as NESCOE 2040, but EE included in Gross Load for study purposes only. Still assumed as a supply resource in markets for the capacity screen. Amount of cleared EE vs. total EE in the same proportion as we see today.*		*see: EV storage*			
Alternative Scenario C Nuclear Retirement (NextEra/Dominion)						

	Load-Related					
Scenario	**Gross Load**	**Energy Efficiency**	**Behind-the-Meter Distributed Energy Resources**	**Storage**	**Heating**	**Transportation**
Alternative Scenario D 100% clean electricity (Anbaric)	same as Matrix Scenario 3	same as Matrix Scenario 3	same as Matrix Scenario 3	same as Matrix Scenario 3 on supply side to accommodate additions & retirements	same as Matrix Scenario 3	same as Matrix Scenario 3
Alternative Scenario E onshore/ offshore grids (Anbaric)	same as Alternative Scenario #5	same as Alternative Scenario #5	same as Alternative Scenario #5	same as Alternative Scenario #5	same as Alternative Scenario #5	same as Alternative Scenario #5

	Infrastructure					
Scenario	**Transmission Toplogy / Interface Transfer Limits**	**Existing Resources**	**Existing External Ties Import Limits**	**Existing External Ties Export Limits**	**New Ties**	**Retirements**
Matrix Scenario 1	Assume unconstrained internal transmission but interfaces at the Regional System Plan zonal level will be monitored at 2029 limits (FCA 16 topology)	FCA 15 resources with a CSO, Modeled at their SCC value (or CSO if no SCC)	Historical flows on external ties with existing limits monitored; NY exchange at 0MW	Historical flows on external ties with existing limits monitored; NY exchange at 0MW	NECEC at 1,200 MW nameplate	FCA 15 cleared retirements plus, all New England coal units, and 75% of the conventional New England oil, including dual-fuel units, based on age

	Infrastructure					
Scenario	**Transmission Toplogy / Interface Transfer Limits**	**Existing Resources**	**Existing External Ties Import Limits**	**Existing External Ties Export Limits**	**New Ties**	**Retirements**
Matrix Scenario 2	Assume unconstrained internal transmission but interfaces at the Regional System Plan zonal level will be monitored at 2029 limits	Same as Scenario 1	Historical flows on external ties with existing limits monitored	Historical flows on external ties with existing limits monitored	NECEC (1,200 MW nameplate) and one additional 1,000 MW tie injecting into Northern New England	Retirements: 8,400 MW fossil fuel units (including all remaining coal & oil). Fossil fuel unit retirements based on age, heat rate, market revenues, and emissions targets.
Matrix Scenario 3	Zonal transfer limits from RIO[1] model results were mapped to the system topology used in this study: RIO had six New England state zones, plus New York, Hydro Quebec, and New Brunswick. RIO included economic transmission expansion from 2020-2050 based on $/MW-mile cost assumptions drawn from ReEDS[2] documentation	Same as Others - FCA 15 resources with a CSO, Modeled at their SCC value (or CSO if no SCC) - Resource Mix from RIO model output from MA EEA 80x50	Historical flows on external ties with existing limits monitored	Historical flows on external ties with existing limits monitored	NECEC (1,200 MW nameplate) and one additional 1,000 MW tie injecting into Northern New England 450 MW increase in transfer limit between NY and ISO-NE (subject to continued review of zonal transfer limits from RIO model results)	FCA 15 cleared retirements plus, all remaining Coal, Oil and Refuse (subject to continued review of resource mix from RIO model results)

	Infrastructure					
Scenario	**Transmission Toplogy / Interface Transfer Limits**	**Existing Resources**	**Existing External Ties Import Limits**	**Existing External Ties Export Limits**	**New Ties**	**Retirements**
Alternative Scenario A Bi-Directional Transmission (National Grid)			Historical flows for existing external ties to Quebec as in the B_Track sensitivity of the 2020 Economic Study (see Dec 17 PAC presenation p. 24-25); NY exchange at 0MW	NY exchange at 0MW	Add uncapped exchange between Quebec and NEMA; Use iterative approach for modeling exchange profile and tracking storage accounting according to 2020 Economic Study sensitivities presented at Dec PAC	
Alternative Scenario B Vehicle to Grid (Multi Sector A)						
Alternative Scenario C Nuclear Retirement (NextEra/Dominion)						Retire all remaining nuclear by 2035

	Infrastructure					
Scenario	**Transmission Toplogy / Interface Transfer Limits**	**Existing Resources**	**Existing External Ties Import Limits**	**Existing External Ties Export Limits**	**New Ties**	**Retirements**
Alternative Scenario D 100% clean electricity (Anbaric)	same as Matrix Scenario 3 open to matching others	same as others upon reaching consensus values here the additions can be adjusted to be 'net' rather than 'total' values			same as Matrix Scenario 3	same as Matrix Scenario 3 plus retire all remaining fossil
Alternative Scenario E onshore/ offshore grids (Anbaric)	approach to topology is same as others -- more OSW interconnected to Boston and CT (can advise once base case assumptions on geographic split of OSW interconnection MW is available)	same as Alternative Scenario #5			same as Alternative Scenario #5	same as Alternative Scenario #5

	Resource Portfolio					
Scenario	**Additions**	**Storage Approach**	**Resource Availability**	**Profiled Resource Production**	**Weather Year**	**Active Demand Response**
Matrix Scenario 1	Incremental Additions: 1,330 MW Land-Based Wind 8,009 MW Offshore Wind (assumes existing 29MW for Block Island) 6,425 MW Solar PV, >5MW (assumes existing 1666MW and 697MW assumed by ISO for 2020) Renewable additions include announced additions, as well as generic additions to bridge the gap between what is announced and what may be required to meet announced policy needs (i.e. RPS/CES requirements). Generic utility-scale PV, onshore wind, and offshore wind installed quantities/locations selected based on implied needs in policies goals to achieve a balanced portfolio across renewables types and zones that could plausibly be constructed. Offshore Wind interconnected proportional to ISO-NE's queue at NESCOE 2019 Economic Study locations for scenario 8000_1	See Storage under Load Assumptions; $3/MWh variable O&M costs in each directions will be reflected in the dispatch of batteries; pumped storage will be modeled consistent with historical experience	Same as used in FCA 15 Need for MARS runs only (EFORd and Maintenance Hours)	DNV-GL weather profiles for onshore wind, offshore wind, and PV	2019	FCA 15

