Final 2018 PV Forecast

Outline

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- Forecast Assumptions and Inputs
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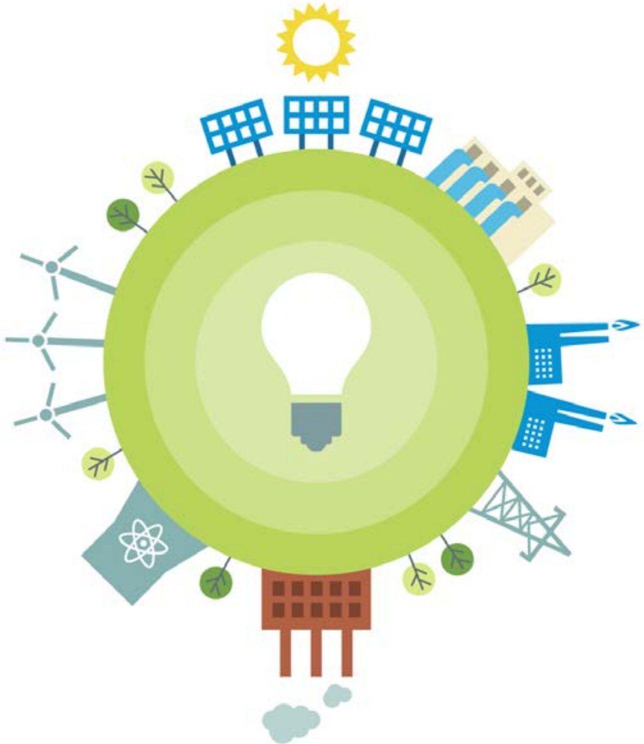
- 2018 PV Energy Forecast
- Breakdown of PV Forecast into Resource Types
- 2018 Behind-the-meter PV (BTM PV) Forecast
- Geographic Distribution of PV Forecast
- Appendix: Example Calculation of Estimated Summer Peak Load Reductions from BTM PV



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

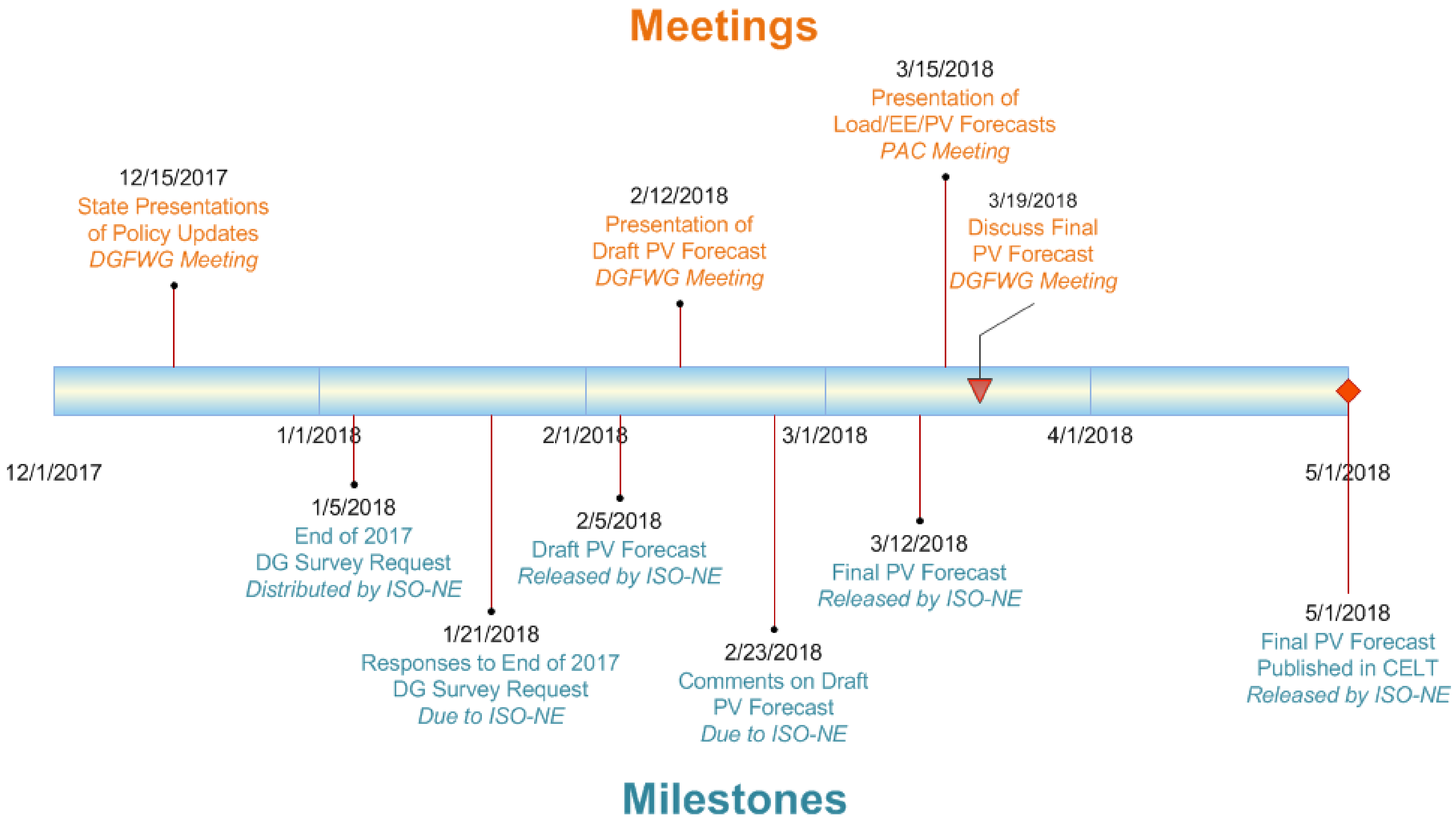
Forecast Focuses on State Policies in All Six New England States

- 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 2018 PV forecast]() with the DGFWG at the February 12, 2018 meeting
- Stakeholders provided comments on the draft forecast
  - See: https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=134447
- The final PV forecast is published in the 2018 CELT (Section 3):
  - See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/

2018 PV Forecast Schedule



DISTRIBUTION OWNER SURVEY RESULTS

Installed PV – December 2017

Determining Total PV Installed Through December 2017

- ISO requested distribution owners to provide the total nameplate of all individual PV projects (in MW_{AC}) that is already installed and operational within their respective service territories as of December 31, 2017
  - PV projects include FCM, EOR, and BTM PV projects that are < 5 MW_{AC} in nameplate capacity
- The following Distribution Owners responded:

CT	CL&P, CMEEC, UI
ME	CMP, Emera Maine
MA	Braintree, Chicopee, Reading, National Grid, NSTAR,
	Shrewsbury, Unitil, WMECO
NH	Liberty, NHEC, PSNH, Unitil
RI	National Grid
VT	Burlington, GMP, Stowe, VEC, VPPSA, WEC

- Thank you to all respondents for providing timely information that is critical to a successful 2018 PV forecast
- Based on respondent submittals, installed and operational PV resource totals by state and distribution owner are listed on the next slides

December 2017 Year-To-Date PV Installed Capacity

State-by-State

The table below reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. The values represent installed nameplate as of 12/31/17.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	1,602.25	78,047
Connecticut	365.65	29,512
Vermont*	257.24	9,773
New Hampshire	69.68	7,330
Rhode Island	62.23	4,148
Maine	33.46	3,598
New England	**2,390.51**	**132,408**

* Includes values based on MA SREC data or VT SPEED data

December 2017 Year-to-Date Installed PV by Distribution Owner

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
CT	Connecticut Light & Power	284.54	22,749
	Connecticut Municipal Electric Energy Co-op	9.93	6
	United Illuminating	71.17	6,757
	Total	**365.65**	**29,512**
MA	Braintree Electric Light Department	2.31	22
	Chicopee Electric Light	12.98	24
	Unitil (FG&E)	20.02	1,407
	National Grid	865.38	40,043
	NSTAR	444.90	27,189
	Reading Municipal Lighting Plant	7.08	115
	Shrewsbury Electric & Cable Operations	2.98	60
	SREC I	54.20	586
	SREC II	62.67	1,263
	Western Massachusetts Electric Company	129.73	7,338
	Total	**1,602.25**	**78,047**
ME	Central Maine Power	29.92	3,035
	Emera	3.54	561
	Total	**33.46**	**3,596**

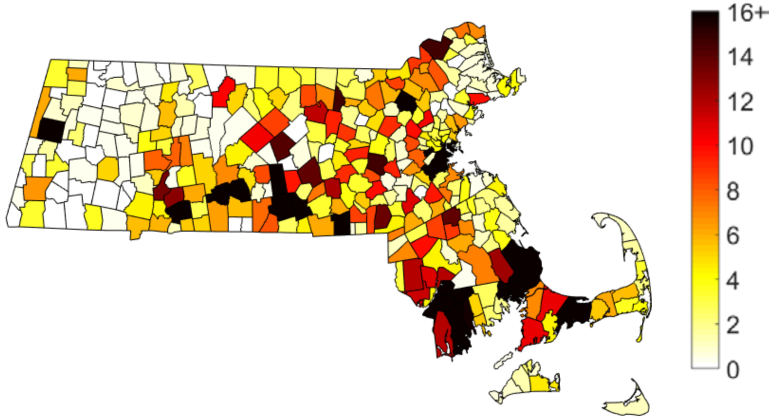
December 2017 Year-to-Date Installed PV by Distribution Owner

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	3.77	409
	New Hampshire Electric Co-op	7.18	896
	Public Service of New Hampshire	51.71	5,272
	Unitil (UES)	7.01	752
	Total	**69.68**	**7,329**
RI	National Grid	62.23	4,148
	Total	**62.23**	**4,148**
VT	Burlington Electric Department	3.15	199
	Green Mountain Power	218.48	7,860
	Stowe Electric Department	1.56	68
	Vermont Electric Co-op	24.40	934
	Vermont Public Power Supply Authority	5.14	335
	VT Other Municipals	0.10	1
	Washington Electric Co-op	4.41	376
	Total	**257.24**	**9,773**
New England		**2,390.51**	**132,408**

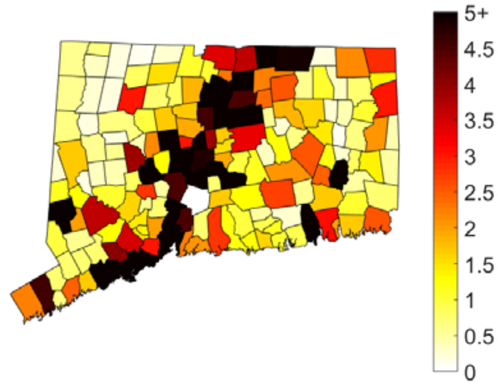
Installed PV Capacity as of December 2017

State Heat Maps

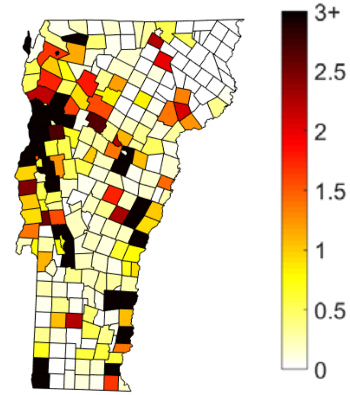
Massachusetts



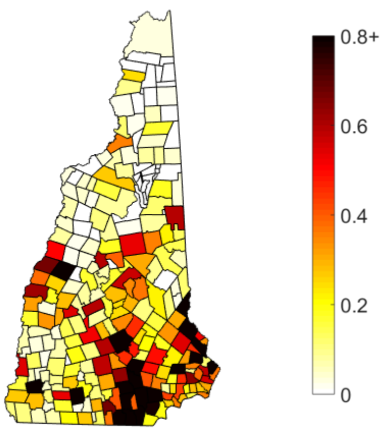
Connecticut



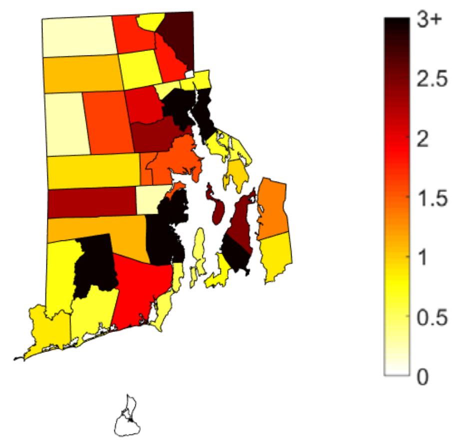
Vermont



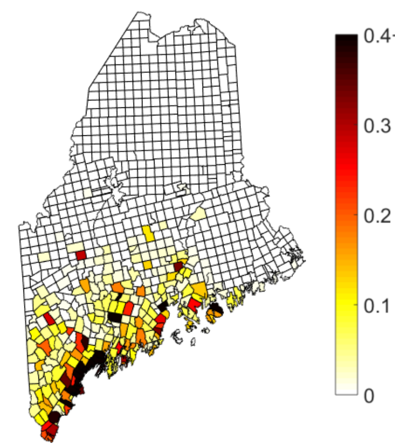
New Hampshire



Rhode Island



Maine



Note: Legend to the right of each state plot shows color scale of nameplate megawatts per town

