AGENDA
JOINT MEETING
NEPOOL MARKETS & RELIABILITY COMMITTEES
Friday, February 26, 2021

Location: Teleconference
Call-in Number: 1-866-711-7475 / Access Code: 8562734
WebEx: WebEx Link
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: January 19, 2020	9:30 – 9:45
2*	FUTURE GRID RELIABILITY STUDY (Project Administrator: Peter Flynn) (10th Joint MC/RC Mtg) Review incremental changes to scenario assumptions; the following proponents will discuss an overview of similarities and differences in their scenarios, and report on latest developments: A) National Grid (Julia Grasse) B) Eversource (Nic Baldenco) C) NESCOE (Ben D'Antonio) D) Multi-sector Group (Doug Hurley) E) Anbaric (Luis Ortiz)	9:45 – 12:00
	LUNCH	12:00 – 12:30
2*	FUTURE GRID RELIABILITY STUDY (Project Administrator: Peter Flynn) (10th Joint MC/RC Mtg) Review incremental changes to Framework Document for Phase 1	12:30 – 1:30
3*	ADDITIONAL FEEDBACK ON FUTURE GRID RELIABILITY STUDY FRAMEWORK DOCUMENT (ISO-NE: Carissa Sedlacek) (10th Joint MC/RC Mtg)	1:30 – 3:00

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

A) ISO's revised stakeholder schedule assuming the 2021 Economic Study path, and additional feedback to the draft framework document sent to ISO for review on December 29, 2020. (ISO-NE: Carissa Sedlacek)
B) Review of DNV-GL data for modeling wind/solar resources (ISO-NE: Steven Judd)
C) Electric Vehicle modeling discussion (ISO-NE: Wayne Coste)

4	DETERMINE WHETHER THERE IS CONSENSUS TO REQUEST PHASE I AS THE 2021 ECONOMIC STUDY	3:00 – 3:30
5	REFLECTION AND NEXT STEPS ON PHASE II	3:30 – 4:30
6	OTHER BUSINESS	4:30 – 4:35

Scenario	Load-Related					
	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 (2020 Economic Study June 17, 2020 PAC, Slide 24 July 22, 2020 PAC Slides 32-37)	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.* (2020 Economic Study May 20, 2020 PAC, slide 13 July 22, 2020 PAC, slides 29-31)	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 *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).* (2020 Economic Study May 20, 2020 PAC, slide 13 June 17, 2020 PAC, slides 22-23

Input Assumptions

	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 June 17, 2020 PAC, slides 5-6	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; (2020 Economic Study June 17, 2020 PAC, slides 7-8 for Import Limits)	Historical flows on external ties with existing limits monitored; NY exchange at 0MW; (2020 Economic Study July 22, 2020 PAC, slides 7-16)	NECEC at 1,200 MW nameplate (2020 Economic Study May 20, 2020 PAC, slide 14)	FCA 14 cleared retirements plus, all New England coal units, and 75% of the conventional New England oil, including dual-fuel units, based on age (2020 Economic Study June 17, 2020 PAC, slides 11)

Input Assumptions

	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	2021 CELT generator list *Open to adopting consistent approach*	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)

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Input Assumptions

	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 2400MW controllable (HVDC) tie from Quebec to 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, (2020 Economic Study June 17, 2020 PAC, slides 18 July 22, 2020 PAC, slides 20, 21 & 23 for details of wind & solar estimates)	See Storage under Load Assumptions; $3/MWh variable O&M costs will be reflected in dispatch of electric storage (2020 Economic Study July 22, 2020 PAC, slides 33-37 for details of battery storage estimates; other than change to VOM listed as 0 on slide 35)	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 (2020 Economic Study June 17, 2020 PAC)	2015 per DNV-GL study profiles	Update to FCA 15, (FCA 14 used in 2020 Economic Study was for 592MW Modeled as dispatchable in GridView with First 100 MW dispatched at $50/MWh Remainder at $500/MWh; June 17, 2020 PAC, slides 15)

	Resource Portfolio					
Scenario	**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.	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	Extrapolated from 2021 CELT
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.* Interested in sensitivity with $2/MWh variable O&M costs for electric 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	

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 1	*Consistent approach pending agreement*	*Open to adopting consistent approach* 120% of the first contingency in ten minutes split between Ten-Minute Spinning Reserve (TMSR) = 50% Ten-Minute Non-Spinning Reserve (TMNSR) = 50% (2020 Economic Study June 17, 2020 PAC, slides 14)	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 (2020 Economic Study June 17, 2020 PAC, slides 13)

Input Assumptions

			Marginal Cost Inputs		
Scenario	**Curtailment Prices / Threshold Prices**	**Reserve Margin / Capacity Assessment**	**Fuel Price Forecasts**	**Seasonal Volatility Adjustments**	**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*	RIO results based on hourly zonal reserve margin constraints Open to adopting consistent approach, including reserve requirement assumptions	Same as Others	Same as Others	Same as Others

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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)	*Dependent upon decision of what to use (REC-inspired?) for the diagonal scenarios and pending discussion with the ISO-NE following 2020 Economic Study Sensitivities and Results* (See February PAC presentation p. 16 and p. 30 for two options)				
Alternative Scenario B Vehicle to Grid (Multi Sector A)					
Alternative Scenario C Nuclear Retirement (NextEra/Dominion)					

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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)					

NEPOOL Future Grid Study
Draft Proposed Study Framework

February 26, 2021

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.

The New England Power Pool (NEPOOL) is embarking on this Future Grid Reliability Study (Study) to understand better the implications of this substantially changed future grid. Specifically, the Study 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 Document) constitutes the "Study Framework" for Phase 1. 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 will be 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..

I. Study Objective / Scope

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

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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)

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 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. Phase 2 will consist of revenue sufficiency and system security analyses. The details and timing of those analyses are being considered further and will be addressed in a future separate document to be reviewed by the MC/RC.

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 profiles. Unless specified, simulations will be performed under unconstrained conditions, where the New England transmission system will be modeled as a single-bus system. For certain assessments, constrained conditions will be modeled. For constrained conditions, 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]

As part of the Production Cost Simulation analysis, high-order-of-magnitude transmission build-out estimates will be developed (no costs). These high-order-of-magnitude transmission build-out estimates will be evaluated for a constrained

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

transmission system identifying integrator[3] and congestion-relief systems for the individual matrix and alternative scenarios. A similar approach to the one taken in ISO-NE's 2016 and 2017 Economic Studies will be used.[4] A detailed transmission analysis that would be required to fully develop plans that identify and comprehensively price transmission upgrades will not be done as part of this Study.

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 electric storage cycling will be assumed to be $3/megawatt-hour one way. 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.

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 and Consultant)

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 products, and b) other ancillary services market products. Estimate quantities of

[3] The integrator system ties the point of interconnection of each individual plant to the main portion of the bulk power system. They do not include individual plant-development and interconnection facilities, which are assumed to be part of generation development and addressed as part of the Open Access Transmission Tariff Schedules 22/23 interconnection process.

[4] Study reports are available at: https://www.iso-ne.com/system-planning/system-plans-studies/economic-studies/

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 performance, 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, 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. If certain resources or resource types do not run in the GridView simulation for a given scenario, the ISO may run sensitivities that examine the impact of retiring resources.

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

[*Placeholder: Need to define how to treat new resources with respect to capacity supply obligations, the percentage of resources that will have capacity supply obligations and their capacity values*.]

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 the energy market simulation to ensure that LOLE is met for expected system loads. Include the creation of marginal reliability index demand curves.

Methods: Customary approach to ICR performed at a high-level to screen for resource adequacy, 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[5] for the case to solve. Some sensitivities could be performed for different proxy resources. [*Placeholder: Need to define the proxy resources.]*

Metrics: Evaluate all matrix and alternative scenarios to determine system reliability during the peak hours of the study year. Produce marginal reliability curves for select scenarios chosen by the MC/RC.

2. Probabilistic Resource Availability Analysis

Objective: Analyze the periods of time and system conditions *outside* of system peaks that may not meet LOLE due to factors such as insufficient capacity, flexible demand, weather risk, etc.

Methods: For select matrix and alternative scenarios chosen by the MC/RC, examine correlation of loss of load risk and multi-day VER 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 analysis.

Learning points: Observations 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 about whether the results suggest scenarios for further study or some iterations with the energy and ancillary services analyses; the results will inform the system security analysis.

5 Proxy resources may be a single resource type or composed of various resource types. If various resource types are chosen, then priority order must be assigned to be added to the system first to meet LOLE.

III. Scenarios

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

Matrix of Scenarios for Energy and Ancillary Services Market Simulations

	OSW 8,000 MW DER 18,000 MW	**OSW 8,000 MW DER 25,000 MW**	**OSW 17,000 MW DER 31,000 MW**
Buildings 9,600 GWh Transport 7,300 GWh	Scenario 1 + Alternatives	1 Case	1 Case
Buildings 6,600 GWh Transport 18,500 GWh	1 Case	Scenario 2 + Alternatives	1 Case
Buildings 38,900 GWh Transport 37,500 GWh	1 Case	1 Case	Scenario 3 + Alternatives

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

The diagonal scenarios will be run first and, based on the results, an assessment will be made by ISO-NE whether any of the other matrix scenarios appear to be unrealistic, infeasible or not likely to tell something new. Based on that assessment, the MC/RC could decide to drop certain scenarios.

Stakeholders proposed some alternative scenarios. An assessment will be made by the MC/RC after the matrix scenarios as to whether to run each of the alternative scenarios based on factors such as whether an alternative scenario: 1) is likely to answer questions not already answered by the matrix scenarios or another study; 2) is feasible (meaning that the data/assumptions are available); and 3) can be completed in reasonable time.

<u>Alternative Scenarios</u>
A. Bi-Directional Transmission (see National Grid 2035)
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)

Energy and Ancillary Service Market Simulations:
9 Matrix Scenarios + 15 Alternative Scenarios = 24 Potential Scenarios

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 appended table.

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 a 2,400 MW bi-directionally capable controllable direct current tie injecting into Northeast Massachusetts.

E. Alternative Scenario B:

The objective is to analyze the impact of vehicle to grid storage. It assumes that an additional 100 gigawatts 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.

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 plants.

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.

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 scenario G 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).

IV. Assumptions

The detailed assumptions for the different scenarios are shown in the Assumptions Document 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.

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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 system peaks. Include the creation of marginal reliability index demand curves for selected scenarios.

4. Analyze the periods of time and system conditions outside of 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 carbon emission / emission reduction levels in:

    a. The power sector through the GridView results

    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

February 26, 2021

	2021											2022											
	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec
MC/ RC Mtg	X	X	X		X			X			X			X		X Final							
PAC Mtg			X	X	X	X	X		X	X	X	X			X Final								
			4/1 – ES Request Due At PAC Meeting, present request By NEPOOL	Review ES Request Scope & Assump-tions with PAC (ISO)																			
	Assumptions Development Matrix Scenarios																						
	Assumptions Development Alternative Scenarios																						
										Review / Update Assumptions													
			Preliminary production cost simulations																				
					Preliminary production cost results discussed with PAC																		
						Final production cost simulations																	
									Final production cost results discussed with PAC														
							Ancillary services simulations																
										Ancillary services results discussed with PAC													
									MARS analyses														
											MARS results discussed with PAC												
												Phase 1 Report writing											

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 Study
Draft Proposed Study Framework
February 26175January 1210, 2021

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.

The New England Power Pool (NEPOOL) is embarking on this Future Grid Reliability Study (Study) to understand better the implications of this substantially changed future grid. Specifically, the Study 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 appended assumptions spreadsheet (Assumptions Document)table constitutes the "Study Framework" for Phase 1. The Study Frameworkwhich 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 will be 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 or any consultant based on continued consultation among regarding the studies described below. Close collaboration will be required between ISO-NE, NEPOOL representatives and- scenario proponents.any consultants retained by NEPOOL.

I. Study Objective / Scope

NEPOOL approved the Study objective and scope in a document commonly referred to as the "bubble chart."[2] The objective is to assess and discuss the future state of the regional power system in light of current 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 existing markets in effect on

[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)

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 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, with immediate efforts focused on phase 1 analyses as described below. Phase 1 will consist The first phase consists of the production cost simulation, ancillary services simulation, resource adequacy screen and probabilistic resource analysis. The Phase 1 work is described in detail below. Phase 2 will consist The second phase consists of revenue sufficiency and system security analyses. The details and timing of those analyses are being considered further and in the process of being developed. They will be addressed in a future separate document to be reviewed by the MC/RC.

II. Areas of Analysis

A. Production Cost Simulation: ABB GridView (ISO-NE) – Phase 1

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 profiles. Unless specified, simulations will be performed under unconstrained conditions, where the New England transmission system will be modeled as a single-bus system. For certain assessments, constrained conditions will be modeled. For constrained conditions, 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 limitsAssume unconstrained internal transmission. initially.[3] Some unconstrained runs transmission

[3] Unless specified, simulations will be performed under unconstrained conditions, where the New England transmission system will be modeled as a single-bus system. For certain assessments, constrained conditions

sensitivities could may be addedrun secondarily.[3] Interfaces at the Regional System Plan zonal level (RSP bubbles) will be monitored as part of the analyses such that some sensitivities that recognize constraints may be run.

As part of the Production Cost Simulation analysis, high-order-of-magnitude transmission build-out estimates will be developed (no costs). These high-order-of-magnitude transmission build-out estimates will be evaluated for a constrained transmission system identifyingfor integrator[4] and congestion-relief systems for the individual matrix and alternative scenarios. A similar approach to the one taken in ISO-NE's 2016 and 2017 Economic Sstudies will be used.[5] A detailed transmission analysis that would be required to fully develop plans that identify and comprehensively price transmission upgrades, and will not be done as part of this Sstudy.

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 electric storage cycling will be assumed to be $3/megawatt-hour one way. Sensitivities may be performed. Aand 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.

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 yearthe timing of when those conditions might occur; observations about whether the results suggest scenarios for further study; the results will feed into the probabilistic resource availability analysis.

will be modeled. For constrained conditions, 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. For additional information, see https://www.iso-ne.com/about/key-stats/maps-and-diagrams.

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

[4] The integrator system ties the point of interconnection of each individual plant to the main portion of the bulk power system. They do not include individual plant-development and interconnection facilities, which are assumed to be part of generation development. and addressed as part of the the Open Access Transmission TariffATT Schedules 22/23 interconnection process.

[5] Study reports are available at: https://www.iso-ne.com/system-planning/system-plans-studies/economic-studies/

[Placeholder: Further thought is required on: 1) the mix of market facing and non-market facing distributed energy resources; 2) the impact of non-market facing distributed energy resources on load profiles; and 3) a baseline for modeling the duration of battery storage devices. Allow for sensitivities to examine the impact of different duration assumptions.]

B. Ancillary Services Simulation: EPECS (ISO-NE and Consultant) – Phase 1

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 products, and b) other ancillary services market products. 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 performance, 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, 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) – Phase 1

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. If certain resources or resource types do not run in the GridView simulation for a given scenario, the ISO may run sensitivities that examine the impact of retiring resources.

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

[*Placeholder: Need to defineFurther thought is required on how to treat new resources with respect to capacity supply obligations, the percentage of resources that will have capacity supply obligations and their capacity values*.]

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 the energy market simulation to ensure that LOLE is met for expected system loadpeaks. Include the creation of marginal reliability index demand curves.

