Final 2019 PV Forecast

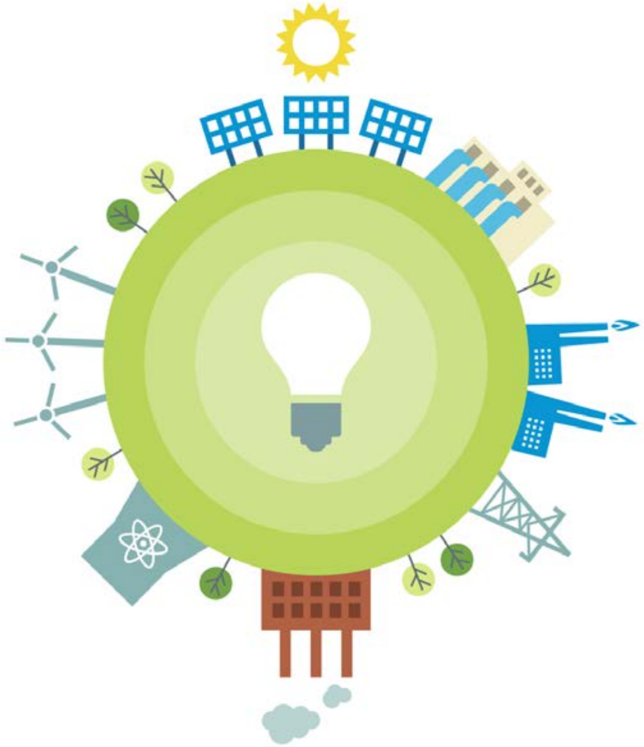
Distributed Generation Forecast Working Group

Jon Black

MANAGER, LOAD FORECASTING

Presentation Outline

- Updates to Draft 2019 PV Forecast
- Final 2019 PV Nameplate Forecast
- 2019 PV Energy Forecast
- Classification of PV Forecast
  – Background and Methods
- Classification of 2019 PV Forecast
- 2019 CELT BTM PV Forecast
  – Estimated Energy & Summer Peak Load Reductions
- Geographic Distribution of PV Forecast
- Summary and Next steps



UPDATES TO DRAFT 2019 PV FORECAST

Forecast Review Process

- The ISO discussed the draft 2019 PV forecast with the DGFWG at the February 15, 2019 meeting
- Stakeholders provided comments on the draft forecast
  - See: https://www.iso-ne.com/committees/planning/distributed-generation/?eventId=137521
- The final PV forecast will be published in the 2019 CELT

Changes Reflected in the Final 2019 PV Forecast

State	Changes/Comments
Connecticut	Based on comments from CT DEEP, "CT WISE successor" policies (for SCEF, RSIP, and ZREC) are in place for 2020-2026, and the growth values CT DEEP presented for these programs at the December DGFWG meeting were likely conservative. For this reason, ISO applied policy-based discount factors rather than post-policy discount factors to the input values from 2020-2026 for these successor programs.

Discount Factors Used in 2019 Forecast

Note: No changes made to draft discount factors

Policy-Based

Forecast	Draft 2019	Final 2019
2019	10%	10%
2020	10%	10%
2021	15%	15%
2022	15%	15%
2023	15%	15%
2024	15%	15%
2025	15%	15%
2026	15%	15%
2027	15%	15%
2028	15%	15%

Post-Policy

Forecast	Draft 2019	Final 2019
2019	35.0%	35.0%
2020	36.7%	36.7%
2021	38.3%	38.3%
2022	40.0%	40.0%
2023	41.7%	41.7%
2024	43.3%	43.3%
2025	45.0%	45.0%
2026	46.7%	46.7%
2027	48.3%	48.3%
2028	50.0%	50.0%

FINAL 2019 PV NAMEPLATE FORECAST

Draft 2019 PV Forecast

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
CT	464.3	68.4	85.2	77.8	76.4	49.1	47.7	46.3	44.9	43.5	42.1	**1,046.0**
MA	1871.3	292.0	288.0	272.0	272.0	272.0	204.0	176.0	170.7	165.3	160.0	**4,143.2**
ME	41.4	7.1	7.1	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	**109.7**
NH	83.8	12.7	12.7	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	**205.6**
RI	116.7	51.3	51.3	48.5	42.4	42.4	42.4	42.4	42.4	42.4	42.4	**564.6**
VT	306.3	31.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**530.3**
Regional - Annual (MW)	**2883.8**	**463.1**	**466.9**	**438.3**	**430.8**	**403.6**	**334.2**	**304.8**	**298.0**	**291.3**	**284.6**	**6,599.4**
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3813.8**	**4252.2**	**4683.0**	**5086.6**	**5420.8**	**5725.5**	**6023.6**	**6314.9**	**6599.4**	**6,599.4**

