2021 Economic Study: Future Grid Reliability Study Phase 1

Overview of Assumptions – Part 2

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Introduction

- On March 12, 2021, NEPOOL submitted the Future Grid Reliability Study (FGRS) Phase 1 as a 2021 Economic Study Request
- On April 1, 2021, ISO New England accepted the request and will perform the FGRS as the 2021 Economic Study
- Part one of study assumptions were presented by the ISO at the [April 2021 PAC meeting]
- Today's presentation will focus on:
  - Assumptions for:
    - Supply Modeling
    - Demand Modeling
  - Weather Year Assumptions
  - Scope of the High-Level Transmission Analysis

2021 Economic Study Past Presentations & Materials

Presentation & Materials	Date (Link)
High-level draft scope of work and assumptions (Part 1)	April 14, 2021
FGRS Assumptions Table Submitted to ISO-NE	March 31, 2021
FGRS Framework Document Submitted to ISO-NE	March 31, 2021
ISO-NE Feedback on FGRS	March 31, 2021
Modeling of Electric Vehicles	February 22, 2021
ISO-NE Revised Schedule and Feedback on FGRS	February 22, 2021

SUPPLY MODELING ASSUMPTIONS

Production Cost and Ancillary Services Simulations

Wind and Solar PV Resources

- Offshore wind resources will be distributed as described in the table on the following slide and onshore wind distributions are described in Appendix I
- Offshore floating wind requested for Scenario 3 will be represented as offshore fixed wind using the DNV_GL profiles. ISO does not have production profiles for offshore floating wind.
- Solar photovoltaic (PV) resources will be distributed based on the following guidelines:
  – When a specific distribution for a scenario has been requested, the ISO will utilize that. In absence of a specific distribution, then:
    - Utility scale solar (market facing) will be distributed similar to today's distribution of Energy-Only Resource (EOR) and Forward Capacity Market (FCM) solar PV from the ISO forecast
    - Rooftop solar (non-market facing) will be distributed following the ISO's forecast for behind-the-meter photovoltaic (BTM PV)

Offshore Wind Interconnection Points

Assumption	Block Island (RI)	CT	RI	SEMA	Boston	SME	NH	Total
Matrix Scenario 1	29	800	1,000	4,000	2,200	0	0	8,029
Matrix Scenario 2	29	1,400	1,400	5,200	0	0	0	8,029
Matrix Scenario 3	29	636	2,695	6,323	3,000	3,075	904	16,662

* System Planning Subareas ("RSP bubbles") connection points were not defined in the 2021 Economic Study request and will be distributed among ME's RSP bubbles. See appendix for onshore wind distribution

Energy Storage Related Assumptions

- Battery and Pumped Storage dispatched by modeling software
  - More information in this presentation
- Pumped storage and Hydro Quebec energy banking
  - Pumped storage with 74% efficiencies and $0 Variable Operation & Maintenance (VOM)
  - Alternative Scenario A assumes storage in Hydro Quebec's reservoirs via bi-directional transmission using threshold prices for dispatching
- Assumptions for Battery Energy Storage Systems (BESSs) range widely
  - Types of batteries range from 1 to 36 hours
  - $3/MWh VOM cost (see presentation)
  - Round trip storage efficiency of 86%
- Alternative Scenario BESS Assumptions
  - Alternative Scenario B assumes 200,000 MWh of bi-directional vehicle-to-grid batteries
    - Higher $9/MWh VOM cost accounts for mobile battery degradation
  - Alternative Scenario D assumes a significant energy storage margin with 2,393,000 MWh of storage

Energy Storage Related Assumptions, cont.

- Installed batteries will be divided into 25 independent BESS resources per RSP area (325 total)
  - Located at unconstrained busses in each RSP area
  - BESS distributed by RSP share of New England load
  - All stationary batteries with use the same VOM
  - Round trip storage efficiency of 86 percent
  - No explicitly represented co-located BESS with solar / wind
    - Any constraints imposed by co-location can only reduce system-wide benefits

BESS Characteristics

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

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

* Significant energy storage capability assumed via flexible EV charging.