Methods: Customary approach to ICR performed at a high-level to screen for resource adequacy, 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[6] for the case to solve. For the matrix scenarios, the proxy resourcesunit that will be added to the model to ensure resource adequacy areis a lithium-ion batteriesy with X hours of discharge capability. Some sensitivities could be performed for different proxy resources. [*Placeholder: Need to define the proxy resourcesShould market-facing battery storage be used for the proxy resources? If yes, .]what battery duration or durations should be assumed?]*

Metrics: Evaluate all matrix and alternative scenarios to determine system reliability during the peak hours of the study year. Produce marginal reliability curves for select scenarios chosen by the MC/RC.

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6 Proxy resources may be a single resource type or composed of various resource types. If various resource types are chosen, then priority order must be assigned to be added to the system first to meet LOLE.

~~**[Placeholder**: Some issues that require further thought are: i) what should be the proxy resource(s) types and should they differ among the scenarios; and ii) what level of availability should be assumed for VERs.]~~

2. Probabilistic Resource Availability Analysis

Objective: Analyze the periods of time and system conditions *outside* of system peaks that may not meet LOLE due to factors such as insufficient capacity, flexible demand, weather risk, etc.

Methods: For select matrix and alternative scenarios chosen by the MC/RC, examine correlation of loss of load risk and multi-day VER 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 analysis.

Learning points: Observations 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 about whether the results suggest scenarios for further study or some iterations with the energy and ancillary services analyses; the results will inform the system security analysis.

~~D. Revenue Sufficiency Analysis: Consultant-based software tool (Consultant) Phase 2~~

~~**Objective:** Compare revenues from the existing markets to resource costs by technology type.~~

~~**Scope:** Resources located in New England only; assume an unconstrained internal transmission system but interfaces at the RSP bubbles will be monitored. Some sensitivities that recognize constraints may be run.~~

~~**Methods:** For some matrix and alternative scenarios selected by the MC/RC, conduct a Forward Capacity Market simulation for a few bookend" prices. Add the resultant revenues to the revenues from the energy and ancillary services market analyses results. Compare the revenues from these existing markets to resource going-forward cost estimates. Present results in appropriate metrics for a technology type (e.g., $/kilowatt-month, $/year)~~

~~**Learning points**: High-level observations of whether revenues will be sufficient to attract and retain different types of resources.~~

~~**[Placeholder:** Further thought is required on how to develop resource going-forward cost estimates.]~~

~~E. System Security – Phase 2~~

1. ~~Transmission Thermal and Voltage Analysis: PSS/E or similar software (Consultant)~~

~~**Objectives:** Screen the transmission system for thermal overloads and voltage limits for representative scenarios to identify key areas that may need transmission reinforcement. Make additions of transmission and possibly other devices as needed to have secure cases on which to conduct the stability analysis.~~

~~**Scope:** High level review identifying the need for additional transmission and possibly other devices to develop secure cases for stability analysis~~

~~**Methods:** The MC/RC selects a few representative scenarios to do a high-level screen for the purpose of identifying and then relieving transmission constraints before performing the stability analysis. The level of detail is less than what is typically modeled in a transmission reliability study. Assumptions will be made by the consultant to relieve constraints without optimizing potential solutions. There will be some flexibility to iterate model simulations with greater or lesser amounts of VERs informed by the results of prior model runs and other areas of analysis.~~

~~**Metrics:** Identification of significant thermal overloads or voltage constraints for which relief should be assumed before conducting a stability analysis for the selected scenarios.~~

2. Stability Analysis: PSS/E or similar software (Consultant)

Objective: Do a high-level screen to show whether the decline in inertia from rotating machines combined with the growth of inverter-based resources will result in stability issues that may or may not be solvable with inverter capability. The change in inertia and generation with governors will change the system's ability to respond to large losses of generation through inertial pickup and increased output from conventional generators.

Scope: New England interconnected to New Brunswick and New York, external areas that will be modeled assuming decarbonization on the same scale as New England. Secure cases will be developed by identifying needed additions of transmission and possibly other devices based on the thermal and voltage testing described above.

Methods: Model the dynamic response capability of both conventional and inverter-based resources. The stability analysis will determine what, if any, devices are needed to maintain stability on the system for representative contingencies. Start with minimum load conditions (i.e. spring, weekend, mid-day) and consider also testing at peak loads.

Metrics: Determine if there is a gap that needs to be addressed by different operational or planning procedures or possible new market mechanisms to procure the required resources needed to maintain reliability.

Learning points: The gap analysis will inform the separate discussion that will be held about potential market approaches to solutions such as resource retention, fast-frequency responsive load, primary frequency response from inverter-based resources, minimum inertial generation dispatch requirements (including operation of conventional resources as synchronous condensers), using ultra quick start inverter-based batteries to provide an increase in megawatts (MWs) during a frequency decline, etc.

[**Placeholder:** Ask inverter manufacturers about their capability to provide inertia and use that information to inform the modeling.]

III. Scenarios

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

Matrix of Scenarios for Energy and Ancillary Services Market Simulations

	OSW 8,000 MW DER 18,000 MW	**OSW 8,000 MW DER 25,000 MW**	**OSW 17,000 MW DER 31,000 MW**
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OSW = Offshore wind
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The diagonal scenarios will be run first and, based on the results, an assessment will be made by ISO-NE whether any of the other matrix scenarios appear to be unrealistic, infeasible or not likely to tell something new. Based on that assessment, the MC/RC could decide to drop certain scenarios.

Stakeholders proposed some alternative scenarios. An assessment will be made by the MC/RC after the matrix scenarios as to whether to run each of the alternative scenarios based on factors such as whether an alternative scenario: 1) is likely to answer questions not already answered by the matrix scenarios or another study; 2) is feasible (meaning that the data/assumptions are available); and 3) can be completed in reasonable time.

Alternative Scenarios
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B. Vehicle to Grid (see Multi-Sector A)
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Energy and Ancillary Service Market Simulations:
9 Matrix Scenarios + 15 Alternative Scenarios = 24 Potential Scenarios

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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 appended table.

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 a 2,41,200 MW bi-directionally capable controllable direct current tieline injecting into Northeast Massachusetts.

E. Alternative Scenario B:

The objective is to analyze the impact of vehicle to grid storage. It assumes that an additional 100 gigawatts of energy storage isare 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.

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 plants.

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.

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 scenario G~~E~~ 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~~between SEMA~~, Boston and Connecticut~~T~~).

IV. Assumptions

The detailed assumptions for the different scenarios are shown in the Assumptions Document which is part of this Study Framework~~appended table~~.

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.~~Compare revenues from the existing markets to resource costs by technology type for a selection of existing and new resources~~

2.Going-forward cost estimates, including a reasonable rate of return, for existing resources and cost of new entry estimates for new resources, both prepared by a third-party consultant, from the revenue sufficiency analysis

3.The "bookend prices" used to estimate potential capacity market revenues.

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

54.Provide insight to expected revenues from the existing ancillary services markets under the scenarios studied from the GridView and EPECS results. Due to 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.

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 system peaks. Include the creation of marginal reliability index demand curves for selected scenarios.
4. Analyze the periods of time and system conditions outside of system peaks that may not meet LOLE due to factors such as insufficient capacity or flexible demand, weather risk, operational risk, etc.
4.
5. Show at a high level whether the decline in inertia from rotating machines combined with the growth of inverter-based resources will result in stability issues that may or may not be solvable with inverter capability, and provide insight on what, if any, devices are needed to maintain system stability

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 carbon emission / emission reduction levels in:
   a. The power sector through the GridView results
   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 shows a plausible schedule. It is not a target. Opportunities to overlap and expedite work shouldwill continue to be explored and pursued. Opportunities to overlap and expedite work will be explored.

VI.

Phase 1

This section shows what the schedule might be. It is not a target. e schedule reflects a preliminary view and is not a target. Opportunities to overlap and expedite work will be explored. So when I try to fix the document, text disappears and I don't know why.

Study Aassumptions development for matrix scenarios: February 2021 - are finalized by March 1, 2021

Assumptions development for alternative scenarios: February 2021- April 2021

Preliminary production cost simulations: AprilMarch 2021 – AugustSeptember 2021

Preliminary production cost results discussed with the MC/RC and the Planning Advisory Committee (PAC) and the MC/RCAC: -June 2021 – August 2021

Final production cost simulations: JulySeptember 2021 – DecemberMarch 20212

Ancillary services simulations: AugustSeptember 2021 – DecemberJanuary 20212

Final production cost results discussed with the MC/RC and PAC and the MC/RC: October 2021 -–—December 2021

MARS analyses: October 2021 – January 2022

Review/update assumptions: November 2021 – December 2021

Ancillary services results discussed with the ~~MC/RC and~~ PAC ~~and the MC/RC~~: November 2021 – December 2021

MARS results discussed with the ~~MC/RC and~~ PAC ~~and the MC/RC~~: December 2021- January 2022

~~MARS analyses: October 2021 – January 2022~~

Report writing: January~~February~~ 2022 – Ma~~y~~rch 2022

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~~Phase 2~~

~~Revenue Sufficiency An analysis: TBD but will not start before September 2021~~

~~System Security analyses: TBD but will not start before September 2021~~

	2021											2022											
	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec
MC/ RC Mtg	X	X	X		X			X			X			X		X Final							
PAC Mtg			X	X	X	X	X		X	X	X	X			X Final								
			4/1 – ES Request Due At PAC Meeting, present request By NEPOOL	Review ES Request Scope & Assump-tions with PAC (ISO)																			
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										Ancillary services results discussed with PAC													
									MARS analyses														
											MARS results discussed with PAC												
												Phase 1 Report writing											

VII. VII. Deliverables

The deliverables to both the MC/RC and the PAC will include: 1) periodic status updates to and consultations with the MC/RC; 2) periodic a PowerPoint presentation(s) on simulation and analysis resultsand written report(s) on the preliminary production cost simulation results; and 3) a final PowerPoint presentation and written report on the Phase 1Study results and key findings and observations.

VIII. Stakeholder Process

As an Economic Study, the ISO-NE will isn conducting 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, as needed, to: (i) provide high level reports to the MC/RC on the studies; (ii2), seek MC/RC determinations on any major decision points about the direction and focus of the studies;, and (iii) receiveprovide guidance from the MC/RC to ISO-NE onas the studies as they progress.

Future Grid S1 – Assumptions Details

February 26, 2021

nationalgrid

Scenario 1

- Based on 2020 Economic Study developed from internal modeling with adjustments per ISO-NE and stakeholder discussions
- Load assumptions will be updated per 2021 CELT and will differ from 2020 Economic Study accordingly
- At a high-level S1 compared to S2 and S3 is

Assumption Amounts	Compared to S2	Compared to S3
Gross Load	Equivalent	Cannot determine
Net Load	Lower	Lower
Energy Efficiency	Equivalent*	Cannot determine
BTM-PV	Equivalent*	Lower
Heating	Higher	Lower
Transportation	Lower	Lower
Utility Scale PV	Lower	Lower
Onshore Wind	Lower	Equivalent
Offshore Wind	Equivalent	Lower
Storage	Lower	Higher

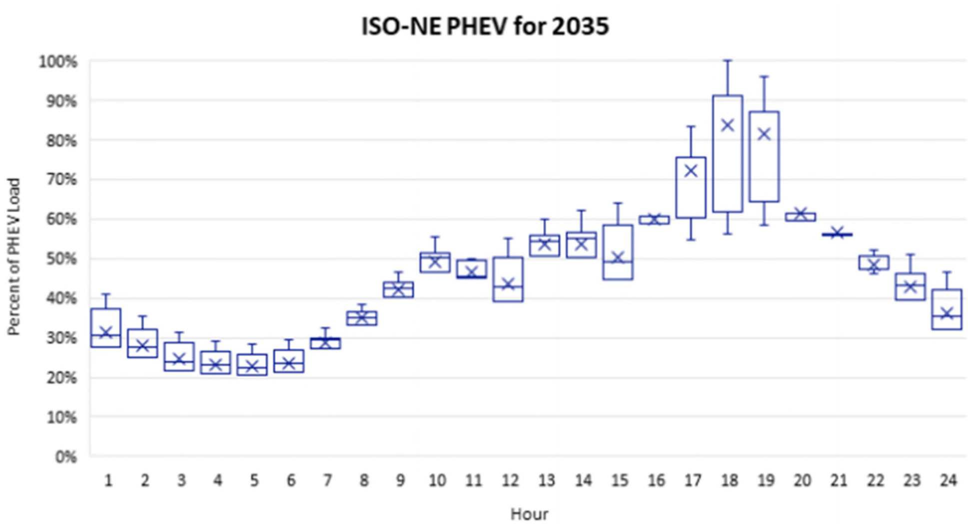
- Please note the table summarizes amount differences only and does not account for locational or profile differences
- *Pending 2021 CELT update values

Task 4

Clarify for the Transportation category in the Assumptions Table for each relevant scenario the EV load in MWs, the number of EVs, location(s) and the impact on emissions reductions

- Distributed based on load, as in table
- Hourly shapes broken down by subarea, given to the ISO for the 2020 Economic Study
- No discharge/generation back into the grid
- Represents 14% emissions reduction in the transportation sector relative to 1990 levels
- On a similar note, heat pump breakdown by zone was also provided to the ISO

State	Percent of Load	Number of Light Duty EVs
Massachusetts	43	946,000
Connecticut	23	506,000
Maine	12	264,000
New Hampshire	11	242,000
Rhode Island	6	132,000
Vermont	5	110,000
New England	100	2,200,000



- Similar % breakdown by state as S2 and S3, but less total vehicles
- Each scenario has own profile

Task 10

Clarify in the Assumptions Table for all relevant scenarios the location/interconnection point of all new resources proposed to be studied

- Specific interconnection points same as 2020 Economic Study (and 2019 Economic Study 8000_1)
- Correction to Assumptions Table: 6,425MW incremental PV solar, assumes 697MW already in-service for a total of 7,122MW
  - Consistent with 2020 Economic Study
- If additional resources are needed due to the change in load outlined in Task 13, we can provide additional resources broken down by type and zone

Zone	Utility-scale PV (MW)	Offshore Wind (MW)	Onshore Wind (MW)
CT	1,669	800	
ME	742		1,300
NH	165		30
NMABO	1	2,200	
RI	368	1,000	
SEMA	5	4,000	
VT	1,275		
WCMA	2,201		
Total	6,425	8,000	1,330

- Similar offshore and onshore wind amounts to S2, but less utility-scale PV
- Less offshore and utility-scale PV than S3

Task 13

Clarify how the load growth rate should be determined for all matrix scenarios

- Proposed method:
  - Start with 2021 CELT
  - Calculate a 3-year CAGR (2028-2030) for each zone
  - Apply to each future year to extrapolate to 2040
- Differs from the 2020 Economic Study
  - If the change in load growth results in a need for more resources to meet load, additional renewables may be added
- Aligns with S2

Task 14

Clarify what the demand reductions for EE, BTM-PV, etc. will be from for all relevant scenarios

- Pending revision per the 2021 CELT
- Values in the table reflect the 2020 Economic Study from the 2020 CELT

Category	Peak (MW)	Total (GWh)
EE	6,777	36,030
BTM	1,774	8,579

Task 15

Specify the battery storage resource characteristics for all relevant scenarios

- 2000MW of market-facing 4-hour battery storage
- Starting with $3/MWh VOM
- 86% efficiency, unless the ISO has an updated value
- Dispatched as outlined by the ISO in its detailed presentations, responsive to LMP
- Aggregated by RSP Zone based on the BESS in the ISO-NE queue
    - Differs from S2, which is based on system needs
- Consistent with the 2020 Economic Study except for VOM which is consistent with S2 and S3 for this study