Scenario	Resource Portfolio					
	Additions	**Storage Approach**	**Resource Availability**	**Profiled Resource Production**	**Weather Year**	**Active Demand Response**
Matrix Scenario 2	Incremental Additions: 7,290 MW Utility Scale PV 9,469 MW Distributed PV 1,500 MW Onshore Wind 7,904 MW Offshore Wind Total Capacity: 8,820 MW Utility Scale PV 11,899 MW Distributed PV 2,803 MW Onshore Wind 7,934 MW Offshore Wind	Storage capacity added as needed as a balancing resource Storage operation is not on a fixed schedule, charge/discharge is an output of hourly model driven by wholesale energy prices. $3/MWh variable O&M costs in each directions will be reflected in the dispatch of batteries; pumped storage will be modeled consistent with historical experience	Same as Scenario 1	Same as Scenarios 1 and 3. DNV-GL weather profiles for onshore wind, offshore wind, and PV	final determination based on review of DNV-GL dataset	Same as Scenario 1
Matrix Scenario 3	Total Capacity: 15,467 MW GroundMount PV 8,032 MW Offshore (Fixed) 8,601 MW Offshore (Floating) 600 MW Battery Storage (subject to continued review of resource mix from RIO model results)	Batteries (600MW) *Similar to other scenarios, preference for Pumped Storage and Batteries to be economically dispatched.* $3/MWh variable O&M costs in each directions will be reflected in the dispatch of batteries; pumped storage will be modeled consistent with historical experience. Interested in sensitivity with $2/MWh variable O&M costs for battery storage and $0.60/MWh for pumped storage.	Same as Others	Same as Others – DNV-GL weather profiles for onshore wind, offshore wind, and PV	RIO - 2012 Weather Year (open to comparability) *(Preference for latest available resource production)*	Same as Others *(See also Flexible Load under Storage)*

	Resource Portfolio					
Scenario	**Additions**	**Storage Approach**	**Resource Availability**	**Profiled Resource Production**	**Weather Year**	**Active Demand Response**
Alternative Scenario A Bi-Directional Transmission (National Grid)						
Alternative Scenario B Vehicle to Grid (Multi Sector A)	EV storage: 100 GW at 2 hours available to grid. Based upon one quarter of a 100 kWh battery per vehicle. 8 million EV in New England by 2040	*Charging focused on periods of renewable curtailment; discharging at a price slightly lower than natural gas-fired resources*				
Alternative Scenario C Nuclear Retirement (NextEra/Dominion)						

	Resource Portfolio					
Scenario	**Additions**	**Storage Approach**	**Resource Availability**	**Profiled Resource Production**	**Weather Year**	**Active Demand Response**
Alternative Scenario D 100% clean electricity (Anbaric)	(based on Matrix Scenario 3 total net load of 169.8 TWh) final resource mix (can be adjusted to 'net' additions need final resource mix assumption) 26,300 MW OSW 1,400 MW LBW 52,100 MW solar PV 600 MW hydro 970 MW hydro imports from (NECEC) similar mix can be prepared for National Grid 2035 & Eversource 2040 cases based on their annual net load tally; seems to be 150 TWh and 139.1 TWh respectively w. common basis as Matrix Scenario 3 = 169.8 TWh (please confirm)	(based on Matrix Scenario 3 total net load of 169.8 TWh) 7,000 MW 4hr storage 10,000 MW 8hr storage 60,700 MW 36hr storage total: 2,293.2 GWh of battery storage similar mix can be prepared for National Grid 2035 & Eversource 2040 cases based on their annual net load tally; seems to be 150 TWh and 139.1 TWh respectively w. common basis as Matrix Scenario 3 = 169.8 TWh (please confirm)	same as others	willing to use same as others preference to use DNV GL 20 year load & production data for weather year (Stochastic Engine work @ ISONE)	present additions and storage values based on 2018; would prefer common weather year for all studies and willing to use consensus weather year (determines load profile, resource mix & storage)	
Alternative Scenario E onshore/ offshore grids (Anbaric)	same as Alternative Scenario #5 more OSW interconnected to Boston and CT (can advise once base case assumptions on geographic split of OSW interconnection MW is available)	same as Alternative Scenario #5	same as Alternative Scenario #5	same as Alternative Scenario #5	same as Alternative Scenario #5	

			Marginal Cost Inputs		
Scenario	**Curtailment Prices / Threshold Prices**	**Reserve Margin / Capacity Assessment**	**Fuel Price Forecasts**	**Seasonal Volatility Adjustments**	**Emission Allowance Price Forecasts**
Matrix Scenario 1	Import Priority	120% of the first contingency in ten minutes split between Ten-Minute Spinning Reserve (TMSR) = 50% Ten-Minute Non-Spinning Reserve (TMNSR) = 50%	EIA's 2020 AEO Base Forecast	*Consistent approach pending agreement*	NO_X = \$ 4.00 /ton SO_X = \$ 2.00 /ton CO_2 = \$33.52 /ton

Input Assumptions

Scenario	Curtailment Prices / Threshold Prices	Reserve Margin / Capacity Assessment	Marginal Cost Inputs: Fuel Price Forecasts	Marginal Cost Inputs: Seasonal Volatility Adjustments	Marginal Cost Inputs: Emission Allowance Price Forecasts
Matrix Scenario 2	*Consistent approach pending agreement*	Same as Scenario 1	EIA's 2020 AEO Base Forecast	Same as Others	Same as Others
Matrix Scenario 3	*Open to adopting consistent approach*	Same as Scenarios 1 and 2	Same as Others	Same as Others	Same as Others

Input Assumptions

			Marginal Cost Inputs		
Scenario	**Curtailment Prices / Threshold Prices**	**Reserve Margin / Capacity Assessment**	**Fuel Price Forecasts**	**Seasonal Volatility Adjustments**	**Emission Allowance Price Forecasts**
Alternative Scenario A Bi-Directional Transmission (National Grid)					
Alternative Scenario B Vehicle to Grid (Multi Sector A)					
Alternative Scenario C Nuclear Retirement (NextEra/Dominion)					

Input Assumptions

			Marginal Cost Inputs		
Scenario	**Curtailment Prices / Threshold Prices**	**Reserve Margin / Capacity Assessment**	**Fuel Price Forecasts**	**Seasonal Volatility Adjustments**	**Emission Allowance Price Forecasts**
Alternative Scenario D 100% clean electricity (Anbaric)					
Alternative Scenario E onshore/ offshore grids (Anbaric)					

Proposed Assumptions and Methodologies

Future Grid Reliability Study (FGRS) – Phase 1

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Introduction

- ISO-New England has been coordinating with NEPOOL to develop assumptions and clarify scenarios as part of performing FGRS Phase 1
- Today's Presentation is focused on discussions relating to:
  - Assumptions for:
    - Production Cost Simulations (GridView)
    - Ancillary Service Simulations (EPECS)
  - Simulation Study Plans for Resource Adequacy Screen and Probabilistic Resource Availability Analysis (MARS)