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 2019 PV Forecast

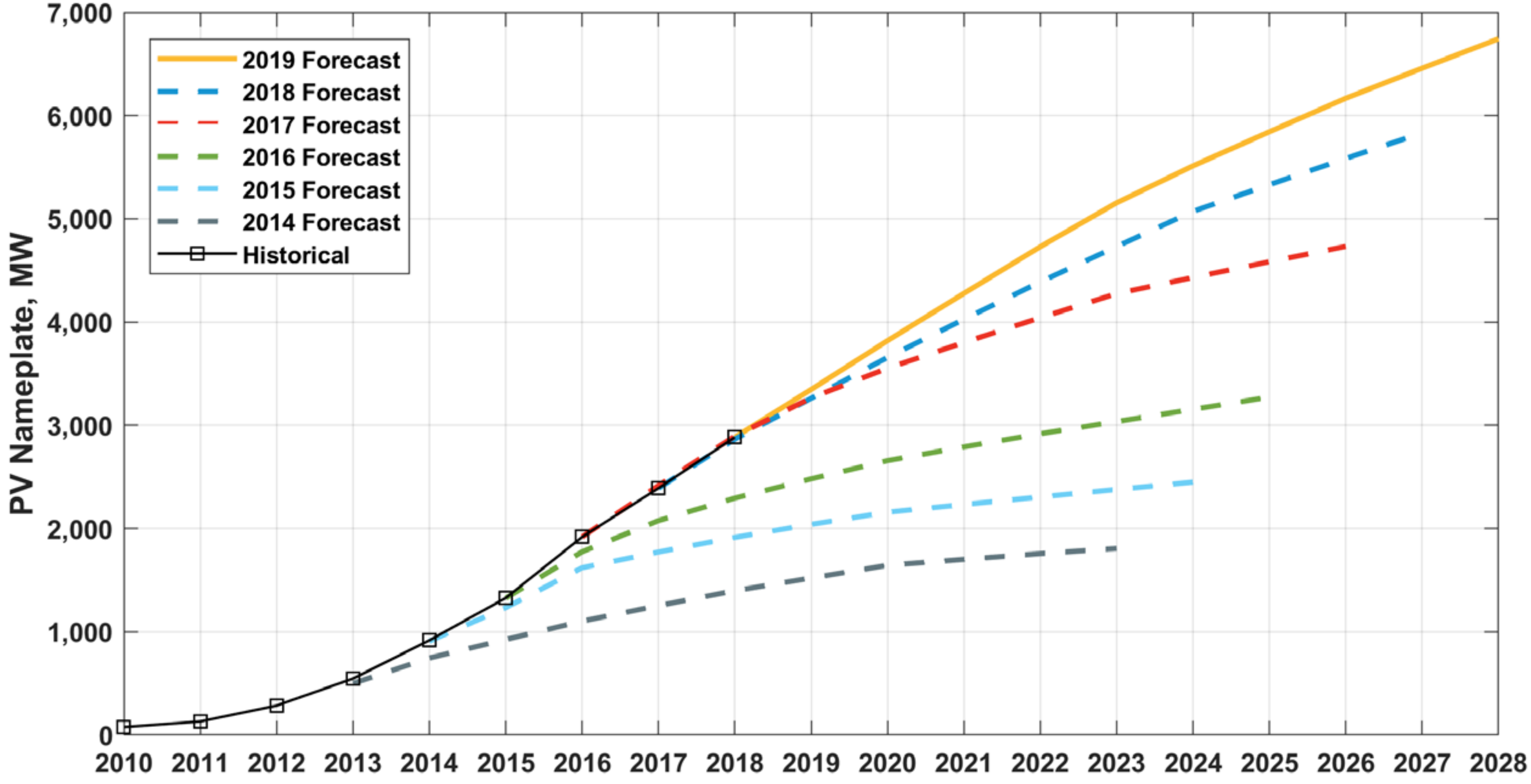
Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
CT	464.3	68.4	91.1	97.5	97.5	71.6	71.6	71.6	71.6	43.5	42.1	**1,190.9**
MA	1871.3	292.0	288.0	272.0	272.0	272.0	204.0	176.0	170.7	165.3	160.0	**4,143.2**
ME	41.4	7.1	7.1	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	**109.7**
NH	83.8	12.7	12.7	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	**205.6**
RI	116.7	51.3	51.3	48.5	42.4	42.4	42.4	42.4	42.4	42.4	42.4	**564.6**
VT	306.3	31.5	22.5	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	**530.3**
Regional - Annual (MW)	**2883.8**	**463.1**	**472.8**	**458.0**	**451.9**	**426.0**	**358.0**	**330.0**	**324.7**	**291.3**	**284.6**	**6,744.4**
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3819.8**	**4277.8**	**4729.7**	**5155.7**	**5513.8**	**5843.8**	**6168.5**	**6459.8**	**6744.4**	**6,744.4**