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

Alternative Scenarios D and E

- Alternative Scenarios D and E envision only Variable Energy Resources (VERs), BESSs, and imports
  - All carbon emitting resources retired
  - Current modeling practice excludes "bidding strategies"
  - Need to proceed cautiously with the analyses for these scenarios as the GridView and EPECS modeling tools may produce unexpected metrics with this configuration
    - Proposed assumptions expected to be outside "comfort" range of the software
    - Given stated goal of these alternative scenarios, modifications to assumptions may be required

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

Summary of Interchange With Neighboring Systems

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3	A* Bi-Directional Transmission
Ties	NB, HQ PHII, HG, NECEC	NB, HQ PHII, HG, NECEC	NB, HQ PHII, HG, NECEC, NY	Same as Parent (Scenario 1 only)
Bi-Directional	No	No	Yes	Yes
Additions	N/A	1000 MW HQ-CMA	1200 MW HQ-CMA plus 450 MW to NY	Unconstrained HVDC to CMA
Base Flow	Historical Profile	Historical Profile	Historical Profile	Same as Parent
New Ties	N/A	Use Rating	Use Rating	N/A

**Alternative Scenarios B, C, D, and E have the same interchanges with neighboring systems as the parent cases.*

Import Priority Threshold Prices

Threshold Prices Prioritizing Imports:

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

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

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

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

REC Inspired Threshold Prices

Bi-directional threshold prices assumed to reflect the value of Renewable Energy Credits (RECs):

- Curtail imports first, then trigger exports, and only curtail renewables when export capability is exhausted
- Can be referred to as "REC Inspired"
- Prices may be adjusted, will be used in Scenarios 2&3 (with NY and bi-directional HQ flows removed in S2)

Price-Taking Resource	Threshold Price ($/MWh)	Priority
Imports from NY	13	First Curtailed
Imports from Second New Ties	12	
Imports from New Ties	11	
Imports from NB	10	
Imports from Existing HQ	5	
NECEC (1090 MW)	2	
Trigger for Exports to Canada	-25	
Trigger for Exports to New York	-28	
Onshore Wind	-30	
Offshore Wind	-40	
FCM and Energy-only PV	-50	
Behind-the-Meter PV	-100	Last Curtailed

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Environmental Emissions Allowances Assumptions

- Focus is on CO_2 emissions, but still monitor NO_x and SO_2
  - CO_2 based on fuel and heat rate
  - NO_x and SO_2 are expected to be minimal
- All imports are assumed "emission free"
- Future Environmental Air Emission Allowances Prices*
  - Example: 2040
    - CO_2 = $47.00/ton
    - NO_X = $4.00/ton
    - SO_2 = $2.00/ton
- CO_2 emissions for Massachusetts affected fossil fuel generators will also be monitored exogenously to confirm that they meet the Massachusetts Global Warming Solutions Act (GWSA) cap

* Source: RGGI Carbon Price for CO_2; NYISO's CARIS for SO_2 & NO_X

DEMAND MODELING ASSUMPTIONS

Load and Energy Efficiency (EE)

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3*	B Vehicle-to-Grid **
Peak Gross Load (MW)	33,707	33,707	42,525	42,525
Gross Load Annual Energy (GWh)	171,040	171,040	182,500	182,500
Peak EE (MW)	6,777	6,777	N/A	N/A
EE Annual Energy (GWh)	36	36	N/A	N/A

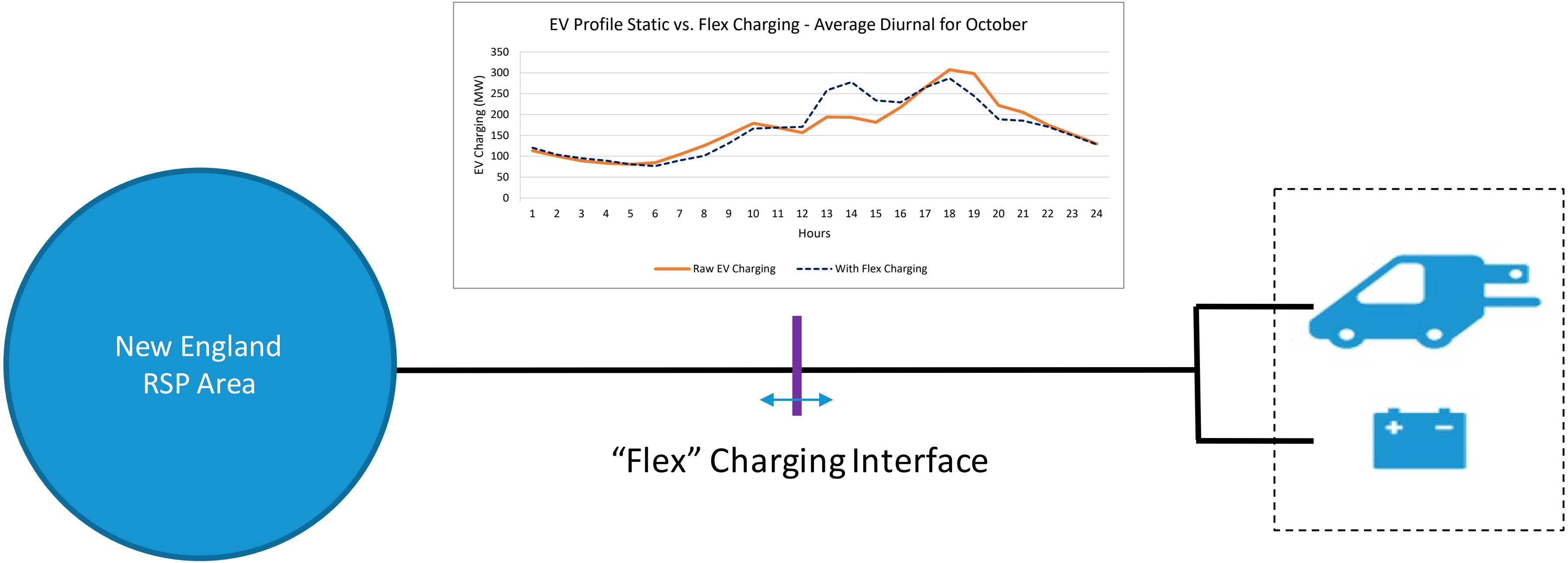
** Matrix Scenario 3 and Alternative B are net load = Gross + Heating + EV – EE – Rooftop Solar PV*

