The Narragansett Electric Co. d/b/a National Grid—Application for Approval of a Change in Electric and Gas Base Distribution Rates (filed on November 27, 2017)

Docket 4770

Request for Information

Requesting Party:	New Energy Rhode Island (NERI)
To:	National Grid
Request No.:	NERI-3
Date of Request:	3.2.18
Response Due Date:	3.23.18 (rolling by agreement)
Subject/Panel:	Book 3—Gredder (Forecast)

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1. Reference p. 8. Please explain in detail how the forecasted total GWh deliveries before DER reductions compare to forecasts after DER reductions are factored in.

   Response can be found on Bates page(s) 1.

2. Reference p. 10.

   a. Please explain how climate change-related weather changes impact the forecast of the impact of weather on the forecasts.

   b. In particular, please address the frequency and severity of storms and average temperatures.

   c. Please explain whether weather normalization masks climate change-related changes in weather patterns, and whether the forecast addresses these effects.

   Response can be found on Bates page(s) 2.

3. Reference p. 12. Please explain whether the econometric models assume any correlation between economic growth and forecasted electricity sales.

   Response can be found on Bates page(s) 3.

4. Reference p. 28. Please explain whether the estimation of solar PV impacts accounted for coincidence of solar production and hourly summer peaks. If not, please explain why not.\

   Response can be found on Bates page(s) 4.

5. Schedule JFG-15. Please explain why the PV forecast drops so dramatically in 2021 and after. How does this assumption impact the forecasts?

   Response can be found on Bates page(s) 5-70.

NERI 3-1

Request:

Subject: Book 3—Gredder (Forecast)

Reference p. 8. Please explain in detail how the forecasted total GWh deliveries before DER reductions compare to forecasts after DER reductions are factored in.

Response:

Schedule JFG-10, Schedule JFG-11, Schedule JFG-12, and Schedule JFG-13 of Mr. Gredder's pre-filed direct testimony (Book 3) show in detail the forecasted GWh deliveries both before and after distributed energy resources.

NERI 3-2

Request:

Subject: Book 3—Gredder (Forecast)

Reference p. 10.

a. Please explain how climate change-related weather changes impact the forecast of the impact of weather on the forecasts.

b. In particular, please address the frequency and severity of storms and average temperatures.

c. Please explain whether weather normalization masks climate change-related changes in weather patterns, and whether the forecast addresses these effects.

Response:

a. Mr. Gredder's pre-filed direct testimony (see Bates Pages 13 and 14 of Book 3) discusses the process used to weather-adjust the historical sales and what is used as the basis for the weather-normalized values for the projected Rate Year and Data Years (2019, 2020, and 2021). The Company uses the most recent ten-year weather history to calculate the normalized cooling and heating degree days. During each of its annual planning cycles, this value is refreshed with the most recent data. This allows the impacts of any underlying changes in average temperatures to be incorporated into the sales forecasts.

b. As described above, any changes in average temperatures are captured in its methodology. The Company does not attempt to predict the frequency and severity of storms in its sales forecasting process. To the extent that storms have retrospectively impacted (lowered) historical sales, these would be embedded in the underlying data set used to perform the modeling.

c. For the reason cited in the response to part a. above, specifically the use of the most recent ten-years of weather data to determine the weather-normalized values used in the forecast, as opposed to longer historical windows, no long-term impacts of climate change are masked. In addition, the relatively short future planning horizon of three years for the rate case, mainly Rate Year 2019 and Data Years 2020 and 2021, would not be impacted by any additional long-term structural changes due to weather not already captured.

Prepared by or under the supervision of: Joseph Gredder

NERI 3-3

Request:

Subject: Book 3—Gredder (Forecast)

Reference p. 12. Please explain whether the econometric models assume any correlation between economic growth and forecasted electricity sales.

Response:

Yes, Mr. Gredder's pre-filed direct testimony (Book 3), on pages 14 through 23 describe the econometric models in detail for each revenue class, including commentary on the economic variables used in each model and the statistical strength of correlation of each variable to energy sales. Schedule JFG-22 contains the regression models and related statistics for each model. Correlation for each economic dependent variable can be gauged by the p-value. P-values of less than 0.05 indicate strong correlation.

Prepared by or under the supervision of: Joseph Gredder

NERI 3-4

Request:

Subject: Book 3—Gredder (Forecast)

Reference p. 28. Please explain whether the estimation of solar PV impacts accounted for coincidence of solar production and hourly summer peaks. If not, please explain why not.

Response:

Pages 27-28 of Mr. Gredder's sales forecast pre-filed direct testimony (Book 3) provides an overview of the process used to reduce energy sales for the impacts of PV. This includes a discussion of the capacity factor, or the amount of energy as related to installed capacity used. The overall capacity factor on annual basis was 15 percent. Schedule JFG -14 contains the monthly capacity factors. The concept of coincidence of solar production and hourly summer peaks are not germane to Mr. Gredder's sales forecast testimony referenced on Page 28.

Attachment DIV 5-33-2 in the Company's response to Division 5-33 contains a description of the methodology used to reduce the peak forecast for PV. The coincidence factor, or the relationship of system peak to installed capacity, used was 21 percent. This is documented in footnote 5 on Page 7 of the attachment.

Prepared by or under the supervision of: Joseph Gredder

NERI 3-5

Request:

Subject: Book 3—Gredder (Forecast)

Schedule JFG-15. Please explain why the PV forecast drops so dramatically in 2021 and after. How does this assumption impact the forecasts?

Response:

Pages 27-29 of Mr. Gredder's pre-filed direct testimony (Book 3) describe the approach used for considering the impacts of PV on the sales forecast. As discussed in Mr. Gredder's testimony, the Company uses the ISO-NE's forecast for PV for Rhode Island, which considers numerous factors, including state policies in its projections. The Company participates in the ISO-NE's Distributed Generation Working Group, which develops the methods and resulting projections for PV. Other transmission and distribution companies, state agencies including the Rhode Island Office of Energy Resources, market participants, and regulators also participate in this collaborative endeavor. Attachment NERI 3-5 contains a complete discussion of the ISO's PV projections.

Pages 28-29 of Mr. Gredder's testimony describe the impact of PV for this rate case. Schedule JFG-11, Schedule JFG-12, and Schedule JFG-13 to that testimony include the impact of PV over the rate case and additional Data Year 1 and Data Year 2 (years 2019, 2020, and 2021).

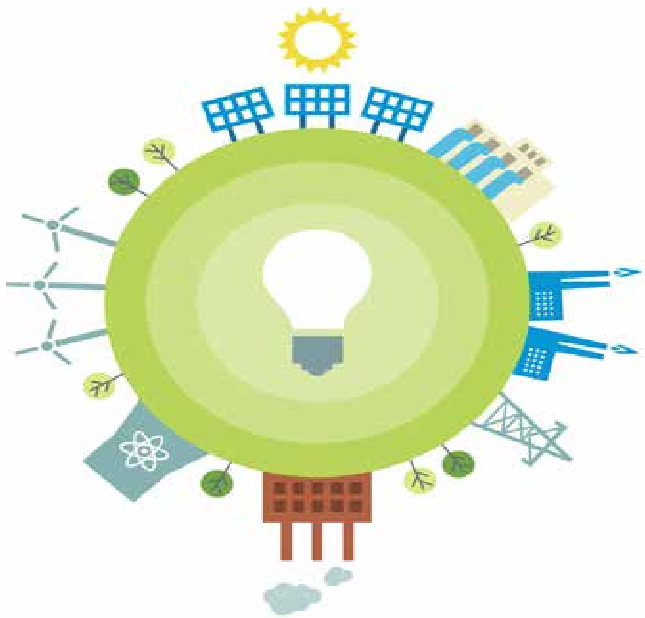
Prepared by or under the supervision of: Joseph Gedder

MAY 1, 2017 | HOLYOKE, MA

Final 2017 PV Forecast

Outline

- Background & Overview
- Distribution Owner Survey Results
- Forecast Assumptions and Inputs
- 2017 PV Forecast - Nameplate MW
- 2017 PV Energy Forecast
- Breakdown of PV Forecast into Resource Types
- 2017 Behind-the-meter (BTM) PV Forecast
- Geographic Distribution of PV Forecast



BACKGROUND & OVERVIEW

Background

- Many factors influence the future commercialization potential of PV resources, some of which include:
  - Policy drivers:
    - Feed-in-tariffs (FITs)/Long-term procurement
    - State RPS programs
    - Net energy metering (NEM)
    - Federal Investment Tax Credit (ITC)
  - Other drivers:
    - Role of private investment in PV development
    - PV development occurs using a variety of business/ownership models
    - Future equipment and installation costs
    - Future wholesale and retail electricity costs

The PV Forecast Incorporates State Public Policies and Is Based on Historical Data

- The PV forecast process is informed by ISO analysis and by input from state regulators and other stakeholders through the Distributed Generation Forecast Working Group (DGFWG)
- The PV forecast methodology is straightforward, intuitive, and rational
- The forecast is meant to be a reasonable projection of the anticipated growth of out-of-market, distributed PV resources to be used in ISO's System Planning studies, consistent with its role to ensure prudent planning assumptions for the bulk power system
- The forecast reflects and incorporates state policies and the ISO does not explicitly forecast the expansion of existing state policies or the development of future state policy programs

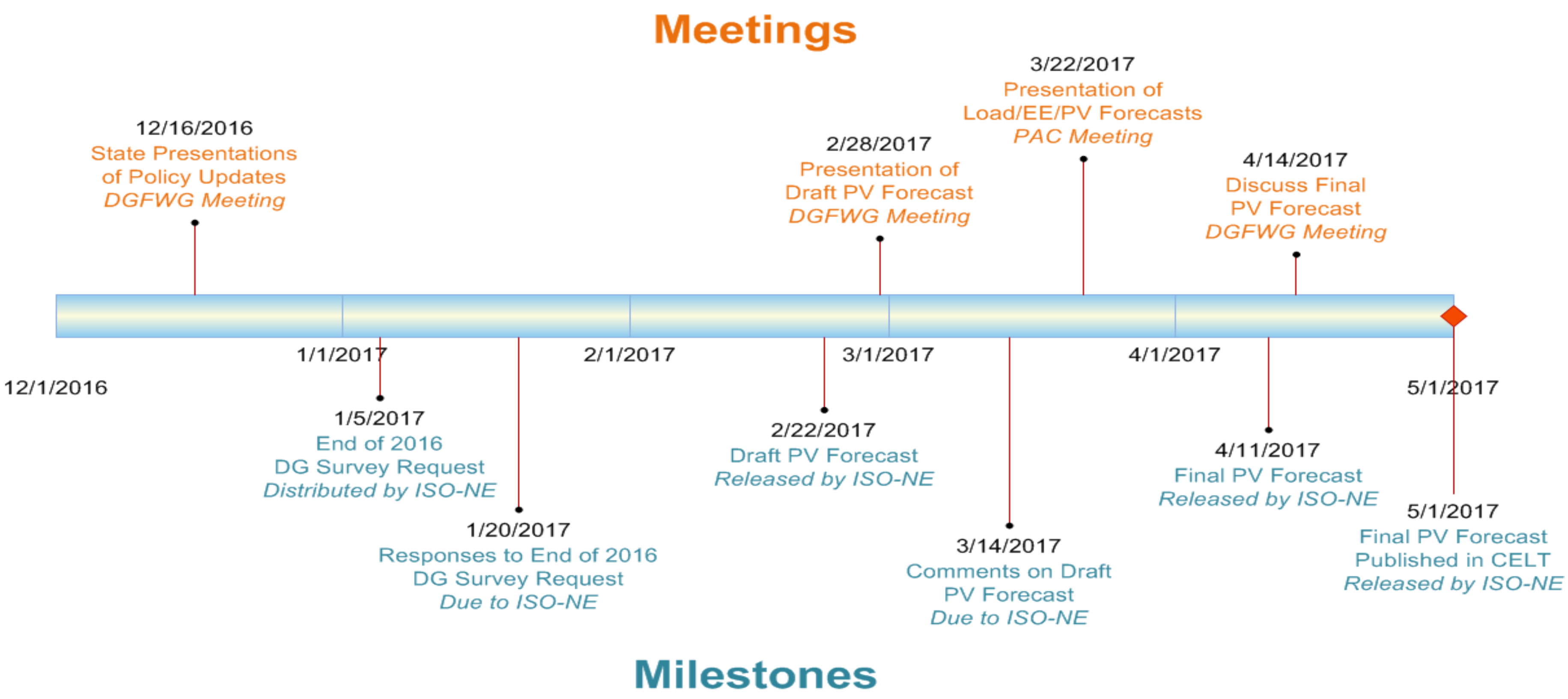
Forecast Focuses on State Policies in All Six New England States