GRIDVIEW AND EPECS

Assumptions Discussion

Background:
Production Cost and Ancillary Services Simulations

- This presentation provides an overview of the Phase 1 assumptions
  - ISO recommendations for unresolved assumptions
  - Clarifies work products that are anticipated to be produced
  - Attempts to balance and achieve as many of the following objectives as possible
    - Requested issues to be addressed and analyzed
    - Effort to realize the requested analysis in a timely manner
    - Balance granularity vs. uncertainty in the assumptions
    - Honor the diversity in visions about the future that stakeholders have expressed

Phase 1 Studies Additional Clarifications

Production Cost and Ancillary Services Simulations

- At the February 26 RC/MC meeting
  - The ISO reviewed the assumptions documented to date
  - Identified where key assumptions are needed
- The following slides outline the additional assumption details needed for the Scenario Matrix and Alternative Scenarios
- After today's meeting
  - The ISO will continue to review assumptions defined in the latest version of the Framework document as they start to build the models
  - Will seek clarification as needed from the MC/RC
  - Discussions will begin in May at the PAC on the 2021 Economic Study

SCENARIO MATRICES

Production Cost (GridView) and Ancillary Services (EPECS)

Scenario Matrices

GridView and EPECS Simulations

- Scenarios described by the matrices have been fully enumerated
  - Ensures stakeholders know the specific cases envisioned to be analyzed
  - Some scenarios may result in unserved energy or other issues
  - Many combinations and permutations
    - Results in 34 GridView scenarios
    - Manageable number of scenarios for GridView analysis
    - Suitable for investigating a range of economic and operational issues
  - EPECS simulations focus on *physical* quantities
    - Predominately related to reserves
      - Following the ISO's initial review, fewer simulations are likely to be needed to produce desired metrics
      - "Corner bookends" illuminate the range of physical quantities
    - Eight EPECS scenarios believed to be sufficiently diverse to capture range of physical quantities
      - Other scenarios are within the bounds of identified EPECS scenarios

FGRS Phase GridView 1 Matrix

Describes 34 Scenarios Reading "Down and Across"

	(Resource 1) OSW 8,000 MW DER 18,000 MW	(Resource 2) OSW 8,000 MW DER 25,000 MW	(Resource 3) OSW 17,000 MW DER 31,000 MW
(Load 1) Buildings 9,600 GWh Transport 7,300 GWh	**(5 Scenarios) Matrix Scenario 1 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 1) Scenario 2 (Resource 2 and Load 1) Scenario 3 (Resource 2 and Load 1)	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 1) Scenario 2 (Resource 3 and Load 1) Scenario 3 (Resource 3 and Load 1)
(Load 2) Buildings 6,600 GWh Transport 18,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 2) Scenario 2 (Resource 1 and Load 2) Scenario 3 (Resource 1 and Load 2	**(5 Scenarios) Matrix Scenario 2 plus Alternatives A, C, D and E**	(3 Sensitivity Scenarios) Scenario 1 (Resource 3 and Load 2) Scenario 2 (Resource 3 and Load 2) Scenario 3 (Resource 3 and Load 2)
(Load 3) Buildings 38,900 GWh Transport 37,500 GWh	(3 Sensitivity Scenarios) Scenario 1 (Resource 1 and Load 3) Scenario 2 (Resource 1 and Load 3) Scenario 3 (Resource 1 and Load 3	(3 Sensitivity Scenarios) Scenario 1 (Resource 2 and Load 3) Scenario 2 (Resource 2 and Load 3) Scenario 3 (Resource 2 and Load 3)	**(6 Scenarios) Scenario 3 plus Alternatives A, B, C, D and E**

EPECS Matrix

Describes 8 Scenarios of Most Interest

	(Resource 1) OSW 8,000 MW DER 18,000 MW	(Resource 2) OSW 8,000 MW DER 25,000 MW	(Resource 3) OSW 17,000 MW DER 31,000 MW
(Load 1) Buildings 9,600 GWh Transport 7,300 GWh	**(1 Scenario) Matrix Scenario 1**		(1 Scenario) Scenario 3 (Resource 3 and Load 1)
(Load 2) Buildings 6,600 GWh Transport 18,500 GWh		**(1 Scenario) Matrix Scenario 2**	
(Load 3) Buildings 38,900 GWh Transport 37,500 GWh	(1 Scenario) Scenario 1 (Resource 1 and Load 3)		**(4 Scenarios) Scenario 3 plus Alternatives B, D and E**

Phase 1 Studies Recommendations

Assumptions for both GridView and EPECS

System Topology

- New England interface flows will be compared against FCA 15 limits for quantifying transmission flows exceedances (except Surowiec South which will have a limit of 2,500 MW).

- Conceptual high-level transmission build-outs will be evaluated against constrained transmission system limits
  - Quantify benefit of conceptual high-level transmission build-outs
    - Investigate three main matrix scenarios first
    - Additional matrix and alternate scenarios as warranted

Phase 1 Studies Recommendations, cont.

Assumptions for both GridView and EPECS

Load-Related Assumptions

- Weather years for base load pattern and Variable Energy Resources (VERs)
  - 2019 for Matrix Scenarios 1-3
  - Historical 2012 & 2015 one-minute resolution ISO load data is no longer available
  - 2019 may be best “jumping off” weather year because
    - High PV penetration
    - Load volatility on one-minute time scale encapsulates high PV penetration
  - Translation of Matrix Scenarios 1, 2 and 3 load shapes to 2019 weather required

Phase 1 Studies Recommendations, cont.

Assumptions for both GridView and EPECS

Battery Energy Storage Systems (BESS) Related Assumptions

- Installed batteries will be divided into 25 independent BESS resources per RSP area (325 total)
  - Located at unconstrained busses in each RSP area (345kV)
  - BESS distributed by RSP share of New England load
  - No explicitly represented co-located BESS and solar / wind
    - Any constraints imposed by co-location can only reduce system-wide benefits
  - BESS characteristics
    - Equal amounts (25% each) of one, two, four and eight hour batteries
    - A one-hour battery is able to discharge its full output over only one hour whereas an eight-hour battery can discharge its energy at full output for eight hours
    - Round trip storage efficiency of 86 percent

BESS Characteristics

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3	A Bi-Directional Transmission	B Vehicle to Grid	C Nuclear Retirement	D 100% Clean Electricity	E Onshore / Offshore Grids
Amount Inverter MW	Existing 600 + 1,400	Existing 600 + 3,340	Existing 600 only*	Same as Parent	Add 100,000	Same as Parent	77,700	77,700
Energy (MWh)	7,500	12,525	2,250	Same as Parent	Add 200,000	Same as Parent	2,393,000	2,393,000

Note: "Parent" refers to the scenario to which the alternative is applied. For example when, Alternative Scenario C ("Nuclear Retirement") is applied to Matrix Scenario 1, Matrix Scenario 2 and Matrix Scenario 3 the amount of batteries will be determined by the assumptions for batteries in Matrix Scenario 1, Matrix Scenario 2 and Matrix Scenario 3, respectively.