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



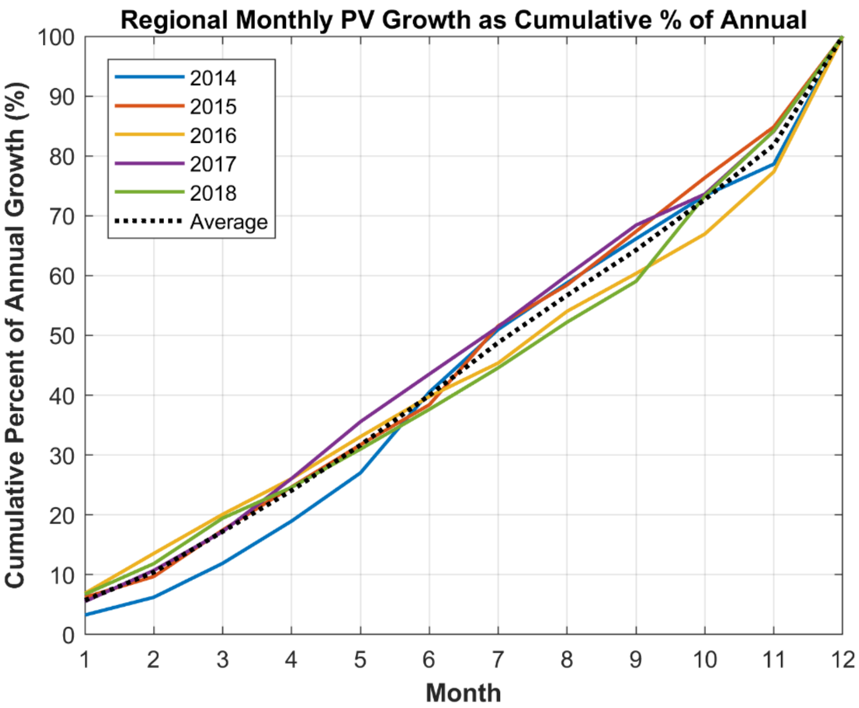
2019 PV ENERGY FORECAST

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 2014 and 2018 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 and state average monthly capacity factors (CF) developed from 5 years of PV performance data (2014-2018)
  - Resulting state CFs are tabulated to the right, and plots of individual monthly capacity factors in each state are shown on slide 15