- A policy-based forecasting approach has been chosen to reflect the observation that trends in distributed PV development are in large part the result of policy programs developed and implemented by the New England states
- The ISO makes no judgment regarding state policies, but rather utilizes the state goals as a means of informing the forecast
- In an attempt to control related ratepayer costs, states often factor anticipated changes in market conditions directly into policy design, which are therefore implicit to ISO's policy considerations in the development of the forecast

Background and Forecast Review Process

- The ISO discussed the draft PV forecast with the DGFWG at the February 28, 2017 meeting
  - See: https://www.iso-ne.com/static-assets/documents/2017/02/2017_draft_pvforecast_20170228.pdf
- Stakeholders provided many helpful comments on the draft forecast
  - See: https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=131960
- The final PV forecast is published in the 2017 CELT (Section 3): https://www.iso-ne.com/static-assets/documents/2017/05/2017_celt_report.xls

2017 PV Forecast Schedule



DISTRIBUTION OWNER SURVEY RESULTS

Installed PV – December 2016

December 2016 Year-to-Date Installed PV Capacity
Survey Details

- ISO requested distribution owners to provide the total nameplate PV (in MW_{AC}) that is already installed and operational within their respective service territories as of December 31, 2016
- The following Distribution Owners responded:
  - CT: CL&P, CMEEC, UI
  - ME: CMP, Emera Maine
  - MA: Braintree, Chicopee, National Grid, NSTAR, Reading Shrewsbury, Unitil, WMECO
  - NH: Liberty, NHEC, PSNH, Unitil
  - RI: National Grid
  - VT: Burlington, GMP, Stowe, VEC, VPPSA, WEC
- Based on respondent submittals, installed and operational PV resource totals by distribution owner and state are listed on the following slides

December 2016 Year-to-Date Installed PV Capacity

Breakout by State

The table below reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. The values represent installed nameplate capacity as of 12/31/2016.

State	Installed Capacity (MW_{AC})	No. of Installations
Connecticut	281.55	23,544
Massachusetts*	1,324.77	65,883
Maine	22.14	2,745
New Hampshire	54.30	5,873
Rhode Island	36.81	2,202
Vermont*	198.39	7,612
New England	**1,917.96**	**107,859**

Notes:
* Includes values based on MA SREC data and VT SPEED data

December 2016 Year-to-Date Installed PV Capacity

Breakout by Distribution Owner

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
CT	Connecticut Light & Power	223.40	18,910
	Connecticut Municipal Electric Energy Co-op	6.45	3
	United Illuminating	51.69	4,631
	Total	**281.55**	**23,544**
MA	Braintree Electric Light Department	1.98	17
	Chicopee Electric Light	7.84	15
	Unitil (FG&E)	14.43	1,184
	National Grid	643.42	33,821
	NSTAR	480.12	23,466
	Reading Municipal Lighting Plant	4.21	81
	Shrewsbury Electric & Cable Operations	2.93	51
	Other municipals (per MA SREC data)	87.65	1,517
	Western Massachusetts Electric Company	82.18	5,731
	Total	**1,324.77**	**65,883**
ME	Central Maine Power	19.76	2,348
	Emera	2.38	397
	Total	**22.14**	**2,745**

December 2016 Year-to-Date Installed PV Capacity

Breakout by Distribution Owner

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	3.31	377
	New Hampshire Electric Co-op	6.25	778
	Public Service of New Hampshire	38.95	4,080
	Unitil (UES)	5.79	638
	Total	**54.30**	**5,873**
RI	National Grid	36.81	2,202
	Total	**36.81**	**2,202**
VT	Burlington Electric Department	2.64	146
	Green Mountain Power	173.31	6,204
	Stowe Electric Department	1.47	59
	Vermont Electric Co-op	12.95	637
	Vermont Public Power Supply Authority	4.11	314
	Other Municipals (per VT SPEED data)	0.10	1
	Washington Electric Co-op	3.80	251
	Total	**198.39**	**7,612**
New England		**1,917.96**	**107,859**

Historical Installed PV Capacity Survey Results

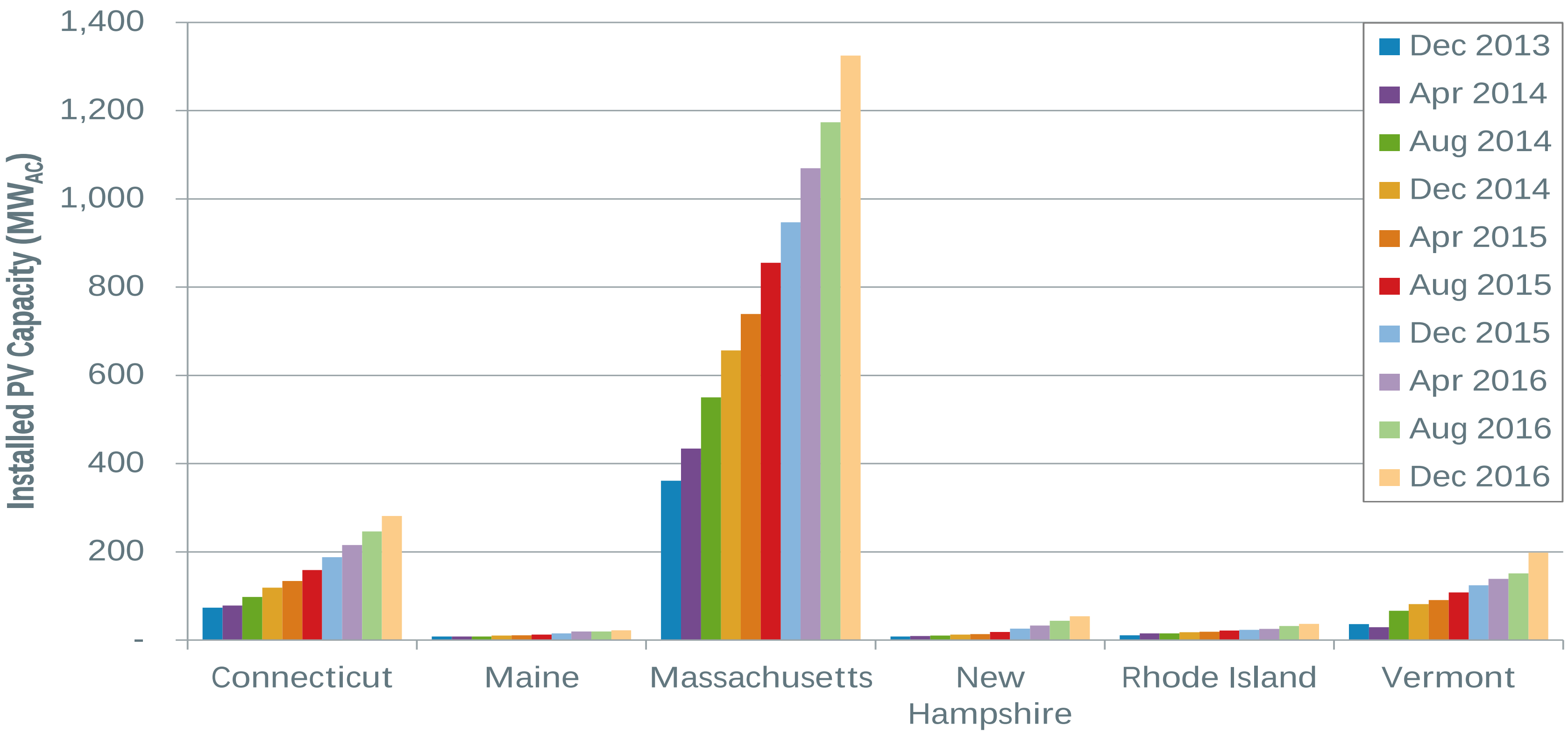
December 2013 - December 2016 (MW_{AC})

Survey Date	CT	ME	MA	NH	RI	VT	New England
Dec 2013	73.75	8.12	361.55	8.22	10.90	36.13	498.67
Apr 2014	78.42	8.51	434.39	9.35	15.29	29.40	575.36
Aug 2014	98.02	8.16	550.54	10.17	15.52	66.55	748.96
Dec 2014	118.80	10.38	656.73	12.74	18.21	81.85	898.71
Apr 2015	133.83	11.04	739.48	13.93	19.08	90.76	1,008.12
Aug 2015	158.73	12.43	855.03	18.37	21.51	108.27	1,174.34
Dec 2015	188.01	15.34	947.11	26.36	23.59	124.57	1,324.98
Apr 2016	215.56	19.54	1,069.85	33.11	25.74	139.13	1,502.90
Aug 2016	246.45	19.83	1,173.56	43.77	32.21	151.22	1,667.04
Dec 2016	281.55	22.14	1,324.77	54.30	36.81	198.39	1,917.96

Reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. Values represent installed megawatt AC (MW_{AC}) nameplate.

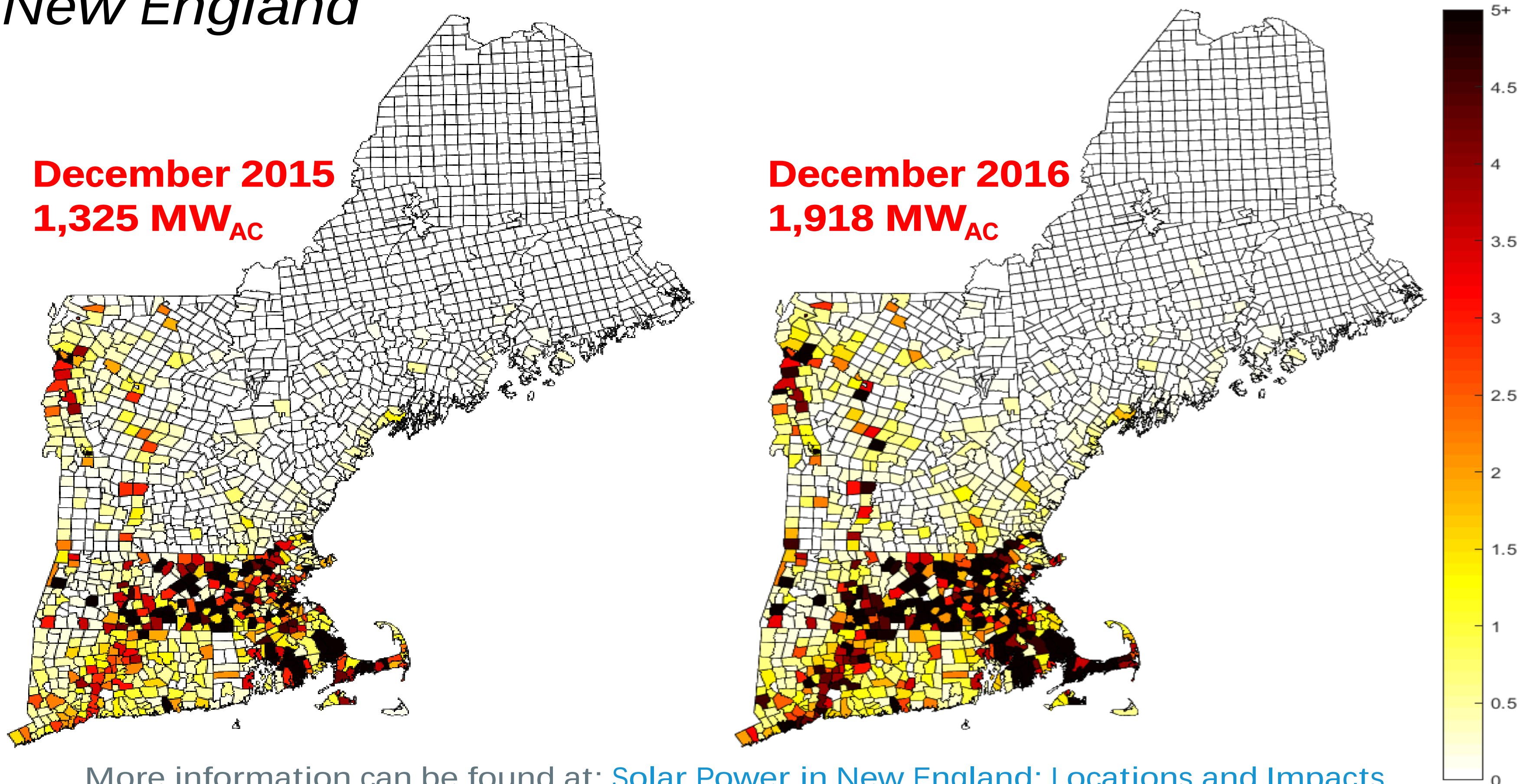
Historical Installed PV Capacity Survey Results