Installed PV Capacity as of December 2017

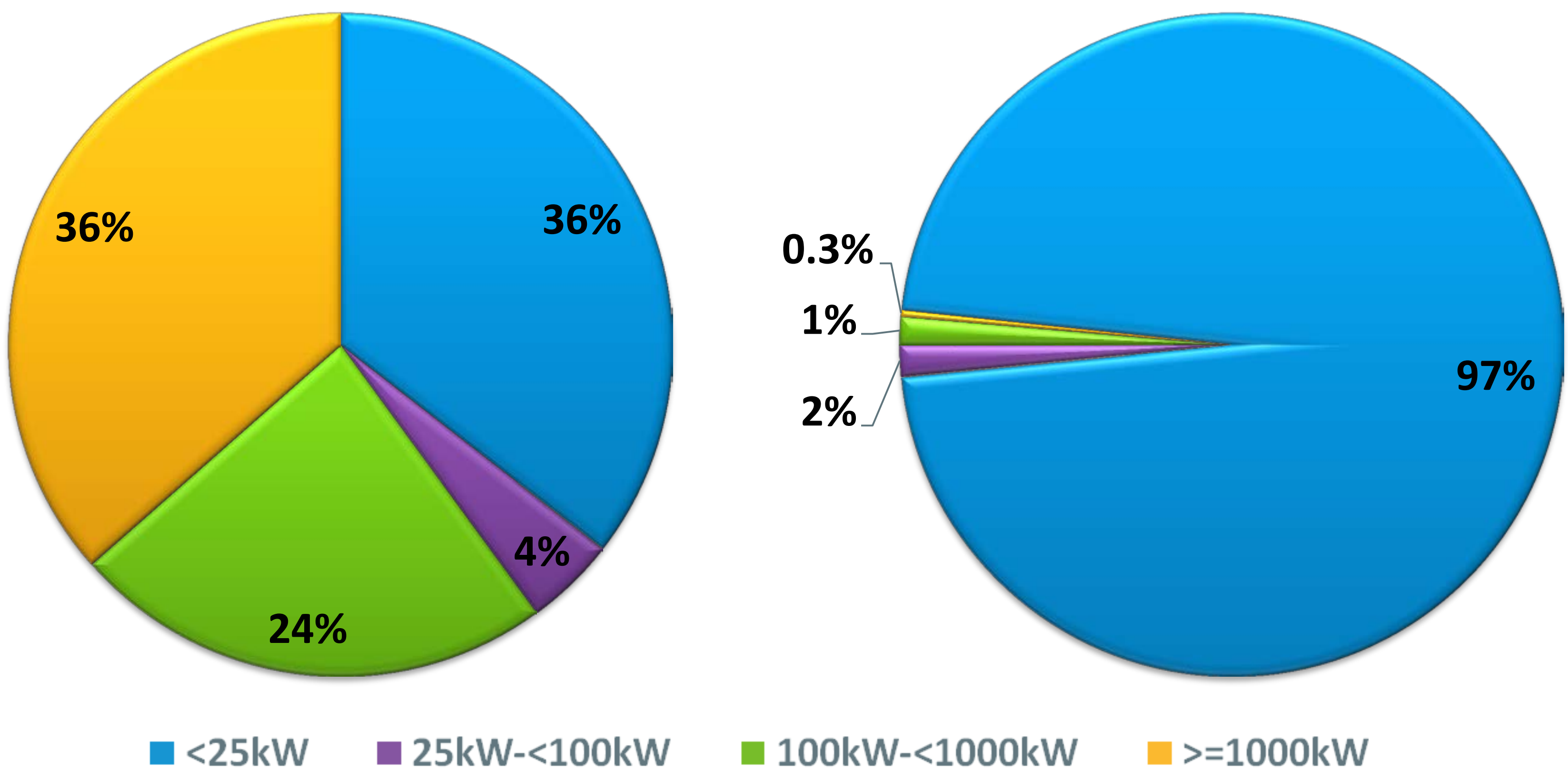
ISO-NE by Size Class

Installed Capacity (MW_{AC})

Total = 2,391 MW_{AC}

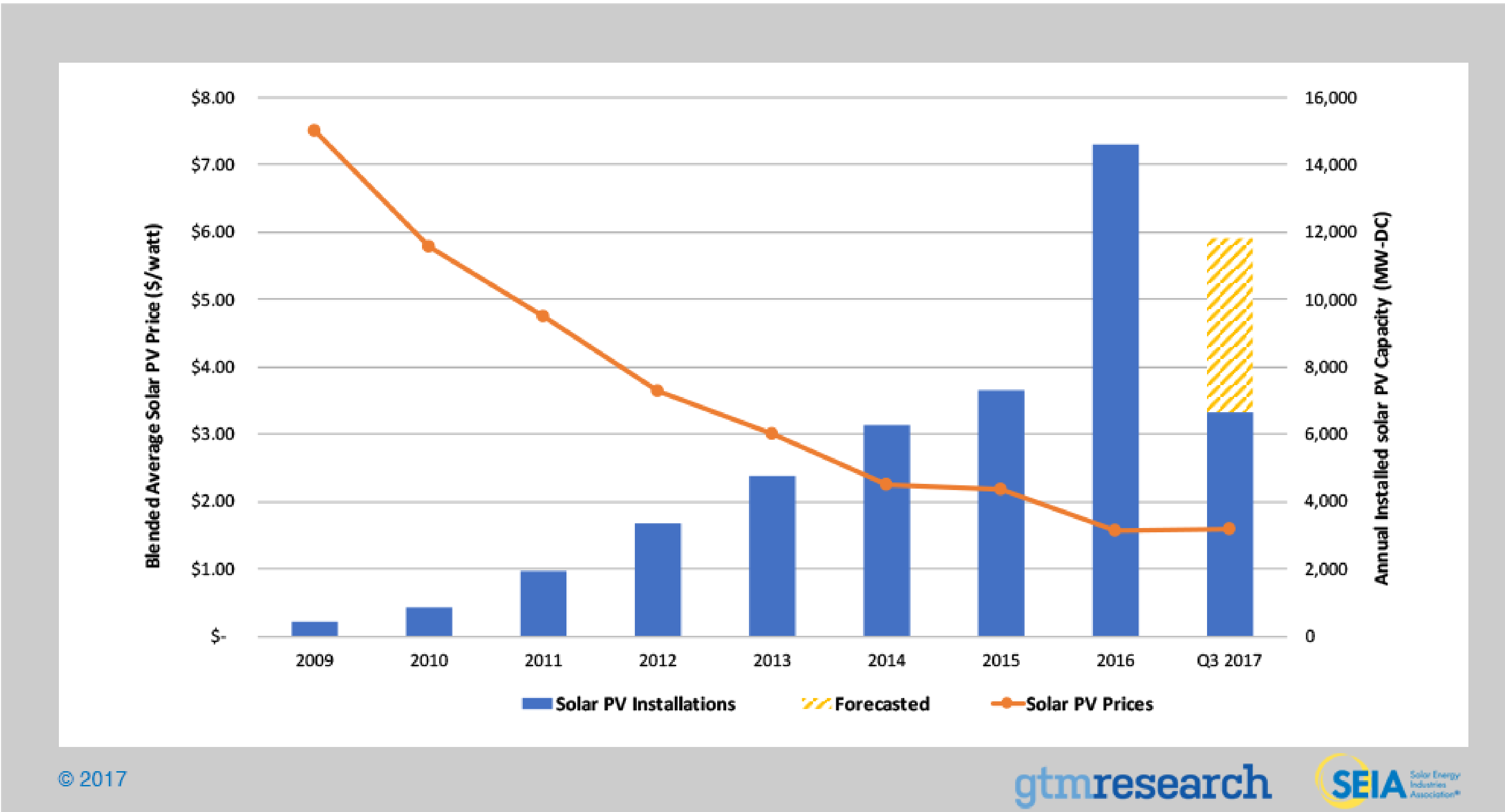
Number of Sites

Total = 132,408



FORECAST ASSUMPTIONS AND INPUTS

U.S. Installed Cost Reductions Are Leveling Off



Source: https://www.seia.org/sites/default/files/inline-images/growth-falling-prices_q42017.png

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 2017 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

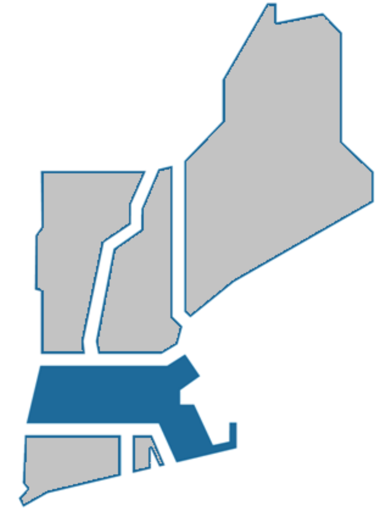
ITC by Date of Construction Start	
Year construction starts	Credit
2016	30%
2017	30%
2018	30%
2019	30%
2020	26%
2021	22%
2022	10%
Future Years	10%

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

Other Federal Policies Impacting PV Development

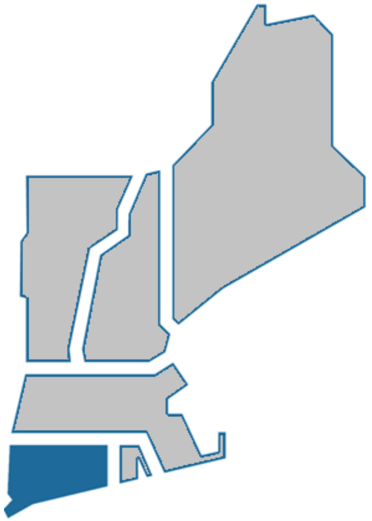
- Anticipated impacts of final federal tax bill are mixed and uncertain, with major features including:
  - Maintain current phase-down schedule for ITC
  - Lower corporate tax rate could decrease tax “appetite” of investors, potentially limiting their ability to monetize the ITC, while also increasing the value of operating projects due to increased after-tax revenue
  - New base erosion anti-abuse tax (BEAT) could reduce amount of tax equity used for investment in many PV projects
- U.S. tariff on imported PV cells and modules
  - Modules represent roughly 10-25% of total installed PV costs
  - Tariff is 30% in year 1, stepping down to 15% by the fourth year
  - Annually allows 2.5 GW of unassembled imported solar cells tariff-free
  - Effect will offset some of the decreasing trend in installed PV costs in past years
- The overall result of these federal policy changes, when considered in tandem with the approaching ITC phase-down and continued decreases in state policy support, is increased near-term uncertainty in the region’s PV outlook

Massachusetts Forecast Methodology and Assumptions



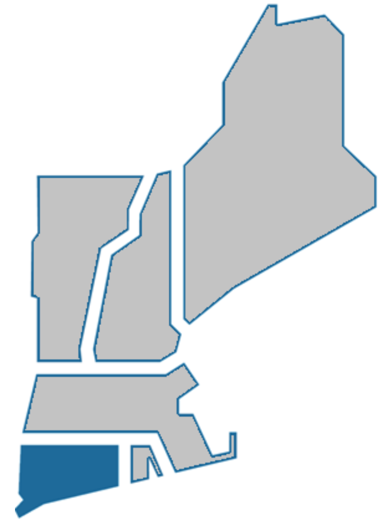
- MA DPU's 12/15/17 DGFWG presentation serves as primary source for MA policy information
- Solar Carve-Out Renewable Energy Certificate (SREC) program
  - A total of 2,200 MW_{DC} developed as part of SREC-I/SREC-II programs
  - Convert: 2,200 MW_{DC} = 1,826 MW_{AC} (83% AC-to-DC ratio assumed)
  - MA Distribution Owners reported 1,602.3 MW_{AC} installed by 12/31/17
    - Of this total, approximately 1,575 MW are SREC-I/SREC-II projects
  - Assume remaining SREC I/II capacity (~250 MW_{AC}) is installed in 2018
- Solar Massachusetts Renewable Target (SMART) Program
  - Sets forth a post-SREC 1,600 MW_{AC} program goal
  - Program achieved over the period 2018-2024 (7 years)
    - Assume 80 MW installed in 2018;
    - Assume remaining 1,520 MW divided evenly over 5 years from 2019-2024
- The annual growth in 2022 is carried forward at constant rate throughout the remaining years of the forecast period and post-policy discount factors are applied