State	Average CF, %
CT	14.7
ME	14.5
NH	14.1
RI	14.8
VT	13.8
MA	14.5

Historical Monthly PV Growth Trends, 2014-2018



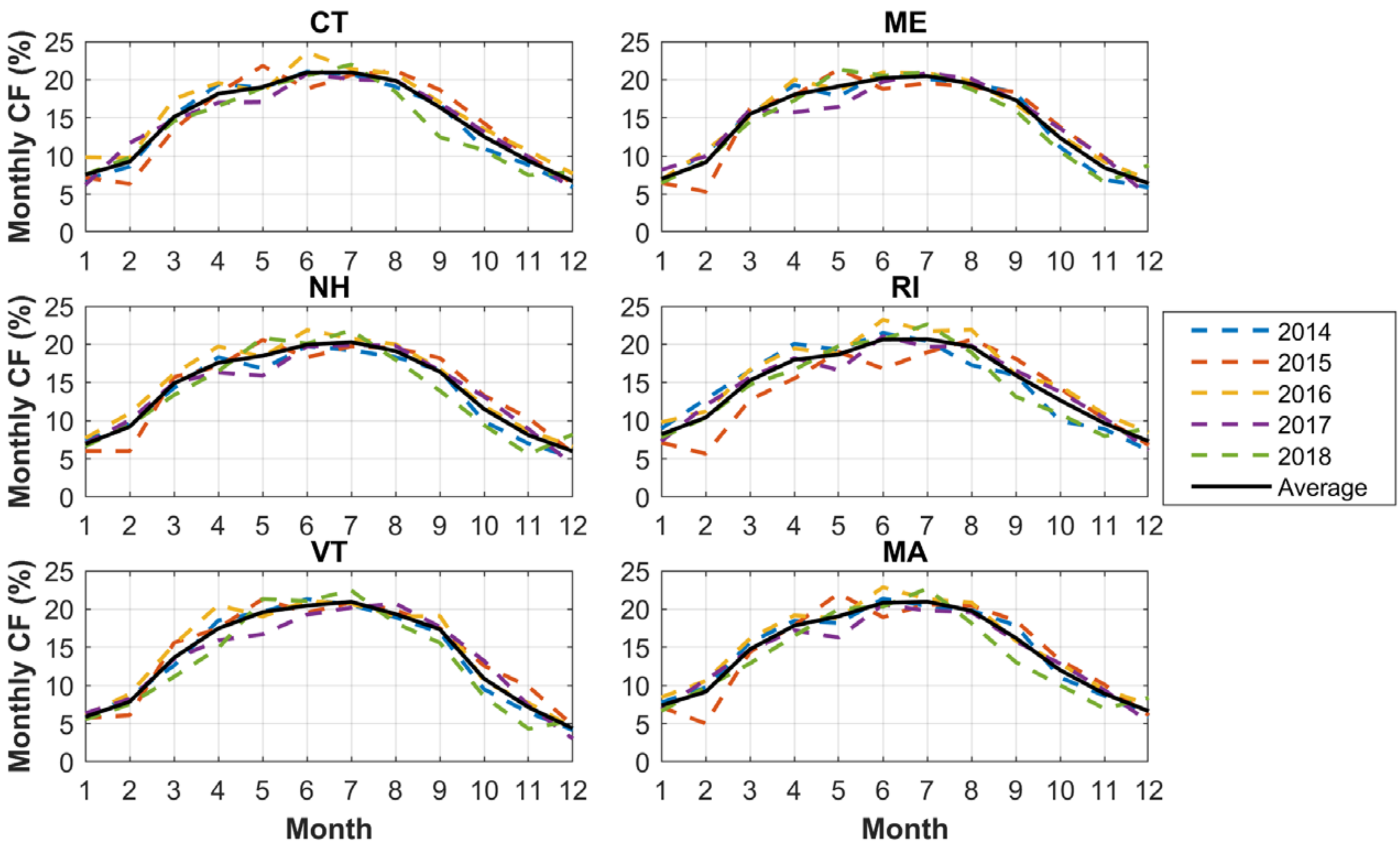
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6	6
2	5	10
3	7	17
4	7	24
5	8	32
6	8	40
7	9	49
8	8	57
9	8	64
10	8	73
11	9	82
12	18	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, 2014-2018