December 2013 - December 2016 (MW_{AC})



Year-Over-Year Installed PV Capacity

New England



More information can be found at: [Solar Power in New England: Locations and Impacts]

2017 FORECAST ASSUMPTIONS AND INPUTS

Federal Investment Tax Credit

- The federal residential and business Investment Tax Credit (ITC) is a key driver of PV development in New England
- There are no changes to the ITC since the 2016 forecast

Residential ITC

Maximum Allowable Residential ITC	
Year	**Credit**
2016	**30%**
2017	**30%**
2018	**30%**
2019	**30%**
2020	**26%**
2021	**22%**
Future Years	**0%**

Business ITC

ITC by Date of Construction Start	
Year construction starts	**Credit**
2016	**30%**
2017	**30%**
2018	**30%**
2019	**30%**
2020	**26%**
2021	**22%**
2022	**10%**
Future Years	**10%**

Sources: http://programs.dsireusa.org/system/program/detail/658 **and** http://programs.dsireusa.org/system/program/detail/1235

Massachusetts Forecast Methodology and Assumptions

- MA DPU's 12/16/16 DGFWG presentation serves as primary source for MA policy information
- MA SREC I/II program goals met and Emergency Regulations result in expansion of SREC II
  - 83% AC-to-DC ratio assumed
  - Converted original 2020 goals: 1,600 MW_{DC} = **1,328 MW_{AC}**
  - Emergency Regulations result in additional 400 MW_{DC} = **332 MW_{AC}**
  - **Total of 1,660 MW_{AC}**
- MA Distribution Owners report a total of 1,324.77 MW_{AC} installed by 12/31/16
  - Assume 30 MW_{AC} is non-SREC capacity (i.e., "legacy")
  - This results in 1,294.77 MW_{AC} of SREC projects installed by 12/31/16
  - This leaves 365.23 MW_{AC} of SREC projects remaining
- SREC I/II programs assumed to end in 2018; remaining capacity applied:
  - 2017 – 273.9 MW (75%)
  - 2018 – 91.3 MW (25%)

Massachusetts Forecast Methodology and Assumptions *continued*

- MA DOER finalized design of Solar MA Renewable Target (SMART) program:
  http://www.mass.gov/eea/docs/doer/rps-aps/final-program-design-1-31-17.pdf
  – Sets forth a 1,600 MW_{AC} SMART program goal
  – Program capacity goal is divided evenly over 2018-2022 (5 years) and post-policy discount factor is applied
  – ISO is seeking updated information concerning the regulatory process and implementation of the new SMART program

Connecticut Forecast Methodology and Assumptions

- CT DEEP's 12/16/16 DGFWG presentation serves as primary source for CT policy information
- LREC/ZREC program assumptions provided by CT DEEP
  - Solicitations for years 1-5 yielded 315.68 MW PV
  - As proxy for year 6 solicitation planned for 2017, ISO used year 5 solicitation results, which included:
    - Medium/Large ZREC & LREC total 57.73 MW of PV
    - Small ZREC projects – assumed 20 MW PV total
    - 77.73 MW total PV from Year 5 assumed to be procured in Year 6
  - This yields a total of 393.41 MW PV from LREC/ZREC solicitations
    - This is a slight increase from 360 MW assumed in 2016 PV forecast
  - Based on Distribution Owner data, approximately 113 MW of ZREC projects in service by 12/31/16
  - Remaining 280.41 MW were divided and applied to 2017-2020 as follows:
    - 2017-2019: 84.12 MW/year
    - 2020: 28.04 MW
  - Post-ZREC (after 2020) forecast values are kept at 2020 growth level, but discounted at applicable post-policy discount factor

Connecticut Forecast Methodology and Assumptions *continued*

- CEFIA/Green Bank Residential Solar Incentive Program (RSIP) and Solar Home Renewable Energy Credit (SHREC) program
  - Total 300 MW goal by 2022, but CT DEEP anticipate goal met by 2019
  - Based on Distribution Owner data, approximately 154 MW installed as of 12/31/16 ; with 146 MW remaining
    - 48.67 MW/year from 2017-2019
  - Post-2019: Forecast inputs kept at 48.67 MW/year and post-policy discount factor applied
- Small Scale Procurement (< 5MW) associated with Public Act 15-107
  - Total of 5 MW expected to go into service in 2020
- A 20 MW project in Sprague/Lisbon removed from forecast since it is larger than 5MW

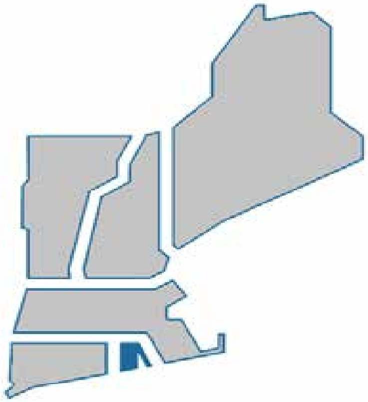
Vermont Forecast Methodology and Assumptions

- VT DPS’ 12/16/16 DGFWG presentation serves as primary source for VT policy information, with supplemental information provided as comments on the draft forecast
- DG carve-out of the Renewable Energy Standard (RES)
  - Assume 85% of eligible resources will be PV and a total of 25 MW/year will develop
- Standard Offer Program
  - Will promote a total of 110 MW of PV (of the 127.5 MW total goal)
  - All prospective renewable energy certificates (RECs) from Standard Offer projects will be sold to utilities and count towards RES DG carve-out
- Net metering
  - All prospective RECs from net metered projects will be sold to utilities and count towards RES DG carve-out

New Hampshire Forecast Methodology and Assumptions

- NH PUC's 12/16/16 DGFWG presentation serves primary source for NH policy information
- Based on distribution owner survey results, net metering and other state rebate/grants resulted in 27.9 MW of PV growth in 2016
- Net metering
  – The new 100 MW cap is reflected in draft forecast
  – Assume all of the remaining 30.1 MW will be PV, and 100 MW net metering cap reached by 2018

Rhode Island Forecast Methodology and Assumptions



- RI OER's 12/16/16 DGFWG presentation serves as primary source for RI policy information
- DG Standards Contracts program
  - A total of 30 MW of 40 MW program goal will be PV
  - Estimated 18 MW installed by 12/31/16, and 12 MW remaining assumed to be installed at 6 MW/year from 2017-2018
- Renewable Energy Growth Program (REGP)
  - Total of 144 MW of 160 MW of program goal will be PV
  - Estimated 4.8 MW installed by 12/31/16, and remaining 139.2 MW installed over years 2017-2021
- Renewable Energy Fund & Net Metering (joint policy drivers)
  - Historically has supported a total of ~14 MW of PV through 12/31/16
    - Form EIA-826 data indicates 13.741 MW through 11/30/16
  - Includes a new 30 MW virtual net metering program created in 2016
  - Assumed to yield 4 MW/year over the forecast horizon (total of 40 MW)

Maine Forecast Methodology and Assumptions

- ME PUC's 12/16/16 DGFWG presentation serves as primary source for ME policy information
- Based on Distribution Owner survey results, net metering and other state grants/incentives resulted in 6.84 MW of PV growth in 2016
- This annual growth is carried forward at constant rate throughout forecast period

Discount Factors

- Discount factors were developed and incorporated into the forecast to reflect uncertainty in future PV commercialization and policy support beyond existing policy landscape
- Discount factors were developed for two types of future PV inputs to the forecast (and all discount factors are applied equally in all states)
- Policy-based and post-policy discount factors were reduced from those used in 2016 due to higher-than-expected PV growth for three consecutive years
  - Slide 33 shows previous PV forecasts and historical PV growth

Policy-Based *PV that results from state policy*	**Post-Policy** *PV that may be installed after existing state policies end*
Discounted by values that begin at 0% for first 3 years and then increase up to a maximum value of 15%	**Discounted by values increasing annually from 35% to 50% due to the high degree of uncertainty associated with possible future expansion of state policies and/or future market conditions required to support PV commercialization in the absence of policy expansion**

Discount Factors Used in 2017 PV Forecast

Policy-Based

Forecast Year	Final 2017
2017	0%
2018	0%
2019	0%
2020	10%
2021	15%
2022	15%
2023	15%
2024	15%
2025	15%
2026	15%

Post-Policy

Forecast Year	Final 2017
2017	35.0%
2018	36.7%
2019	38.3%
2020	40.0%
2021	41.7%
2022	43.3%
2023	45.0%
2024	46.7%
2025	48.3%
2026	50.0%

Summary of State-by-State 2017 Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
CT	281.5	132.8	132.8	132.8	81.7	76.7	76.7	76.7	76.7	76.7	76.7	**1,221.9**
MA	1324.8	273.9	358.0	266.7	266.7	266.7	266.7	266.7	133.3	133.3	133.3	**3,690.0**
ME	22.1	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	**90.5**
NH	54.3	18.1	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	**180.7**
RI	36.8	41.3	41.3	35.3	35.3	17.9	17.9	17.9	17.9	17.9	17.9	**297.6**
VT	198.4	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	**448.4**
Pre-Discount Annual Policy-Based MWs	**1918.0**	**497.9**	**309.3**	**200.0**	**100.2**	**49.8**	**35.8**	**35.8**	**35.8**	**35.8**	**35.8**	**3,254.3**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**266.7**	**278.7**	**327.4**	**355.4**	**369.3**	**369.3**	**236.0**	**236.0**	**236.0**	**2,674.8**
Pre-Discount Annual Total (MW)	**1918.0**	**497.9**	**576.0**	**478.7**	**427.6**	**405.2**	**405.2**	**405.2**	**271.8**	**271.8**	**271.8**	**5,929.1**
Pre-Discount Cumulative Total (MW)	**1918.0**	**2,415.9**	**2,991.9**	**3,470.5**	**3,898.1**	**4,303.3**	**4,708.4**	**5,113.6**	**5,385.5**	**5,657.3**	**5,929.1**	**5,929.1**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 13-25 for details)
(2) Yellow highlighted cells indicate that values include post-policy MWs
(3) All values include FCM Resources, non-FCM Settlement Only Generators and Generators (per OP-14), and load reducing PV resources
(4) All values represent end-of-year nameplate capacities