Task 16

Specify the topology base modeling assumption for all relevant scenarios

- Existing system plus RSP planned projects
- Include Boston Needs RFP solution
- Include NECEC at 1200MW
- External interfaces pending (may elect 0MW exchange with NY, Quebec historical)
- Include Cape Cod Cluster Study and 2019 Economic Study transmission buildouts as sensitivities

Task 19

Define the proxy units and their characteristics for the MARS runs for all relevant scenarios

- Market-facing battery storage
  - Internal analysis has shown battery storage becomes the principle capacity resource post-2030

Alternate Scenario A

Analyze the impact of bi-directional controllable transmission to Quebec as a long-term storage and balancing resource

- Addition of a 2400MW bi-directional HVDC tie to each diagonal scenario injecting into NEMA
  - Update from originally proposed 1200MW due to final results of 2020 Economic Study (presented to PAC on 2/17/21)
- Proposal to model as the “Track” method used in the 2020 Economic Study
  - Utilize iterative process to optimize banked energy; may only import energy up to the amount that was exported
  - Threshold pricing triggers exports, curtails in-region renewables when export capability is exhausted, imports must run
  - Pending discussion with the ISO
- No other changes to the diagonal scenarios

nationalgrid

NEPOOL Future Grid Scenario 2 Assumption Details

February 26, 2020

Task 2: In-market versus out-of-market storage

EVERSOURCE ENERGY

- Scenario 2 proposes ~4GW of new battery storage
- Stakeholders have asked about whether storage will be modeled as in-market or as a demand reducing resource
- Eversource proposes modeling all storage as in-market resources that respond to LMP

Task 4: Modeling EVs

EVERSOURCE ENERGY

- # EVs calculated by following process:
  1. Start with number of total vehicle miles traveled to calculate vehicle emissions
  2. Required vehicle mile reduction calculated based on 66% emission reduction relative to 1990
  3. Using EV efficiencies, implied emissions rate of electric sector, miles per vehicle, etc. – calculate implied number of EVs
- EV profiles based on ISO-NE Final Draft 2020 Transportation Electrification Forecast

Zone	Light Duty EVs	Annual GWh
BHE	59,440	296
ME	201,027	1,002
SME	144,698	721
NH	362,633	1,808
VT	202,558	1,010
BOS	774,859	3,864
CMA	218,113	1,088
WMA	281,259	1,402
SEMA	366,915	1,830
RI	216,924	1,082
CT	414,980	2,069
SWCT	287,329	1,433
NOR	172,630	861
Total	**3,703,365**	**18,466**

Task 10: Capacity Addition Assumptions

EVERSOURCE ENERGY

- Eversource shared detailed data with ISO modeling team
- Updates based on ISO feedback:
  - Scenario 2 has Millstone 2 retired. ISO noted that is unique among scenarios and that Scenario C tests specifically for nuclear retirements. Scenario 2 will keep Millstone 2 in service.
  - OSW additions were focused in SEMA. Scenario 2 will instead spread OSW across SEMA, RI, and CT closer to the 2019 economic study.

Task 13: Load Growth Assumptions

- Proposed method:
  - Start with 2021 CELT
  - Calculate a 3-year CAGR (2028-2030) for each zone
  - Apply to each future year to extrapolate to 2040
  - Does not apply to heating and transportation load, which are driven by decarbonization assumptions
- Same as Scenario 1

Task 14: Demand Reduction

- EE and BTM PV based on 2021 CELT using same methodology as load growth
- Same as Scenario 1

Task 15: Storage operation

- 3,940 MW new battery storage
  - Mix of 2-hr, 4-hr, and 8-hr technologies
  - 90% efficiency
- Storage distributed to zones based on system needs (e.g. zones with more intermittent resources require more solar for balancing)
- Additional storage beyond 3,940 MW added as necessary during model development

Task 16: Transmission topology

- Same as Scenario 1

Task 19: Resource Adequacy Proxy Units

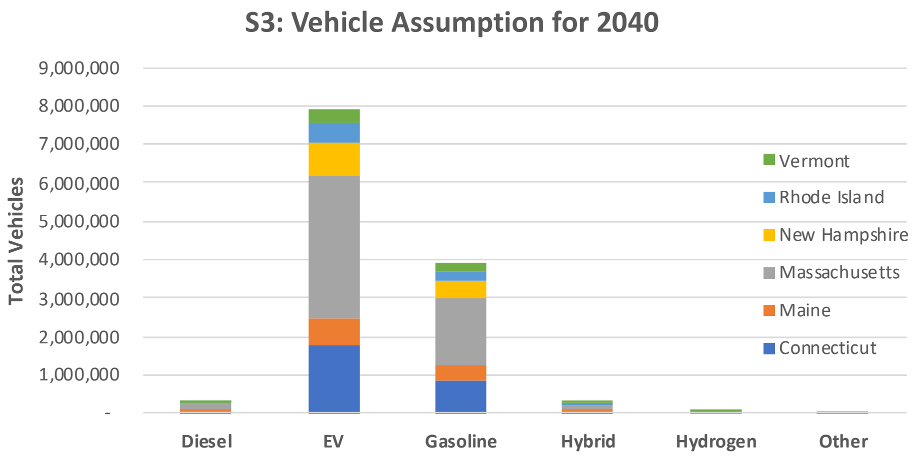
- Agreed with National Grid, NESCOE, and Anbaric on using battery storage as proxy unit

Future Grid Reliability Study
Scenario 3: Assumption Details

February 19, 2021

(4) EVs

- Clarify for the Transportation category in the Assumptions Table for each relevant scenario the EV load in MWs, the number of EVs, location(s) and the impact on emissions reductions
  - Technically – not needed for the analysis due to load forecast from Roadmap
  - For information:



	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Grand Total
Diesel	69,660	36,897	144,696	31,372	23,492	16,247	322,364
EV	1,771,747	719,581	3,697,445	828,080	552,391	348,086	7,917,330
Gasoline	873,732	378,167	1,770,740	420,145	265,755	183,439	3,891,978
Hybrid	63,613	24,356	125,073	28,456	19,936	12,028	273,462
Hydrogen	12,138	5,419	25,005	5,577	3,887	2,424	54,451
Other	672	419	1,526	346	248	180	3,391

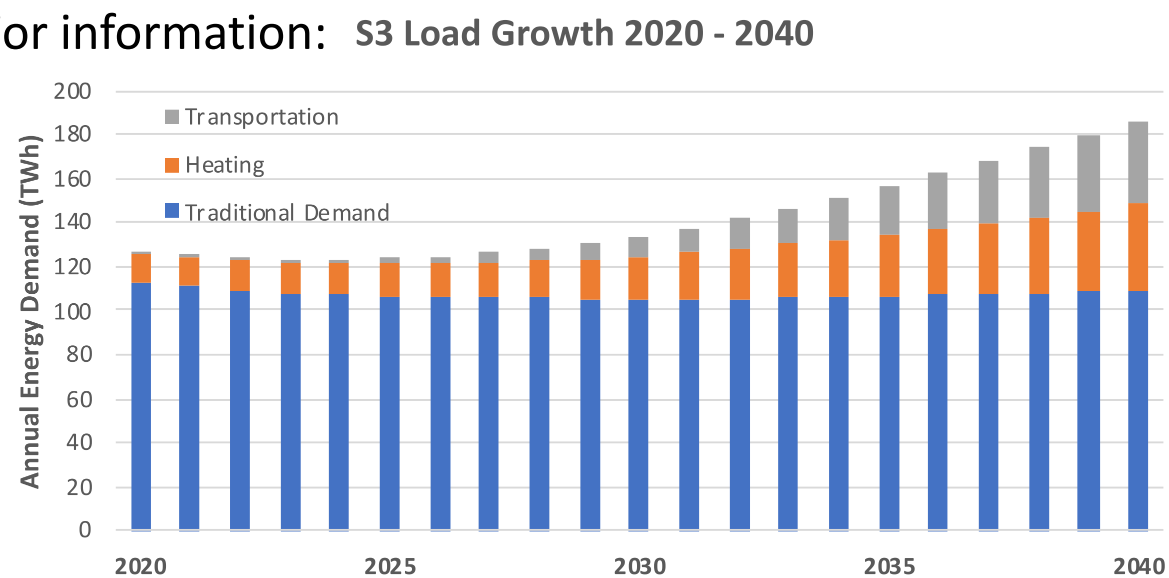
12,462,976

(10) Interconnection Locations

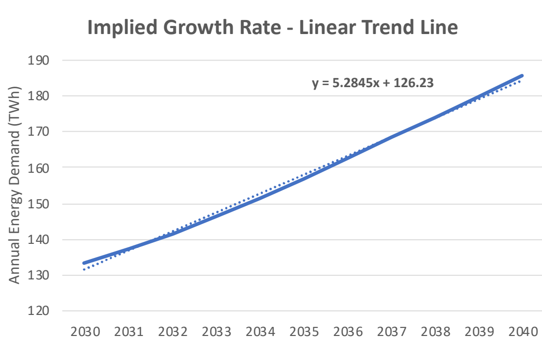
	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Grand Total
Biomass	43	652	53	229	40	82	1,099
Combined Cycle Gas Turbine	3,292	1,290	5,640	1,998	2,154	658	15,032
Combustion Turbine	284	61	657	94	13	333	1,442
Ground Mounted PV	4,319	95	4,406	5,088	51	1,508	15,467
Hydro	122	732	267	504	3	331	1,959
Nuclear	2,101	-	-	1,251	-	-	3,352
Offshore Wind Fixed	636	60	6,656	190	490	-	8,032
Offshore Wind Floating	0	3,015	2,667	714	2,205	-	8,601
Oil	8	9	9	8	2	2	38
Onshore Wind	15	359	447	182	45	290	1,338
Rooftop Solar PV	3,166	1,091	5,994	938	788	694	12,671
Pumped and Battery Storage	401	18	1,827	55	67	44	2,412

(13) Load Growth Rate

- Clarify how the load growth rate should be determined for all matrix scenarios
  - Technically – not needed for the analysis due to load forecast from Roadmap
  - For information:



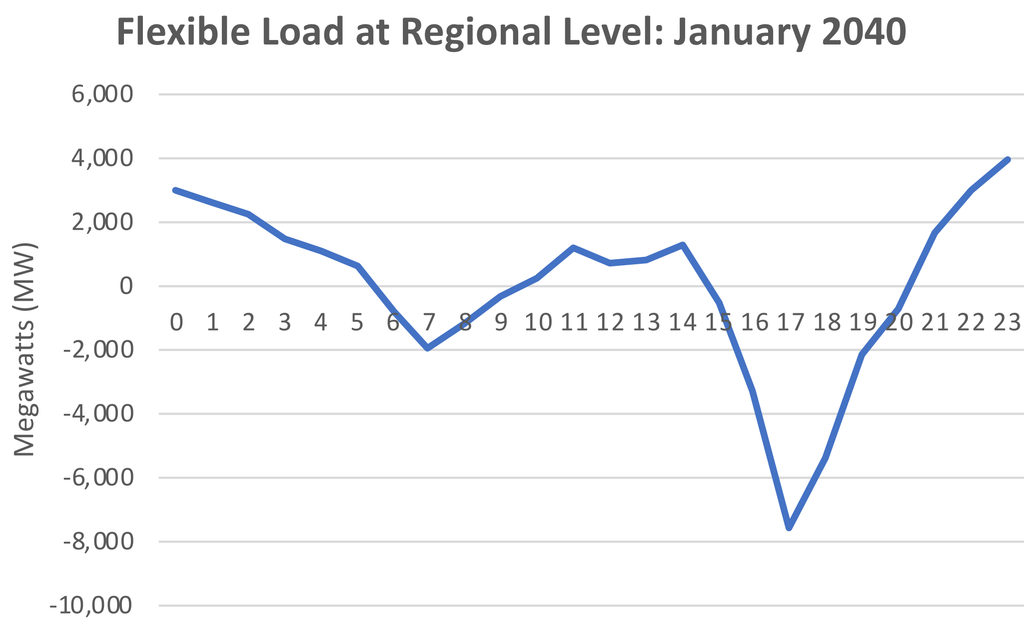
Translates to
~ 4.19% AGR
2030-2040



(14) Load Reductions & BTM Resources

Clarify what the demand reductions for EE, BTM-PV, etc. will be:

- EE:
  - Technically – not needed for the analysis due to load forecast from Roadmap
  - Not available – Would require additional counterfactual simulation to estimate EE
- BTM-PV:
  - Rooftop Solar PV on supply side in Roadmap analysis – 12,671 MW in 2040
    - Annual Energy Production 16,013 GWh
- 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 to be added to the 8,760 load profile



(15) Battery Storage

- Specify the battery storage resource characteristics for all relevant scenarios
  - Roadmap results aggregate pumped storage and battery storage
    - After deducting existing pumped storage facilities ~ 610 MW of battery storage

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Grand Total
Battery Storage	373	18	53	55	67	44	610

  - Market-facing battery storage resources with $3/MWh variable O&M assumption, to start
    - Interested in sensitivity with $2/MWh variable O&M costs for electric storage and $0.60/MWh for pumped storage

(16) Transmission Network Topology

- Specify the topology base modeling assumption for all relevant scenarios:
  - Zonal transfer limits from RIO 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 documentation
  - ISO-NE has reviewed topology and interchange data and confirmed with NESCOE

(19) Resource Adequacy Proxy Units

- Define the proxy units and their characteristics for the MARS runs for all relevant scenarios
  - Battery Storage – Market Facing with same characteristics as before

Questions and Discussion for S3

Future Grid Reliability Study Alternative Scenario B: Multi-Sector.