Connecticut Forecast Methodology and Assumptions



- CT DEEP's 12/15/17 DGFWG presentation serves as primary source for CT policy information
- LREC/ZREC program assumptions
  - Seventh LREC/ZREC solicitation is now funded
  - Assume the total PV procured in LREC/ZREC is 470.4 MW
    - Assume Year 7 Solicitation yields additional 77 MW
  - According to utility data, approximately 140 MW of LREC/ZREC projects are in-service
  - Assume remaining 330.4 MW of capacity comes into services evenly over the next 5 years, 2018-2022
    - The period before LREC/ZREC projects are all completed was extended due to consistently slow LREC/ZREC development over past few years
  - The annual growth in 2022 is carried forward at constant rate throughout the remaining years of the forecast period and post-policy discount factors are applied

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 anticipates goal met by 2021
  - Recent CT budget sweeps will not impact program
  - Based on Distribution Owner data, approximately 185 MW installed as of 12/31/17 ; with 115 MW remaining
    - 28.75 MW/year from 2018-2021
  - Post-2021: Forecast inputs kept at 28.75 MW/year and post-policy discount factors are applied
- DEEP Small Scale Procurement (< 5MW) associated with Public Act 15-107
  - Total of 5 MW expected to go into service in 2020
- Shared Clean Energy Facility (SCEF) Pilot Program
  - Assumed a total of two SCEF projects with nameplate capacities of 3.62 MW and 1.6 MW go into service in 2018 and 2019, respectively

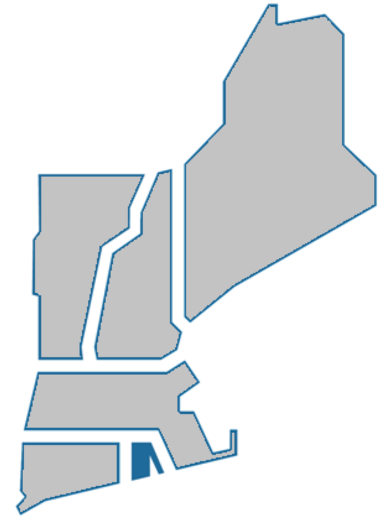
Vermont Forecast Methodology and Assumptions

- VT DPS' 12/15/17 DGFWG presentation serves as the primary source for VT policy information
- 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 forward-looking renewable energy certificates (RECs) from Standard Offer projects will be sold to utilities and count towards RES DG carve-out]
- Net metering
  - In all years after 2018 (see below), all renewable energy certificates (RECs) from net metered projects will be sold to utilities and count towards RES DG carve-out, resulting in 25 MW/year as stated above
- For 2018 only, a total of 35 MW is anticipated in VT, which is in excess of the anticipated 25 MW/year due to the RES DG carve-out
  - This reflects expectations that, similar to the past couple of years, PV development will be greater than that needed for compliance with the RES DG carve out for one more year

New Hampshire Forecast Methodology and Assumptions

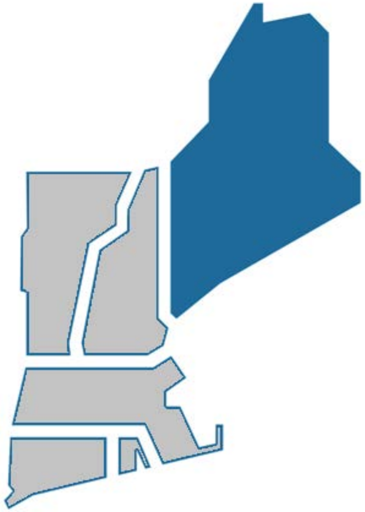
- NH PUC's 12/15/17 DGFWG presentation serves as the primary source for NH policy information
- NH Distribution Owners reported a total of 15.37 MW of PV growth in 2017
- Assume the new Net Energy Metering Tariff (NEM 2.0), effective September 1, 2017, continues to support the 2017 rate of growth throughout the forecast horizon

Rhode Island Forecast Methodology and Assumptions



- RI OER’s 12/17/17 DGFWG presentation serves as the 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
- Newly extended Renewable Energy Growth Program (REGP)
  – Assume REGP supports 36 MW_{DC}/year of PV throughout forecast horizon
    - Convert: 36 MW_{DC} = 29.88 MW_{AC} (83% AC-to-DC ratio assumed)
- Renewable Energy Development Fund & Net Metering
  – Assumed to yield 8 MW/year over the forecast horizon

Maine Forecast Methodology and Assumptions



- ME PUC's 12/17/17 DGFWG presentation serves as the primary source for ME policy information
- ME Distribution Owners reported a total of 11.32 MW of PV growth in 2017
- Assume the new Net Energy Billing Rule (effective April 1, 2018), with gradually reduced rates of compensation, continues to support the 2017 rate of growth throughout the forecast horizon

Discount Factors

- Discount factors are:
  - Developed and incorporated into the forecast to ensure a degree of uncertainty in future PV commercialization is considered
  - Developed for two types of future PV inputs to the forecast, and all discount factors are applied equally in all states
  - Applied to the forecast inputs (see slide 29) to determine total nameplate capacity for each state and forecast year

Policy-Based *PV that results from state policy*	**Post-Policy** *PV that may be installed after existing state policies end*
Discounted by values that increase over the forecast horizon up to a maximum value of 15%	**Discounted by 35-50% 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 2018 PV Forecast

Policy-Based

Forecast	Final 2017	Final 2018
2018	0%	10%
2019	0%	10%
2020	10%	10%
2021	15%	15%
2022	15%	15%
2023	15%	15%
2024	15%	15%
2025	15%	15%
2026	15%	15%
2027	--	15%

Post-Policy

Forecast	Final 2017	Final 2018
2018	36.7%	35.0%
2019	38.3%	36.7%
2020	40.0%	38.3%
2021	41.7%	40.0%
2022	43.3%	41.7%
2023	45.0%	43.3%
2024	46.7%	45.0%
2025	48.3%	46.7%
2026	50.0%	48.3%
2027	--	50.0%

Final 2018 Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
CT	365.6	98.5	96.4	99.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8	**1,324.2**
MA	1602.3	329.6	253.3	253.3	253.3	253.3	253.3	253.3	253.3	253.3	253.3	**4,211.9**
ME	33.5	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	**146.7**
NH	69.7	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	**223.4**
RI	62.2	38.3	38.3	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	**417.9**
VT	257.2	35.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	**517.2**
Pre-Discount Annual Policy-Based MWs	**2390.5**	**528.1**	**439.8**	**439.7**	**434.7**	**406.0**	**339.9**	**339.9**	**86.6**	**86.6**	**86.6**	**5,578.4**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**28.8**	**94.8**	**94.8**	**348.2**	**348.2**	**348.2**	**1,262.9**
Pre-Discount Annual Total (MW)	**2390.5**	**528.1**	**439.8**	**439.7**	**434.7**	**434.7**	**434.7**	**434.7**	**434.7**	**434.7**	**434.7**	**6,841.3**
Pre-Discount Cumulative Total (MW)	**2390.5**	**2,918.6**	**3,358.4**	**3,798.1**	**4,232.9**	**4,667.6**	**5,102.4**	**5,537.1**	**5,971.8**	**6,406.6**	**6,841.3**	**6,841.3**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 20-26 for details)
(2) Yellow highlighted cells indicate that values contain 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 installed capacities

2018 PV NAMEPLATE CAPACITY FORECAST

Includes FCM, non-FCM EOR, and BTM PV

Final 2018 PV Forecast

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
CT	365.6	88.6	86.8	89.8	80.6	72.9	53.7	52.2	50.6	49.0	47.4	**1,037.3**
MA	1602.3	**296.7**	228.0	228.0	215.3	215.3	215.3	215.3	135.1	130.9	126.7	**3,608.9**
ME	33.5	10.2	10.2	10.2	9.6	9.6	9.6	9.6	9.6	9.6	9.6	**131.4**
NH	69.7	13.8	13.8	13.8	13.1	13.1	13.1	13.1	13.1	13.1	13.1	**202.7**
RI	62.2	34.5	34.5	31.4	29.6	29.6	29.6	29.6	29.6	29.6	29.6	**370.2**
VT	257.2	**31.5**	22.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**482.5**
Regional - Annual (MW)	**2390.5**	**475.3**	**395.8**	**395.8**	**369.5**	**361.9**	**342.7**	**341.1**	**259.3**	**253.5**	**247.7**	**5,832.9**
Regional - Cumulative (MW)	**2390.5**	**2865.8**	**3261.6**	**3657.4**	**4026.9**	**4388.8**	**4731.4**	**5072.5**	**5331.8**	**5585.3**	**5832.9**	**5,832.9**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast
(3) All values represent end-of-year installed capacities
(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

Final 2018 PV Forecast

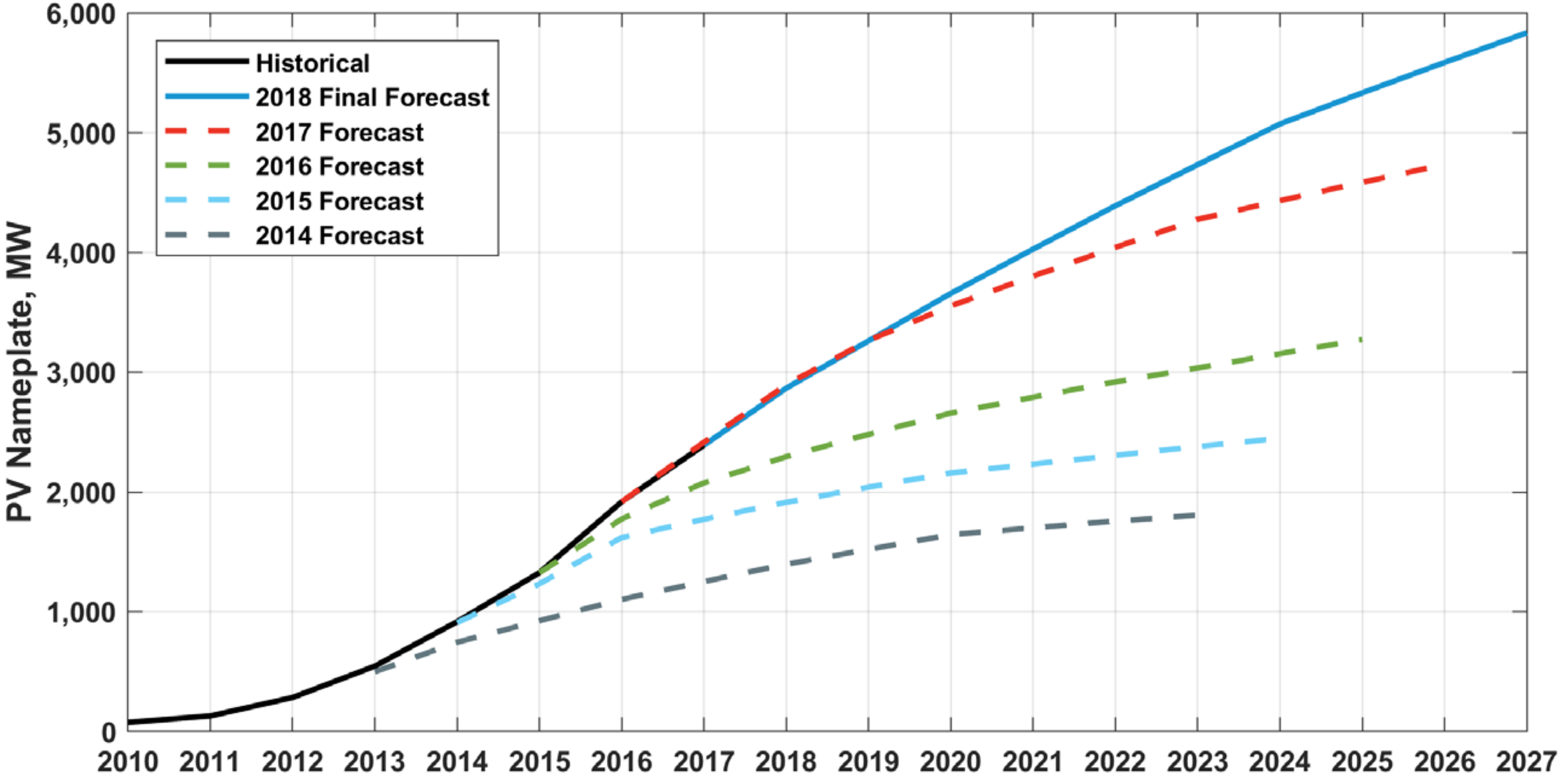
Cumulative Nameplate, MW_{ac}

States	Cumulative Total MW (AC nameplate rating)										
	Thru 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CT	365.6	454.3	541.0	630.9	711.5	784.4	838.2	890.3	940.9	989.9	1037.3
MA	1602.3	1898.9	2126.9	2354.9	2570.3	2785.6	3000.9	3216.3	3351.4	3482.3	3608.9
ME	33.5	43.6	53.8	64.0	73.6	83.3	92.9	102.5	112.1	121.8	131.4
NH	69.7	83.5	97.4	111.2	124.3	137.3	150.4	163.5	176.5	189.6	202.7
RI	62.2	96.7	131.2	162.6	192.3	221.9	251.6	281.2	310.9	340.5	370.2
VT	257.2	288.7	311.2	333.7	355.0	376.2	397.5	418.7	440.0	461.2	482.5
Regional - Cumulative (MW)	**2390.5**	**2865.8**	**3261.6**	**3657.4**	**4026.9**	**4388.8**	**4731.4**	**5072.5**	**5331.8**	**5585.3**	**5832.9**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast
(3) All values represent end-of-year installed capacities
(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