2017 PV NAMEPLATE CAPACITY FORECAST

Includes FCM, non-FCM, and BTM PV

Final 2017 PV Forecast

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	
CT	281.5	132.8	132.8	132.8	58.9	44.7	43.5	42.2	40.9	39.6	38.4	**988.2**
MA	1324.8	273.9	260.2	164.4	160.0	155.6	151.1	146.7	71.1	68.9	66.7	**2,843.3**
ME	22.1	6.8	6.8	6.8	6.2	5.8	5.8	5.8	5.8	5.8	5.8	**83.7**
NH	54.3	18.1	12.0	7.4	7.2	7.0	6.8	6.6	6.4	6.2	6.0	**138.2**
RI	36.8	41.3	41.3	35.3	31.8	15.2	11.3	11.1	10.8	10.6	10.4	**255.9**
VT	198.4	25.0	25.0	25.0	22.5	21.3	21.3	21.3	21.3	21.3	21.3	**423.4**
Regional - Annual (MW)	**1918.0**	**497.9**	**478.2**	**371.8**	**286.6**	**249.6**	**239.8**	**233.6**	**156.3**	**152.4**	**148.5**	**4,732.7**
Regional - Cumulative (MW)	**1918.0**	**2415.9**	**2894.1**	**3265.9**	**3552.5**	**3802.1**	**4041.9**	**4275.5**	**4431.8**	**4584.2**	**4732.7**	**4,732.7**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Resources, and behind-the-meter PV
(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals
(3) All values represent end-of-year installed capacities

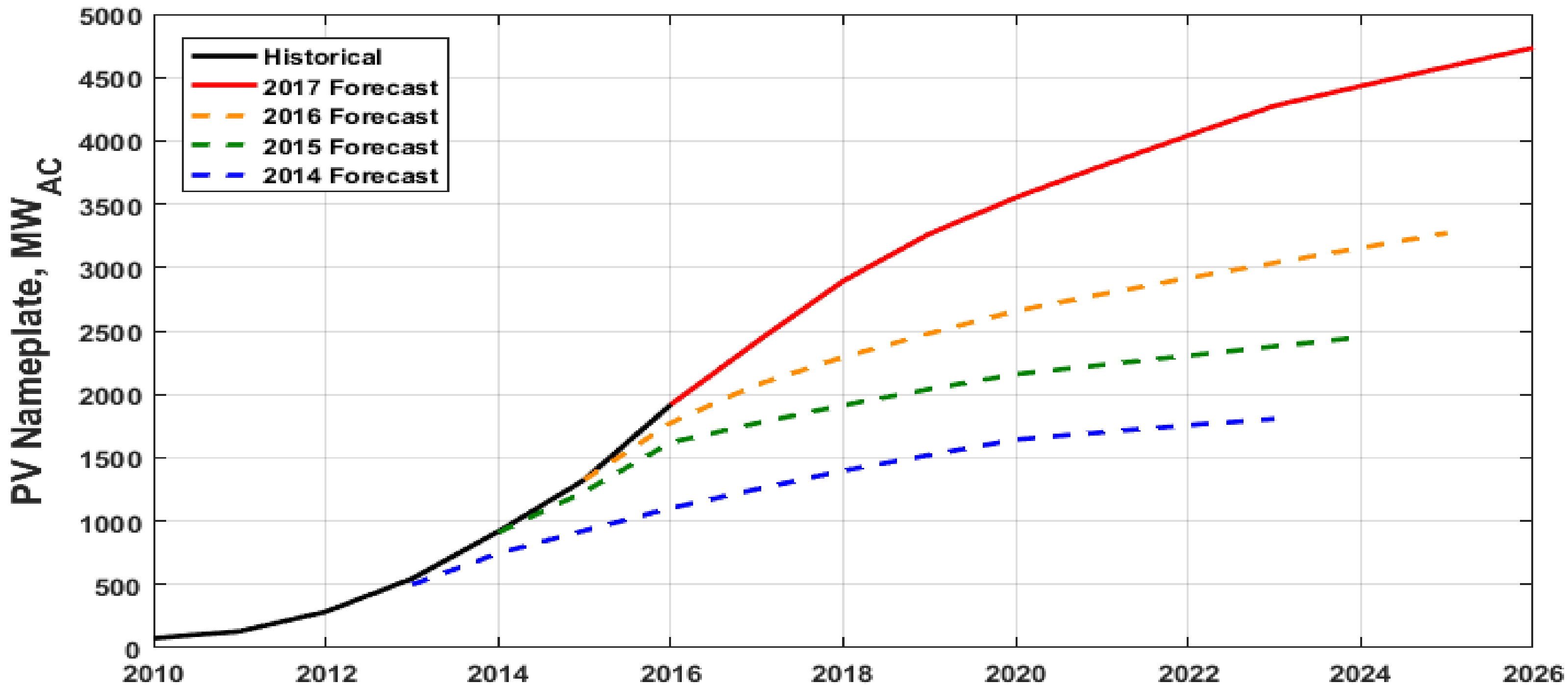
Final 2017 PV Forecast

Cumulative Nameplate, MW_{ac}

States	Cumulative Total MW (AC nameplate rating)										
	Thru 2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CT	281.5	414.3	547.1	679.9	738.9	783.6	827.1	869.3	910.2	949.8	988.2
MA	1324.8	1598.7	1858.9	2023.3	2183.3	2338.9	2490.0	2636.7	2707.8	2776.7	2843.3
ME	22.1	29.0	35.8	42.7	48.8	54.6	60.4	66.3	72.1	77.9	83.7
NH	54.3	72.4	84.4	91.8	99.1	106.1	112.9	119.5	125.9	132.2	138.2
RI	36.8	78.1	119.5	154.8	186.6	201.8	213.1	224.1	235.0	245.6	255.9
VT	198.4	223.4	248.4	273.4	295.9	317.1	338.4	359.6	380.9	402.1	423.4
Regional - Cumulative (MW)	**1918.0**	**2415.9**	**2894.1**	**3265.9**	**3552.5**	**3802.1**	**4041.9**	**4275.5**	**4431.8**	**4584.2**	**4732.7**

***Notes*:**
(1) Forecast values include FCM Resources, non-FCM Energy Only Resources, and behind-the-meter PV
(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals
(3) All values represent end-of-year installed capacities

PV Growth: Reported Historical vs. Forecast

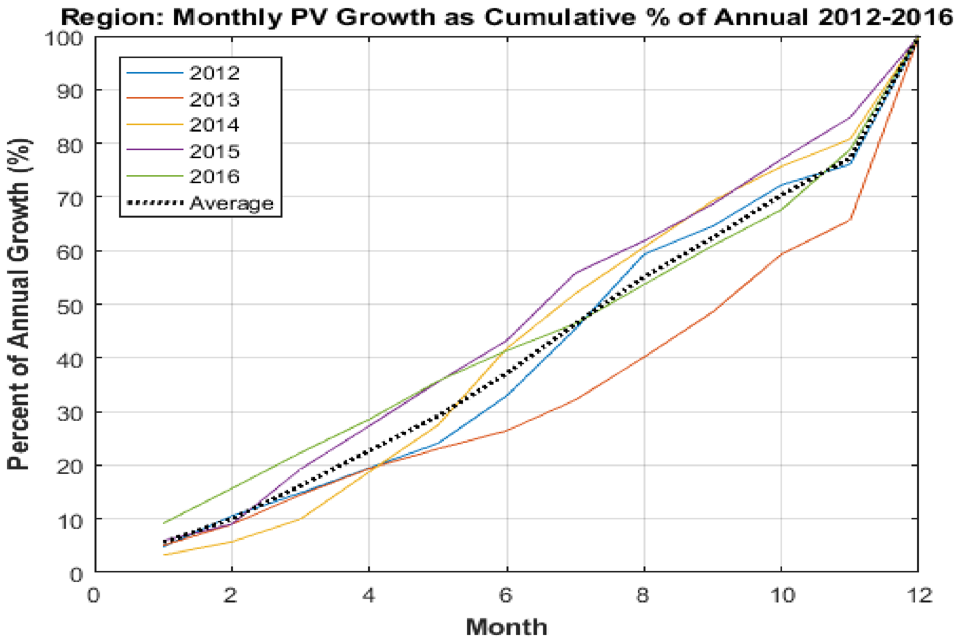


2017 PV ENERGY FORECAST

Development of PV Energy Forecast

- The 2017 PV nameplate forecast reflects end-of-year values
- Energy estimates in the PV forecast are inclusive of incremental growth during a given year
- ISO assumed that historical PV growth trends across the region are indicative of future intra-annual growth rates
  - Growth trends between 2012 and 2016 were used to estimate intra-annual incremental growth over the forecast horizon (*see next slide*)
- The PV energy forecast was developed using a monthly nameplate forecast along with average monthly capacity factors developed from 5 years of PV performance data (2012-2016)
  - Annual capacity factor = 14.4%
  - Refer to slides 15 and slides 24-45

Historical Monthly PV Growth Trends, 2012-2016



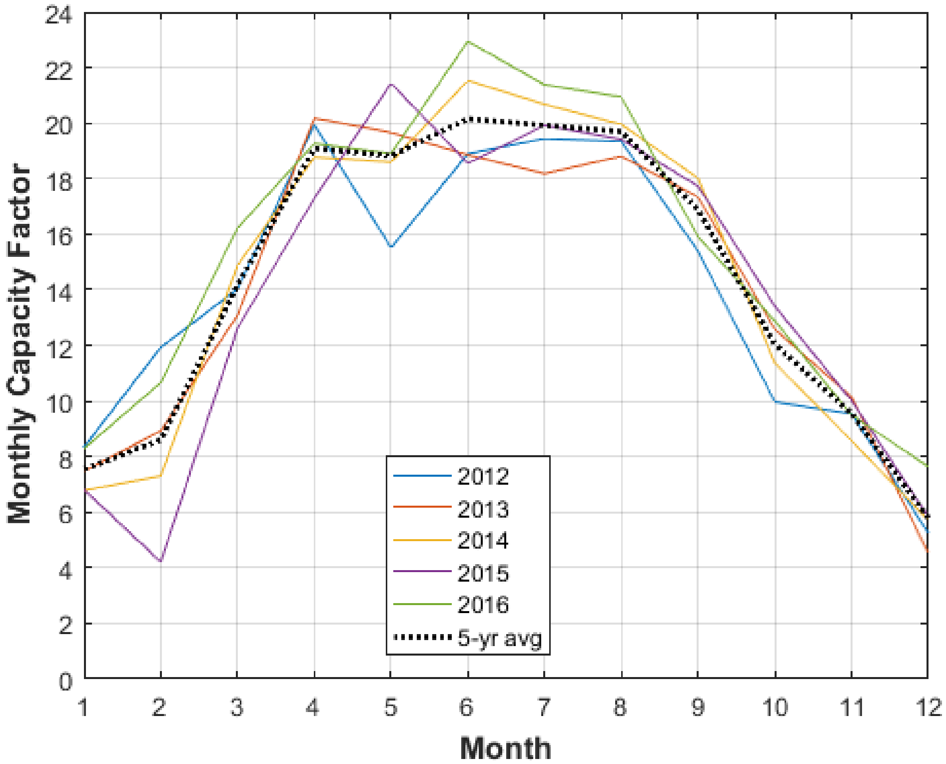
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6%	6%
2	4%	10%
3	6%	16%
4	7%	23%
5	6%	29%
6	8%	37%
7	9%	46%
8	9%	55%
9	7%	62%
10	8%	70%
11	7%	77%
12	23%	100%

<u>Note</u>:
Monthly percentages represent end-of-month values, and may not sum to total due to rounding