***Alternative Scenarios A, C, D, and E have the same interchanges with neighboring systems as the parent cases.*

Transportation Electrification Load

- Electric vehicle (EV) charging load is provided as a specific profile
  - Proponents claim to have time-of-use embedded in provided profiles
  - Time-of-use may be most appropriate when VER production trends are predictable months and years in advance
    - Likely hours with significant PV generation can be predicted with some confidence
    - With a large penetration of wind, the production cannot be predicted with confidence
  - Alternative Scenario B envisions significant vehicle-to-grid (V2G) capability
- ISO proposed a 'flexible' EV load model that incorporates a GridView adjustable energy storage component
  - Shifts charging of EVs based on Locational Marginal Prices (LMPs) (i.e., more charging during low/negative prices experienced during high renewables output)
  - Charging modification is preferred by proponents vs. bi-directional V2G paradigm

Flexible EV Charging Model



An interface is used to control and modify charging interface. The example flex charging implementation shows increased charging during times of low LMPS (during solar production) and reduced charging at higher LMPs (evening after solar).

Electric Vehicle Assumptions

	Matrix Scenario Assumptions			Flex Model Assumptions		
Scenario	**Number of Vehicles (Million)**	**Total EV Peak Charging (MW)**	**Total EV Battery Storage (MWh)***	**EV/Battery Flexible Capacity (MW)**	**EV/Battery Flexible Energy (MWh)**	**Mode**
Matrix Scenario 1	2.2	1,817	180,400	909	3,634	Modify Charging
Matrix Scenario 2	3.7	3,578	303,400	1,789	7,156	Modify Charging
Matrix Scenario 3	7.9	14,714	647,800	7,357	29,428	Modify Charging
Alt Scenario B	7.9	14,714	647,800	100,000	200,000	V2G

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

Electric Vehicle Assumptions, cont.

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3	B* Vehicle-to-Grid
Peak Charging Load	1,817 MW	3,578 MW	14,714 MW	Same as Parent
Annual Charging Energy	7.3 TWh	18.5 TWh	40.0 TWh	Same as Parent
Operation	Flexible Delay Charging	Flexible Delay Charging	Flexible Delay Charging	100 GW of 2 hour storage acting as battery

* Alternatives A, C, D, and E use the same EV load as the parent cases.