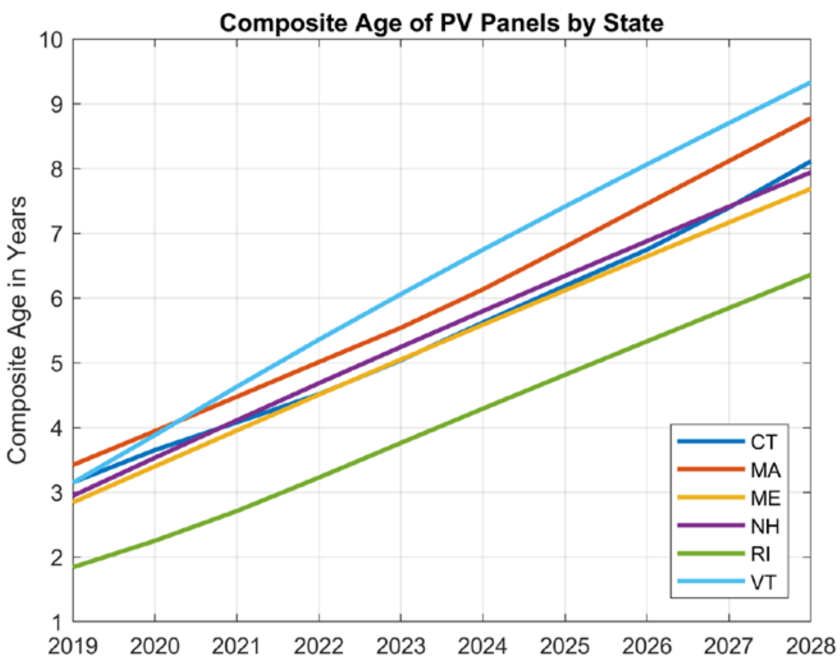
PV Panel Degradation Factors

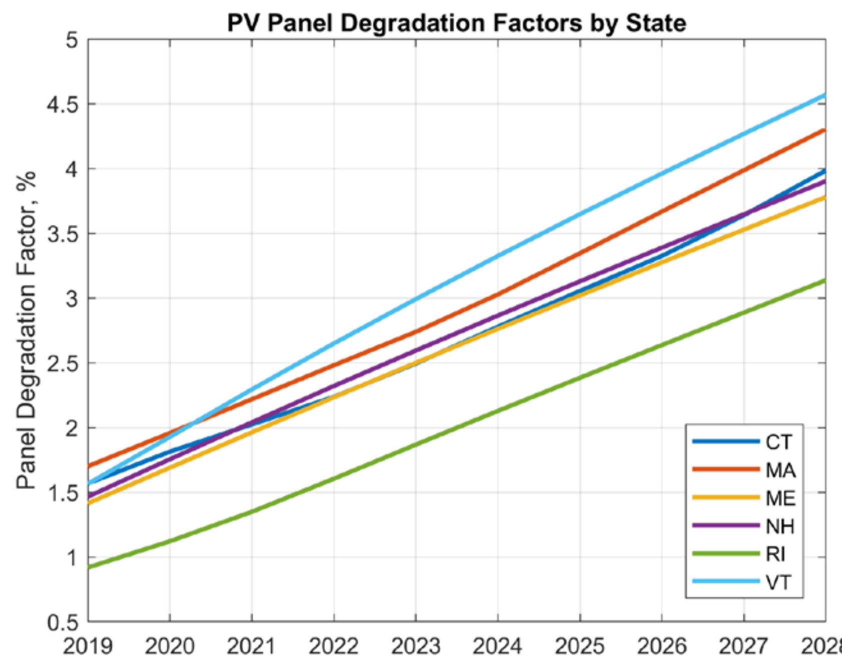
- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecasts of BTM PV energy and estimated summer peak load reductions include the effects of a 0.5%/year panel degradation rate to account for the expected declining conversion efficiency of solar panels over time
  - Accounting for this degradation becomes more important as the region's PV panels age
- 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
- 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 2019 PV Energy Forecast

Total PV Forecast Energy, GWh

States	Total Estimated Annual Energy (GWh)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	660	763	885	1,014	1,129	1,223	1,313	1,404	1,480	1,534
MA	2627	3,010	3,370	3,719	4,067	4,386	4,618	4,829	5,032	5,235
ME	59	68	77	86	94	103	112	120	129	137
NH	114	131	146	161	176	191	206	221	235	250
RI	185	255	323	385	441	498	553	608	664	720
VT	402	437	462	487	512	537	561	585	610	635
Regional - Annual Energy (GWh)	**4047**	**4,664**	**5,263**	**5,852**	**6,419**	**6,939**	**7,361**	**7,767**	**8,149**	**8,511**

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

CLASSIFICATION OF PV FORECAST: BACKGROUND & METHODS

Classification Needed to Determine BTM PV

- Ultimately, the ISO needs to determine the amount of PV that is not expected to participate in wholesale markets, and instead reduces load
  - This is the amount of BTM PV that should be reflected in the long-term load forecast
- In order to properly account for existing and future PV in planning studies and avoid double counting, ISO classifies PV into three distinct categories related to its assumed market participation/non-participation
- Accounting for these market distinctions is performed for both installed nameplate capacity (historical and forecast) and estimates of hourly energy production (historical), and is important for the ISO's use of the PV forecast for load forecasting and a wide range of planning studies

Three Mutually Exclusive Categories

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

Nameplate Classification By State

- Classification varies by state
  - Market disposition of PV projects can be influenced 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 13
  2. **Non-FCM EOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2018 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