* Significant energy storage capability assumed via flexible EV charging

Reference: Modeling of Battery Storage in Economic Studies, December 16, 2020
https://www.iso-ne.com/static-assets/documents/2020/12/a9_modeling_of_battery_storage_in_economic_studies.pdf

Phase 1 Studies Recommendations, cont.

Assumptions for both GridView and EPECS

- Alternative Scenarios D and E envision only VERS, BESS and ties
  - All carbon emitting resources retired
  - Current modeling practice excludes "bidding strategies"
  - Need to proceed cautiously with the analyses for these scenarios as GridView and EPECS may produce unexpected metrics with this configuration
    - Proposed assumptions expected to be outside "comfort" range of the software
    - Modifications, given stated goal of these alternative scenarios, may be required

Duration	Inverter (MW)	Energy (MWh/MW)	Storage (MWh)
4 hour	7,000	4	28,000
8 hour	10,000	8	80,000
36 hour	60,700	36	2,185,000
Total	**77,700**	-	**2,293,000**

Phase 1 Studies Recommendations, cont.

Assumptions for both GridView and EPECS

- Unless specified otherwise, PV will be added to each RSP area as follows
  - Allocated to states based on the Draft 2021 CELT Photovoltaic (PV) Forecast
  - Within states with multiple RSP areas, allocation will be by the fraction of RSP load

Reference: Draft 2021 Photovoltaic (PV) Forecast, February 22, 2021
https://www.iso-ne.com/static-assets/documents/2021/02/draft_2021_pv_forecast.pdf

Summary of Interchange With Neighboring Systems

Assumptions for both GridView and EPECS

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3	A Bi-Directional Transmission	B Vehicle to Grid	C Nuclear Retirement	D 100% Clean Electricity	E Onshore / Offshore Grids
Ties	NB, HQ PHII, HG, NECEC	NB, HQ PHII, HG, NECEC	NB, HQ PHII, HG, NECEC and NY	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Bidirectional	No	No	Yes	Yes	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Additions	n/a	1000 MW QU-CMA	1200 MW QU-CMA plus 450 MW to NY	Unconstrained HVDC to CMA	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Base Flow	Historical Profile	Historical Profile	Historical Profile	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent
New Ties	Use Rating	Use Rating	Use Rating	Use Rating	Same as Parent	Same as Parent	Same as Parent	Same as Parent

Threshold Price Recommendations

Assumption for GridView Simulations

Bi-directional threshold prices assumed to reflect the value of RECs:

- Curtail imports first, then trigger exports, and only curtail renewables when export capability is exhausted
- Can be referred to as "REC Inspired"
- Prices may be adjusted, will be used in Scenarios 2&3

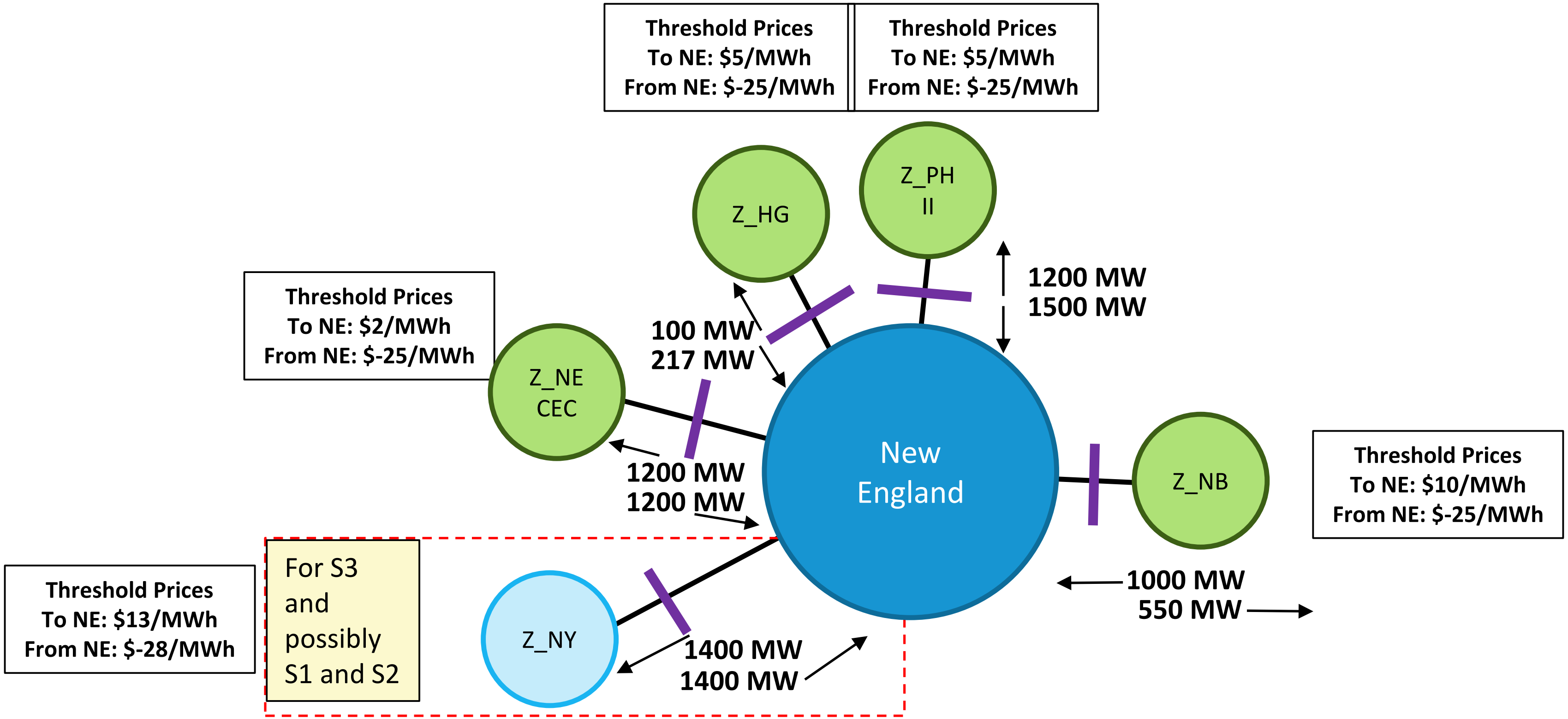
Price-Taking Resource	Threshold Price ($/MWh)
Behind-the-Meter PV	-100
FCM and Energy-only PV	-50
Offshore Wind	-40
Onshore Wind	-30
Trigger for Exports to New York	-25
Trigger for Exports to Canada	-25
NECEC (1090 MW)	2
Imports from Existing HQ	5
Imports from NB	10
Imports from New Ties	11
Imports from Second New Ties	12
Imports from NY	13

Threshold prices are used to facilitate the analysis of load levels where the amount of $0/MWh resources exceeds the system load

- They are not indicative of "true" cost, expected bidding behavior or the preference for one type of resource over another
- Use of a different order for threshold prices than indicated will produce different outcomes, particularly curtailment by resource

Bi-directional Model With NY Added

Assumptions for both GridView and EPECS



Import Priority Threshold Prices

Threshold Prices Prioritizing Imports:

- Triggers exports, curtail renewables when export capability is exhausted. Imports are must run
- Referred to as “Import Priority”
- Used previously in the 2020 Economic Study Sensitives.
- Will be used for Scenario 1.