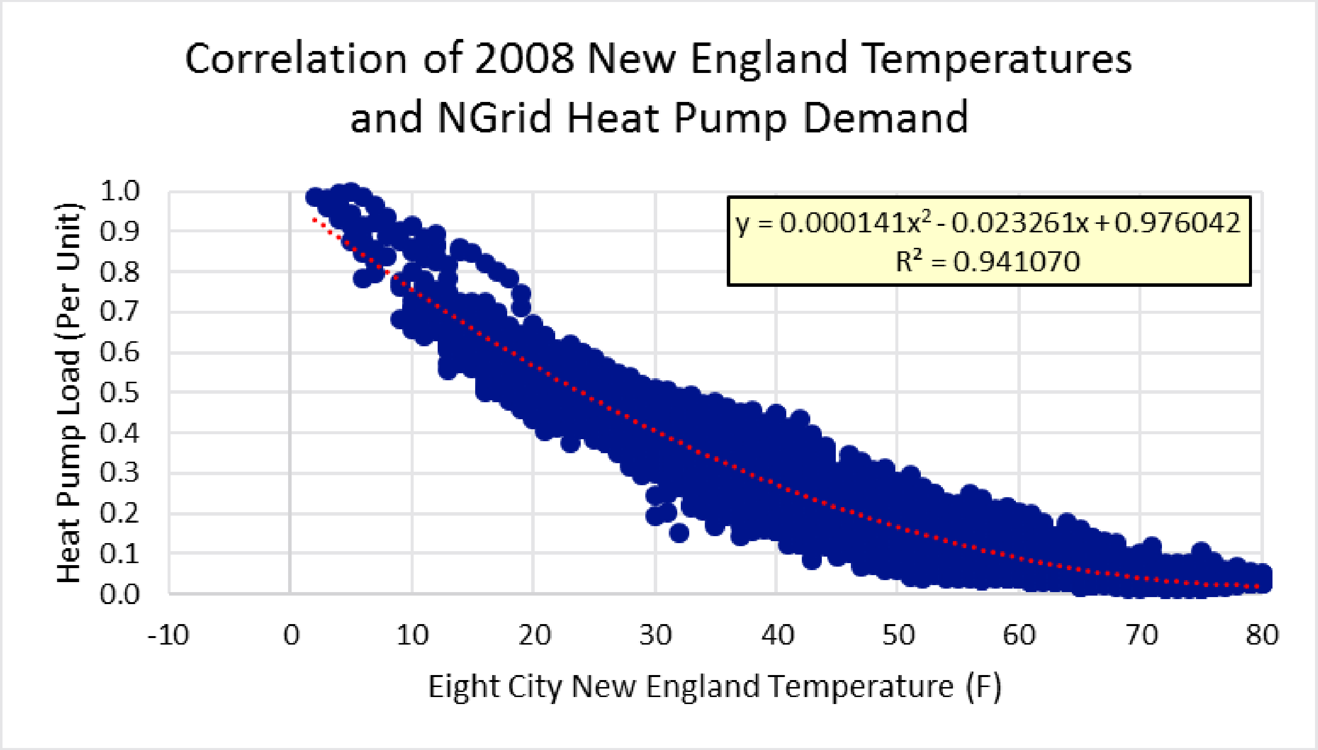
Reference: Developing a GridView Flexible Electric Vehicle Charging Model, February 26, 2021, https://www.iso-ne.com/static-assets/documents/2021/02/a03c_ev_penetration_and_modeling_2021_02_26.pdf

Heating Electrification Load

Assumption	Matrix Scenario 1	Matrix Scenario 2	Matrix Scenario 3
Peak Load	5,214 MW	2,991 MW	23,244 MW*
Energy	9.6 TWh	6.6 TWh	42.6 TWh*
Load Shape	Based on hourly temp	Based on hourly temp	Based on hourly temp

