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2021 Economic Study: Future Grid Reliability Study Phase 1

Overview of Assumptions – Part 1

Planning Advisory Committee

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Introduction

- On March 12, 2021, NEPOOL submitted the Future Grid Reliability Study (FGRS) Phase 1 as a 2021 Economic Study Request
- On April 1, 2021, ISO New England accepted the request and will perform the FGRS as the 2021 Economic Study
- 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 in Gridview
    - Ancillary service simulations in Electric Power Enterprise Control System (EPECS)
  - Analysis Methodology and metrics
- Future presentations to the PAC will cover more details of the 2021 Economic Study
  - This presentation is meant to provide PAC participants with an high-level overview of assumptions discussed at the NEPOOL Joint Markets Committee/Reliability Committee (MC/RC) FGRS meetings

ASSUMPTIONS

Gridview and EPECS

FGRS Phase 1 Goals for Analysis

Based on the Framework Document

- The economic analyses (production cost and ancillary services) will seek to provide insight to:
  - What are the forecasted market revenues?
  - Will they be sufficient to attract and retain the different types of resources that will be needed to reliably operate the system?
- The engineering analyses (ancillary services, resource adequacy, and probabilistic availability and system security) will seek to provide insight to:
  - What conditions will likely present operational or reliability issues?

Scenario Overview

FGRS Phase 1

- Given the uncertainty associated with forecasting the future, the FGRS proposes numerous different future scenarios for 2040
  - There are three main scenarios referred to as 'matrix scenarios'.
    - Three different amounts of building and transportation electrification loads are proposed.
    - Three different amounts of offshore wind and distributed energy resources are proposed.
    - Each variation of electrification loads and variable energy resources will be tested creating nine matrix scenarios
  - There are five alternative scenarios that are applied to some or all of the main matrix scenarios
  - Amounts to a total of 34 production cost simulations scenarios, 8 ancillary services scenarios; 1-3 probabilistic resource adequacy analyses

Scenario Overview, *continued*

Scenario	Proponent	Alternate Scenario Name or Notes
1	National Grid	Based on the 2020 Economic Study
2	Eversource	London Economics
3	NESCOE	Energy Pathways Study
A	National Grid	Bi-Directional Transmission & HQ Storage
B	Synapse (Multi Sector Group B)	Vehicle to Grid
C	NextEra/Dominion	Nuclear Retirement
D	Anbaric	100% Clean Electricity
E	Anbaric	Onshore/Offshore Grids

GridView 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**

System Topology

- New England topology represented by Pipe and Bubble configuration (see slide 24)
- New England interface flows will be compared against FCA 16 limits for quantifying transmission flows exceedances (except Surowiec South which will have a limit of 2,500 MW)
  - The latest FCA 16 transfer limits have become available and the ISO recommends using them instead of FCA 15 transfer limits
- 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
  - This work will start once production cost and ancillary service simulations for the three matrix scenarios are completed

Load and Energy Efficiency (EE)

- 2021 CELT Load is basis for National Grid (Matrix Scenario 1) and Eversource's (Matrix Scenario 2) requests
  - Study proponents have suggested the loads to use
  - "Nominally" the study year is 2040 – which requires an extrapolation
    - Typically growth past the horizon year is based on a linearized trajectory of ISO's "CELT Gross Loads"
    - Historical hourly loads scaled to forecast values
      - Scaling factors based on monthly peaks
      - Scaling factors 'feathered' from one monthly peak to another
      - Historical year implies the weather year to use for variable energy resource (VER) production
  - Energy efficiency
    - Hourly EE profiles is currently based on a algorithm that matches extrapolated values for capacity and annual EE energy

- NESCOE (Matrix Scenario 3) provided an internally consistent set of load shapes based on a 2012 weather year
  - The load is already net of EE

Weather Year

- A weather year provides the basis for the *shape* of base load pattern and variable energy resources (VERs). The values from that year are then scaled to the year of study based on the CELT forecast and expected installed capacity of VERs
  - Participants requested historical 2012 & 2015 weather years, but one-minute resolution ISO load data needed for ancillary services analysis is no longer available for those years
  - Using a common weather year for all scenarios and will facilitate comparisons
  - 2019 is a preferred weather year because
    - One-minute time scale ISO data is available for the full year
    - Does not include effects of the pandemic as was seen in 2020
  - Translation of matrix scenarios 1 & 2 (and 3 if feasible) electrification load shapes (heating and transportation) to 2019 weather