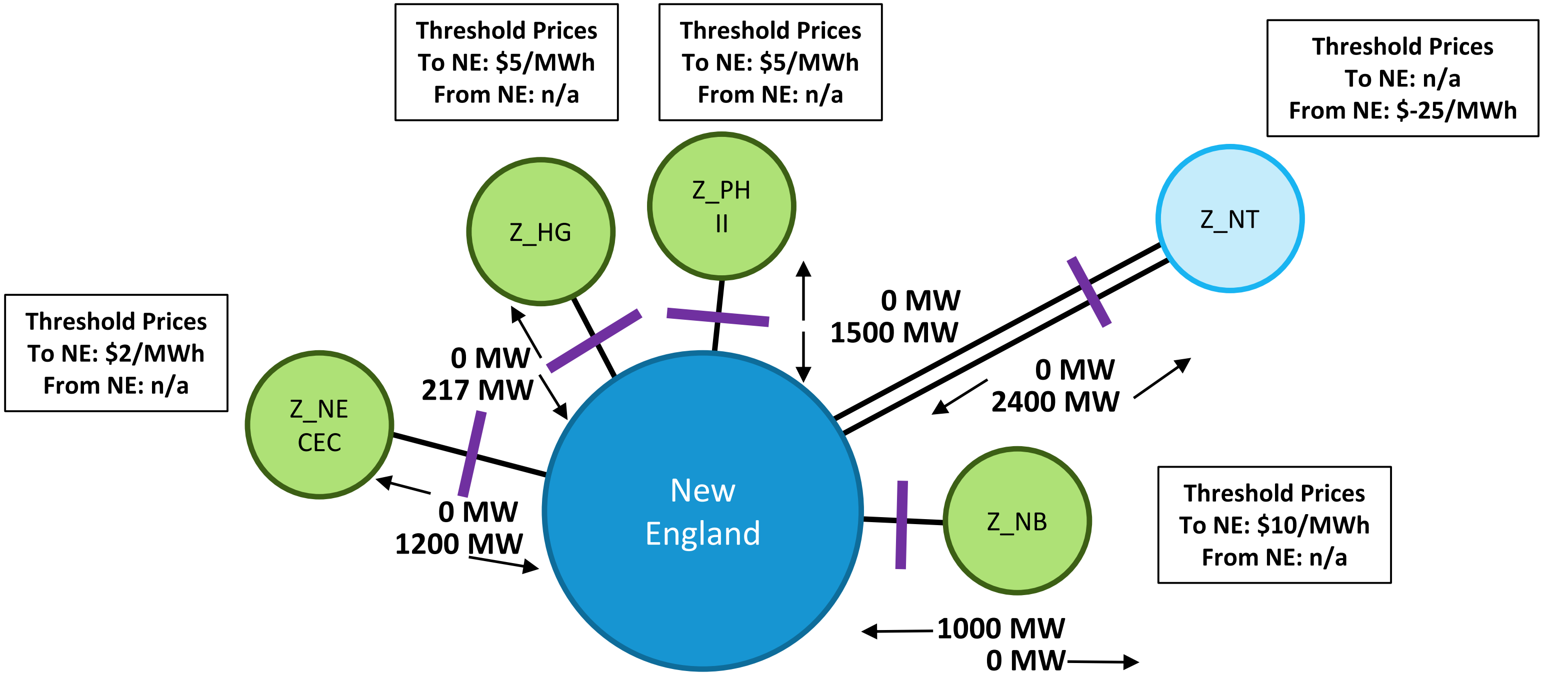
Price-Taking Resource	Threshold Price ($/MWh)
Behind-the-Meter PV	-100
NECEC	-99
Imports from Canada over Existing Lines	-50
FCM and Energy-only PV	-45
Offshore Wind	-40
Onshore Wind	-35
Trigger for Exports on New Line	-25
Imports on New Tie Line	-5

Threshold prices are used to facilitate the analysis of load levels where the amount of $0/MWh resources exceeds the system load

- They are not indicative of “true” cost, expected bidding behavior or the preference for one type of resource over another
- Use of a different order for threshold prices than indicated will produce different outcomes, particularly curtailment by resource