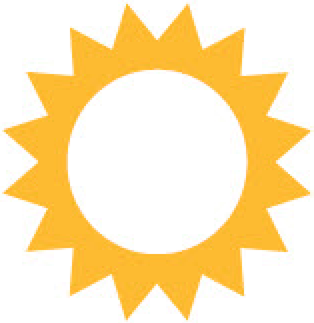
Data and Assumptions

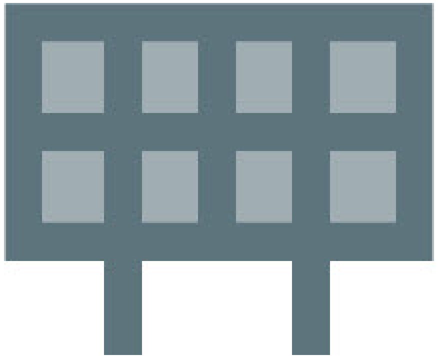
- **FCM**
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 13
  - Assume aggregate total PV in FCM as of FCA 13 remains constant from 2022-2028
- **Non-FCM Gen/EOR**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/18
  - CT, MA, ME, NH, VT: Assume % share of nameplate PV in energy market as of 12/31/18 remains consistent throughout the forecast horizon
  - RI: Average of 60% of forward-looking MWs are assumed to be EOR, based on
    - Assume % share of nameplate in energy market as of 12/31/18 applies to all growth driven by REGP and DGSC programs (52.9%)
    - Assume 85% of net metered/virtual net metered projects become EOR
- Other assumptions:
  - Supply-side FCM PV resources operate as EOR/Gen prior to their first FCM commitment period (this has been observed in MA and RI)
  - 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

January 1, 2012 – December 31, 2018

- Historical BTM PV production estimates are needed at the hourly level for reconstitution in the development of the long-term gross load forecast
- The ISO estimates historical hourly BTM PV using:
    1. Historical BTM PV performance data
    2. Installed capacity data submitted by utilities
    3. Historical energy production of market-facing PV
- In order to estimate historical hourly BTM PV production, ISO develops hourly state PV profiles as described on the next slide





Estimation of Hourly BTM PV For Reconstitution

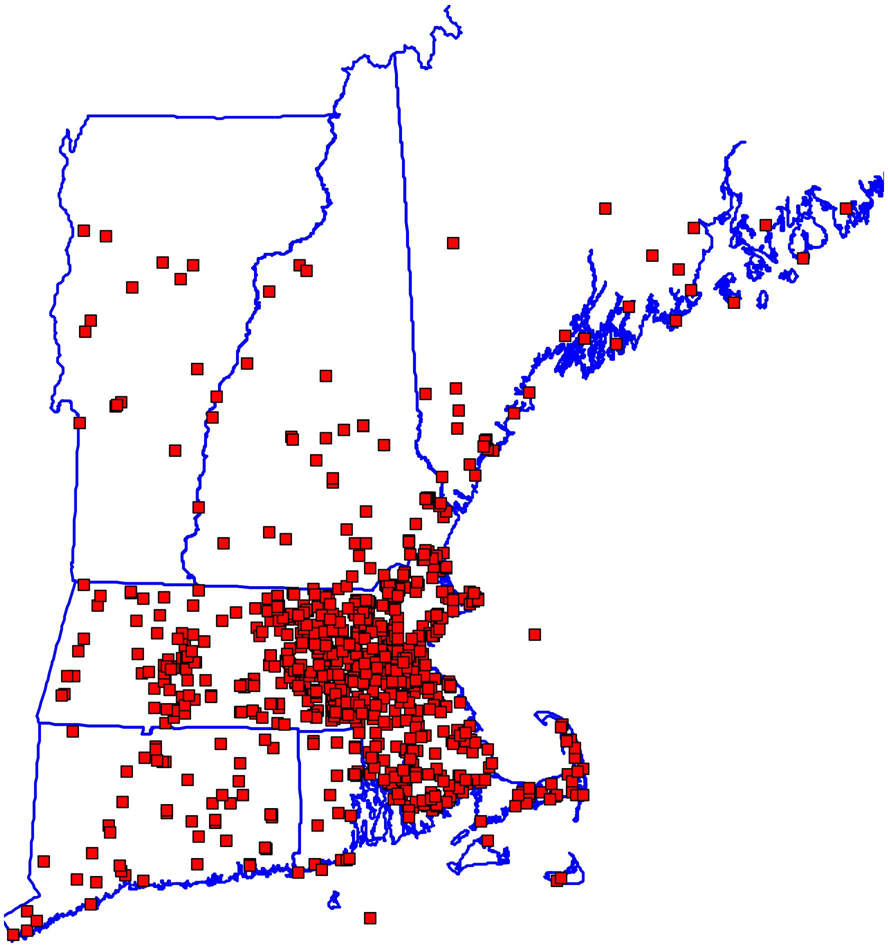
January 1, 2012 – December 31, 2018 (Continued)