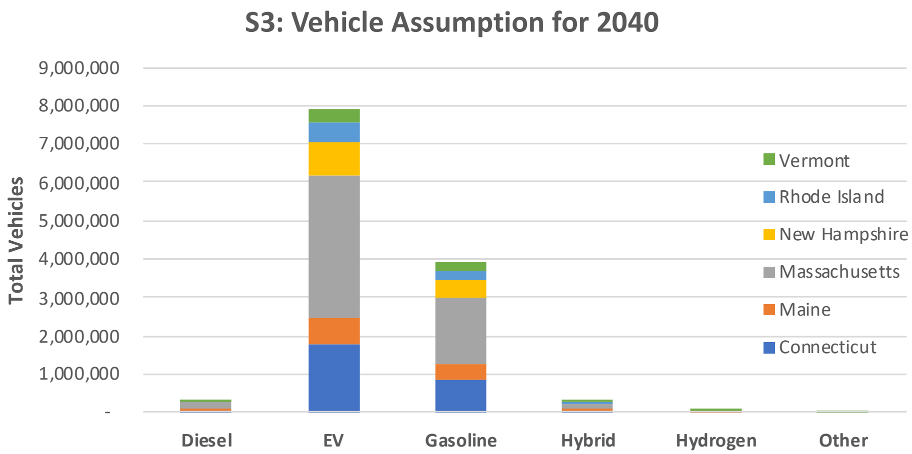
February 19, 2021

Premise

- Start with Scenario 3
- Make only the adjustments indicated here
- Intent is to focus on general availability of mobile storage from EVs to employ Vehicle-to-Grid technology for 25% of battery capacity, on average
- Results in a much larger amount of storage on the system: 100 GW / 200 GWh of additional battery storage available.
- Will impact market studies and transmission assessment with such a large amount of local storage naturally distributed throughout the system

(4) EVs from Scenario 3 (repeated for reference)

- Clarify for the Transportation category in the Assumptions Table for each relevant scenario the EV load in MWs, the number of EVs, location(s) and the impact on emissions reductions
  - Technically – not needed for the analysis due to load forecast from Roadmap
  - For information:



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Gasoline	873,732	378,167	1,770,740	420,145	265,755	183,439	3,891,978
Hybrid	63,613	24,356	125,073	28,456	19,936	12,028	273,462
Hydrogen	12,138	5,419	25,005	5,577	3,887	2,424	54,451
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							12,462,976

(10) Interconnection Locations

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Grand Total
Battery Storage	100 GW/200 GWh distributed with population, adjusted for population density. (Fewer cars per capita in large urban centers)						

(15) Battery Storage in Scenario 3
(repeated for reference)

- Specify the battery storage resource characteristics for all relevant scenarios
  - Roadmap results aggregate pumped storage and battery storage
    - After deducting existing pumped storage facilities ~ 610 MW of battery storage

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Grand Total
Battery Storage	373	18	53	55	67	44	610

  - Market-facing battery storage resources with $3/MWh variable O&M assumption, to start
    - Interested in sensitivity with $2/MWh variable O&M costs for electric storage and $0.60/MWh for pumped storage

(15) Battery Storage in Alternative B
(repeated for reference)

- Specify the battery storage resource characteristics for all relevant scenarios
  - Roadmap results aggregate pumped storage and battery storage
    - In addition to storage in Scenario 3 - 100 GW/200 GWh of battery storage

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont	Grand Total
Battery Storage	100 GW/200 GWh distributed with population, adjusted for population density. (Fewer cars per capita in large urban centers)						

  - Market-facing battery storage resources with $0/MWh variable O&M assumption, to start
    - Variable O&M costs better treated as periodic capital expenditures

Questions and Discussion for Alternative B

Anbaric alternative scenarios

26 February 2021

Anbaric's two future grid scenarios extend the Matrix scenarios' baseline

- scenario D is based on a future electricity grid with zero-emissions
- scenario E is a variant on scenario D with OSW interconnection points being more evenly distributed between SEMA, Boston and CT
- by looking at full decarbonization of the electricity sector in similar timeframes as the Matrix scenarios these alternatives provide corner points for analysis (allowing interpolation to be more accurate)

Q: Clarify the consideration of new or under construction resources that would be in the model for Anbaric's alternative scenarios

- in general, our scenario is flexible on resource assumptions – just with the tenor that this is a zero emissions scenario for the electricity system (no matter when fossil resources are assumed to have been added – retire them and then run the scenario)

- we will use the same assumptions as Matrix Scenario #3 – except that we want any units that are fossil units to be retired

Q: Clarify in the Assumptions Table the location/interconnection point of all new resources proposed to be studied

- mostly follow the lead of the matrix scenarios
- storage to be located proportionally to the fossil retirements

Q: Specify the battery storage resource characteristics for all relevant scenarios

- assumptions table presently shows three different storage durations and associated MW levels (all summing to 2.3 TWh of storage in total)

- while not a performance characteristic – we would suggest that the three durations be dispatched under different paradigms
    - the 4h (and even most of the 8h) storage layer would be dispatched similarly to the storage in the Matrix scenarios (market facing, dispatched based on LMP, etc.)
    - the long duration layer should be considered more as a grid resource for balancing renewable variability on a longer timescale (potentially under a tolling/RMR or tariff contract) – this may follow the way other ramping and reserve elements are modeled in the present system

Q: Define the proxy units and their characteristics for the MARS runs for all relevant scenarios

- open to following the lead of the Matrix scenarios with storage as the default proxy unit for all scenarios (likely 4h or 8h storage as the proxy)

alternative scenario E

Q: Clarify in the Assumptions Table the location/interconnection point of all new resources proposed to be studied

- alternative scenario E would like to have OSW connected to Boston and CT load zones (to the extent that base scenarios do not have significant amounts of OSW connecting there but rather connecting to SEMA with on-land upgrades)

- suggest that the proportional split be based on relative loads (SEMA : Boston : CT)

Q: Specify the topology base modeling assumption for all relevant scenarios

- alternative scenario E assumes topology that interconnects more OSW to Boston & CT
  - eliminates any topology additions that were added for OSW in the Matrix scenarios and alternative scenario D

ISO new england

Future Grid Reliability Study

Additional Feedback on Modeling and Assumptions for Phase 1 Studies

Carissa P. Sedlacek

DIRECTOR, PLANNING SERVICES | SYSTEM PLANNING

Background

- Since fall 2020, stakeholders at the joint NEPOOL Markets Committee (MC) and Reliability Committee (RC) meetings have been developing a Framework document supporting their Future Grid Reliability Study (FGRS)
  - The ISO has participated in the joint MC/RC meetings in an advisory role, answering technical questions as they arose
  - At the September 1, 2020 meeting, the ISO explained its technical ability to support the various studies that may comprise the FGRS
  - On December 29, 2020, NEPOOL formally asked the ISO for feedback on the proposed FGRS Framework document studies
  - At the January 19, 2021 meeting, the ISO:
    - Confirmed they could perform the Phase 1 studies
    - Agreed to continue reviewing the Phase 1 study assumptions
    - Offered to examine whether the Phase 1 studies could be done sooner

Updates on Phase 1 Study Assumptions:
What has Happened Since the January 19, 2021 MC/RC Meeting?

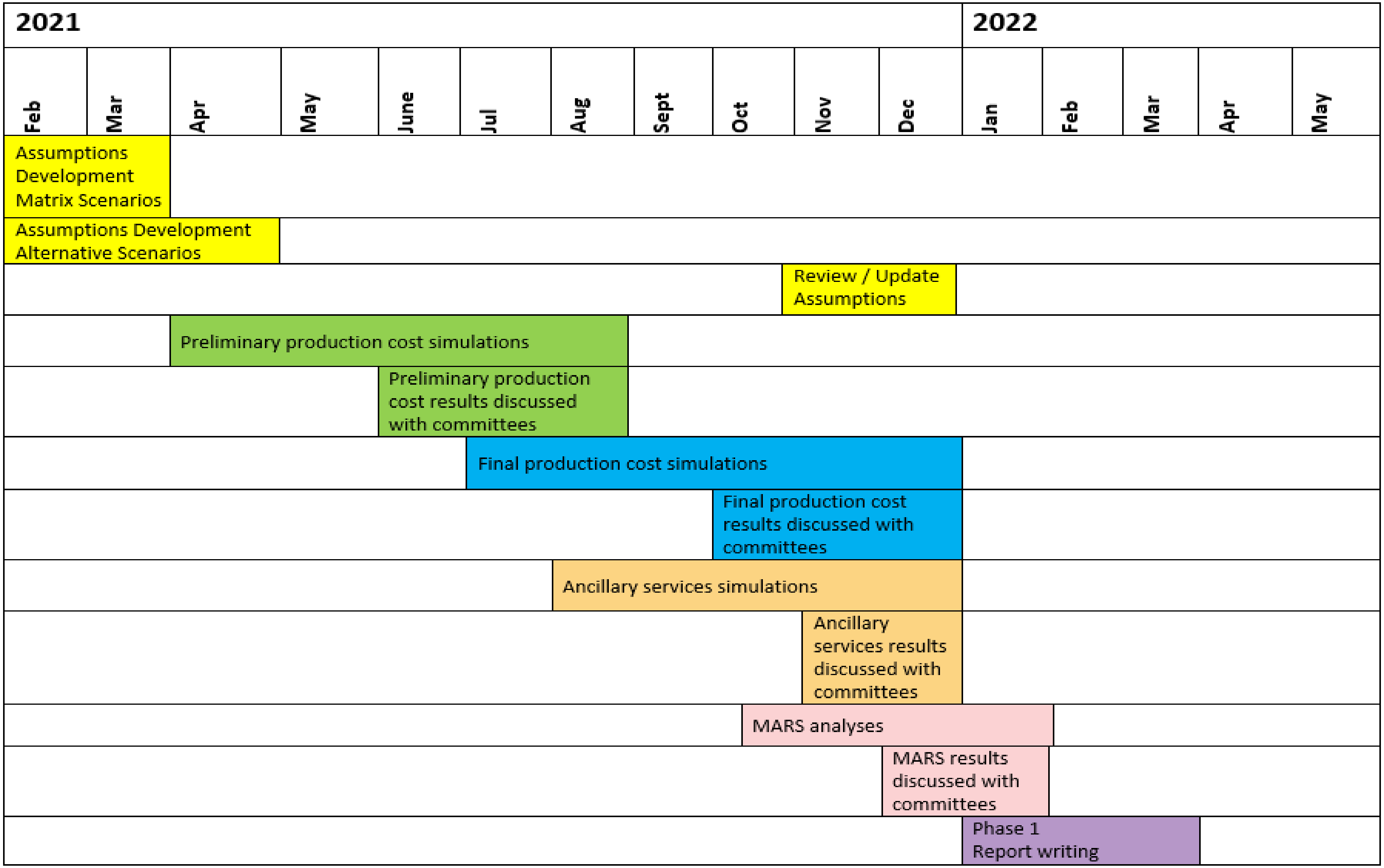
- Efforts continued to solidify the Phase 1 study assumptions for both the matrix scenarios and alternative scenarios
  - Related framework revisions led by Peter Flynn
  - Goal: to create a comprehensive list of assumptions to hand off to the ISO for Phase 1 study efforts as soon as practicable
- The ISO has had additional discussions with study proponents regarding Phase 1 study assumptions
  - Sought clarification and more detail so GridView and EPECS models can be developed sooner
- The ISO has further reviewed the Resource Adequacy Screen and Probabilistic Resource Availability Analysis assumptions related to the MARS runs and needs additional clarity
- The ISO developed two modeling presentations related to the Phase 1 studies for discussion today
  - Review of DNV GL data for modeling wind/solar resources
  - Electric Vehicle (EV) modeling

Schedule

Phase 1 Studies

- As requested, the ISO has reviewed the timeline with an effort to improve the proposed schedule
- The schedule has been shortened by two months
  - Includes additional overlap of studies
- Added "check-in" points for initial review and then further review of assumptions
  - Needed for sensitivities to matrix and alternative scenarios
- Added anticipated meetings with MC/RC (as the study proponent) and PAC
  - Schedule assumes the FGRS Phase 1 studies become a 2021 Economic Study

Schedule: Phase 1 Studies (updated)



Preliminary Committee Schedule

	2021											2022					
	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June
MC/RC Meeting	X	X	X		X			X			X			X		X Final	
PAC Meeting			X	X	X	X	X		X	X	X	X			X Final		

- The PAC will meet regularly to discuss the 2021 Economic Study once the Phase 1 studies are underway
- The MC/RC will be invited to PAC to participate, and the MC/RC will also reconvene periodically to make decisions that may be needed to set direction for the study

2021 Economic Study Submittal Process

- Submittal of the FGRS Phase 1 study as the 2021 Economic Study requires a letter to be sent to PACMatters@iso-ne.com (attention Carissa P. Sedlacek, Director Planning Services – System Planning) by **April 1, 2021 at 5:00 pm**.
  - The Framework document and assumptions table should be an attachment to the letter requesting the Economic Study
- Upcoming key milestones
  - Submission of the FGRS Phase 1 studies as a 2021 Economic Study will NOT affect the timeline or the ISO efforts to work with stakeholders on study scope, assumption clarity or creating models

Key Milestone	2021 Due Dates
Submission of Economic Study Request	April 1 by 5 pm
ISO to contact all presenters of Economic Study Requests regarding logistics	April 5 by Noon
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

Why use the Economic Study Process?

- Formally provides ownership of the request to the MC/RC members
  - NEPOOL has previously submitted an Economic Study - See 2016 Economic Study
- Provides an avenue for NEPOOL to get the FGRS Phase 1 study work done in a timely manner with clear structure
  - If the ISO did not use the Tariff-defined Economic Study structure as outlined in Attachment K, the ISO could get multiple Economic Study requests under the Tariff that could pre-empt non-Tariff request
- Using the PAC for presentation of FGRS Phase 1 study results should not slow the process
  - MC/RC members will be invited to PAC meetings
- “Scope Creep” is unlikely because the Framework document is already well defined

Phase 1 Studies Additional Clarifications

Production Cost and Ancillary Services Simulations

- As of February 12, the ISO has reviewed the assumptions documented to date
  - Some assumptions need further clarification
- The following slides outline the additional assumption details needed for the matrix and alternative scenarios
- After today's meeting, the ISO will continue to review proposed assumptions as they start to build the models, and will seek clarification as needed

Phase 1 Studies Additional Clarifications

Necessary Assumptions for both Gridview and EPECS

Load-Related Assumptions

- Confirmation that BTM PV Resources will use the same weather year data as wind and load?
- Matrix Scenario S2: Battery Energy Storage Systems (BESS) characteristics
  - Need to assign discrete ratings for BESS
    - 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
  - Interconnection locations: Distribution of batteries across New England system is still needed

System Topology

- Matrix Scenario S2: Unclear what is meant by "relatively unconstrained flows" for the New England system
  - Recommend removing all system constraints for consistency with other scenarios

Phase 1 Studies Additional Clarifications, cont.

Necessary Assumptions for both Gridview and EPECS

Resource Mix

- Will nuclear and Municipal Solid Waste (MSW)/Landfill Gas (LFG) resources be treated as "must-run units" as they have in prior economic studies?
- Alternative A Scenario: Is the intention to use the room between the existing tie import profiles and the physical maximum of the tie for importing "banked energy?"
  - Energy Banking: Utilize the ties to export energy and lower renewable build-out spillage during periods of low demand. Then, during periods of high demand, import the energy back to New England.
- Matrix Scenario S2: Need specific breakdown of where new PV and wind resources will be located.
- There seemed to be interest in testing *varying* amounts or types of reserves. If so, there needs to be more clarity in what stakeholders are seeking.

Phase 1 Studies Additional Clarifications, cont.

Necessary Assumptions for EPECS

Background

- EPECS simulator consists of four simulation layers addressing different user-defined time scales. The four layers and time scales currently used are:
  - Day-ahead resource scheduling as a security-constrained unit commitment (SCUC)
  - Four-hour-ahead, real-time security-constrained resource scheduling as a real-time unit commitment (RTUC)
  - Fifteen-minute-ahead, real-time balancing as a security-constrained economic dispatch (SCED)
  - Real-time physical power flow with integrated regulation service using one-minute time steps

Phase 1 Studies Additional Clarifications, cont.

Necessary Assumptions for EPECS

- Forecast error allocation for wind, solar, and load in SCUC (day ahead), RTUC, and SCED simulations is needed
  - The ISO can provide recommendations for values for these parameters
  - Recommend using the same forecast error for all scenarios
- In the 2020 Economic Study, hydro resources were modeled using GridView's hydro dispatch model rather than a profile. Should the same approach be used for the FGRS?
  - Or should a static hydro profile be used as an input to EPECS?
- SCUC, RTUC, SCED, 30-minute operating reserve (TMOR) and 10-minute spinning reserve (TMSR) time steps and horizons can be customized
  - The ISO can provide recommendations for values for these parameters
- Should we use “do not exceed limits” to limit reserve fluctuations?
  - Note: Reduces the total need for reserves, thereby reducing overall variability
  - The ISO can provide recommendations
- Should the program attempt to minimize regulation reserve exceedances and system imbalance through re-dispatch?
  - Note: The error is mainly caused by forecast uncertainty. The ISO can allow the EPECS program to do more with dispatch to address this issue.