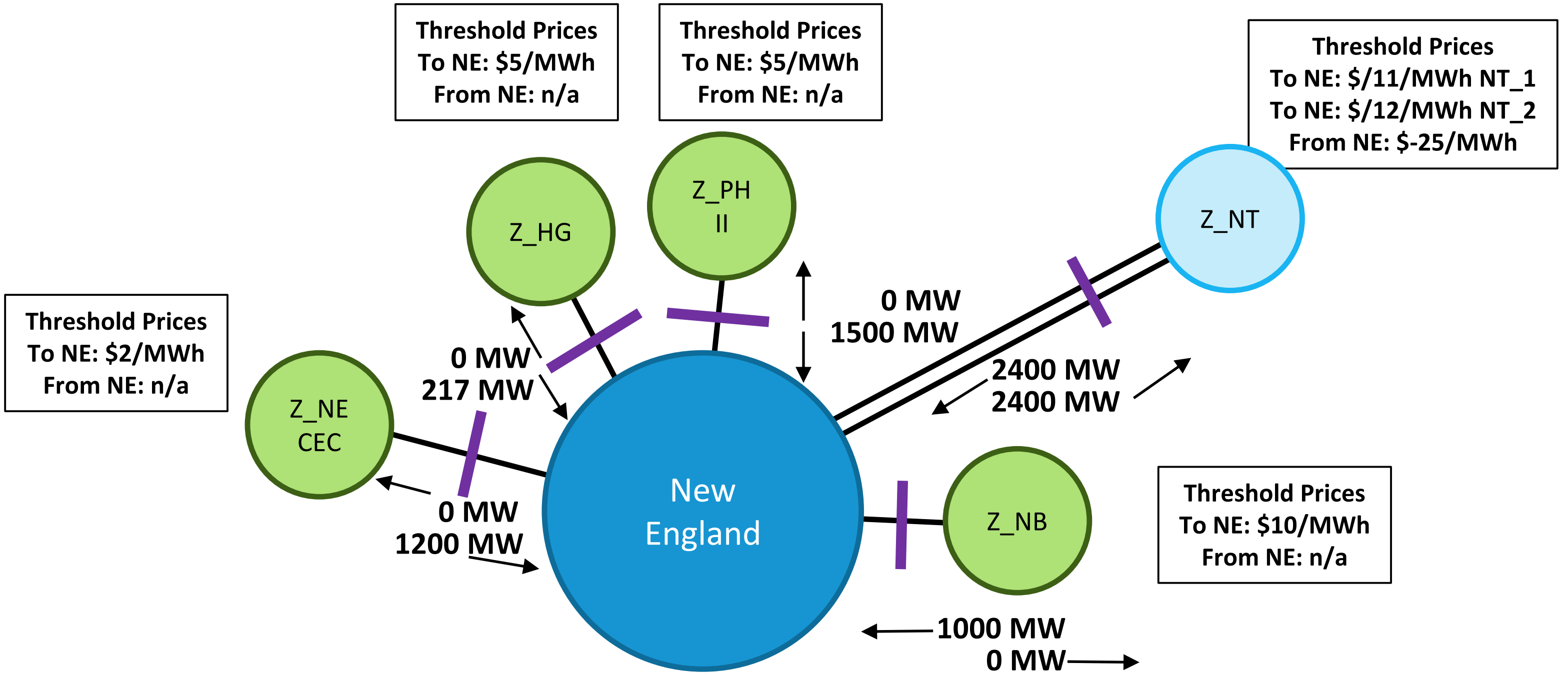
Bi-directional Model Alternative “A” – Step 1

Alternative Scenario A

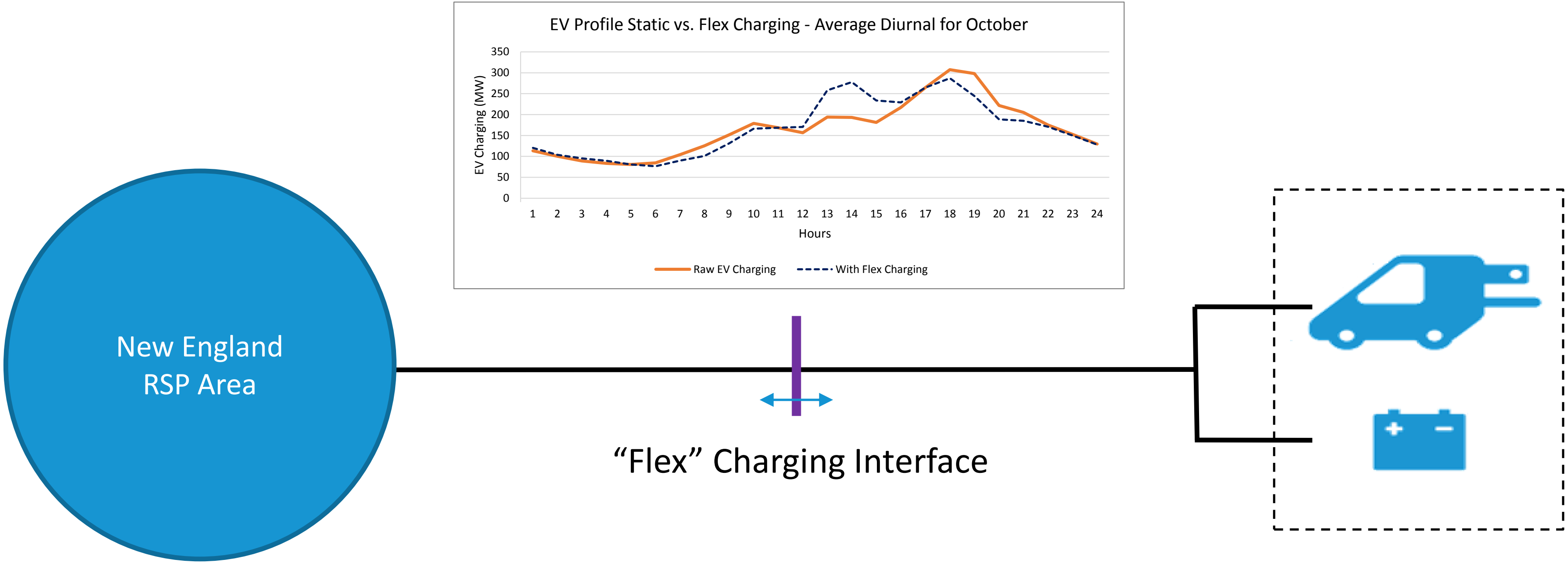


Bi-directional Model Alternative "A" – Step 2

Alternative Scenario A



EV Charging Model: Flows Across Flex Interface



FGRS Matrix Scenario – EV Assumptions

Reduce the Inverter MW so that no energy onto grid as appropriate

	Matrix Scenario Assumptions			Flex Model Assumptions		
Scenario	Number of Vehicles (Million)	Total EV Peak Charging (MW)	Total EV Battery Storage (MWh) *	EV/battery "Inverter" (MW)	EV/Battery Capacity (MWh)	Mode
Matrix Scenario 1	2.2	1,817	180,400	909	3,634	Modify Charging
Matrix Scenario 2	3.7	3,578	303,400	1,789	7,156	Modify Charging
Matrix Scenario 3	7.9	14,714	647,800	7,357	29,428	Modify Charging
Alt Scenario B	7.9	14,714	647,800	100,000	200,000	Vehicle-to-Grid

* Total EV Battery Storage (MWh) based on 82 kWh/vehicle

Summary of Electric Vehicle Load

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3	A Bi-Directional Transmission	B Vehicle to Grid	C Nuclear Retirement	D 100% Clean Electricity	E Onshore / Offshore Grids
Peak Charging Load	1,817 MW	3,578 MW	14,714 MW	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Charging Energy	7.3 TWh	18.5 TWh	40 TWh	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Operation	Flexible Delay Charging	Flexible Delay Charging	Flexible Delay Charging	Same as Parent	100 GW of 2 hour storage acting as battery	Same as Parent	Same as Parent	Same as Parent

Reference: Developing a GridView Flexible Electric Vehicle Charging Model, February 26, 2021, https://www.iso-ne.com/static-assets/documents/2021/02/a03c_ev_penetration_and_modeling_2021_02_26.pdf