PV Growth: Reported Historical vs. Forecast



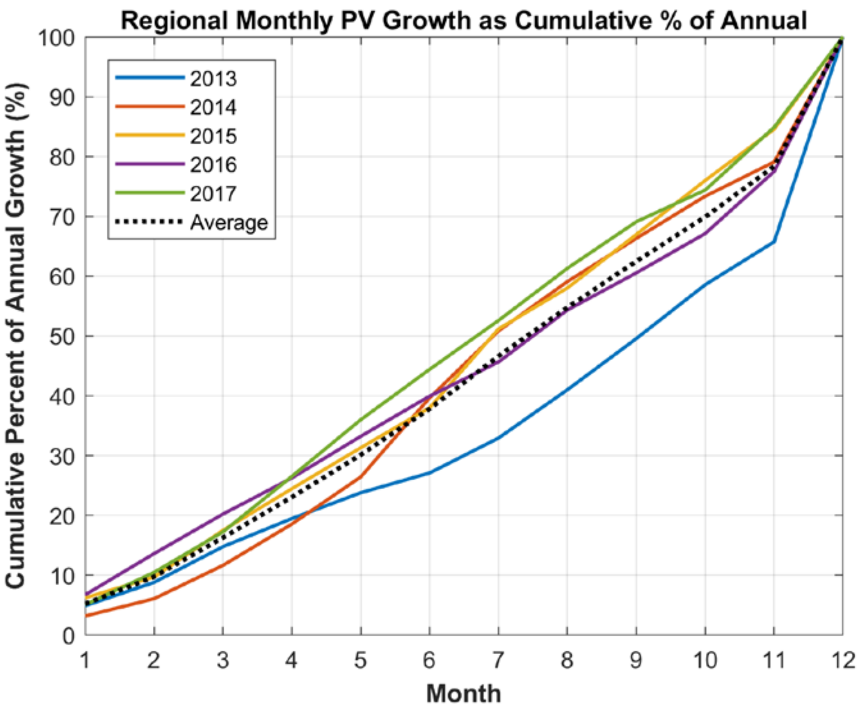
2018 PV ENERGY FORECAST

Development of PV Energy Forecast

- The 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 2013 and 2017 were used to estimate intra-annual incremental growth over the forecast horizon (*see next slide*)
- The PV energy forecast was developed at the state level, using state monthly nameplate forecasts along with state average monthly capacity factors (CF) developed from 4 years of PV performance data (2014-2017)
  - Resulting state CFs are tabulated to the right, and plots of individual monthly capacity factors in each state are shown on slide 37

State	Average CF, %
CT	14.9
ME	14.5
NH	14.2
RI	14.9
VT	14.0
MA	14.7

Historical Monthly PV Growth Trends, 2012-2017



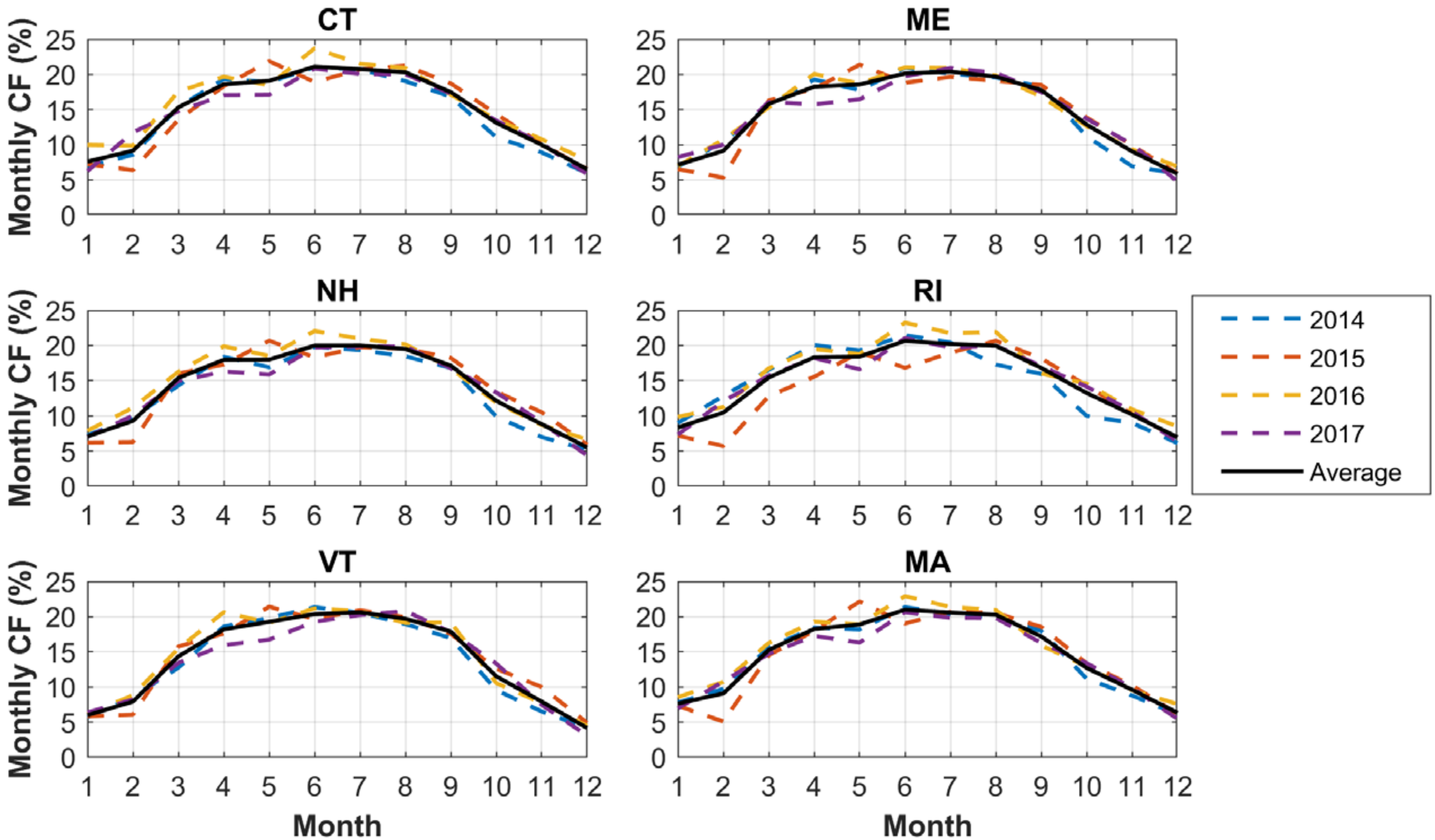
Average Monthly Growth Rates, % of Annual

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%

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

Monthly PV Capacity Factors by State

PV Production Data, 2014-2017



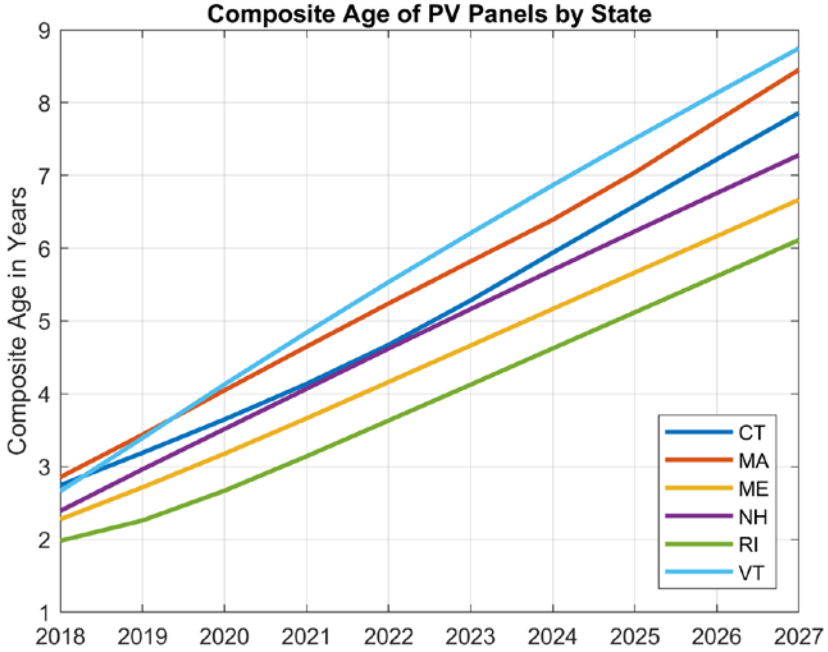
PV Panel Degradation Factors

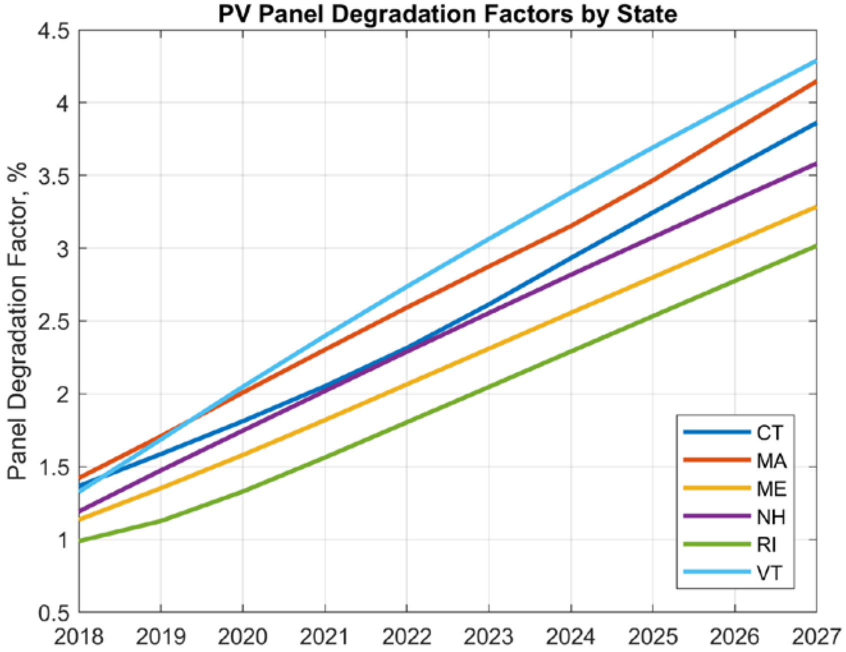
- Associated forecasts of energy and the estimated summer peak load reductions from BTM PV include a 0.5%/year degradation rate to account for expectations regarding a solar panel’s declining conversion efficiency over the longer term
  - The ISO first raised this modeling issue at the January 24, 2014 DGFWG meeting (refer to slide 10)
- Long-term panel degradation is often caused by:
  - Degradation of silicon or solder joints
  - Problems with the encapsulant that cause delamination, increased opacity, or water ingress
- Based on research by the National Renewable Energy Laboratory (NREL), the median rate of degradation is 0.5%/year, and is assumed to be linear over time
  - More information available here: https://www.nrel.gov/pv/lifetime.html
- Accounting for this degradation becomes more important as the region’s PV panels age
- The ISO estimated the capacity-weighted composite age of the forecasted PV fleet to develop appropriate degradation factors to use for the forecast

PV Panel Degradation Factors

Composite Age (left) & Degradation Factors (right) by State

- The resulting capacity-weighted, composite age of PV in each state (left plot) and corresponding degradation factors (right plot) over the forecast horizon are plotted below
- The degradation factors are the assumed percent reduction of PV performance over time that reflect the anticipated degradation of PV panels





Final 2018 PV Energy Forecast

Total PV Forecast Energy, GWh

States	Total Estimated Annual Energy (GWh)									
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
CT	543	662	781	895	998	1,085	1,155	1,218	1,281	1,342
MA	2299	2,659	2,961	3,246	3,523	3,799	4,080	4,307	4,467	4,621
ME	50	63	77	90	102	115	127	139	152	164
NH	97	115	133	150	166	183	199	215	231	247
RI	102	149	195	236	276	316	356	395	434	472
VT	345	380	408	434	459	484	510	535	559	584
Regional - Annual Energy (GWh)	**3436**	**4,028**	**4,554**	**5,051**	**5,525**	**5,981**	**6,427**	**6,809**	**7,125**	**7,431**