Wind and Solar Resources

- Profiles for MW generation developed from DNV 2021 historical data set
  - Wind data includes modeling of all current wind farms and for proposed and hypothetical onshore and offshore wind farms for 2000-2020 (new hypothetical sites shown on next slide)
  - Solar data:
    - Includes aggregate behind the meter profiles for each Load Zone
    - Within states with multiple RSP areas, allocation will be by the fraction of currently installed PV within each RSP zone
- Profiles for the selected weather year are scaled to desired nameplate values for 2040 scenarios

2021 Historical DNV Data Set New Facility Additions

Wind Plant	Latitude	Longitude	Hub Height [m]	Wind Plant Capacity (MW)	State
Maine South (Future)	44.60497	-70.8989	120	600	ME
Main Central (Future)	45.07148	-70.0202	120	600	ME
Main North 1 (Future)	46.12256	-68.5006	120	1,200	ME
Main North 2 (Future)	46.91812	-68.1691	120	1,200	ME
Cape Cod (Future)*	41.46250	-69.5742	150	1,200	Offshore
Boston (Future)*	42.27708	-70.2728	150	1,200	Offshore
Seabrook (Future)*	42.82307	-70.2638	150	1,200	Offshore
Wyman (Future)*	43.72208	-69.0470	150	1,200	Offshore
Bar Harbor (Future)*	44.22864	-67.8431	150	1,200	Offshore
Calais (Future)*	44.50961	-66.9413	150	1,200	Offshore

Solar Plant	Latitude	Longitude	Approx. Elevation [m]	Solar Plant Capacity (MW)	State
Spencer Solar	42.28559	-72.0101	259	100	MA
Cranston Solar	41.73384	-71.5282	85	100	RI
Hartford Solar	41.88470	-72.5482	50	100	CT
Carroll Solar	44.03158	-71.0348	125	100	NH
Addison Solar	44.17892	-73.2494	59	100	VT
Hancock Solar	44.43843	-68.5905	90	100	ME
York Solar	43.38082	-70.9327	119	100	ME

** OSW for the 2021 Economic Study will include the existing DNV-GL sites in the BOEM lease area off of Martha's Vineyard and Nantucket (not pictured here)*

Hydro Resource Modeling

- GridView internal hydro simulation model to be used
  - Replaced pre-2020 Economic Study method of creating an aggregate New England hydro generation model
  - More responsive to high penetrations of variable energy resources

- Hydro resource data developed based on asset level statistics
  - Seven years of historical generation (February 2013 - April 2020)
  - Monthly MWh (Average)
  - Operating Range
    - Average of asset minimum output by month
    - Average of asset maximum output by month
    - Unconstrained range between minimum and maximum allowed
  - Aggregated small hydro units
    - Many not assigned to a bus in the network model
    - Approximately 180 MW (~10% of the hydro capacity)

Conventional Thermal Resources

- Fossil Fuel resources are modeled using heat rate and fuel cost.
  - Modeling today's bidding behavior is likely not reflective of 2040 behaviors.
- No fuel constraints are modeled.
  - Natural gas has up to an 10% seasonal multiplier in the winter.
- Resources qualified for FCA 16 modeled at their FCM Qualified Capacity value.
- FCA 15 retirements, plus all coal, the majority of oil, and some/all dual fuel units based on age (varies by scenario).
- Forced outages of resources are modeled by derating their capacities to reflect the resources' Equivalent Forced Outage Rate demand (EFORd)
- Alternative Scenarios D & E assume the retirement of all fossil fuel resources.

Other Resources

- Nuclear resources will continue to be must run.
  - Alternative scenario C retires all remaining nuclear resources.
- Municipal Solid Waste (MSW), Landfill Gas (LFG), and Wood resources will be modeled as must run
  - Before the 2020 Economic Study, these units were modeled as dispatchable with a low price.
  - The change to must run will result in more curtailment of additional wind and solar resources as well as imports.