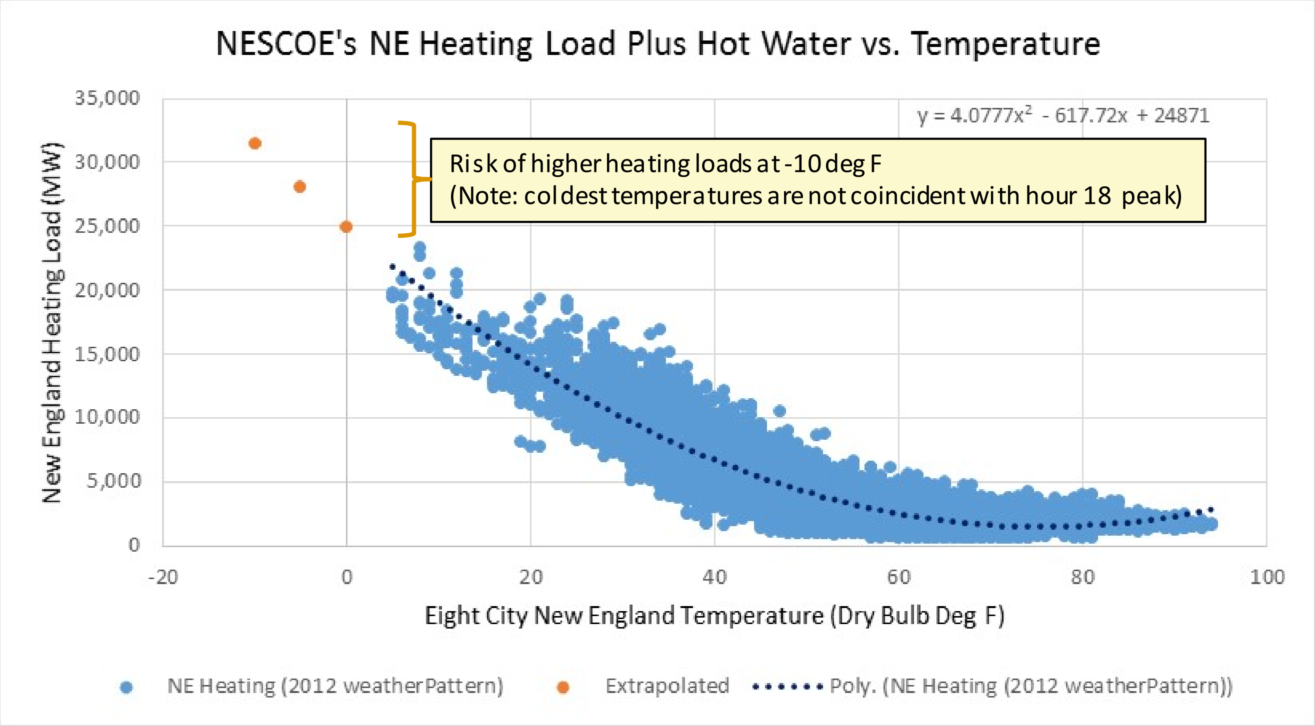
* Sum of residential and commercial profiles for water heating (13.6 TWh) and space heating (29.0 TWh)

Heating Demand: Matrix Scenarios 1&2



Note: At temperatures below -1 degree F, heat pump load continues to rise and exceeds the nominal MW value

Heating Demand: Matrix Scenario 3



ANCILLARY SERVICES ANALYSES SPECIFIC ASSUMPTIONS

Ancillary Services Specific Assumptions

- Grid-facing energy storage
  - All storage dispatched in SCUC and RTUC layers
  - If feasible, one quarter assumed available to respond to regulation (real-time)
- Electric vehicle flexible charging
  - One quarter of flex-charging MW amounts will be available in SCUC and RTUC layers
  - One eighth of flex-charging MW amounts assumed available to respond to regulation (real-time)
- This is done to allow energy storage and EVs to participate in the day-ahead and real-time markets

Ancillary Services Specific Assumptions, cont.

- Fixed profiles will be used when the ancillary services software is not capable of modeling flexible resources
  - This includes but is not limited to bi-directional flow with neighboring systems and dispatch of hydro units (excluding pumped storage)
- Load profiles will be built from the ISO's plant information (PI) database (of historical real-time system operations) that has minute level rather than the database used for production cost modeling which uses hourly data

HIGH LEVEL TRANSMISSION ANALYSIS

High-Level Transmission Analysis

- Unconstrained 8760 hour simulations will monitor interfaces for hours where the flows exceed existing interface limits
- If the exceedances are significant, a high-level transmission project that would increase the limit will be hypothesized
  - E.g., A new 345 kV line between RSP bubbles would be assumed to increase transfer limit X by Y MW
  - No detailed transmission feasibility studies will be run to determine the full system impact of the increase
- For scenarios that add high-level transmission, the simulation will then be re-run respecting constraints both before and after the increase in transfer limit to study the effect of the increased limit with respect to the study metrics

NEXT STEPS

Next Steps

- Preliminary production cost results for Scenario 1 are expected in June 2021
- Preliminary production cost results for other scenarios will be presented in July and August 2021
- Any further assumptions for remaining production cost simulations or ancillary services analyses will be presented between June and August 2021
- Preliminary ancillary services analysis results for Scenario 1 are expected in September 2021
- Results for other scenarios are expected in Q3/Q4 2021

Questions

APPENDIX I

Additional Information

Distribution of Onshore Wind Additions

RSP Subarea	BHE	ME	SME	CMA	NH	CT	WMA	Boston	SEMA	RI	VT	Total
Matrix Scenario 1	941	423	0	0	31	5	0	0	0	0	0	1,335
Matrix Scenario 2	980	107	0	38	325	0	35	4	11	0	0	1,500
Matrix Scenario 3	319	40	0	0	182	15	35	0	412	45	290	1,338

APPENDIX II

Acronyms

Acronyms

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

Acronyms, cont.

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