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) Values include the effects of an assumed 0.5%/year PV panel degradation rate
(4) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

BREAKDOWN OF PV NAMEPLATE FORECAST INTO RESOURCE TYPES

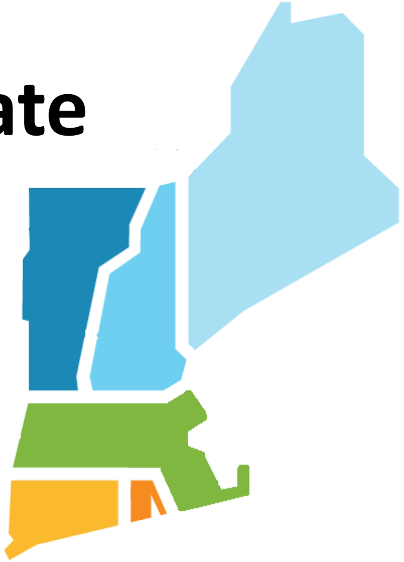
Forecast Includes Classification by Resource Type

- 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
  - This requires historical hourly BTM PV production data to reconstitute PV into the historical load data used to develop the long-term load forecast

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



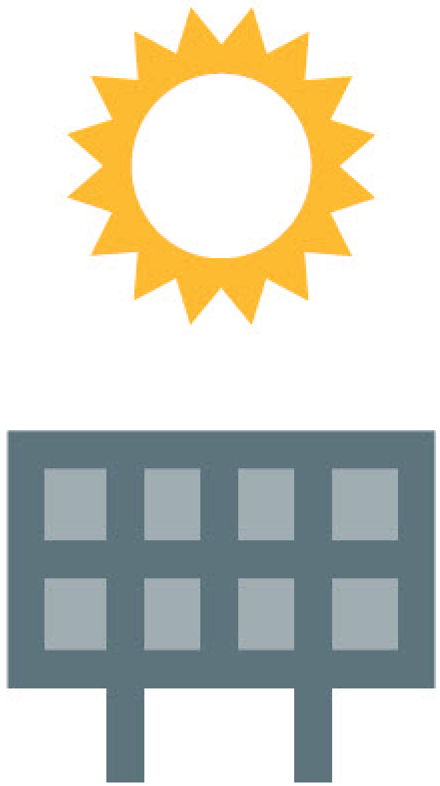
- Resource types vary by state
  - Disposition of PV projects can be influenced by state policies (*e.g.*, net metering requirements)
- The following steps were used to determine PV resource types for each state over the forecast horizon:
  1. **FCM**
     - Identify all Generation and Demand Response FCM PV resources for each Capacity Commitment Period (CCP) through FCA 12
  2. **Non-FCM EOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2017 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 12
  - Assume aggregate total PV in FCM as of FCA 12 remains constant from 2021-2027
- **Non-FCM Gen/EOR**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/17
  - Assume % share of nameplate PV in energy market as of 12/31/17 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 and Rhode Island)
  - 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

- In order to estimate hourly BTM PV production, ISO developed hourly state PV profiles for the period 1/1/2012 –1/31/2017 using historical production data
  - Data are aggregated into normalized PV profiles for each state, which represent a per-MW-of-nameplate production profile for PV
  - Data sources and method are described on the following slides



Estimation of Hourly BTM PV (*continued*)

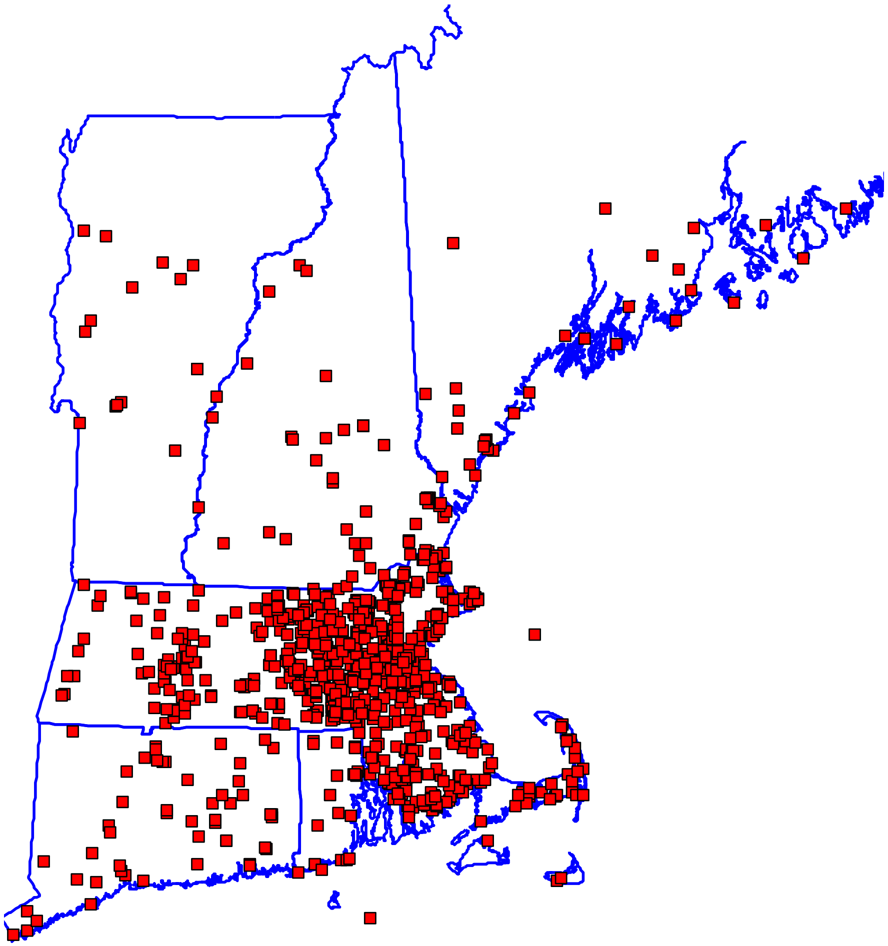
- Using the normalized PV profiles, total state PV production was then estimated by scaling the profiles up to the total PV installed over the period according to recently-submitted distribution utility data
  - (Normalized Hourly Profile) x (Total installed PV Capacity) = Hourly PV production
- Subtracting the hourly PV settlements energy (where applicable) yields the total BTM PV energy for each state
  - BTM profiles were used for PV reconstitution in the development of the gross load forecast

Historical PV Profile Development and Analysis

1/1/12-12/31/13

- 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/

Historical PV Profile Development and Analysis *1/1/14-12/31/17*

- ISO has contracted with a third-party vendor for PV production data services
  - 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 August 12, 2016 at 03:00 pm
  - 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, hourly state PV profiles for years 2014-2016 are developed using the method previously described

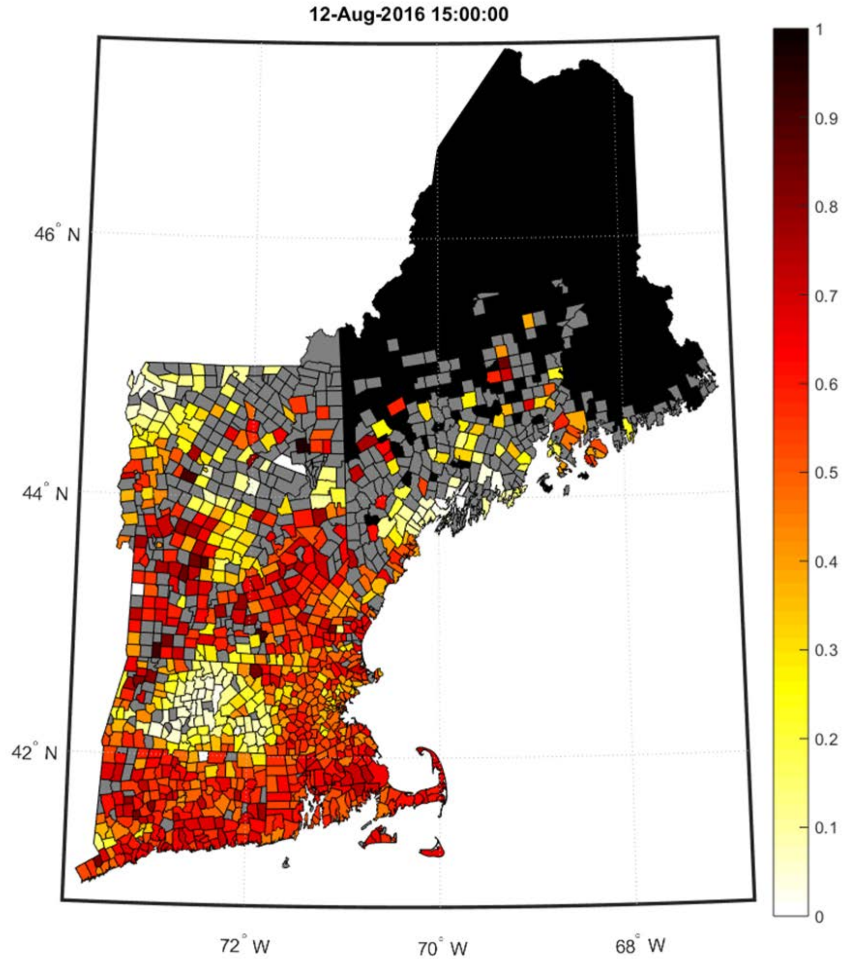


Figure notes:
1. Graphic developed by ISO New England
2. Data source: Quantitative Business Analytics, Inc.

FINAL 2018 PV NAMEPLATE FORECAST BY RESOURCE TYPE

Final 2018 PV Forecast

Cumulative Nameplate, MW_{ac}

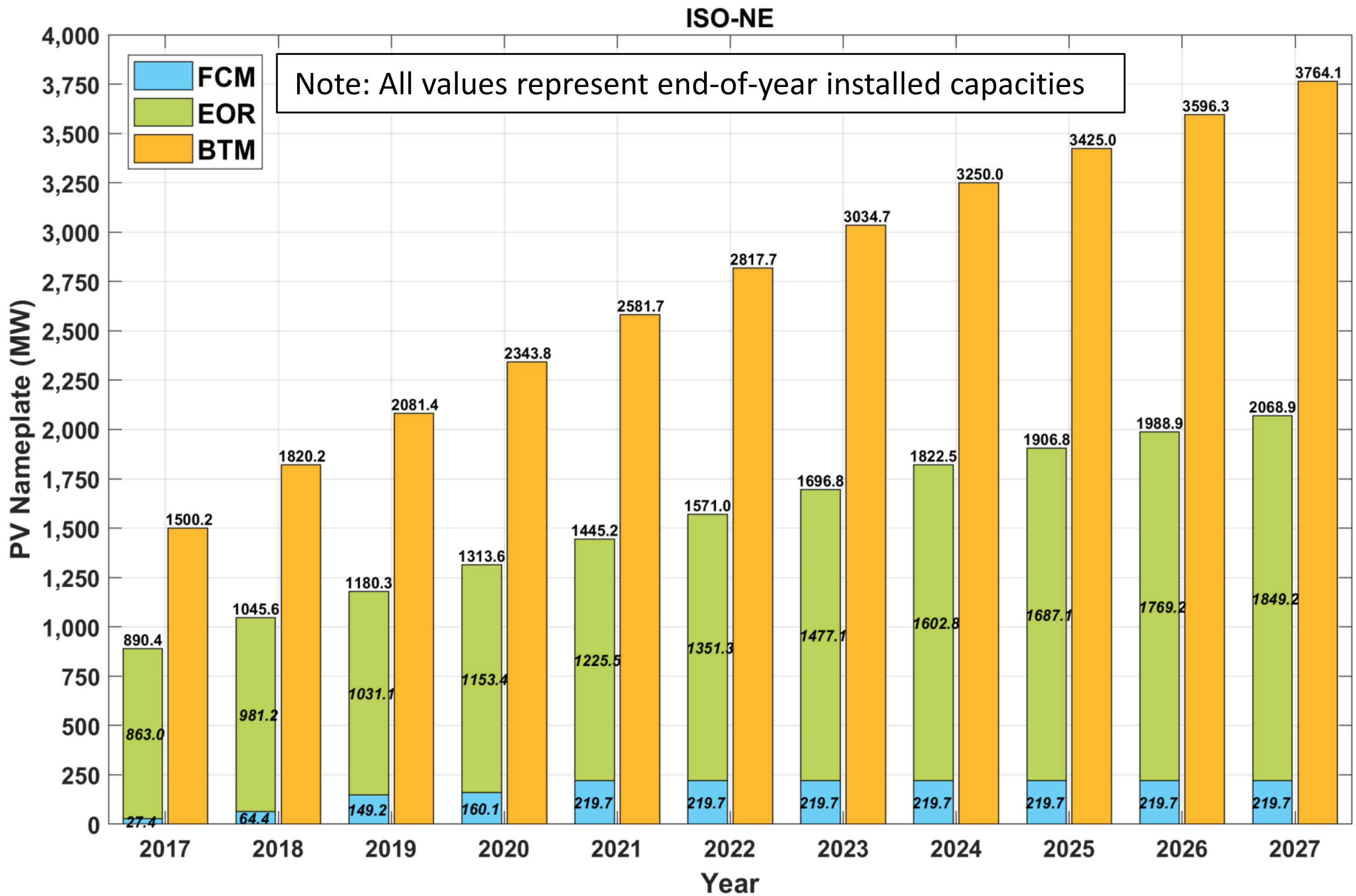
States	Cumulative Total MW (AC nameplate rating)										
	Thru 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CT	365.6	454.3	541.0	630.9	711.5	784.4	838.2	890.3	940.9	989.9	1037.3
MA	1602.3	1898.9	2126.9	2354.9	2570.3	2785.6	3000.9	3216.3	3351.4	3482.3	3608.9
ME	33.5	43.6	53.8	64.0	73.6	83.3	92.9	102.5	112.1	121.8	131.4
NH	69.7	83.5	97.4	111.2	124.3	137.3	150.4	163.5	176.5	189.6	202.7
RI	62.2	96.7	131.2	162.6	192.3	221.9	251.6	281.2	310.9	340.5	370.2
VT	257.2	288.7	311.2	333.7	355.0	376.2	397.5	418.7	440.0	461.2	482.5
Regional - Cumulative (MW)	**2390.5**	**2865.8**	**3261.6**	**3657.4**	**4026.9**	**4388.8**	**4731.4**	**5072.5**	**5331.8**	**5585.3**	**5832.9**