Phase 1 Studies Additional Clarifications, cont.

Necessary Assumptions for EPECS

- Confirmation that the ISO should run full 2040 year studies rather than focus on shoulder periods only
- In EPECS, only regulation reserves are available in real time to respond to system imbalances; while storage exists in the cases, it is dispatched in SCUC and RTUC
  - If participants want a real-time proxy for how battery storage could respond, they should specify it as regulation reserves (or understand we're going to use it as a proxy)
  - How much regulation reserves do they want available to respond in real time?

Phase 1 Studies Expected Results

Energy Production and Ancillary Services Simulations

- When performing economic studies, two primary simulation tools are used by the ISO for the power system production-cost simulations: Gridview and EPECS
  - The GridView model is used for energy-production simulations and the EPECS model for ancillary-services simulations
- GridView performs transmission and security-constrained optimization of the system resources against spatially-distributed loads to produce a realistic forecast of the utilization of power system components and flow patterns in the transmission grid
  - GridView can use either cost-based inputs based on physical quantities or resource owner-determined bids; only cost-based inputs have been used to date
  - Gridview cannot model the distribution system
- The following slide lists the commonly-reported metrics

Phase 1 Studies Expected Results, cont.

Energy Production and Ancillary Services Simulations

- Economic Metrics
  - Production Cost
  - Load-Serving Entity Energy Expense (LSEEE or LSE Energy Expense)
  - Uplift
  - Congestion Costs
    - Congestion
    - Congestion with FTR/ARR Adjustments by Financial Transmission Rights (FTR)/Auction Revenue Rights (ARR)
  - Locational Marginal Prices (LMP)
  - Gross Revenues
  - Net Revenue/Contributions to Fixed Costs (CTFC) by Fuel Type and Technology
- Investment Metrics
  - Relative Annual Resource Cost (RARC) given an assumption such as Annual Carrying Charges (e.g., assuming 16% to 18% of capital cost per year)
- Transmission Metrics
  - Interface Flow
    - MW Flows
    - Percent of Interface Transfer Limit
  - Hours at Interface Transfer Limit
  - Congestion
  - Bottled-In Energy Behind Transmission Transfer Limits
- Operational Metrics
  - Energy Production by Resource Type (GWh)
  - Energy Production by Fuel Type
  - Fuel Setting the Marginal Price
  - Net Load Ramp
  - Reserves
  - Capacity Factor by Unit Class
  - Annual spillage by resource
- Emission Metrics
  - System Emission Targets
    - Carbon Dioxide (CO_2)
    - Nitrous Oxides (NO_X)
    - Sulfur Dioxide (SO_2)
  - Renewable Resource Production vs. RPS Targets

Phase 1 Studies Additional Clarifications

Resource Adequacy Screen and Probabilistic Resource Availability Analysis

Background

- The ISO uses the Multi-Area Reliability Simulation (MARS) model to conduct the Resource Adequacy Screen and Probabilistic Resource Availability Analysis
- MARS is a sequential Monte Carlo simulation program that computes the reliability of a power system comprising a number of interconnected areas containing resources and load
- Through simulating the system chronologically and repeatedly (multiple replications), the MARS program assesses the ability of the system to serve load under a wide range of possible system conditions
  - MARS considers the availability of resources, expected load, and inter-area transfer limitations

Phase 1 Studies Additional Clarifications, cont.

Necessary Assumptions for MARS

Certain modeling assumptions are unique to the MARS analysis and need to be defined:

- Allocation of weather-related uncertainty associated with load forecast, including gross load, ASHP load, EV, and BTM-PV
  - With the assumed increase in the penetration of weather-sensitive load (e.g., ASHP), additional volatility may need to be incorporated in the load model for the winter
  - Should the same weather-related uncertainties used for FCA 16, adjusted for winter, be used for the FGRS Phase 1 study?
- Uncertainty associated with the output of VERs and their correlation with load
  - Sufficient representation of their impacts on establishing resource adequacy for the system, including considerations of extreme events
  - May be able to use the *new* DNV GL wind/solar profiles

Phase 1 Studies Additional Clarifications, cont.

Necessary Assumptions for MARS

- Tie benefits assumptions from external control areas
  - Current tie benefits assumptions used in FCM are annualized equivalent values, reflecting the expected LOLE risks and the need for emergency assistance during the summer, with most assistance provided by winter-peaking neighbors of Quebec and Maritimes
  - If the New England system is expected to evolve to winter peaking or dual summer/winter peaking in the scenarios under study, do stakeholders prefer using seasonal tie-benefits assumptions?
    - Possible to derive some reasonable assumptions based on the past FCM tie-benefits study results
    - Unrealistic to conduct a tie-benefits study due to the efforts required and the tight schedule
- Additional discussions are warranted
  - Next month, the ISO will provide additional detail and potential options

Phase 1 Studies Expected Results

Resource Adequacy Screen and Probabilistic Resource Availability Analysis

- Resource Adequacy Screen
  - Objective: Focus on resource adequacy of each planned, resource-mix scenario in accordance with the LOLE criterion, and identifying:
    - Additional resource/capacity needs in terms of the amount of proxy unit(s), if short
    - Surplus in terms of additional load carrying capability (ALCC), if long
  - Metrics (**expected** reliability indices for as-is and at-criterion condition):
    - Loss-of-Load **Expectation** (LOLE)
    - **Expected** Loss-of-Load Hours (LOLH)
    - **Expected** Unserved Energy (EUE)
  - Produce representative system net ICR for MC/RC selected scenarios
    - Based on current market rules
  - Create System Marginal Reliability Impact (MRI) curves for MC/RC selected scenarios

Phase 1 Studies Expected Results, cont.

Resource Adequacy Screen and Probabilistic Resource Availability Analysis

- Probabilistic Resource Availability Analysis
  - Objective: To understand reliability risks under various system conditions
  - Metrics
    - Boundary of risks: probability distribution of the expected reliability risks identified in Resource Adequacy Screen
    - Timing of risks: season, month, hours during the day
    - Expected frequency of outages
    - Expected outage duration
    - Location of risks: assuming reserve sharing among all subareas
    - Statistics of flows across major interfaces

Next Steps

- The ISO will continue to review the FGRS Phase 1 study portion of the Framework document, including assumptions, to identify additional areas for clarification
  - This work will continue through March
- The ISO is accepting 2021 Economic Study requests now through April 1, 2021
  - May require the Framework document being split into two separate documents highlighting the Phase 1 and Phase 2 work separately

Stochastic Time Series Modeling for ISO-NE

Overview of Work

Steven Judd, PE

PRINCIPAL ENGINEER | SYSTEM PLANNING

Purpose

- Provide stakeholders an overview of the DNV GL stochastic time series analysis of variable energy resources (VER)
- Describe 2021 update to the VER time series data

Overview

- Background
  - 2020 ISO-NE VER Data Set
- Stochastic Time Series Analysis
  - Expansion of 2020 ISO-NE VER Data Set
  - Stochastic Engine (SE)
  - Key Performance Indicators (KPI) Analysis
- 2021 VER Data Series
  - Historical 2020 Data Update
  - New Facility Additions

Background

- During 2019 it became apparent to ISO-NE that a new consistent dataset of offshore wind was needed to serve as inputs to multiple studies across the organization
  - 2019 Economic Studies
  - Transmission Planning Study Assumptions
  - Energy Security Analysis
- We hired DNV GL at the end of 2019 to use their weather modeling software and develop a historical data set of all existing wind plants and future offshore wind plants from 2012-2018. This work was presented to PAC in February 2020 with two presentations
  - ISO-NE presentation and DNV GL presentation
- In early 2020, DNV GL updated the data set with an additional year of historical data and recalibrated the models to create an updated 8 year data set from 2012-2019. (e.g., if a modeled wind farm had two years of historical data instead of one, the model would be recalibrated to more closely match the longer historical record)
- In Summer of 2020, the ISO hired DNV to create a stochastic data set from an expanded historical modeled data set from which the results of that study are being presented today
  - July 22, 2020 ISO-NE PAC scope of work presentation
  - 2020 ISO-NE Variable Energy Resource (VER) Data Series (2000-2019) Rev.3
- In Fall of 2020, the ISO hired DNV to expand and recalibrate the historical data set to include 2020 historical data and additional hypothetical wind/solar plants
  - 2021 ISO-NE VER Data Series (2000-2020) to be posted in Mar-Apr 2021

2020 ISO-NE VER Data Set

- The 2020 ISO-NE VER data set contained hourly time series data for wind resources in New England for 8 years (2012-2019)
- This data set was created using NASA satellite information and advanced modeling software from DNV GL to create historical time series profiles based on New England weather conditions
- The data set was then calibrated with available recorded data to get the best fit possible
  - NOTE: The data set will not match historical values hour-by-hour, since it is based on a model, but the data should still follow overall weather trends and magnitudes and be statistically similar to recorded values
- The data set included the following information
  - 37 existing onshore and 1 existing offshore wind plant wind speed profiles
  - 12 future offshore wind plant wind speed profiles (4 state contracted and 8 hypothetical in BOEM lease area south of Cape Cod)
  - Aggregate wind power profiles (1 onshore and 1 offshore)
    - NOTE: Individual wind plant power profiles are considered market sensitive under the ISO Info Policy
- Revision 2 of this data set was posted to the PAC website on May 1, 2020 (Rev 0 and 1 included minor updates that are detailed in the read me file in the data set)

STOCHASTIC TIME SERIES ANALYSIS

Expansion of 2020 VER Data Set and Stochastic Engine

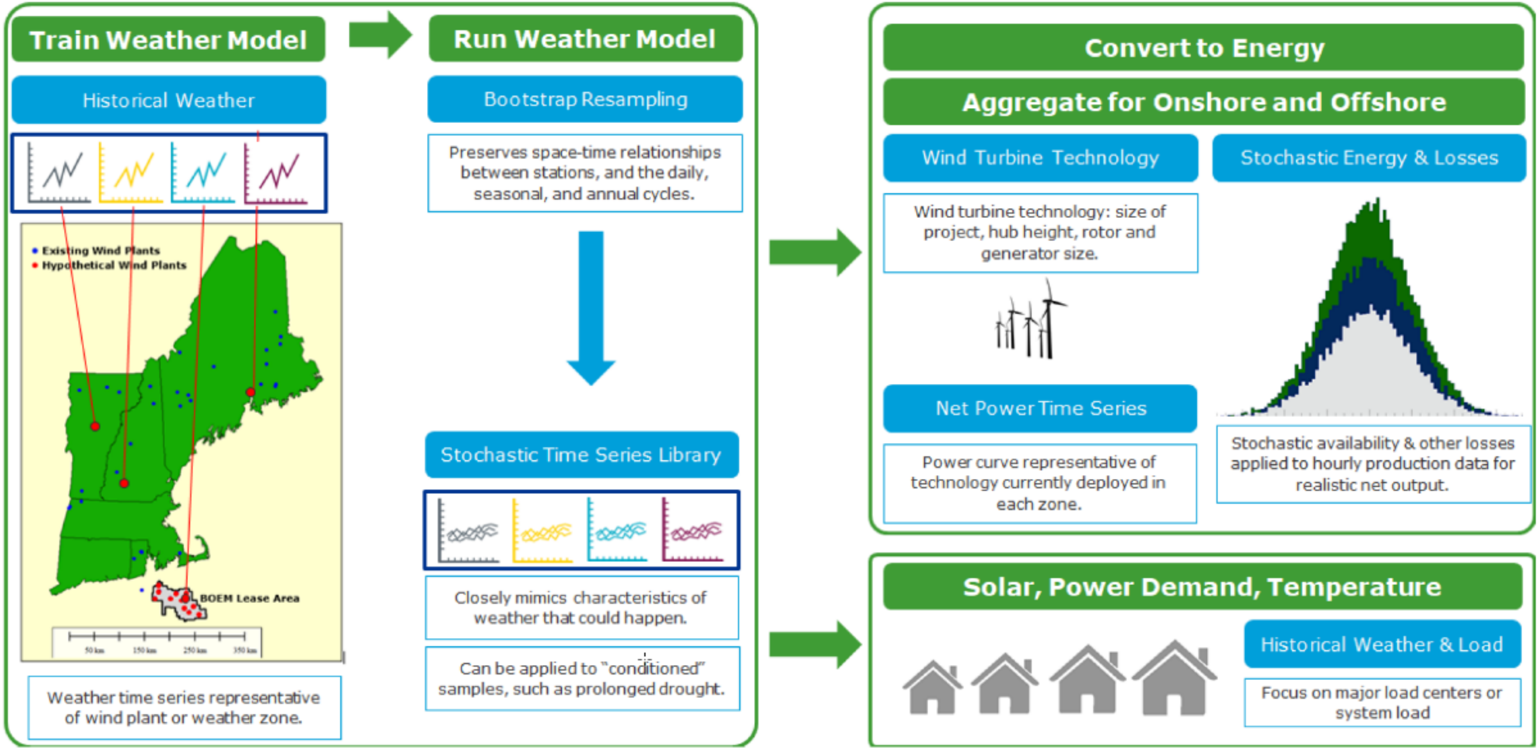
Expansion of 2020 ISO-NE VER Data Set

- In order to provide enough historical weather events for the Stochastic Engine, DNV GL recommend the historical VER data set should be expanded to 20 years
- The historical data set also needed to include solar and load profiles for the full 20 years to provide the co-dependencies between wind, solar, and load
- Revision 3 of the 2020 ISO-NE VER data set was posted on September 21, 2020 and contains hourly time series data for variable energy resources, load, and weather data in New England for a full 20 years (2000-2019)
- The expanded data set added the following information
  - All previous data from Revision 2 expanded to a full 20 years (2000-2019)
  - Aggregate behind-the-meter solar photovoltaic (PV) power profiles by Load Zone
  - Load (gross minus energy efficiency) and weather (temperature, relative humidity [RH], and global horizontal irradiance [GHI]) profiles by Load Zone

Stochastic Engine

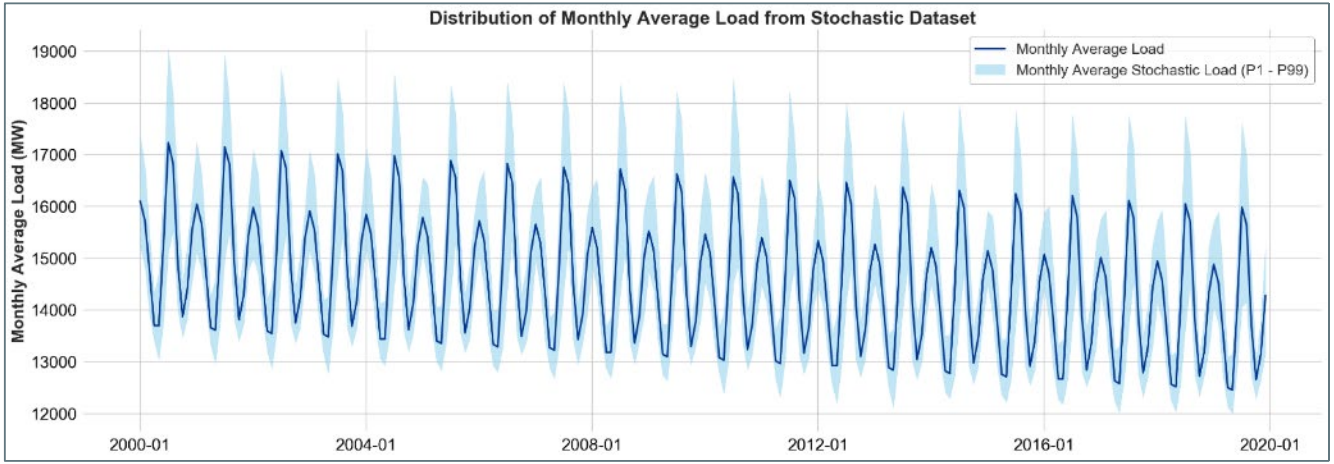
- The Stochastic Engine (SE) is a tool developed by DNV GL to statistically tackle time-series-based problems at scale. It can resample any time series (wind speed, irradiance, price, load) into parallel, plausible, scenarios while preserving all the relationships within the data and between the signals.
- The weather-to-generation models will then simulate the expected power production for each weather scenario, creating at least 20,000 years worth (1,000 20-year simulations) of hourly time series of weather and power outputs for each wind plant, zonal solar, and zonal load.
- Each time series will preserve the correlations from year-to-year, month-to-month, temperature-to-load, and zone-to-zone.
- Each 20-year simulation (also referred to as a realization) can be thought of as an alternate reality of weather conditions that have the same overall climate of New England.
- The stochastic data set is LARGE. It contains **175.2 million hours** worth of data and is **512 GB** in size.