Summary of Heating Electrification Load

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3	A Bi-Directional Transmission	B Vehicle to Grid	C Nuclear Retirement	D 100% Clean Electricity	E Onshore / Offshore Grids
Peak Load	5,214 MW	2,991 MW	23,244 MW*	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Energy	9.6 TWh	6.6 TWh	42.6 TWh*	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent
Load Shape	Based on hourly temp	Based on hourly temp	Specified	Same as Parent	Same as Parent	Same as Parent	Same as Parent	Same as Parent

* Sum of residential and commercial profiles for water heating (13.6 TWh) and space heating (29.0 TWh)

EPECS SPECIFIC ASSUMPTIONS

Background for Phase 1 Studies Using EPECS

EPECS simulator consists of four simulation layers addressing different user-defined time scales. The four layers and time scales currently used are:

Step	Description of Layer
SCUC	Day-ahead resource scheduling as a security-constrained unit commitment)
RTUC	Four-hour-ahead, real-time security-constrained resource scheduling as a real-time unit commitment
SCED	Fifteen-minute-ahead, real-time balancing as a security-constrained economic dispatch
Real-Time	Real-time physical power flow with integrated regulation service using one-minute time steps

Phase 1 Studies Recommendations

Assumptions for EPECS

- Time steps and horizons to be used

Layer or Parameter	Time Step	Horizon
SCUC	1 hour	24 hours
RTUC	15 minutes	4 hours
SCED	10 minutes	10 minutes

Phase 1 Studies Recommendations, cont.

Assumptions for EPECS

- Forecast error for wind, solar, and load will be the same as previous EPECS simulations and applied to all scenarios

Forecast Error Statistics			
	Load	Wind	Solar
SCUC	1.65%	12.00%	7.00%
RTUC	1.50%	3.00%	3.00%
SCED	0.15%	3.00%	3.00%

- Daily diurnal profiles will be used to represent hydro generation
  - Hydro dispatch within EPECS has not been upgraded
  - Daily diurnal approach will minimize effect of hydro on performance metrics

Phase 1 Studies Recommendations, cont.

Assumptions for EPECS

- Grid-facing storage
  - All storage dispatched in SCUC, RTUC, SCED layers
  - If feasible, one quarter assumed available to respond to regulation (real-time)
- Electric Vehicles flexible charging, ISO-NE will explore using:
  - One quarter of flex-charging MW amounts will be available in SCUC, RTUC, SCED layers
  - One eighth of flex-charging MW amounts assumed available to respond to regulation (real-time)

Phase 1 Studies Recommendations, cont.

Assumptions for EPECS

- Curtailment of VERs
  - "Do not exceed limits" will not be used to limit reserve fluctuations
  - If used, overall variability would be reduced at the expense of curtailed energy
- The model will attempt to minimize regulation reserve exceedances and system imbalance through re-dispatch

Questions

MARS SIMULATIONS

Study Plan

Objectives

MARS Simulations

- Identify major assumptions for the GE Multi-Area Reliability Simulation (MARS) model used for:
  - Resource Adequacy Screen
  - Probabilistic Resource Availability Analysis
- Discuss high-level modeling considerations, modeling options, and ISO's recommendations
- Seek stakeholders' feedback

MAJOR ASSUMPTIONS FOR GE MARS

Resource Adequacy Screen and Probabilistic Resource Availability Analysis

Load Model

MARS Simulations

- The loads will be modeled similar to current Installed Capacity Requirement (ICR) calculations. See Market Rule 1, Section 12
  - Three components of load explicitly modeled as base load or load addition/reduction (modeling details in subsequent slides)
    - Base Load
      - Exclude reductions from Passive Demand Capacity Resources (Energy Efficiency) that are modeled as resources
      - Exclude reductions from BTM-PV that are modeled as separate load component
      - Exclude additions associated with forecasts of transportation electrification load that are modeled as separate load component
      - Include additions associated with forecasts of heating electrification load - air-source heat pumps (ASHP)
    - Transportation Electrification Load (addition to Base Load)
    - BTM-PV Load (reduction to Base Load)
  - Battery charging load
    - Not considered in the past Forward Capacity Auction (FCA) ICR calculations
    - See slide 44 of this presentation for additional modeling

Load Model, cont.

MARS Simulations

- Base Load
  - Use an hourly load shape by Regional System Plan (RSP) subareas with assumed load forecast uncertainty (hourly load varies higher or lower with associated probabilities of occurrence)
  - The ISO recommends to use a composite hourly shape for FGRS MARS studies
    - 2002 weather for summer and 2003/2004 weather for winter
    - Considered representative for resource adequacy studies by NPCC and used for its seasonal assessments
      - Have heat waves in 2002 summer and cold snaps in 2003/2004 winter and multiple days exposure to seasonal peaks
  - Hourly load shape will be scaled to projected target forecasts
    - The shape of heating load component associated with the ASHP is scaled to the adoption target specified for each Matrix and Alternative Scenario
    - The shape of non-heating load component to be extrapolated to 2040 from 2021 CELT
    - Above two shapes are then aggregated into a single load shape
  - The ISO recommends to use FCA 16 Load forecast uncertainty assumptions (based on 25 years of weather history) with adjustment for the winter months to account for additional volatility associated with ASHP load

Load Model, cont.

MARS Simulations

- Transportation Electrification Load
  - An addition to Base Load using a deterministic hourly profile by RSP subareas
  - Use the hourly charging profile provided for each Matrix and Alternative Scenario
  - The ISO is considering using a net hourly charging profile that can be developed from the production cost results to reflect the flexible charging

- BTM-PV Load
  - A reduction to Base Load using an hourly profile by RSP subareas with uncertainty incorporated
  - Hourly profile will be based on the same weather year for Base Load (2002 weather for summer and 2003/2004 weather for winter)
  - Uncertainty will be modeled by randomly selecting a daily profile within a 7-day window (+/-3 days) for the day under study
    - The ISO is willing to use a bigger window (e.g. +/- 7, or, +/- 15 days) to reflect higher degree of uncertainty if desired by the MC/RC

Resource Model

MARS Simulations

- Conventional thermal generation resources
  - Include all resources that cleared in FCA 15, while reflecting the assumed retirements specified for each Matrix and Alternative Scenario
  - Modeled in the same way as in the ICR calculations, using the Qualified Capacity ratings, and the availability parameters (EFORd, maintenance requirements)

Resource Model, cont.