ANALYSIS METHODOLOGY AND METRICS

Gridview and EPECS

Software Analytical Capabilities

- ISO will conduct simulations using the GridView production simulation software
  - Designed to simulate 8,760 hourly intervals
  - Produce wide range of production simulation metrics
  - Limited ability to investigate
    - Multi-step unit commitment with forecast uncertainty
    - Supply and demand imbalances in period less than hourly intervals
- Electric Power Enterprise Control System (EPECS) sub-hourly simulations will assess system operational impacts of the study scenarios taking unit commitment and economic dispatch into consideration to produce results relating to:
  - Load-following/Ramping
  - Regulation/Automatic Generation Control (AGC)
  - Operating Reserves

GridView Production Simulation Metrics

- System-wide energy production by resource/fuel type
- System-wide production costs
- Locational Marginal Prices (avg. annual, monthly, on/off peak, etc.)
- Load-serving entity energy expense and uplift
- Congestion by interface (internal and external) and key lines of interest
- Native New England Resource CO_2 emissions, including marginal emissions
- Curtailment
- Energy exports to neighboring systems
- Storage utilization

Ancillary Services Analysis in EPECS

- The EPECS simulation software simulates the techno-economic behavior of an electric power system, with its associated electric power enterprise markets.
- It explicitly addresses the intermittency of renewable resources (i.e., lack of dispatchability) as well as the uncertainty (i.e., forecast errors) of the power grid's distributed net load and quantifies many types of operating reserves/ancillary services.
- The enterprise market behavior includes a security-constrained unit commitment, a real-time unit commitment, a security-constrained economic dispatch, regulation service and a physical model of the electric power grid (AC/DC Power Flow Analysis).
- Previously used in the 2016 Economic Study Phase II – Regulation, Ramping, and Reserves

EPECS Metrics

- Load-Following/Ramping Physical Quantities
- System Level Imbalances
- Regulation Reserves Mileage & Reserve Exhaustion
- Operating Reserves Usage
  - Ten-Minute Synchronized
  - Thirty-Minute Operating
- Curtailment

CLOSING REMARKS

Gridview and EPECS

Closing Remarks

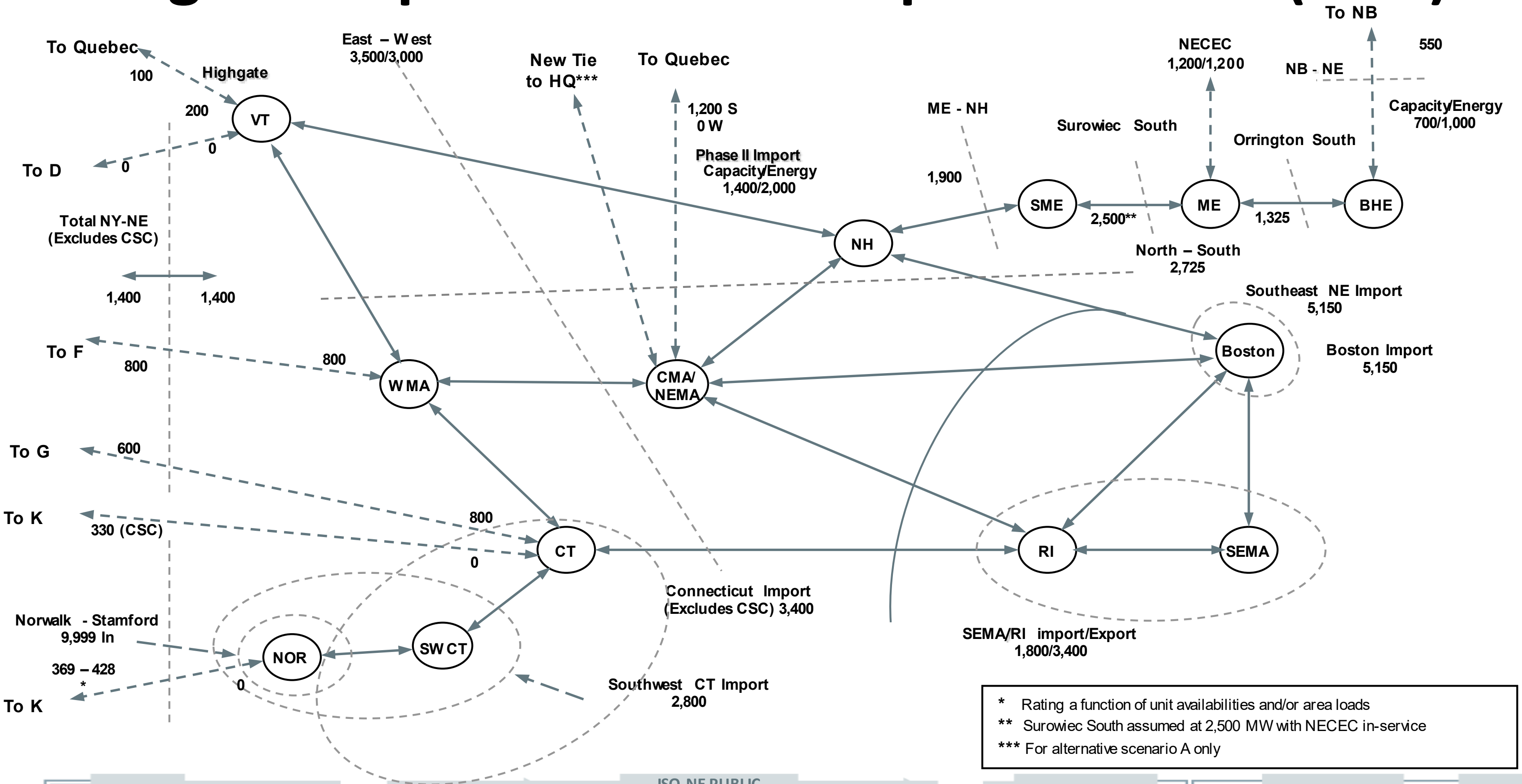
- **Next Steps**:
  - The ISO will return to the PAC in May to continue the discussion of assumptions associated with the Gridview and EPECS simulations
  - Preliminary Gridview production cost results for initial scnearios are expected in June
- **Additional Information**:
  - Final versions of the Future Grid Reliability Study framework document and assumptions tables are available on the ISO-NE website as part of the New England's Future Grid Initiative Key Project
  - The ISO-NE Economic Studies webpage contains additional information about past Economic Studies as well as a reference document