Monthly PV Capacity Factors

PV Production Data, 2012-2016



Final 2017 PV Energy Forecast

Total PV Forecast Energy, GWh

States	Total Estimated Annual Energy (GWh)									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
CT	440	618	796	939	1,012	1,071	1,129	1,185	1,239	1,292
MA	1905	2,266	2,570	2,788	3,001	3,208	3,408	3,570	3,664	3,755
ME	33	42	51	60	68	76	84	92	99	107
NH	81	103	117	127	136	145	155	163	172	180
RI	69	124	177	222	257	276	291	306	320	334
VT	278	311	345	377	407	435	464	492	521	549
Regional - Annual Energy (GWh)	**2805**	**3,463**	**4,055**	**4,514**	**4,881**	**5,211**	**5,530**	**5,807**	**6,015**	**6,218**

Notes:
(1) Forecast values include energy from FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) Monthly in service dates of PV assumed based on historical development
(3) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

BREAKDOWN OF PV NAMEPLATE FORECAST INTO RESOURCE TYPES

Forecast Includes Classification by Resource Type

- In order to properly account for existing and future PV in planning studies and avoid double counting, ISO classified PV into three distinct types related to the resources assumed market participation/non-participation
- These market distinctions are important for the ISO's use of the PV forecast in a wide range of planning studies
- The classification process requires the estimation of hourly PV production that is behind-the-meter (BTM), i.e., PV that does not participate in ISO markets
  - BTM PV reconstitution is discussed in subsequent slides

Three Mutually Exclusive PV Resource Types

1. **PV as a resource in the Forward Capacity Market (FCM)**
   - Qualified for the FCM and have acquired capacity supply obligations
   - Size and location identified and visible to the ISO
   - May be supply or demand-side resources
2. **Non-FCM Energy Only Resources (EOR) and Generators**
   - ISO collects energy output
   - Participate only in the energy market
3. **Behind-the-Meter (BTM) PV**
   - Not in ISO Market
   - Reduces system load
   - ISO has an incomplete set of information on generator characteristics
   - ISO does not collect energy meter data, but can estimate it using other available data

Determining PV Resource Type By State

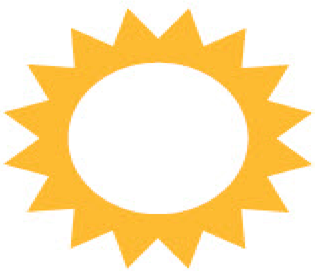
- Resource types vary by state
  - Can be influenced by state regulations and policies (*e.g.*, net metering requirements)
- The following steps were used to determine PV resource types for each state over the forecast horizon:
  1. **FCM**
     - Identify all Generation and Demand Response FCM PV resources for each Capacity Commitment Period (CCP) through FCA 11
  2. **Non-FCM EOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2016 and assume this share remains constant throughout the forecast period
  3. **BTM**
     - Subtract the values from steps 1 and 2 from the annual state PV forecast, the remainder is the BTM PV

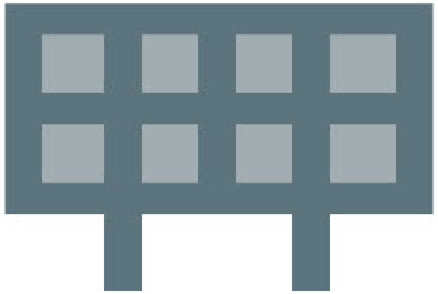
PV in ISO New England Markets

- **FCM**
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 11
  - Assume aggregate total PV in FCM as of FCA 11 remains constant from 2020-2026
- **Non-FCM Gen/EOR**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/16
  - Assume % share of nameplate PV in energy market as of 12/31/16 remains constant throughout the forecast horizon
- *Other assumptions*
  - Supply-side FCM PV resources operate as EOR/Gen prior to their first FCM commitment period (this has been observed in Massachusetts)
  - Planned PV projects known to be > 5 MW_{ac} nameplate are assumed to trigger OP-14 requirement to register in ISO energy market as a Generator

Estimation of Hourly BTM PV for Reconstitution

- Hourly historical BTM PV production data is needed to reconstitute PV into the historical loads used to develop the long-term gross load forecast
- ISO estimates hourly BTM PV production using historical PV production data and utility-provided historical PV installation data
  - Data sources and method are described on the following slides





BTM PV Profiles Used for Reconstitution

Methodology

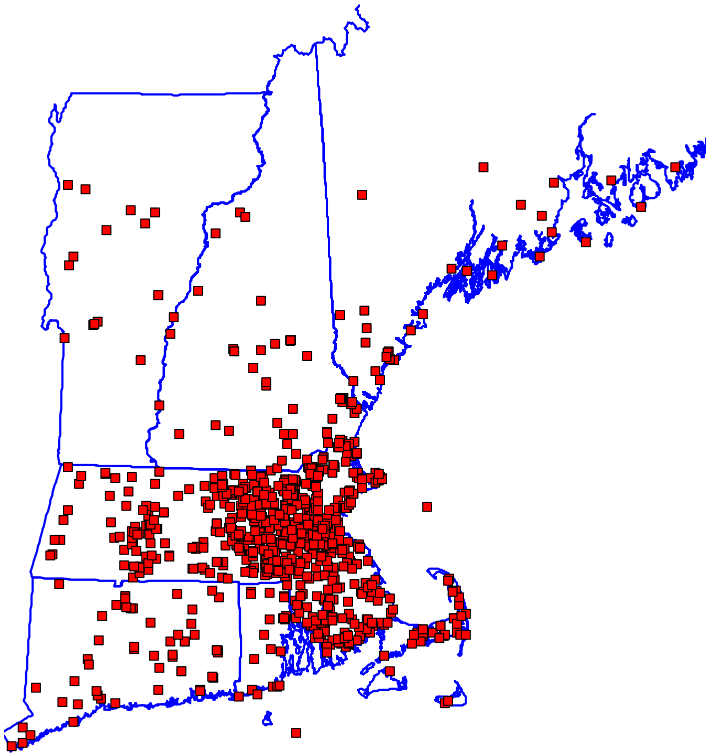
- ISO develops hourly state PV profiles for the period 1/1/2012 –1/31/2016 using historical PV production data
  - Data are aggregated into normalized profiles for each state, which represent a per-MW-of-nameplate production profile for PV
- Total state PV production is estimated by scaling the profiles up to the total PV installed over the period according to distribution utility data
  - (Normalized Hrly Profile) x (Total installed PV Capacity) = Hourly PV production
- Subtracting the hourly PV settlements energy (where applicable) yields the total hourly BTM PV for each state

BTM PV Profiles Used for Reconstitution

Data Source for Period From 1/1/12 to 12/31/13

- Hourly state PV profiles developed for two years (2012-2013) using production data using Yaskawa-Solectria Solar's web-based monitoring system, SolrenView*
  - Represents PV generation at the inverter or at the revenue-grade meter
- A total of more than 1,200 individual sites representing more than 125 MW_{ac} in nameplate capacity were used
  - Site locations depicted on adjacent map

Yaskawa-Solectria Sites



***Source:** http://www.solrenview.com/

BTM PV Profiles Used for Reconstitution

Data Source for Period From 1/1/14 to 1/31/17

- ISO has contracted with a third-party vendor for PV production data services
  - Represents PV generation at the inverter
  - Includes data from more than 9,000 PV installations
  - Data are 5-minutely and at the town level
  - Broad geographic coverage
  - Data provided begins in 2014
- An example snapshot of regional data is plotted to the right
  - Data are from February 2, 2017 at 12:10pm
  - Yellow/red coloring shows level of PV production
  - No data available in towns colored gray
  - Data not requested in towns colored black
- Using these data, state PV profiles are developed as described on the previous slide

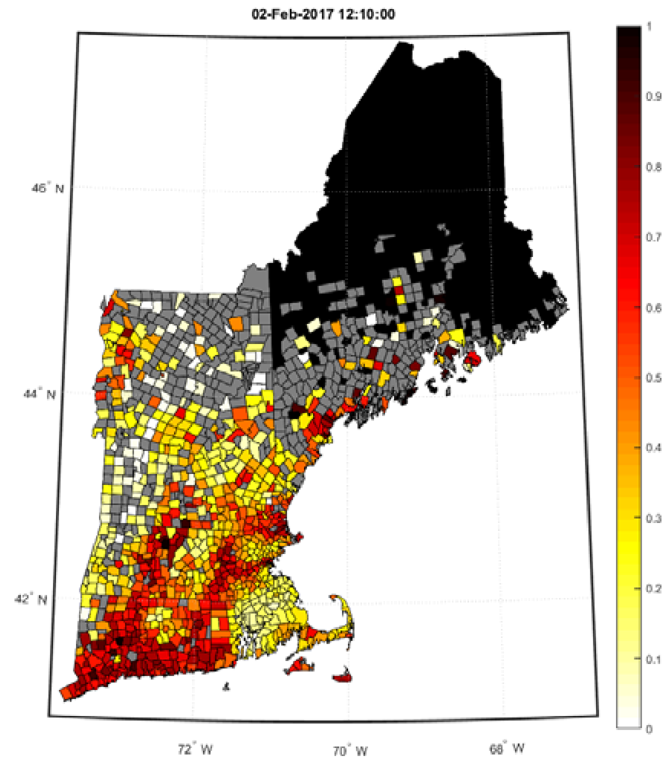
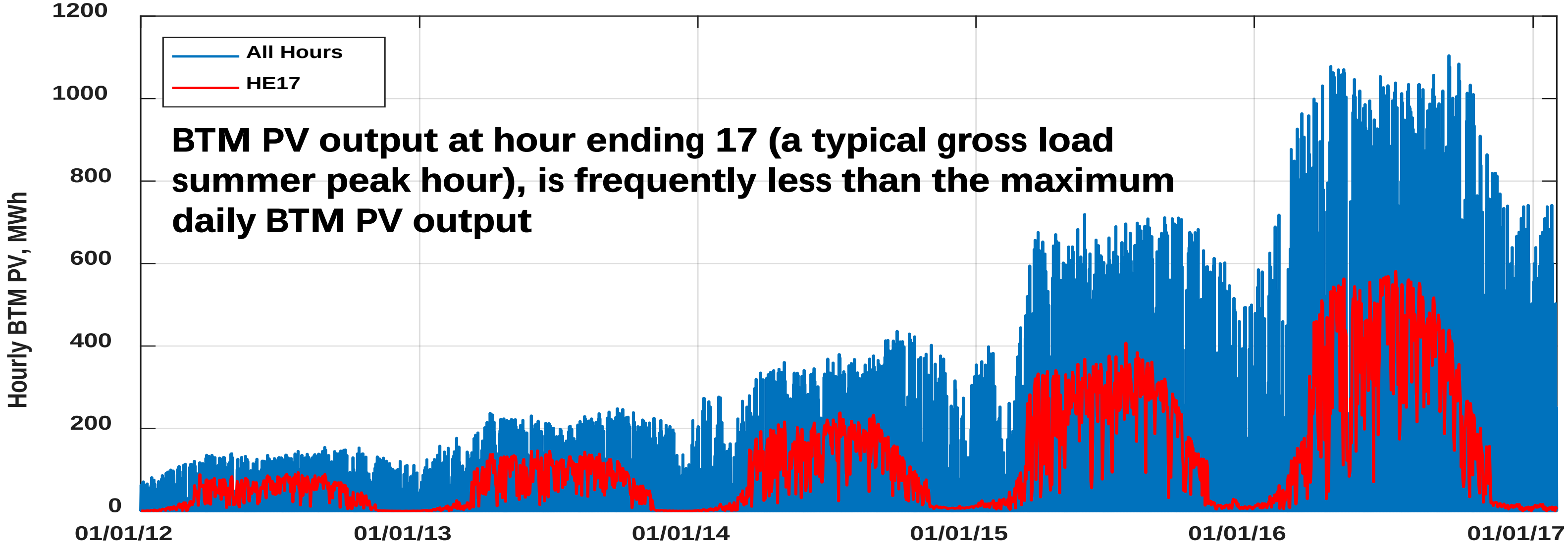


Figure notes:
1. Graphic developed by ISO New England
2. Data source: Quantitative Business Analytics, Inc.