Stochastic Engine, cont.



Stochastic Engine, cont.

- The SE preserves all trends present in the original data set. The figure below presents the distribution of monthly mean load values calculated from the 20,000-year stochastic data set. The original 20 years of input gross load data exhibited a downward trend, in part due to the implementation of energy efficiency programs in recent years. The stochastic data set preserves this trend. The monthly average loads of the data set are shown in the graph below.



STOCHASTIC ANALYSIS RESULTS

Key Performance Indicators

Key Performance Indicators (KPIs)

- The ISO prioritized the following KPIs for DNV GL to analyze in the stochastic data set
  1. Reliability of VER during cold snaps / heat waves
  2. Probability of wind and solar droughts/lulls
  3. Correlation of load, wind, and solar
  4. Representative 8760s
  5. Distributions of wind at peak(min) gross(net) load
  6. Intra-day variability of VER (ramping)
- The ISO had also proposed analyzing the following KPIs, but did not have enough budget in this round to complete
  - Storage requirements for VER to reduce resource variability
  - The probability of high-wind shutdown events for offshore wind
  - Analysis of impacts of upcoming 2024 solar eclipse
- A detailed presentation was made at the Planning Advisory Committee (PAC) on February 17, 2021 describing the results of this work
  - A final report will be posted on the PAC website

2021 VER DATA SERIES

Historical 2020 Data Update and New Facility Additions

2021 VER Data Series – Historical 2020 Update

- The ISO worked with DNV GL to update the 2020 historical data set (2000-2019) and add historical weather for 2020 to augment the model to 21 years (2000-2020)
- Additional historical output from load, wind, and solar will also be reviewed to update the bias and calibration of the models

2021 VER Data Series – New Facility Additions

- In addition to the annual update, the ISO had budget to add new hypothetical wind and solar facilities to explore resource diversity in areas where the region currently doesn't have any existing facilities
  - Note: The new hypothetical wind and solar facilities are NOT included in the stochastic data set described earlier
- In an effort to balance available budget and interest in modeling new hypothetical plants, the following facilities were added to the historical model
  - Six new hypothetical 1,200 MW offshore wind plants off the coast of MA, NH, & ME
    - Located in Federal waters up the coast from southeast of Cape Cod to the Canadian border
  - Four new hypothetical onshore wind plants in previous cluster study regions
    - Two 600 MW facilities, one in Western Maine and one in Central Maine
    - Two 1,200 MW facilities in Northern Maine
  - Seven new hypothetical 100 MW utility scale solar facilities
    - One in VT, NH, MA, CT, and RI and two in ME
    - Located in vicinity of existing or proposed utility scale facilities
- Note: These facilities' locations do not indicate an ISO preference or any indication on feasibility of interconnection. They are for hypothetical purposes only to examine the diversity of wind/solar resources in regions that currently do not have an existing facility

2021 VER Data Series – New Facility Additions, cont.

Offshore Wind Plant	Latitude	Longitude	Hub Height (m)	Wind Plant Capacity (MW)	State
Cape Cod	41.46250	-69.5742	150	1,200	MA
Boston	42.27708	-70.2728	150	1,200	MA
Seabrook	42.82307	-70.2638	150	1,200	NH
Wyman	43.72208	-69.0470	150	1,200	ME
Bar Harbor	44.22864	-67.8431	150	1,200	ME
Calais	44.50961	-66.9413	150	1,200	ME

Onshore Wind Plant	Latitude	Longitude	Hub Height (m)	Wind Plant Capacity (MW)	State
Maine South	44.60497	-70.8989	120	600	ME
Maine Central	45.07148	-70.0202	120	600	ME
Maine North 1	46.12256	-68.5006	120	1,200	ME
Maine North 2	46.91812	-68.1691	120	1,200	ME

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

Timeline

- The 2021 ISO-NE VER data set (2000-2020) with the new facilities is expected to be posted on the PAC website in the March-April 2021 timeframe
  - Similar to previous releases, the wind power data will be aggregated into a single onshore and single offshore profile to avoid any market sensitive data related to wind-to-power curves
- The ISO is seeking input if either the stochastic data set with representative 8760 profiles, or the 2021 historical data set with additional onshore/offshore wind facilities, should be used in the Future Grid Reliability Study as an alternative to current modeling practices

Questions

ISO new england

Developing a GridView Flexible Electric Vehicle Charging Model

Future Grid Reliability Study

Wayne Coste

TECHNICAL MANAGER, RESOURCE STUDIES & ASSESSMENTS | SYSTEM PLANNING

Purpose of this Presentation

- In response to various questions about electric vehicles (EVs), the ISO has prepared this presentation:
  - To review current proposals to represent Electric Vehicles in the Future Grid Reliability Study (FGRS)
  - To discuss limitations in both data and modeling
  - To examine a conceptual model for flexible EV charging suitable for either
    - One-way "charging only" mode
    - Two-way "Vehicle-to-Grid ("V-2-Grid") mode
  - Request feedback on the preference for fixed EV charging profile vs. an LMP based "system benefits" flexible charging model

Conceptual Model of Integrated EV Charging

- Develop a framework where EV charging would respond to system LMPs
  - Mesh with GridView's "objective function" for "minimizing production cost"
  - Represent charging flexibility to allow GridView to maximize "system benefits"
- Explore concepts around flexible charging
  - Amount of flexibility could be adjusted
    - One-way, "charging only" mode
      - Would have a limited operating range to increase or decrease charging
      - Probably limited to the minimum amount of charging load (no exporting to the grid)
    - Two-way, V-2-Grid mode
      - Charging and discharging can be a significant fraction of the charging load
      - Even vehicles not driven (and charged) on a daily basis can be assumed to participate

Background on Electric Vehicle Batteries

- Large amounts of vehicle battery storage capability have been implied
  - 2020 Economic Study assumed 2.2 million electric vehicles
  - Equivalent to 180,000 MWh of vehicle battery storage
    - Based on Tesla Model 3 at 82 kWh
    - About 22 times the assumed market facing batteries in the 2020 Economic Study
      - 2020 study assumed 8,000 MWh
      - Based on assumed 2,000 MW at 4 MWh/MW
    - Only a small portion of the vehicle flexible storage capability MWh will be used
- EV batteries are envisioned to withstand extensive cycling
  - "Million mile batteries" are being developed
  - See https://www.greencarreports.com/news/1128221_gm-battery-chief-600-mile-evs-viable-million-mile-battery-in-sight
  - EV mobile batteries appear resilient and can be repurposed when their energy density to weight ratio degrades (used in stationary battery facilities)

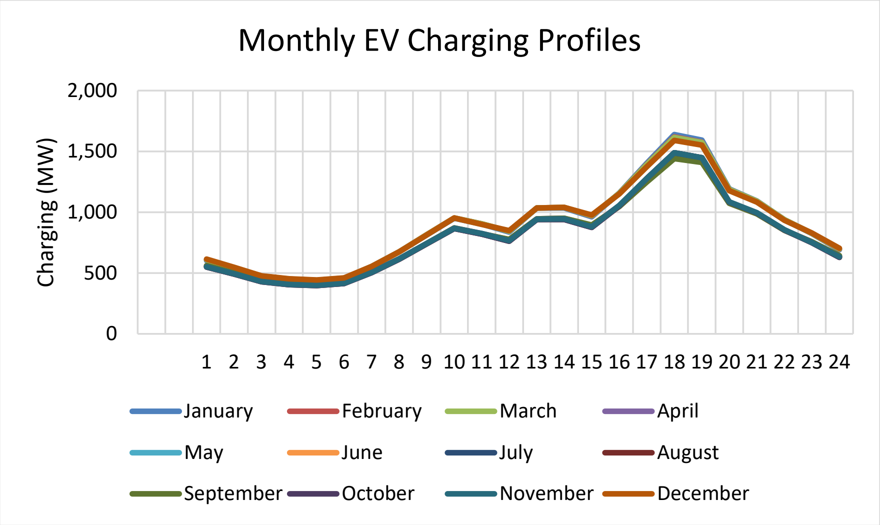
REVIEW OF EV PROPOSALS

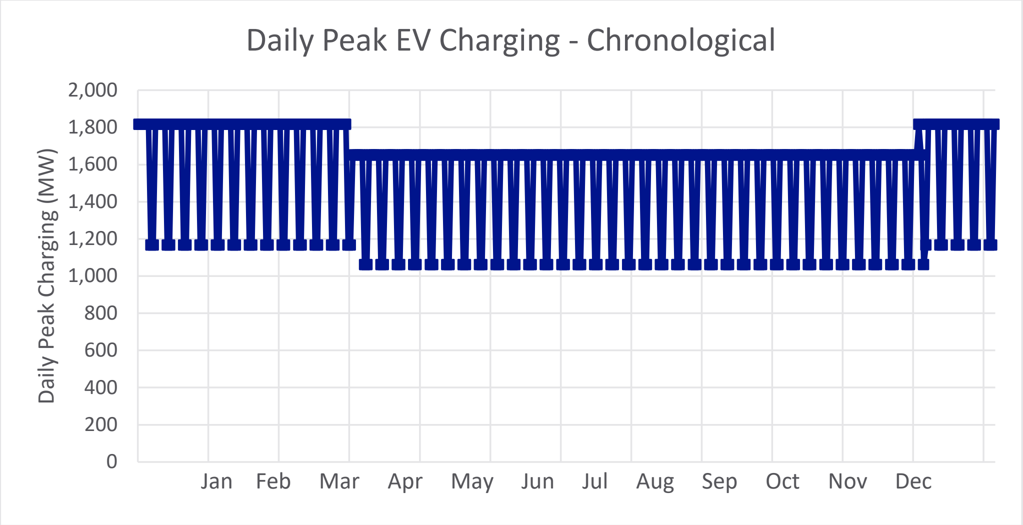
FGRS Matrix Scenarios

Matrix Scenario – EV Assumptions

Scenario	Transportation
Matrix Scenario 1	Peak: 1,817 MW 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 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). May 20, 2020 PAC, slide 13 June 17, 2020 PAC, slides 22-23
Matrix Scenario 2	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	Transportation 39.9 TWh (embedded in load forecast from EnergyPATHWAYS) (Primary fuel type emissions reduced by approximately two-thirds relative to 2020)

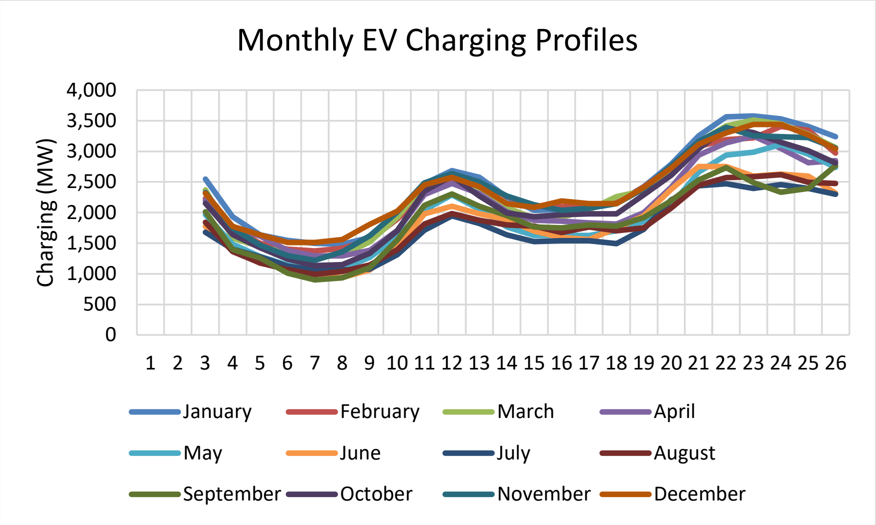
Matrix Scenario 1 – 1,817 MW/7.3 TWh

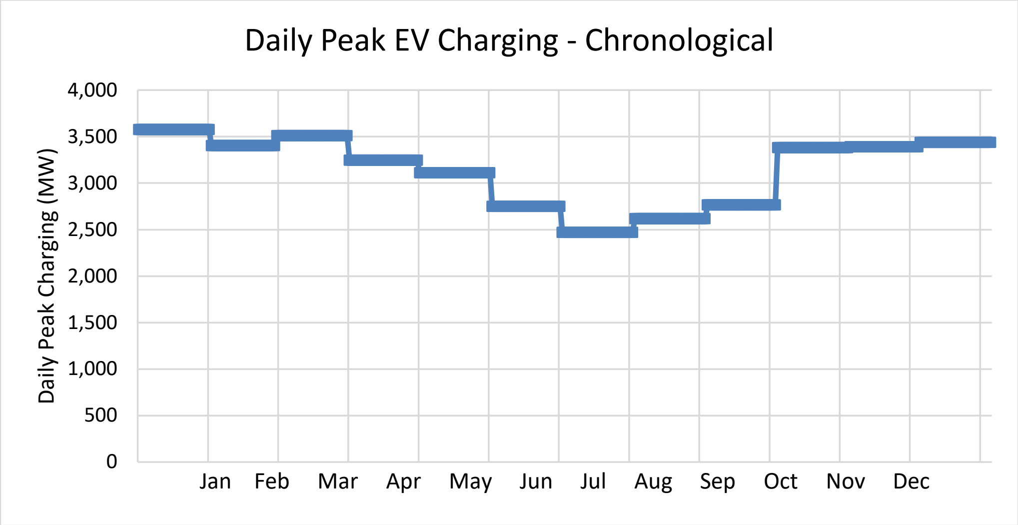




The January 1st weekday charging energy is 12% of the assumed 180,400 MWh fleet capability (based on 82 kWh/vehicle)