Notes:

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

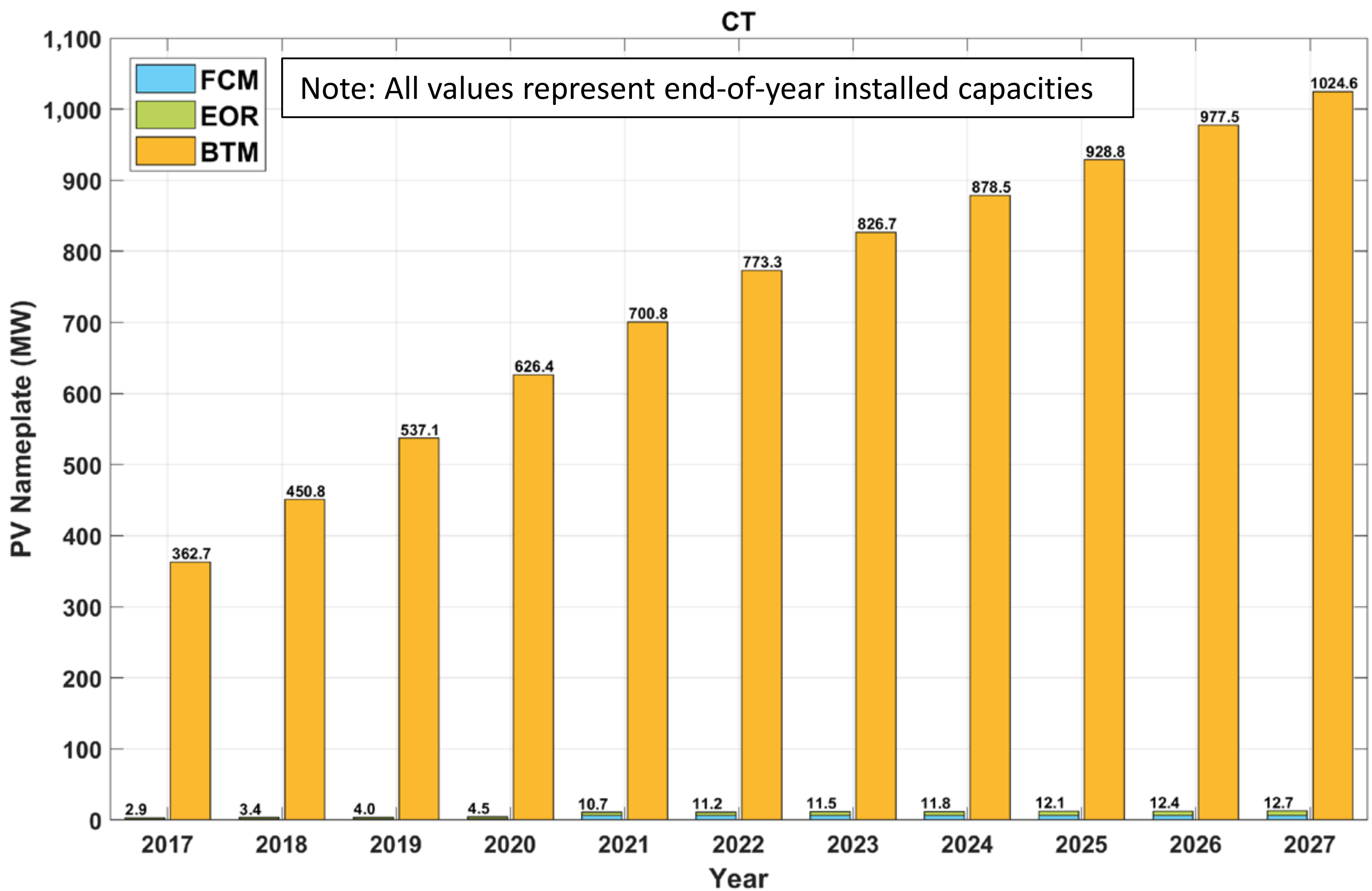
Final 2018 PV Forecast

Cumulative Nameplate, MW_{ac}

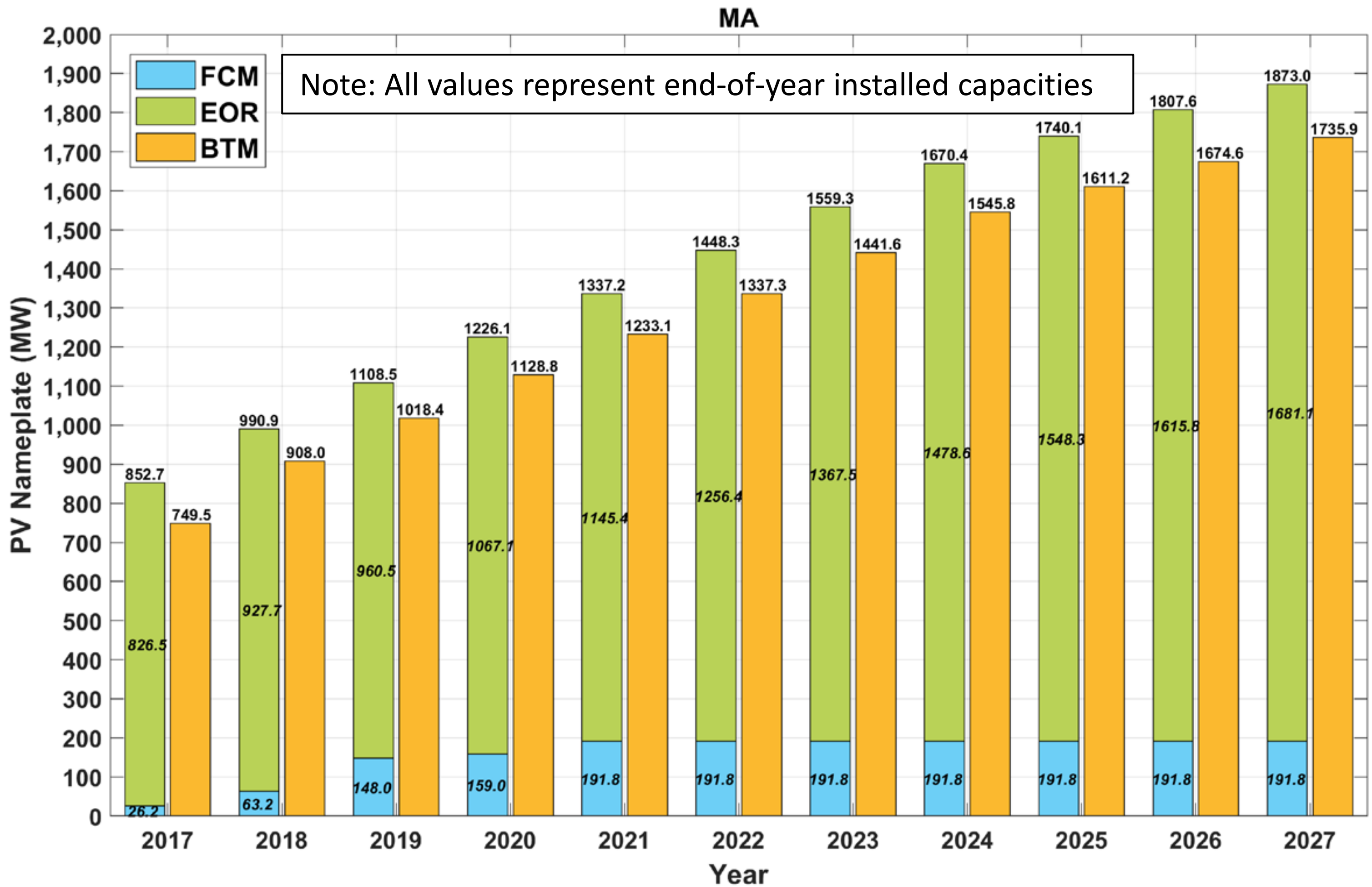


Cumulative Nameplate by Resource Type, MW_{ac}

Connecticut

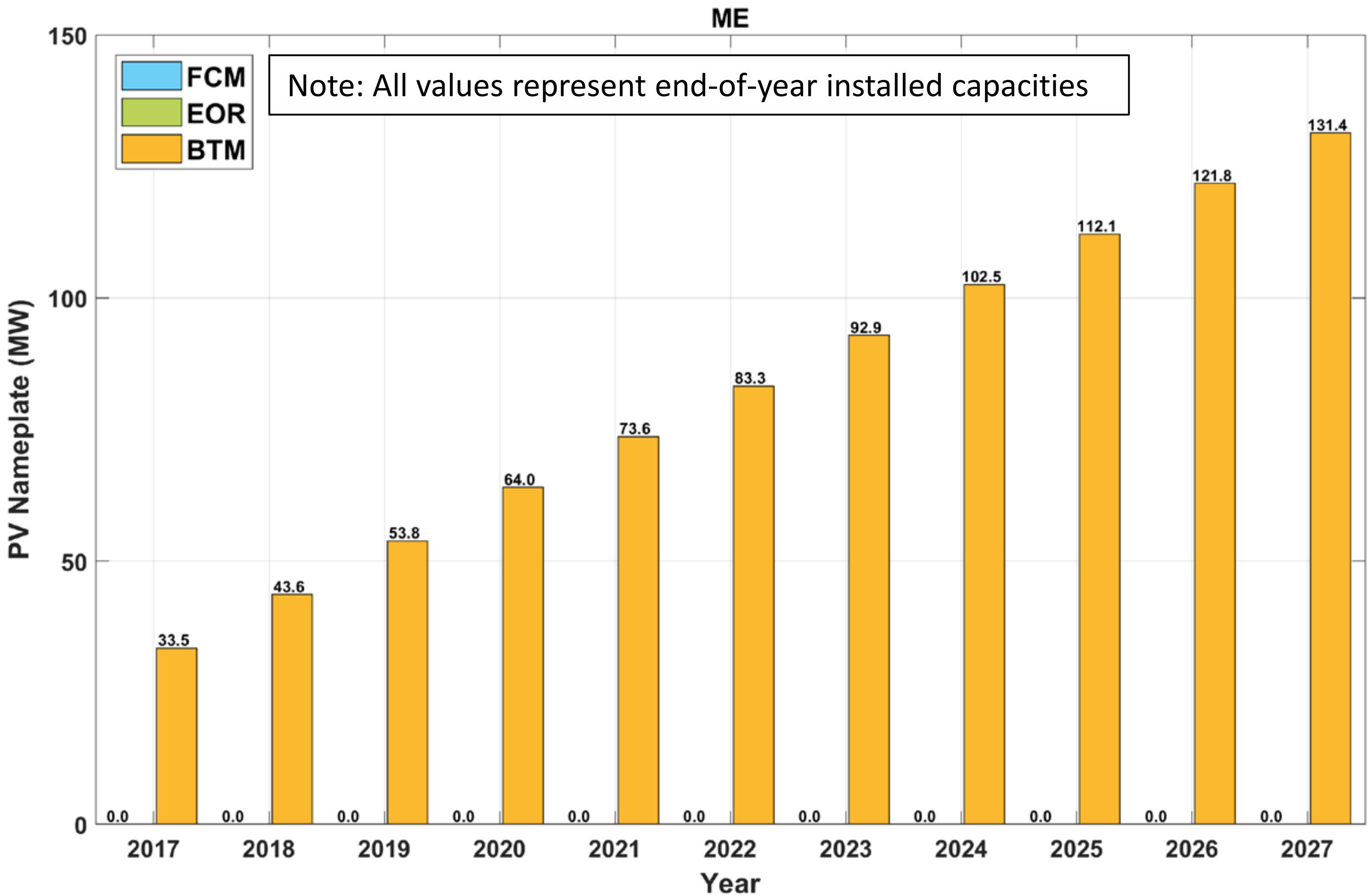


Cumulative Nameplate by Resource Type, MW_{ac}