BTM PV Profiles Used for Reconstitution

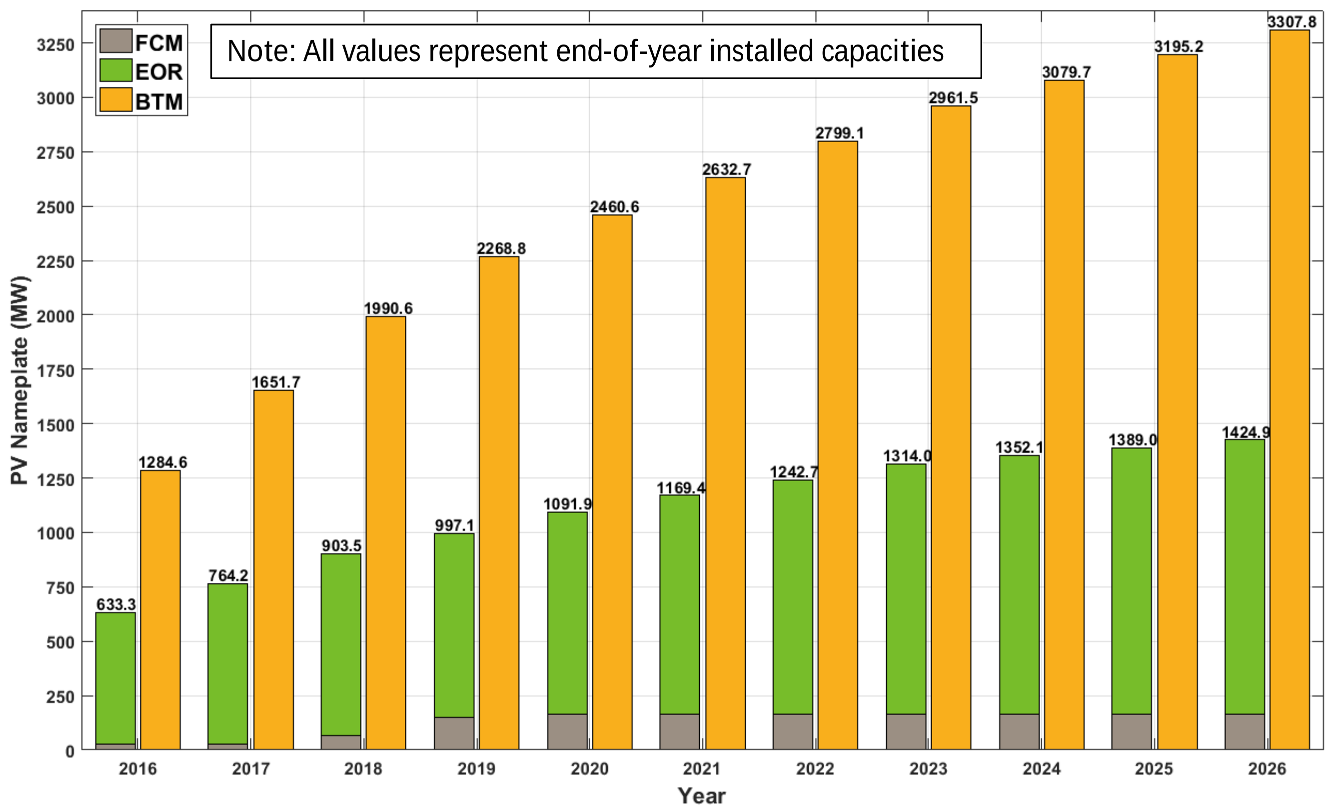
Results for ISO-NE



FINAL 2017 PV NAMEPLATE FORECAST BY RESOURCE TYPE

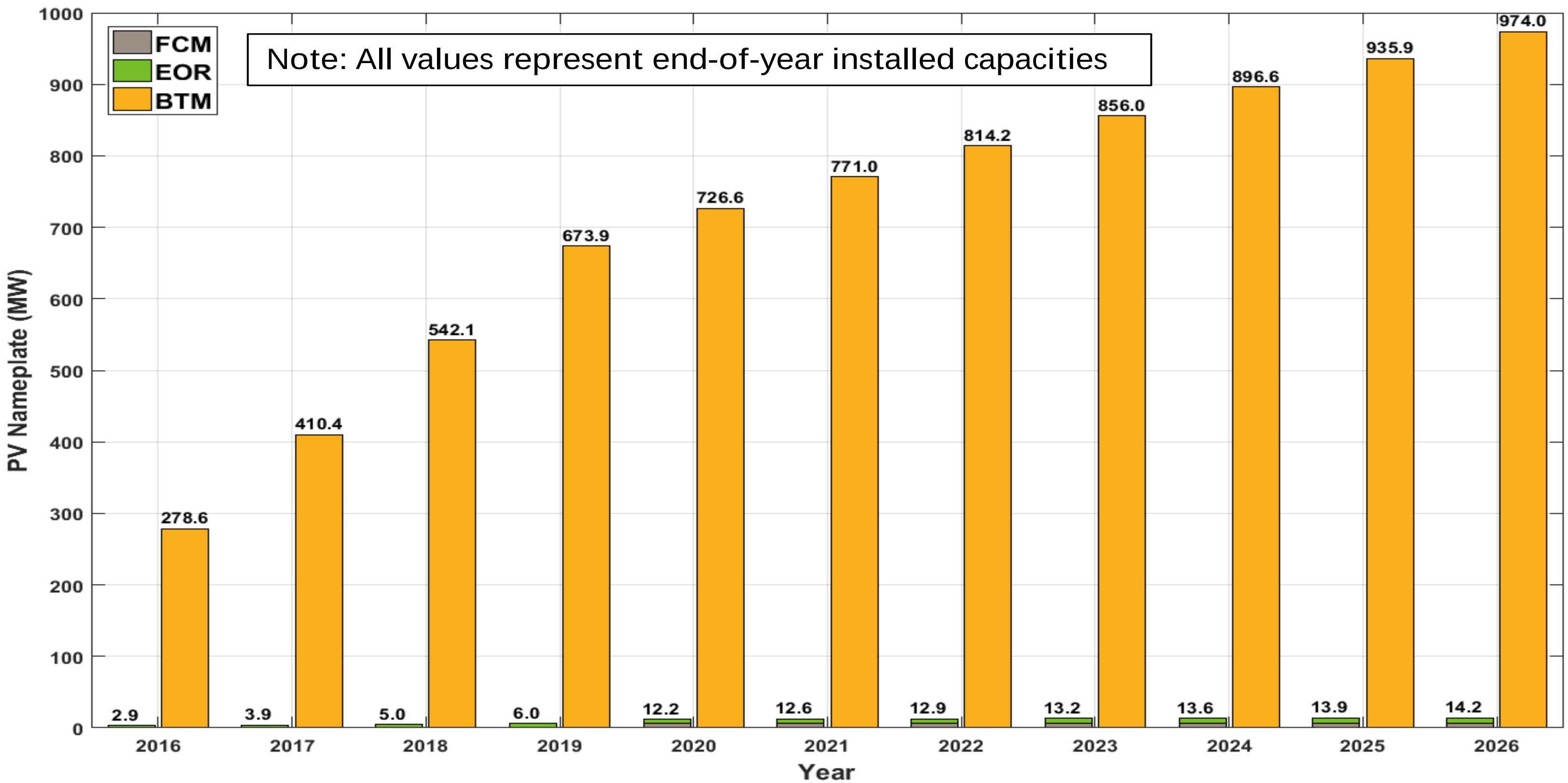
Final 2017 PV Forecast

Cumulative Nameplate, MW_{ac}



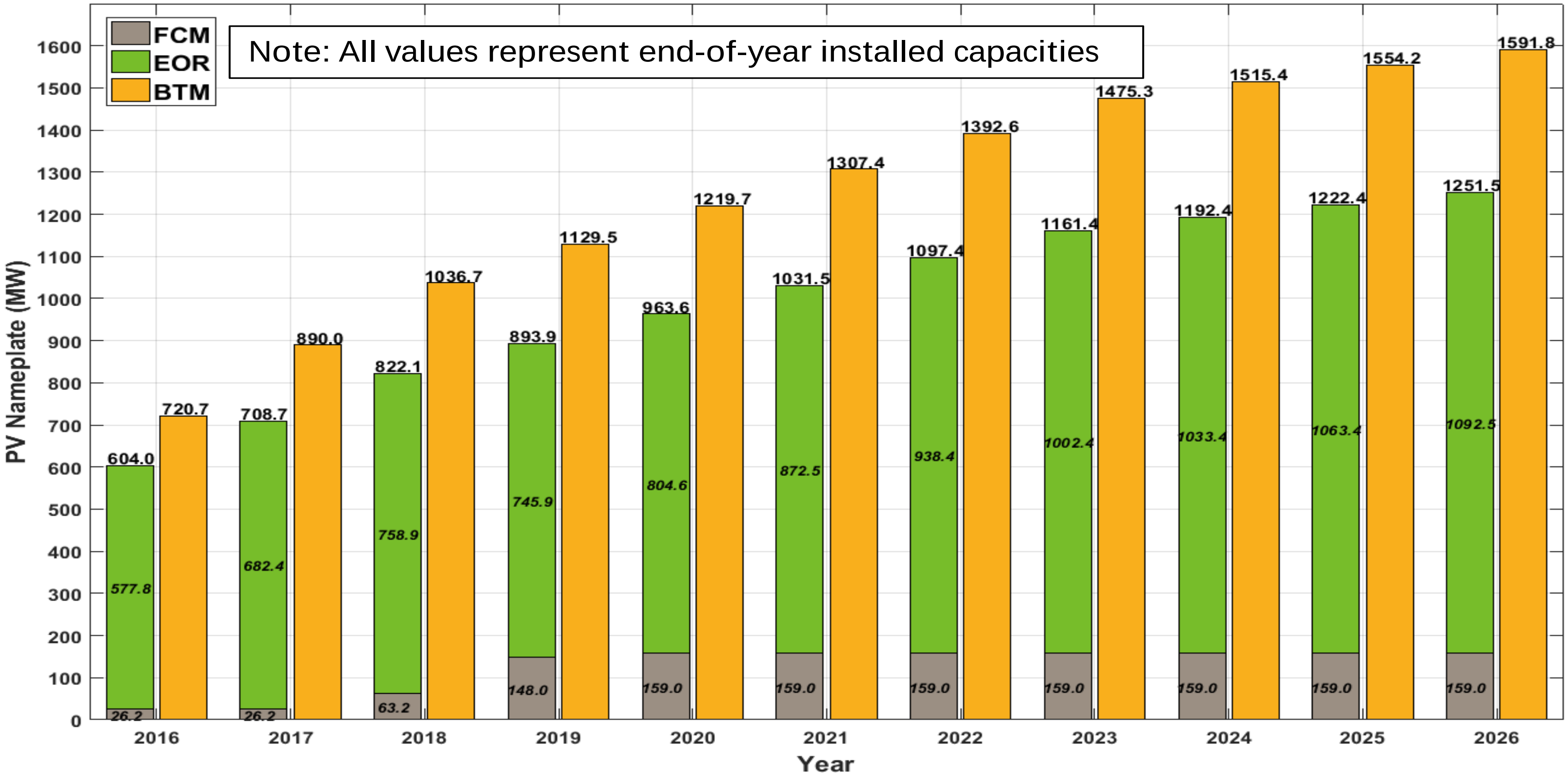
Cumulative Nameplate by Resource Type, MW_{ac}