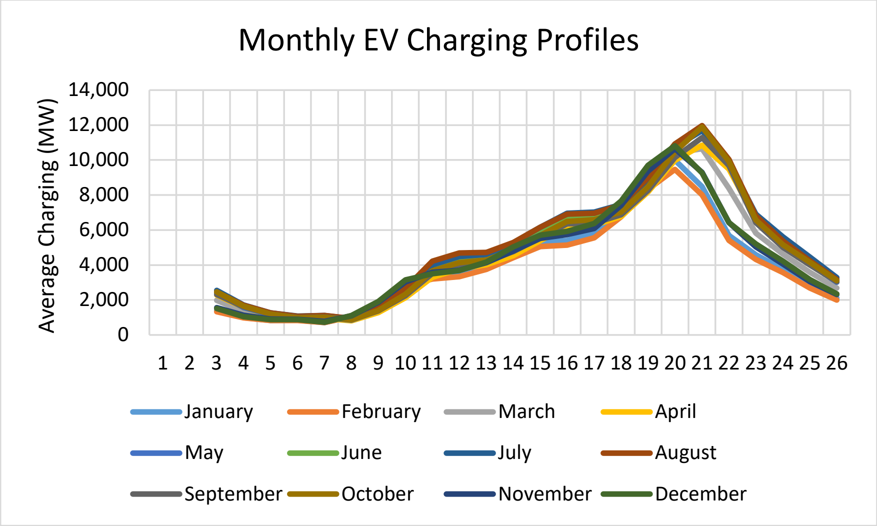
Matrix Scenario 2 – 3,575 MW/18.5 TWh

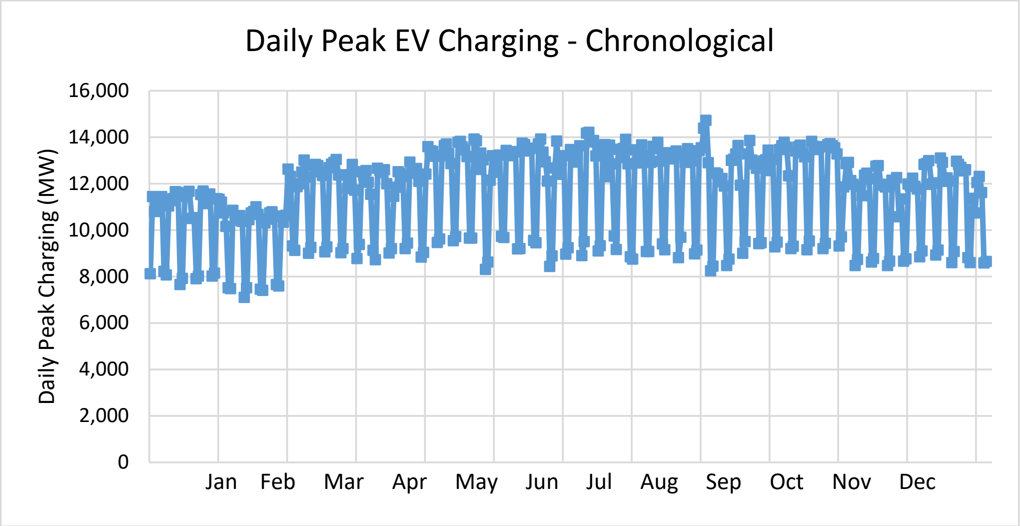




The January 1st weekday charging energy is 19% of the assumed 303,400 MWh fleet capability (based on 82 kWh/vehicle)

Matrix Scenario 3 – 14,714 MW/39.9 TWh





The January 1st weekday charging energy is 15% of the assumed 647,800 MWh fleet capability (based on 82 kWh/vehicle)

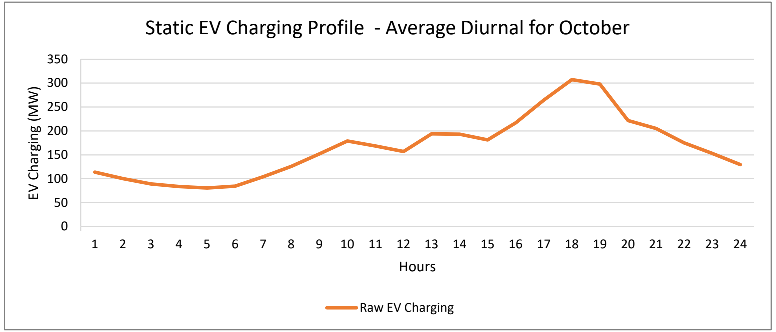
LIMITATIONS IN EV DATA AND MODELING

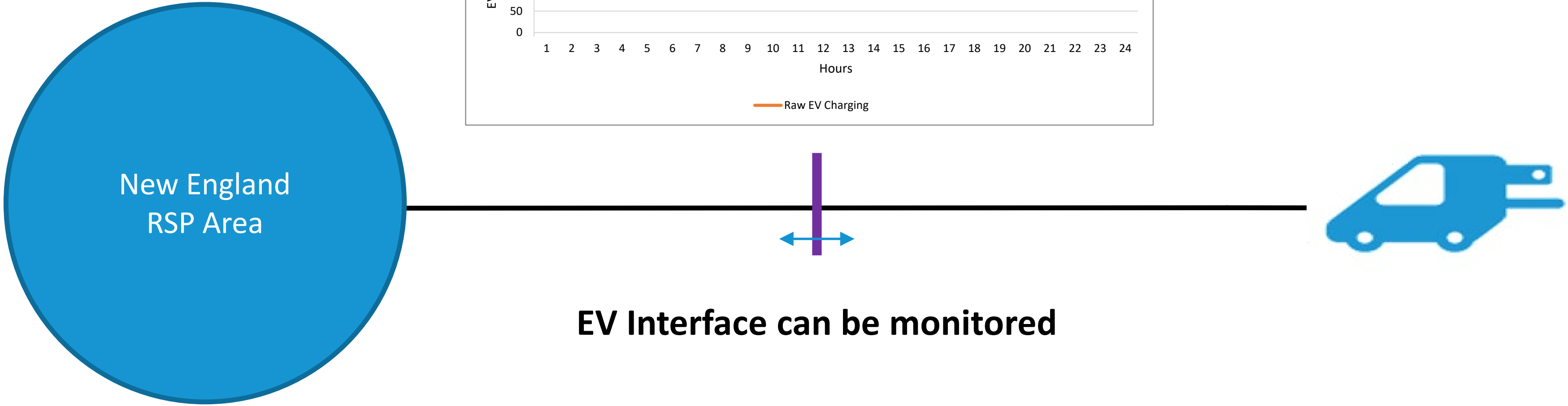
FGRS Modeling Challenge

EV Data Issues

- Future EV charging profiles are unknown
  - Expectations in proposed Matrix Scenario profiles seem to reflect:
    - EV energy consumption (e.g., vehicle mileage driven) will dominate daytime hours and early evening
    - Roughly corresponds to daily work week/school week
    - Charging will be mostly in evenings and overnight
  - Amount of flexibility in future EV charging is unknown and depends on:
    - Driving range capabilities of future EVs (e.g., "range anxiety")
    - Mid-day recharging opportunities (convenience and availability)
    - Time-of-charging incentives
- Incentives for EV charging behavior can influence apparent load

Fixed EV Charging Profile: Flow Across Interface





EV Interface can be monitored

Incentives for EV Charging Behavior

- Time-of-day incentives
  - Unlikely to induce a robust, beneficial charge/discharge profile every day
  - Charging and discharging at inopportune times to be expected

- Potential for two-way interactions between vehicle batteries and “the grid” (V-2-Grid)
  - Charge batteries when LMPs suggest renewable resources are on the margin
  - Discharge batteries when LMPs suggest non-renewable resources are on the margin
  - Provide energy and/or load following ancillary services
    - Assumes V-2-Grid batteries charge and discharge to provide “system benefits”
    - To provide “system benefits” dispatch signals must emanate from ISO control room
      - LMP key parameter for charging/discharging
      - ISO control room regulation signal may also be available for charging and discharging

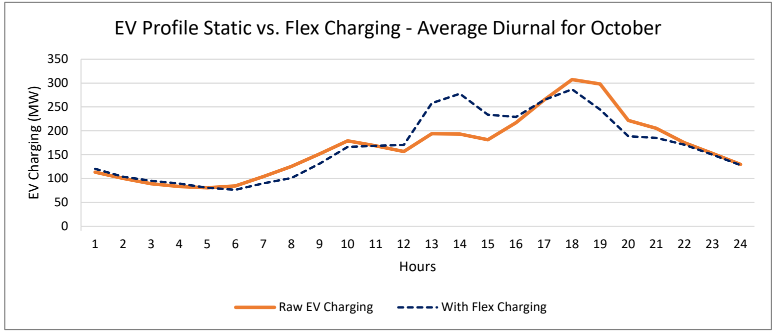
EXPLORING CONCEPTUAL EV FLEX CHARGING

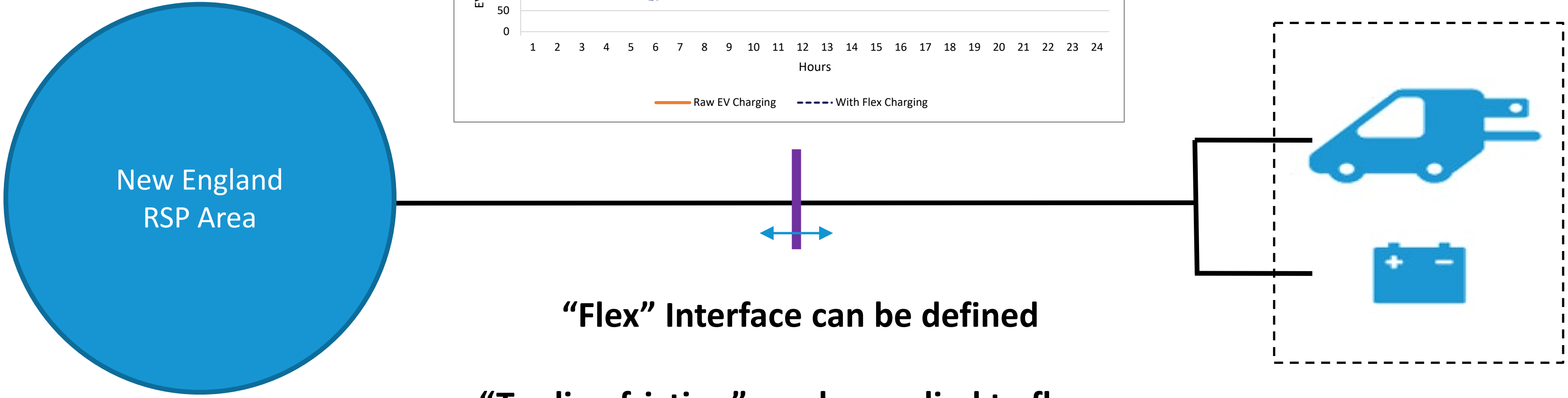
"Systems Benefit" Framework

Exploring a Conceptual EV Model

- Assumptions are required for the conceptual EV model
- Vehicle batteries with highest energy density to weight ratio are preferred
  - Degradation of energy density is a concern of all EV owner/operators
  - Need to reflect a value for the degradation of energy density
- Assumed vehicle battery Variable O&M
  - Variable O&M for mobile batteries need to reflect premium for preservation of energy density to weight ratio
  - Assumed to be $9/MWh (each direction)
- "Trading Friction" on EV interface can also be added to reflect owner/operator reluctance to offer bi-directionality

EV Charging Model: Flows Across Flex Interface





"Flex" Interface can be defined

"Trading friction" can be applied to flows in one or both directions

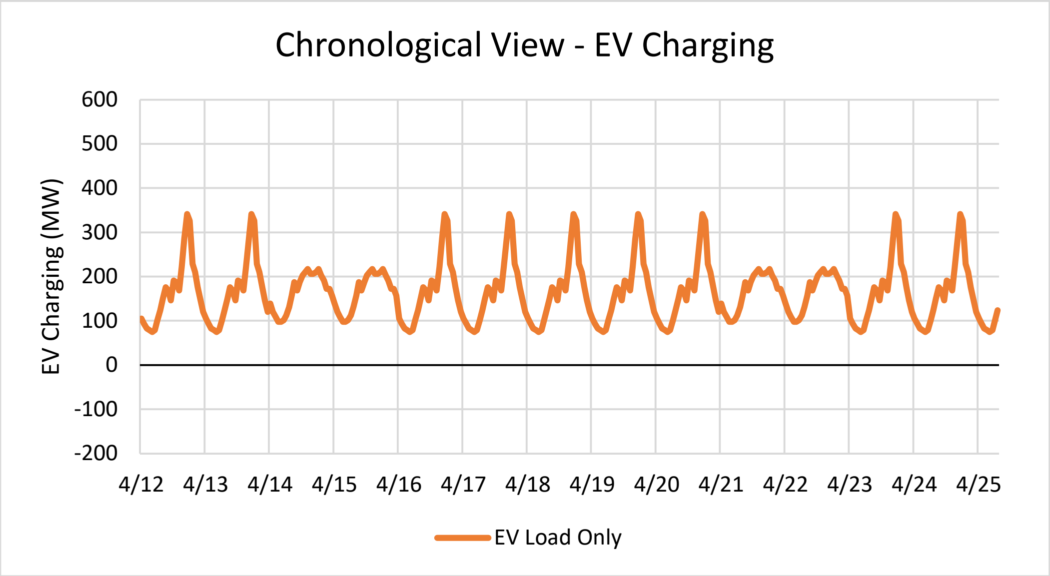
CONCEPTUAL EV MODEL

LMP Responsive EV Model Based on System Benefits

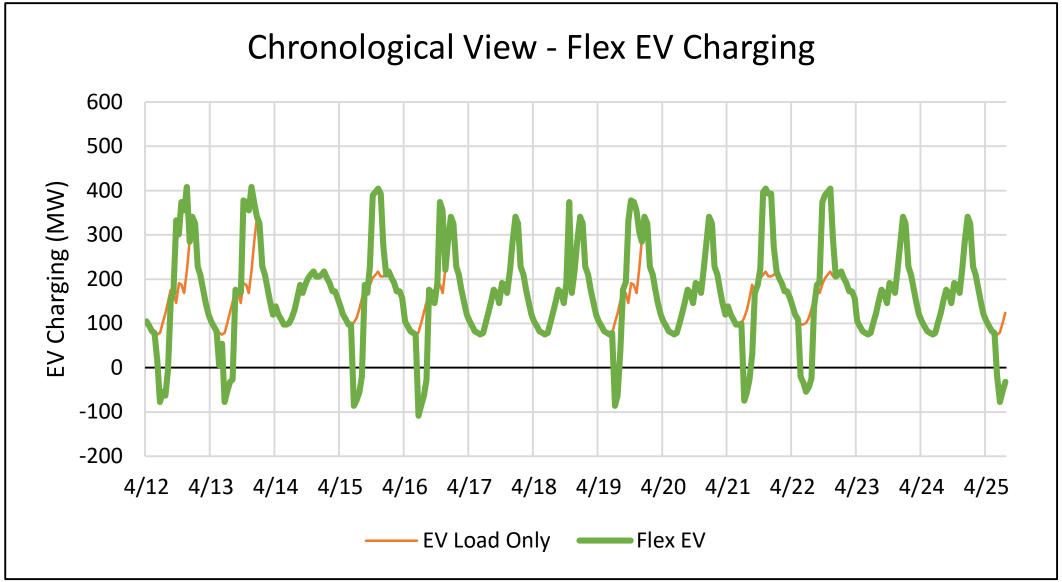
Conceptual EV Flex Charging Model: Example