Massachusetts



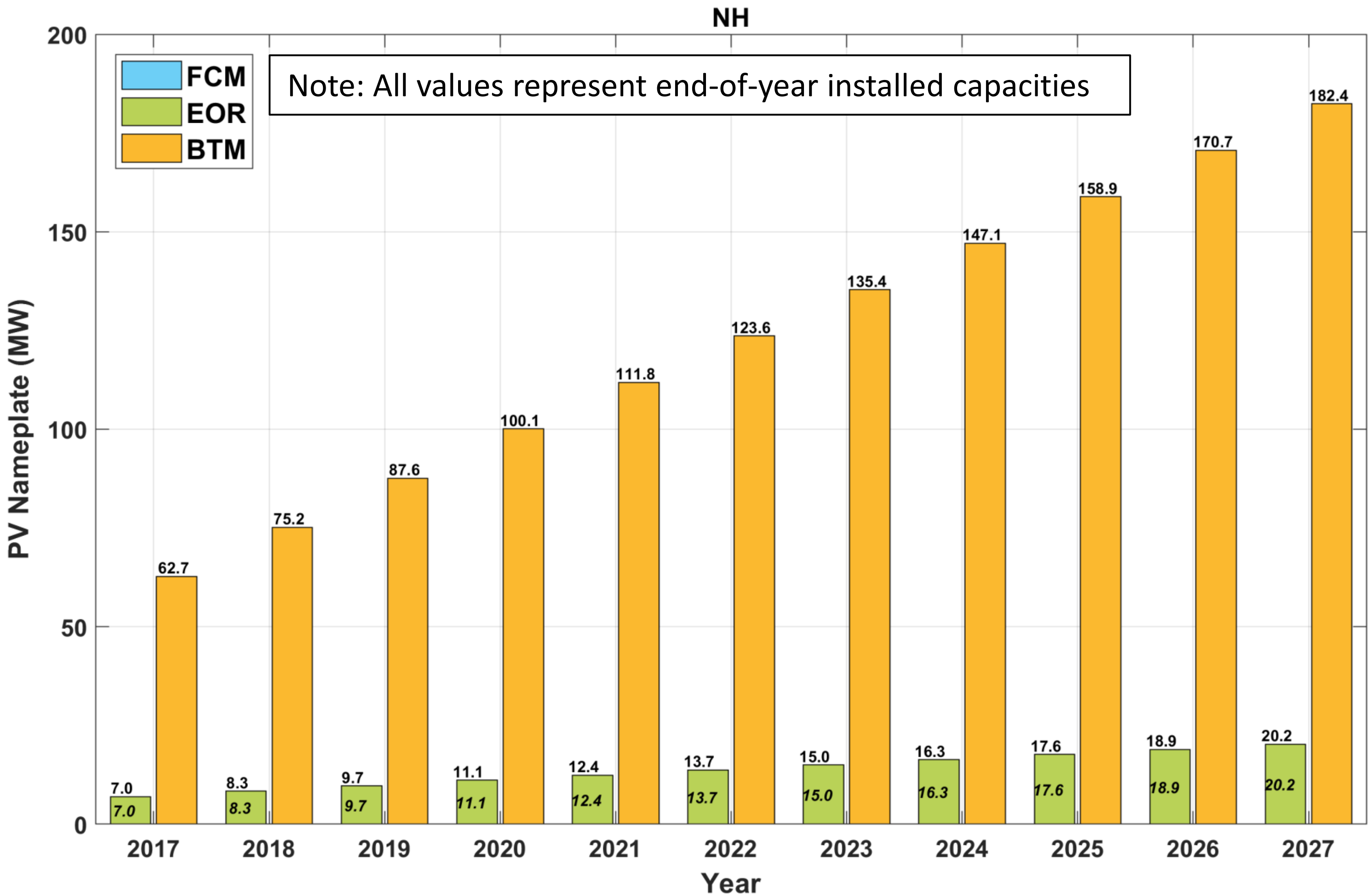
Cumulative Nameplate by Resource Type, MW_{ac}

Maine



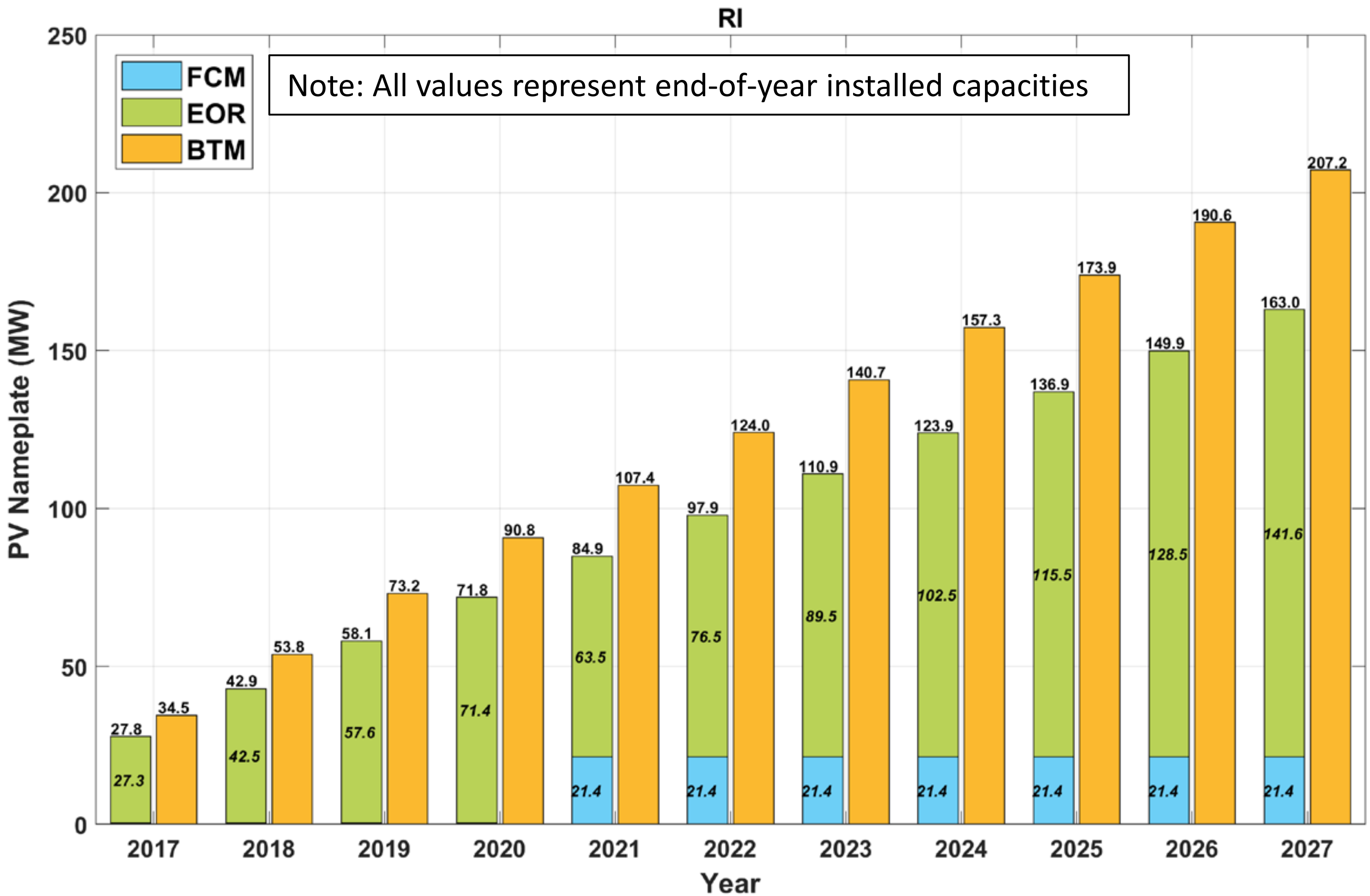
Cumulative Nameplate by Resource Type, MW_{ac}

New Hampshire



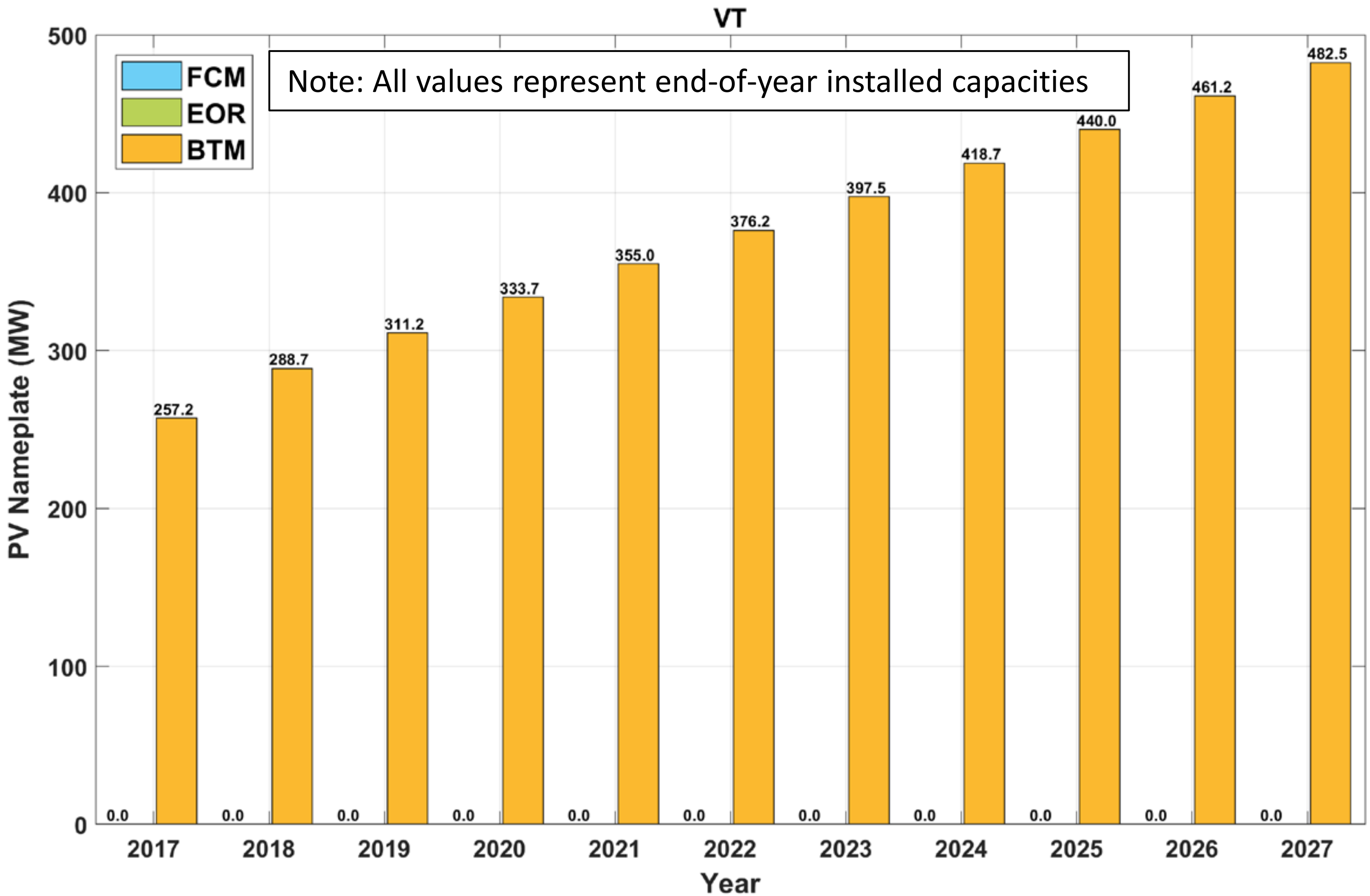
Cumulative Nameplate by Resource Type, MW_{ac}