Questions

APPENDIX I

Additional Material

New England Pipe and Bubble Representation (MW)



* Rating a function of unit availabilities and/or area loads
** Surowiec South assumed at 2,500 MW with NECEC in-service
*** For alternative scenario A only

APPENDIX II

Acronyms

Acronyms

ACDR	Active Demand Capacity Resource	EE	Energy Efficiency
ACP	Alternative Compliance Payments	EFORd	Equivalent Forced Outage Rate demand
AGC	Automatic Generator Control	EIA	U.S. Energy Information Administration
BESS	Battery Energy Storage Systems	EPECS	Electric Power Enterprise Control System
BTM PV	Behind the Meter Photovoltaic	EV	Electric Vehicle
BOEM	Bureau of Ocean Energy Management	FCA	Forward Capacity Auction
CCP	Capacity Commitment Period	FCM	Forward Capacity Market
CELT	Capacity, Energy, Load, and Transmission Report	FGRS	Future Grid Reliability Study
CSO	Capacity Supply Obligation	FOM	Fixed Operation and Maintenance Costs
Cstr.	Constrained	HDR	Hydro Daily, Run of River
DER	Distributed Energy Resource	HDP	Hydro Daily, Pondage
DR	Demand-Response	HQ	Hydro-Québec

Acronyms, *continued*

HY	Hydro Weekly Cycle	OSW	Offshore Wind
LBW	Land Based Wind	O&M	Operation and Maintenance
LFG	Landfill Gas	PHII	Phase II line between Radisson and Sandy Pond
LFR	Load Following Reserve	PV	Photovoltaic
LMP	Locational Marginal Price	RECs	Renewable Energy Credits
LSE	Load-Serving Entity	RFP	Request for Proposals
MSW	Municipal Solid Waste	RGGI	Regional Greenhouse Gas Initiative
NECEC	New England Clean Energy Connect	RPS	Renewables Portfolio Standards
NESCOE	New England States Committee on Electricity	SCC	Seasonal Claimed Capability
NG	Natural Gas	Uncstr.	Unconstrained
NICR	Net Installed Capacity Requirement	VER	Variable Energy Resource
NREL	National Renewable Energy Laboratory		