Connecticut



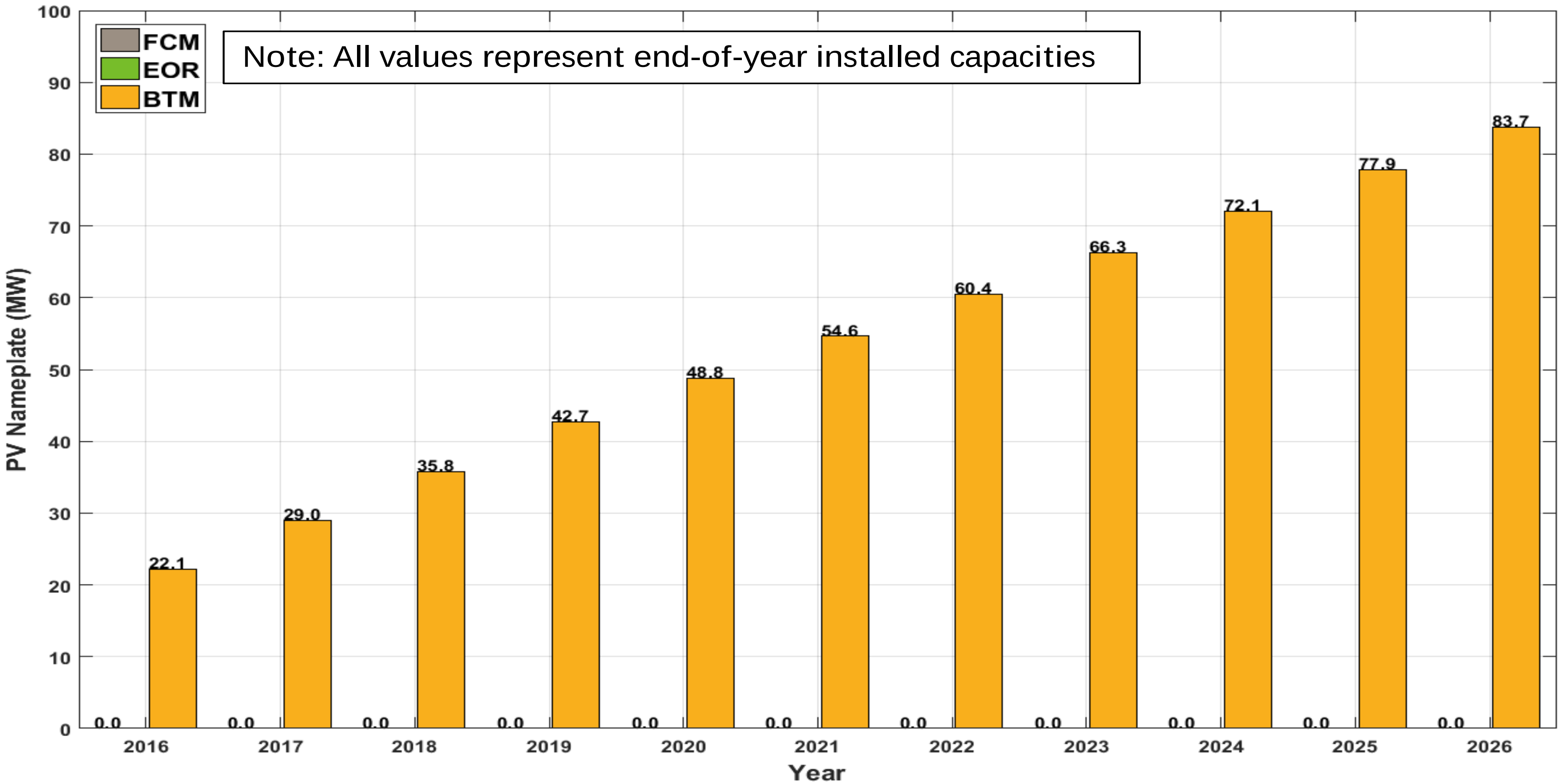
Cumulative Nameplate by Resource Type, MW_{ac}

Massachusetts



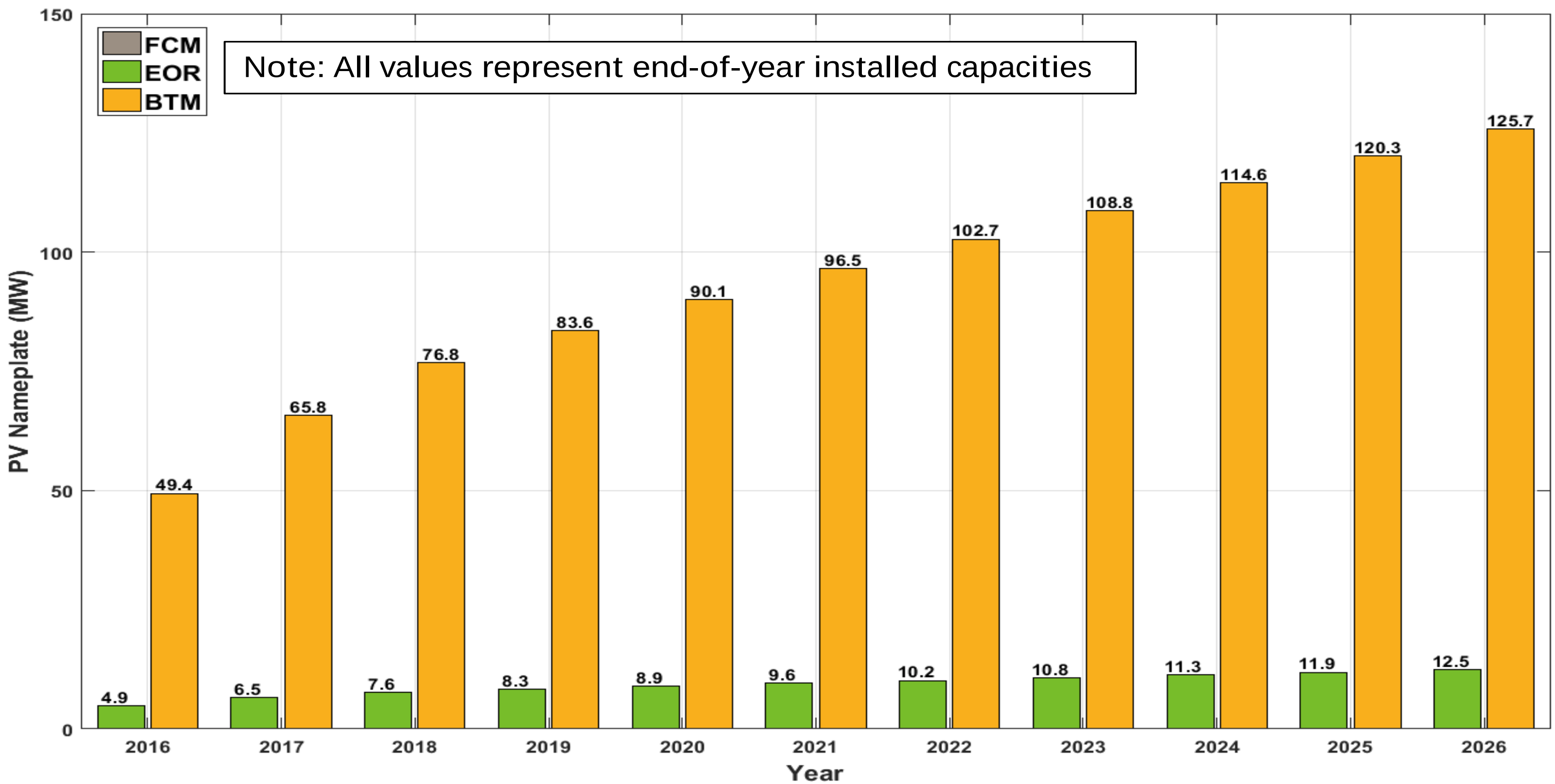
Cumulative Nameplate by Resource Type, MW_{ac}

Maine



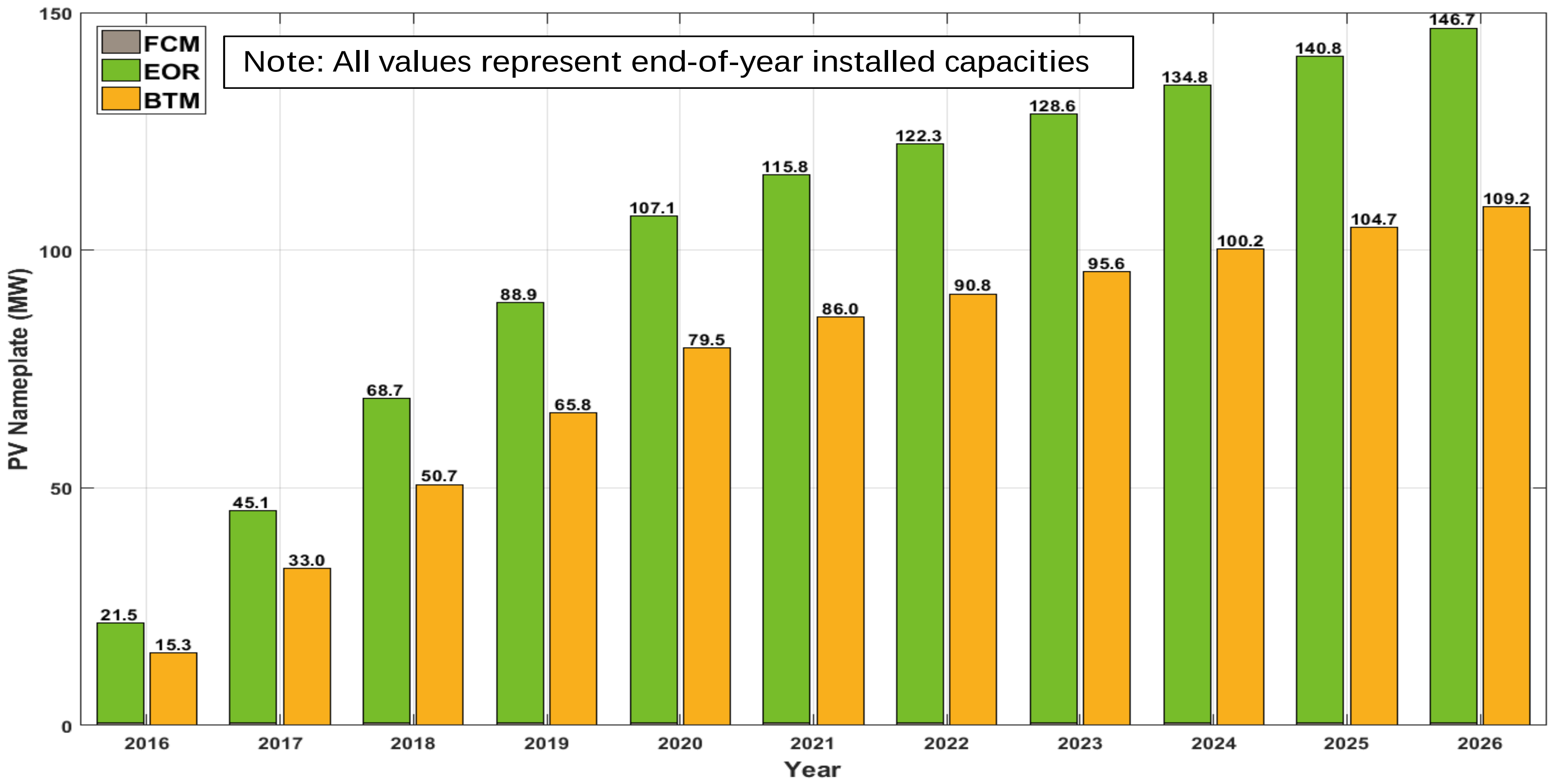
Cumulative Nameplate by Resource Type, MW_{ac}