MARS Simulations

- Wind resources
  - Resource Adequacy Screen Analysis
    - Existing wind resources to use ICR modeling methodology for Intermittent Power Resources (IPR), using their Qualified Capacity ratings at 100 percent availability
    - Future wind resources to also use ICR modeling methodology for IPR, using the capacity ratings as determined for new FCM wind resources based on current market rules. See Market Rule 1, Section 13
  - Probabilistic Resource Availability Analysis
    - Both existing and future wind resources will be modeled probabilistically using aggregated hourly profiles by RSP subareas
    - Recommend to have MARS to randomly select from multiple hourly profiles during the simulation to reflect the variable output under different weather conditions
      - 21 years (2001-2020) of DNV-GL historical profile data are available, will incorporate as many as possible to the extent computation capability allows
      - ISO recommends to use the lowest 10 wind output profiles to reflect extreme wind drought condition
  - After the March 26 MC/RC meeting, based stakeholder comments, the ISO recommends to clarify the language in the Framework document related to use of the DNV GL data for the MARS simulations

Resource Model, cont.

MARS Simulations

- PV resources (in front of meter resources)
  - Resource Adequacy Screen Analysis
    - Existing PV resources to use the ICR modeling methodology for IPR, using their FCA 16 Qualified Capacity ratings at 100 percent availability
    - Future PV resources to also use the ICR modeling methodology for IPR, using the capacity ratings as determined for new FCM PV resources based on current market rules
  - Probabilistic Resource Availability Analysis
    - Both existing and future PV resources will be modeled the same way as the BTM-PV, using an hourly profile by RSP subareas with uncertainty incorporated
    - Hourly profile will be based on the same weather year for Base Load (2002 weather for summer and 2003/2004 weather for winter)
    - Uncertainty will be modeled by randomly selecting a daily profile within a 7-day window (+/-3 days) for the day under study
      - The ISO is willing to use a bigger window (e.g. +/- 7, or, +/- 15 days) to reflect higher degree of uncertainty if desired by the MC/RC
    - The ISO recommends to incorporate an *artificial* hourly profile with a certain probability of occurring to reflect reduced output under an extreme weather condition (e.g. dust storm), for example
      - 90% of probability of using the above hourly profile based on the same weather year for load
      - 10% of probability of using an extreme profile without solar output for several consecutive days

Resource Model, cont.

MARS Simulations

- Demand resources
  - Passive demand resources
    - Both Resource Adequacy Screen Analysis and Probabilistic Resource Availability Analysis to use the projected seasonal peak load reduction values by RSP subareas at 100 percent availability as defined for FCA 16
  - Active demand resources
    - Both Resource Adequacy Screen Analysis and Probabilistic Resource Availability Analysis to use ICR modeling methodology for the active demand resources that cleared in FCA 15, using the Qualified Capacity ratings for FCA 16, and the availability parameters (EFORd, maintenance requirements) of FCA 16

Resource Model, cont.

MARS Simulations

- Imports
  - 1,200 MW capacity import over NECEC

Resource Model, cont.

MARS Simulations

- Battery Storage
  - Both Resource Adequacy Screen Analysis and Probabilistic Resource Availability Analysis use the same modeling
  - Battery discharging
    - Modeled as dispatchable daily energy limited resource
      - Assume one cycle per day
      - Dispatch as needed by the system
  - Battery charging load
    - Modeled as an addition to hourly load during predetermined off-peak hours
      - Use the production cost results to identify the off-peak hours for charging
  - For battery type with greater than 24 hour storage capacity
    - Alternative Scenario D
    - Modeling options are unavailable in MARS
    - Recommendation: Assumed as “perfect” capacity, available all the time (no EFORd)

Other Assumptions

MARS Simulations

Tie Benefits Assumptions

- Resource Adequacy Screen Analysis will use annualized FCA 15 tie benefits assumptions
- Probabilistic Resource Availability Analysis will use seasonal assumptions derived from the FCA 15 tie benefits assumptions
  - Although calculated as annualized values, FCA 15 tie benefits assumptions are simulated under the condition where New England system's expected LOLE risks and the need for emergency assistance occur only in the summer. FCA 15 tie benefits assumptions will be used in this study for the summer period.
  - FCA 15 New York tie benefits represents the assistance available from a similar-size system that peaks at the same time. It is mainly the result of the resource diversity, instead of the load diversity. This analysis assumes this summer amount of assistance continue to be available during the winter
  - FCA 15 tie benefits from Quebec and Maritimes are higher, driven by the seasonal load diversity during the summer. As the load diversity diminishes during the winter
    - This analysis assumes Quebec will only be able provide similar amount of assistance as New York from resource diversity
    - This analysis assumes Maritime will only be able to provide 25% of New York's amount due to smaller system

	Maritime Ties	Quebec Ties	New York Ties	Total
FCA 15 (MW)	454	1,023	258	1,735
Proposed seasonal values for FGRS (MW)	454 (S) 65 (W)	1,203 (S) 258 (W)	258 (S) 258 (W)	1,735 (S) 581 (W)

  - Recommend to use no tie benefits during the winter because of widespread electrification and geographic reliance of VERS across a wide footprint as a sensitivity to a few scenarios

Other Assumptions, cont.

MARS Simulations

- OP-4 Load Relief from 5% voltage reduction
  - Resource Adequacy Screen Analysis
    - Use 1% of net peak (similar to current ICR calculation methodology)
  - Probabilistic Resource Availability Analysis
    - Recommend to assume no load relief from 5% voltage reduction to account for the increased uncertainties and challenges the high penetration of renewable resources introduce in the operation of the grid – voltage variation, frequency control, etc.

Other Assumptions, cont.

MARS Simulations

- Minimum operating reserve requirement
  - Resource Adequacy Screen Analysis
    - Assume 700 MW as currently used in ICR calculations
  - Probabilistic Resource Availability Analysis
    - An Approach is yet to be decided
    - The ISO will consider results of the EPECS Ancillary Services Simulations, and consult with MC/RC before making a final assumption recommendation

Other Assumptions, cont.

MARS Simulations

- System topology
  - Internal transmission interface limits are not enforced
  - Interface flow statistics will be compared against FCA 15 limits (except Surowiec South which will have a limit of 2,500 MW)

Other Assumptions, cont.

MARS Simulations

- Proxy units
  - 150 MW grid connected battery storage resources for the first 1,000 MW
  - 100 MW CT units afterward

Questions

NEXT STEPS

Next Steps

- The ISO will continue to review the Framework document and associated assumptions, to identify additional areas for clarification as they start to build their GridView and EPECS models
  - Preliminary GridView results for Scenario 1 including Sensitivities and relevant Alternative Scenarios to be presented in June to PAC
  - EPECS preliminary results expected in late summer
  - MARS simulations will commence later in 2021 with results closer to year end
- On March 12, NEPOOL submitted the FGRS Phase 1 work as a 2021 Economic Study Request
  - Discussions will be a PAC over the next few months
  - Upcoming PAC milestones are outlined below

Milestone	Dates
Stakeholder presentation materials are due to ISO	April 8 by Noon
Stakeholders present their requests to PAC	April 14
PAC to discuss the requests	May 19

Questions