- A conceptual Flex charging model has been developed
  - Responds to LMPs
    - Opportunity to charge when LMPs are "lower"
    - Opportunities to discharge to the grid when LMPs are "higher"
  - Uses GridView's energy storage algorithm
    - Minimization of production cost
    - Use of battery capability for "system benefit"
  - Example assumes following parameters
    - EV load modeled at an aggregate RSP sub-area level
    - Battery MW ("inverter") size is 50% of RSP sub-area peak charging pattern
    - Battery capability is four MWhs/MW of "inverter"
    - Battery variable O&M is $9/MWh (each way) to represent preservation of high energy density to weight (3 times variable O&M for grid-facing battery)
    - Zero additional trading friction across vehicle-to-grid "interface"
    - Round-trip efficiency of 86 percent

Chronological EV Charging (14 Days in April)

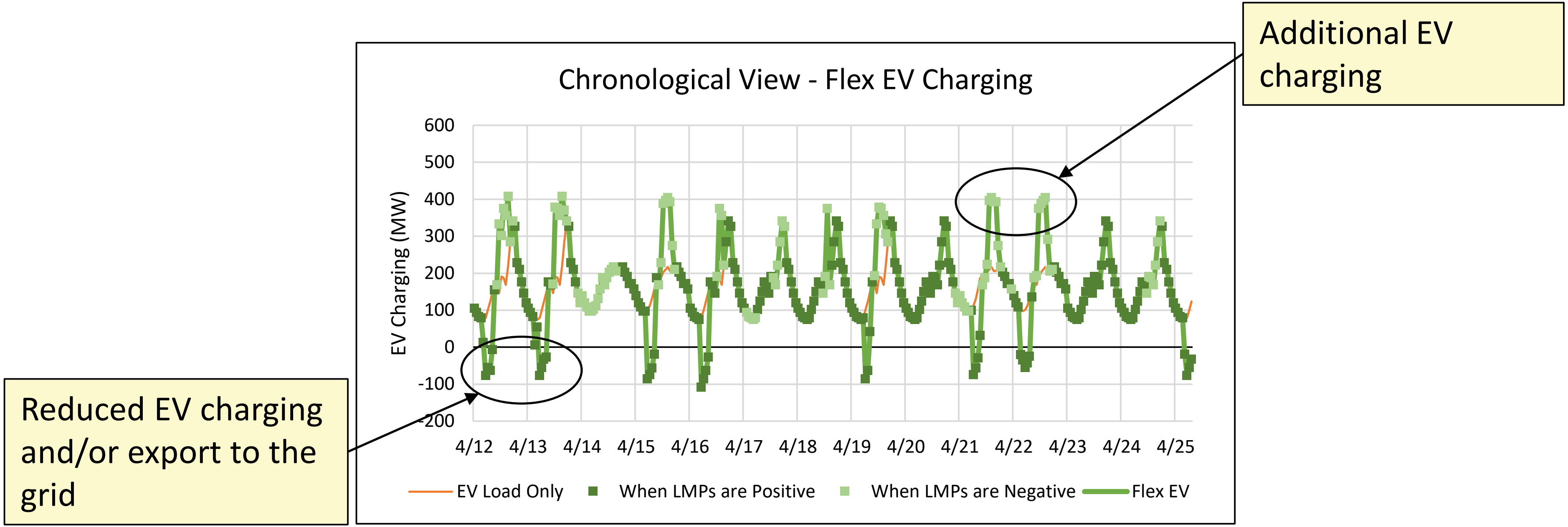


Chronological Flex Charging (14 Days in April)



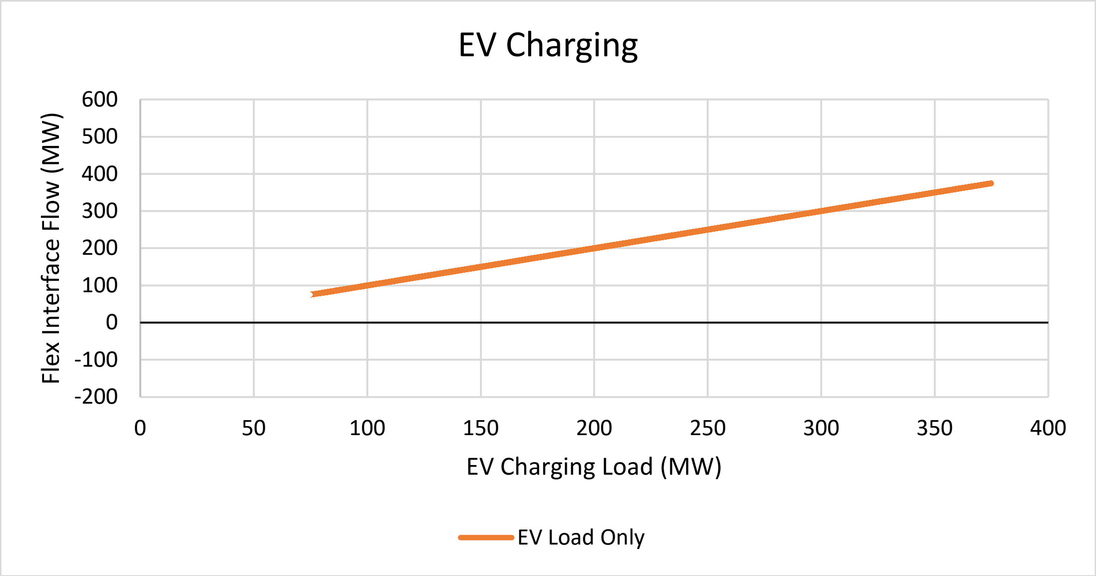
NOTE: LMP induced flows may be either “into” or “out of” the EV/battery system depending on state-of-charge and LMPs in adjacent hours, not just one specific hour.

Chronological Flex Charging With LMPs



NOTE: Charging tends to increase when LMPs are negative.
Charging tends to decrease (or export) when flows are positive

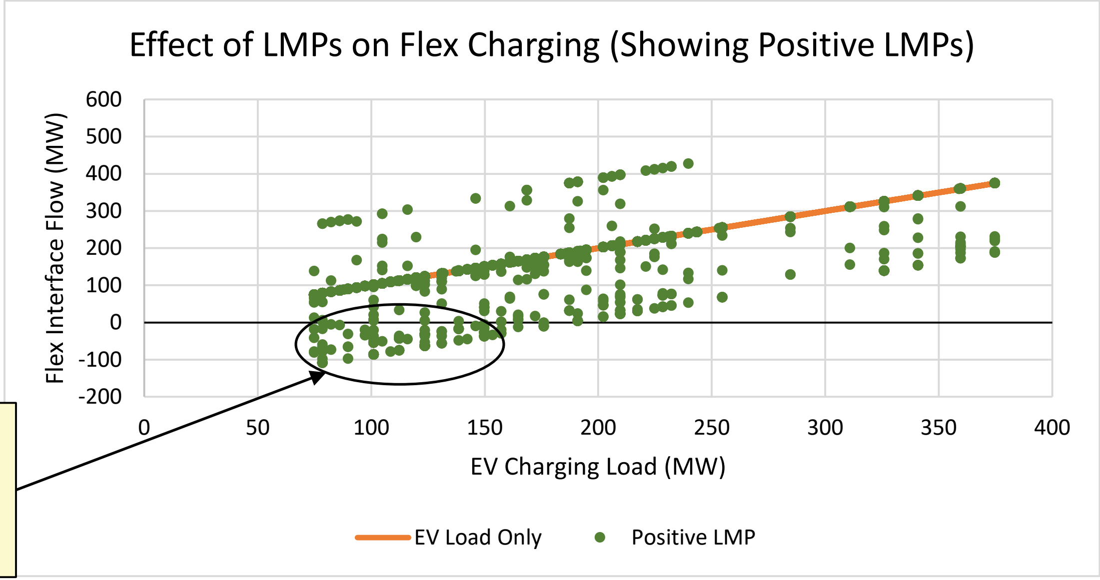
Flex Interface Flow: No Flex – EV Charging Only



All 8760 hours

With no flex charging, interface flow equal EV charging

Flex Interface Flow: When LMPs are Positive

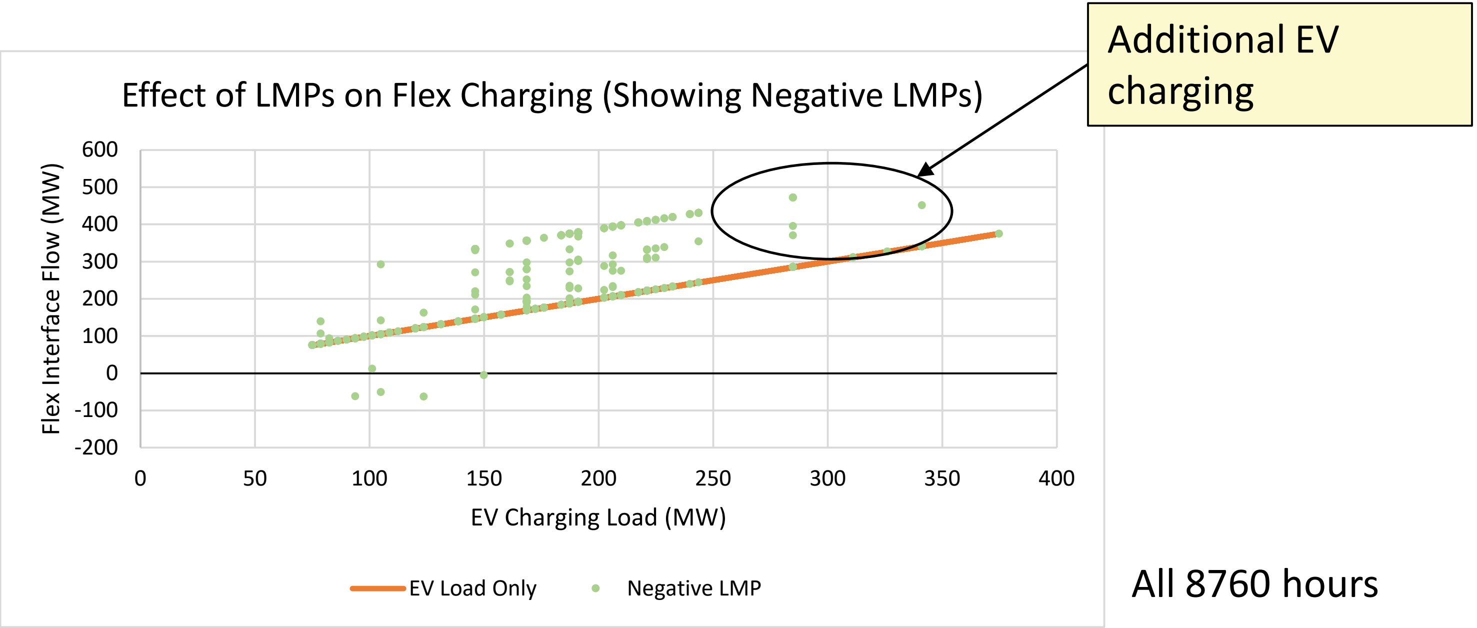


Reduced EV charging and/or export to the grid

All 8760 hours

With Flex charging, positive LMPs tend to decrease charging and possibly export to the grid

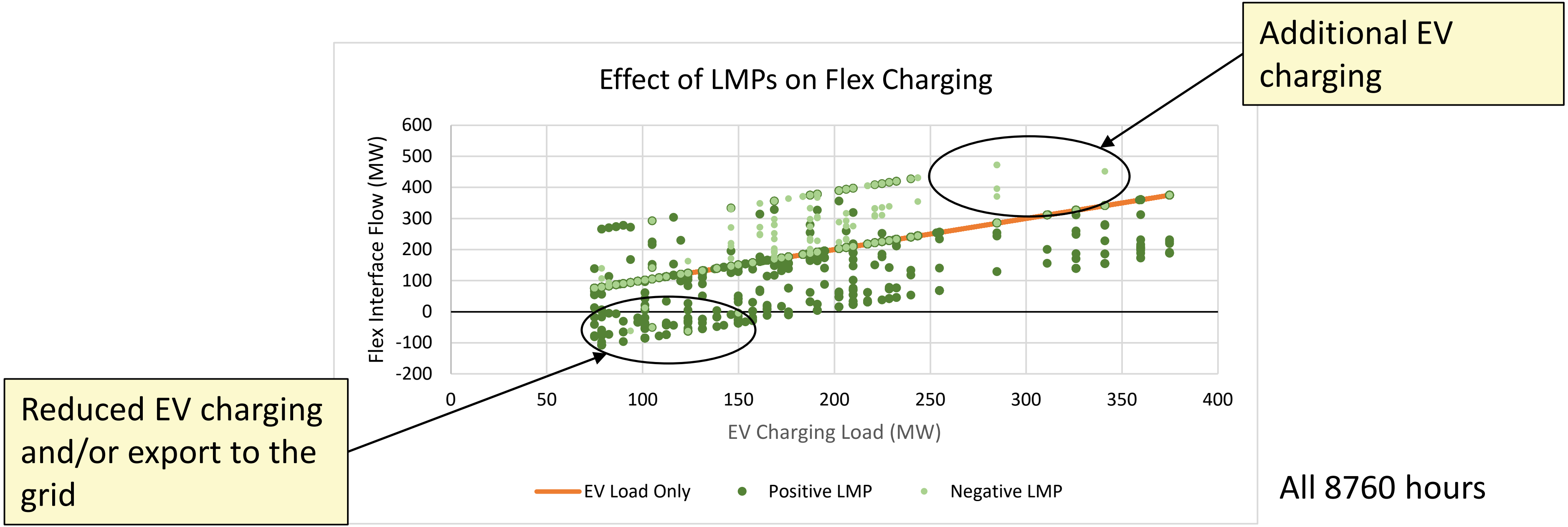
Flex Interface Flow: When LMPs are Negative



All 8760 hours

With flex charging, negative LMPs tend to increase charging

Flex Interface Flow: All LMPs



All 8760 hours

With flex charging, interface flow responds to LMPs

OBSERVATIONS ABOUT FLEX CHARGING MODEL

FGRS EV Modeling Questions

Broad Assumptions Used in Conceptual EV Model

- Key assumptions to review:
  - Flex charging allowed V-2-Grid exports, but exports to the grid are optional
  - Willingness of vehicle owner/operators to make battery capability available to provide “system benefits” was assumed
  - Assumed Flex charging to be 50 percent of EV peak charging MW
  - Assumed 4 MWh/MW of participating EV load for:
    - “additional” charging/absorption
    - “additional” discharging/depletion capability
  - Variable O&M of $9/MWh (each way) seems like a reasonable barrier to excessive degradation of energy density to weight from low-value operation
  - Additional “trading friction” across interface seems unnecessary
  - Distribution system assumed to have an ability to support V-2-grid

FGRS Matrix Scenario – EV Assumptions

	Matrix Scenario (Profile) 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)
Matrix Scenario 1	2.2	1,817	180,400	909	3,634
Matrix Scenario 2	3.7	3,578	303,400	1,789	7,156
Matrix Scenario 3	7.9	14,714	647,800	7,357	29,428

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

Observations About Flex Charging Model

- EV charging has typically been represented as a static profile
  - Static profile can be adjusted to reflect time-of-use incentives
  - However, time-of-use creates a different assumed static profile
- Flexible EV charging may be a better representation than a static profile
  - Responds to system conditions as reflected in LMPs
  - Parameters can be adjusted for “charging only” or two-way “V-2-grid” operation
  - Based on assumptions about
    - Assumed MW discharge to the grid
    - Energy storage available
  - Simulation results show EV/battery has about 1.5 percent capacity factor
- Stakeholder feedback invited

Questions