Rhode Island



Cumulative Nameplate by Resource Type, MW_{ac}

Vermont



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

BTM PV Forecast Used in CELT Net Load Forecast

- The 2018 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 will be reflected in the 2018 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 CELT 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
- A sample calculation showing the method of determining the estimated summer peak load reduction is included in the Appendix

Final 2018 PV Energy Forecast

BTM PV, GWh

Category	States	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
		Estimated Annual Energy (GWh)										
Behind-the-Meter PV	CT	424	539	657	775	886	984	1069	1139	1202	1265	1325
	MA	929	1085	1272	1418	1556	1691	1824	1960	2070	2148	2222
	ME	39	50	63	77	90	102	115	127	139	152	164
	NH	75	88	104	120	135	150	165	180	194	208	223
	RI	30	57	83	109	132	154	177	199	221	243	264
	VT	277	345	380	408	434	459	484	510	535	559	584
Behind-the Meter Total		**1775**	**2162**	**2558**	**2906**	**3233**	**3540**	**3834**	**4115**	**4361**	**4575**	**4783**

Notes:

(1) Forecast values include energy from behind-the-meter PV resources only
(2) Monthly in service dates of PV assumed based on historical development
(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate
(4) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

Final 2018 Forecast

BTM PV: July 1st Estimated Summer Peak Load Reductions

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Behind-the-Meter PV	CT	125.6	154.5	181.6	207.1	229.2	246.2	258.9	266.5	273.4	280.3	286.1
	MA	291.4	315.7	356.4	383.8	408.0	429.0	448.0	465.3	477.2	482.5	486.5
	ME	12.0	14.6	17.9	21.0	23.7	26.2	28.4	30.5	32.5	34.4	36.3
	NH	22.8	26.4	30.0	33.5	36.6	39.3	41.8	44.1	46.2	48.4	50.5
	RI	8.8	16.4	23.1	29.1	34.2	38.6	42.8	46.6	50.2	53.8	57.1
	VT	86.7	105.1	111.6	115.7	119.2	122.2	124.8	127.1	129.4	132.0	134.3
Total	**Cumulative**	547.2	632.6	720.6	790.2	850.9	901.5	944.8	980.1	1008.9	1031.4	1050.7

Notes:

(1) Forecast values are for behind-the-meter PV resources only

(2) Values include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day

(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate

(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

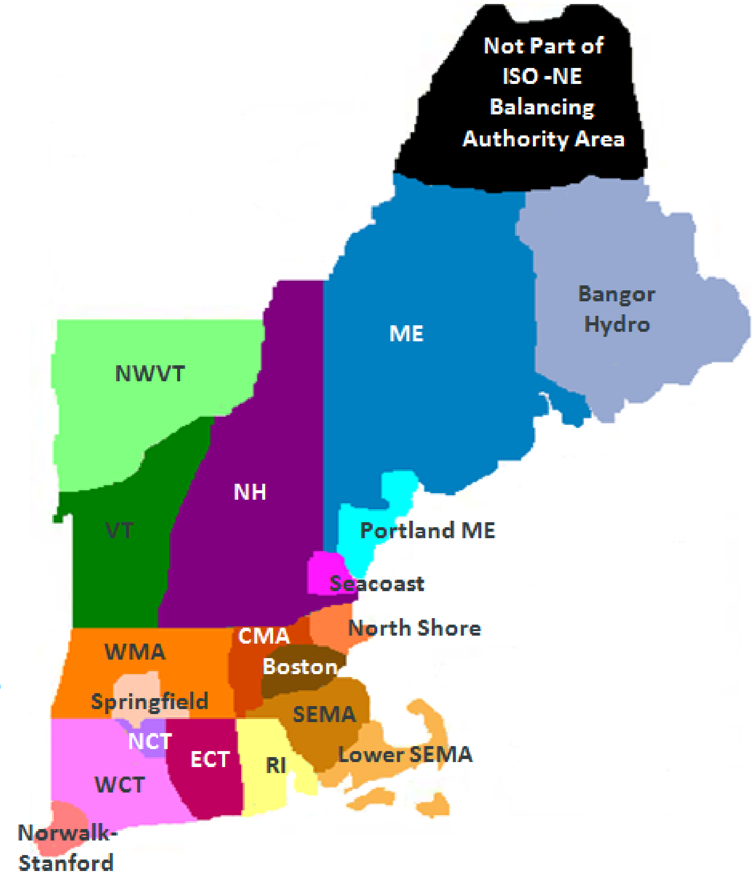
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

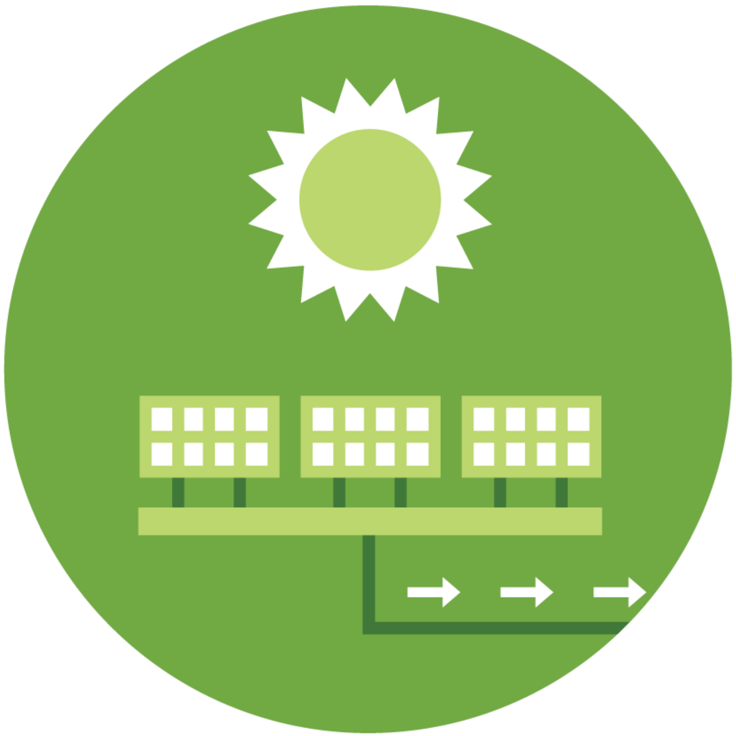
- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of most future PV resources are ultimately unknown
- Mitigation of some of this uncertainty (especially for near-term development) is possible via analysis of available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

Forecasting PV 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, 2017 Utility Data

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.9%
	CT	NorthernCT	19.4%
	CT	Norwalk_Stamford	7.7%
	CT	WesternCT	54.0%
ME	ME	BangorHydro	12.1%
	ME	Maine	52.4%
	ME	PortlandMaine	35.5%
MA	NEMA	Boston	11.5%
	NEMA	NorthShore	5.6%
	SEMA	LowerSEMA	14.4%
	SEMA	SEMA	22.2%
	WCMA	CentralMA	15.0%
	WCMA	SpringfieldMA	6.9%
	WCMA	WesternMA	24.4%
NH	NH	NewHampshire	87.3%
	NH	Seacoast	12.7%
RI	RI	RhodeIsland	100.0%
VT	VT	NorthwestVermont	63.2%
	VT	Vermont	36.8%

APPENDIX

Example Calculation of BTM PV Estimated Summer Peak Load Reduction

Introduction

- The following slides describe an example calculation of estimated summer peak load reductions published in CELT
- The example calculation shown is for Massachusetts in July 2018

Description of Example Calculation Steps & Inputs

Massachusetts BTM PV July 2018 Summer Peak Load Reduction

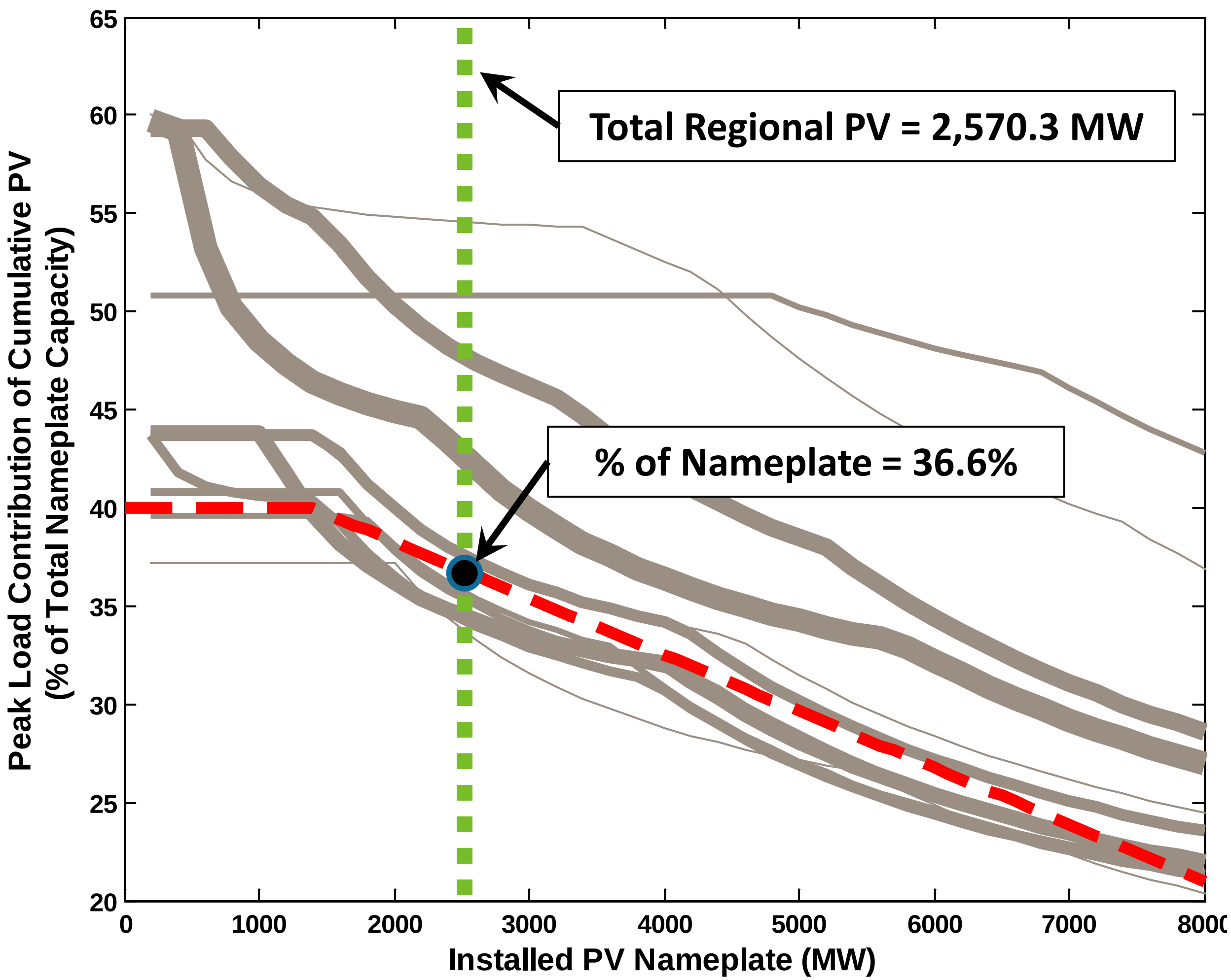
1. State monthly BTM PV nameplate forecast
   - Find BTM PV share of total end-of-year nameplate forecast based on state accounting for categories (FCM, non-FCM EOR, and BTM) – see slide 54
   - Input uses the conversion of cumulative end-of-year state nameplate forecast (slide 51) into monthly forecast using monthly capacity growth rates (slide 36)
2. % of nameplate contribution to summer peak
   - Value is determined by finding the intersection point of total PV nameplate with sloped line shown on next slide
3. Panel degradation multiplier
   - Assumed annual degradation rate (ADR) = 0.5% per year
   - Based on forecasted composite age (CA) in years using equation below
   - State composite ages are plotted on slide 39

$$DegradeMultiplier = (1 - ADR)^{CA}$$

4. Gross-up for assumed transmission & distribution losses
   - Value of 8% is used

% of Nameplate Determination

Estimated Summer Peak Load Reduction



Note:
Graphic is from Appendix of 2016 PV Forecast slides (slide 89): https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf

Final Calculation

Massachusetts BTM PV July 2018 Summer Peak Load Reduction

Calculation Line Item	Relevant Region	
July 2018 Total Nameplate PV Forecast (MW)	ISO-NE	2570.3
July 2018 BTM PV Nameplate Forecast (MW)	MA	809.5
% of Nameplate (from previous slide)	ISO-NE	0.3663
Panel Degradation Multiplier	MA	0.9858
Peak Gross Up Factor	ISO-NE	1.08
Final BTM PV Summer Peak Load Reduction (MW)	MA	**315.7**

Final estimated peak load reduction calculated by multiplying all values highlighted in yellow