New Hampshire



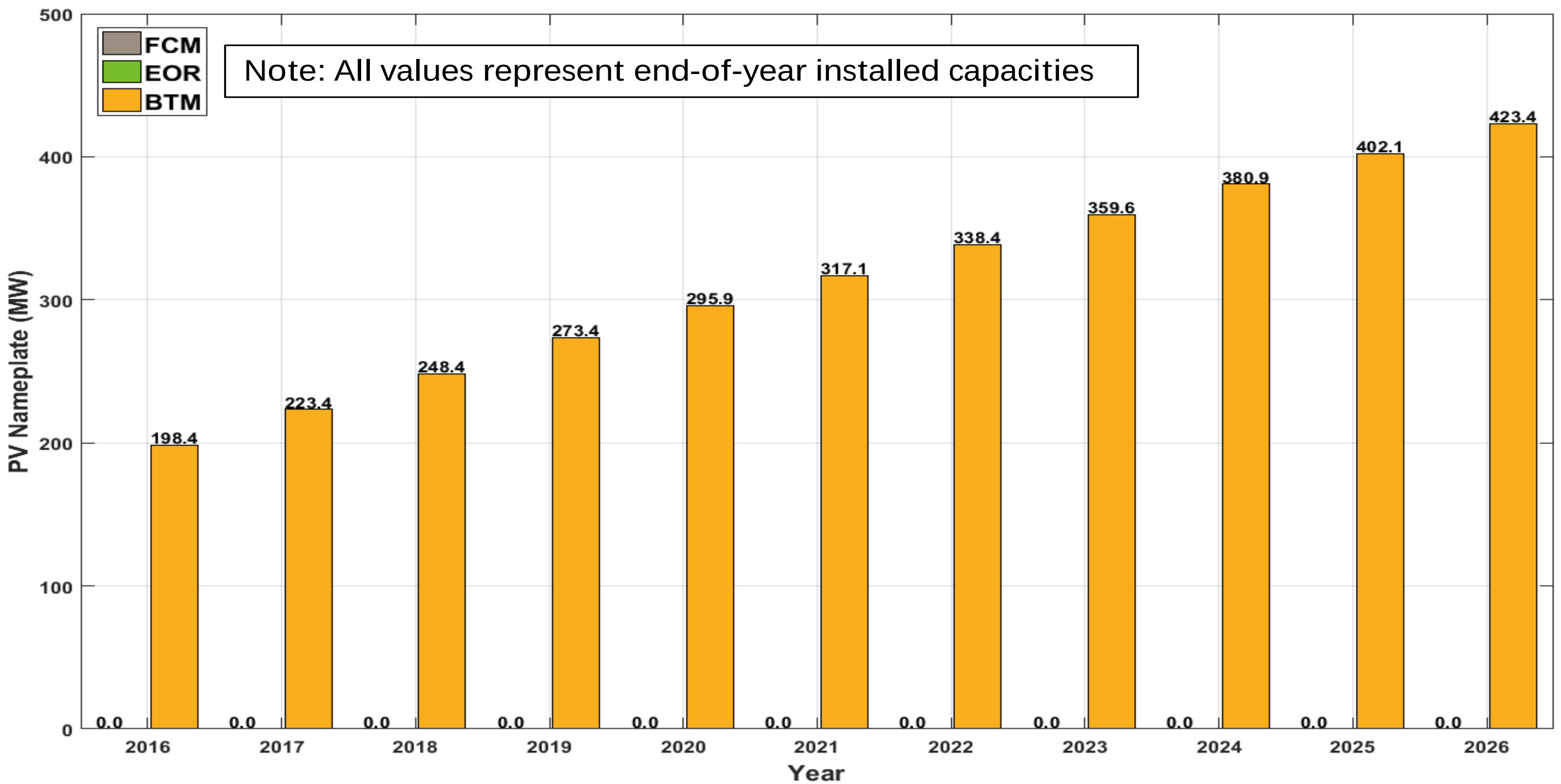
Cumulative Nameplate by Resource Type, MW_{ac}

Rhode Island



Cumulative Nameplate by Resource Type, MW_{ac}

Vermont



2017 CELT BTM PV FORECAST:
ESTIMATED ENERGY & SUMMER PEAK LOAD REDUCTIONS

BTM PV Forecast Used in CELT Net Load Forecast

- The 2017 CELT net load forecast reflects deductions associated with the BTM PV portion of the PV forecast
- The following slides show values for annual energy and summer peak load reductions anticipated from BTM PV that is reflected in the 2017 CELT net load forecast
  - PV does not reduce winter peak loads, which occur after sunset
- ISO developed estimated summer peak load reductions associated with BTM PV forecast using the methodology established for the 2016 PV forecast
  - See Appendix of 2016 PV Forecast slides: https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf

Final 2017 PV Energy Forecast

BTM PV, GWh

Category	States	Estimated Annual Energy (GWh)										
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Behind-the-Meter PV	CT	341	435	612	789	928	995	1054	1112	1167	1221	1273
	MA	947	1046	1262	1434	1557	1677	1793	1906	1997	2051	2102
	ME	27	33	42	51	60	68	76	84	92	99	107
	NH	51	74	93	106	115	124	132	141	149	156	164
	RI	17	29	53	75	95	110	118	124	130	137	143
	VT	197	278	311	345	377	407	435	464	492	521	549
Behind-the Meter Total		**1581**	**1894**	**2373**	**2800**	**3133**	**3381**	**3609**	**3830**	**4027**	**4185**	**4338**

Notes:

(1) Forecast values include energy from FCM Resources, non-FCM Energy Only Resources, and behind-the-meter PV
(2) Monthly in service dates of PV assumed based on historical development
(3) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

Final 2017 Forecast

BTM PV: July 1st Estimated Summer Peak Load Reductions

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Behind-the-Meter PV	CT	94.9	132.6	178.4	220.9	251.2	262.4	271.4	279.5	287.5	296.0	303.8
	MA	255.0	317.3	366.9	400.3	421.3	442.2	461.8	479.5	491.8	496.9	501.4
	ME	8.2	10.0	12.2	14.3	16.3	18.0	19.6	21.1	22.6	24.1	25.6
	NH	14.2	22.5	27.2	29.6	31.2	32.7	34.1	35.4	36.6	37.9	39.1
	RI	5.0	8.9	15.4	21.1	25.7	28.9	30.3	31.2	32.1	33.1	34.0
	VT	61.2	84.1	90.4	96.3	102.1	107.3	112.1	116.7	121.3	126.3	131.1
Total	**Cumulative**	438.6	575.4	690.5	782.5	847.8	891.5	929.3	963.3	991.8	1014.3	1035.0

Estimated Summer Seasonal Peak Load Reduction - % of BTM AC nameplate	39.1%	37.5%	36.0%	34.6%	33.5%	32.7%	31.9%	31.2%	30.6%	30.1%	29.6%

Notes:
(1) Forecast values are for behind-the-meter PV only
(2) BTM PV peak load reductions relate to coincident summer peak loads only; values for non-coincident summer peak loads (for example, at the state level) may be different
(3) Values include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day
(4) All values represent anticipated July 1st installed PV, and are grossed up by 8% to reflect avoided transmission and distribution losses
(5) Different planning studies may use values different that these estimated peak load reductions based on the intent of the study

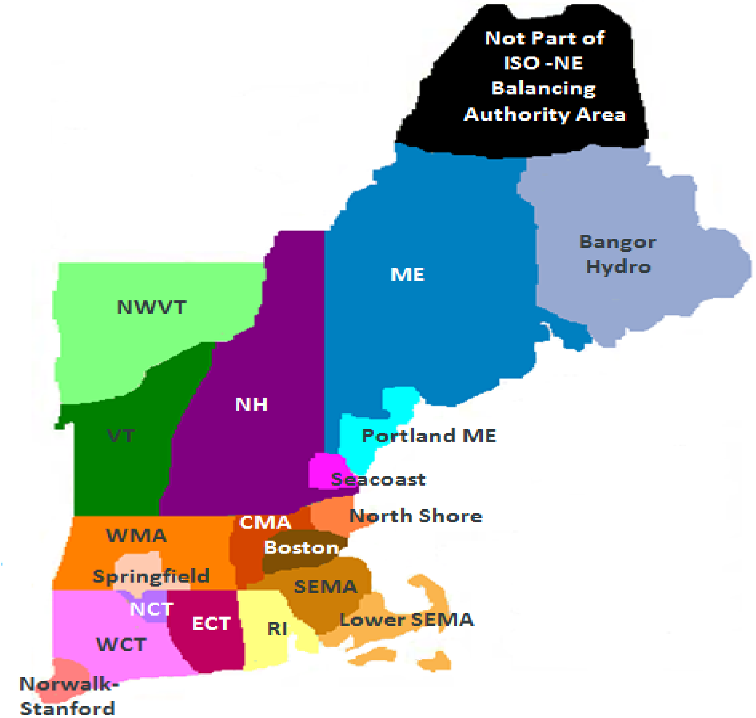
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

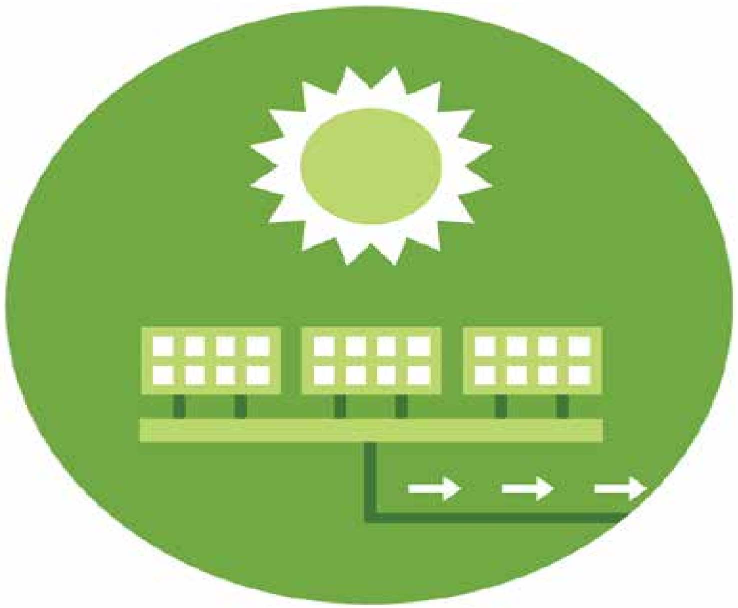
- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of most future PV resources are ultimately unknown
- Mitigation of some of this uncertainty (especially for near-term development) is possible via analysis of available data

Forecasting Solar By DR Dispatch Zone

- Demand Response (DR) Dispatch Zones were created as part of the DR Integration project
- These zones were created in consideration of electrical interfaces
- Quantifying existing and forecasted PV resources by Dispatch Zone (with nodal placement of some) will aid in the modeling of PV resources for planning and operations purposes



Geographic Distribution of PV Forecast



- Existing MWs:
  - Apply I.3.9 project MWs nodally
  - For remaining existing MWs, determine Dispatch Zone locations of projects already interconnected based on utility distribution queue data (town/zip), and apply MWs equally to all nodes in Zone
- Future MWs:
  - Apply I.3.9 project MWs nodally
  - For longer-term forecast, assume the same distribution as existing MWs

Dispatch Zone Distribution of PV

Based on December 31, 2016 Utility Data

State	Dispatch Zone	% of State
CT	CT_EasternCT	18.8%
	CT_NorthernCT	20.3%
	CT_Norwalk_Stamford	7.5%
	CT_WesternCT	53.4%
ME	ME_BangorHydro	11.9%
	ME_Maine	54.3%
	ME_PortlandMaine	33.8%
MA	NEMA_Boston	11.0%
	NEMA_NorthShore	4.9%
	SEMA_LowerSEMA	19.1%
	SEMA_SEMA	21.2%
	WCMA_CentralMA	15.4%
	WCMA_SpringfieldMA	5.9%
	WCMA_WesternMA	22.5%
NH	NH_NewHampshire	88.7%
	NH_Seacoast	11.3%
RI	RI_RhodeIsland	100.0%
VT	VT_NorthwestVermont	63.3%
	VT_Vermont	36.7%