- Historical performance and installed capacity data are combined into normalized (i.e., a per MW-of-nameplate) PV profiles for each state that reflect the effects of both localized weather and geographical distribution of installed capacity
  - Historical PV performance data sources are described on slides 26-27
- Using the normalized PV profiles, total state PV production (i.e., FCM+EOR+BTM) is then estimated by scaling the profiles up to the total PV installed over the period according to distribution utility data
  - (Normalized Hourly Profile) x (Total installed PV Capacity) = Total Hourly PV production
- Subtracting the hourly PV settlements energy (where applicable) from the total hourly PV production yields the hourly BTM PV for each state
  - Resulting hourly BTM PV is used for reconstitution in the development of the gross load forecast

Historical PV Performance Data
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 Performance Data
1/1/14-12/31/18

- ISO has contracted with a third-party vendor for PV production data service
  - Includes data from more than 9,000 PV installations
  - Data are 5-minutely and at the town level
  - Broad geographic coverage
- An example snapshot of regional data is plotted to the right
  - Data are for February 8, 2019 at 1:00 pm
  - Yellow/red coloring shows level of PV production
  - No data available in towns colored gray
  - Data not requested in towns colored blue

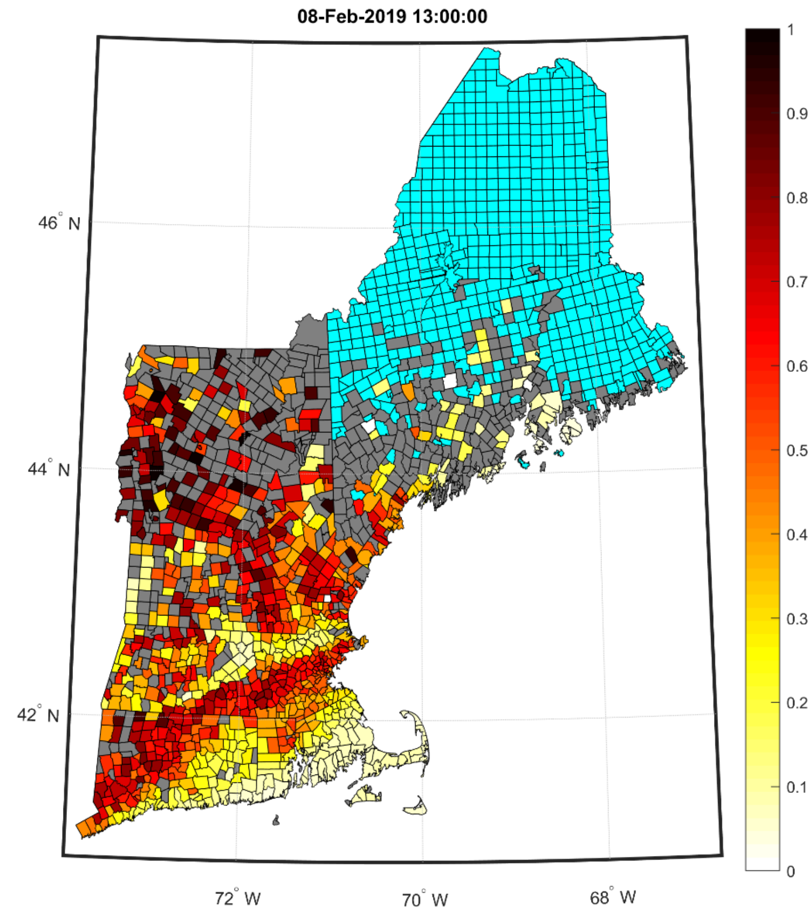


Figure notes:
1. Graphic developed by ISO New England
2. Data source: Quantitative Business Analytics, Inc.

CLASSIFICATION OF FINAL 2019 PV FORECAST

Final 2019 PV Forecast

Cumulative Nameplate, MW_{ac}

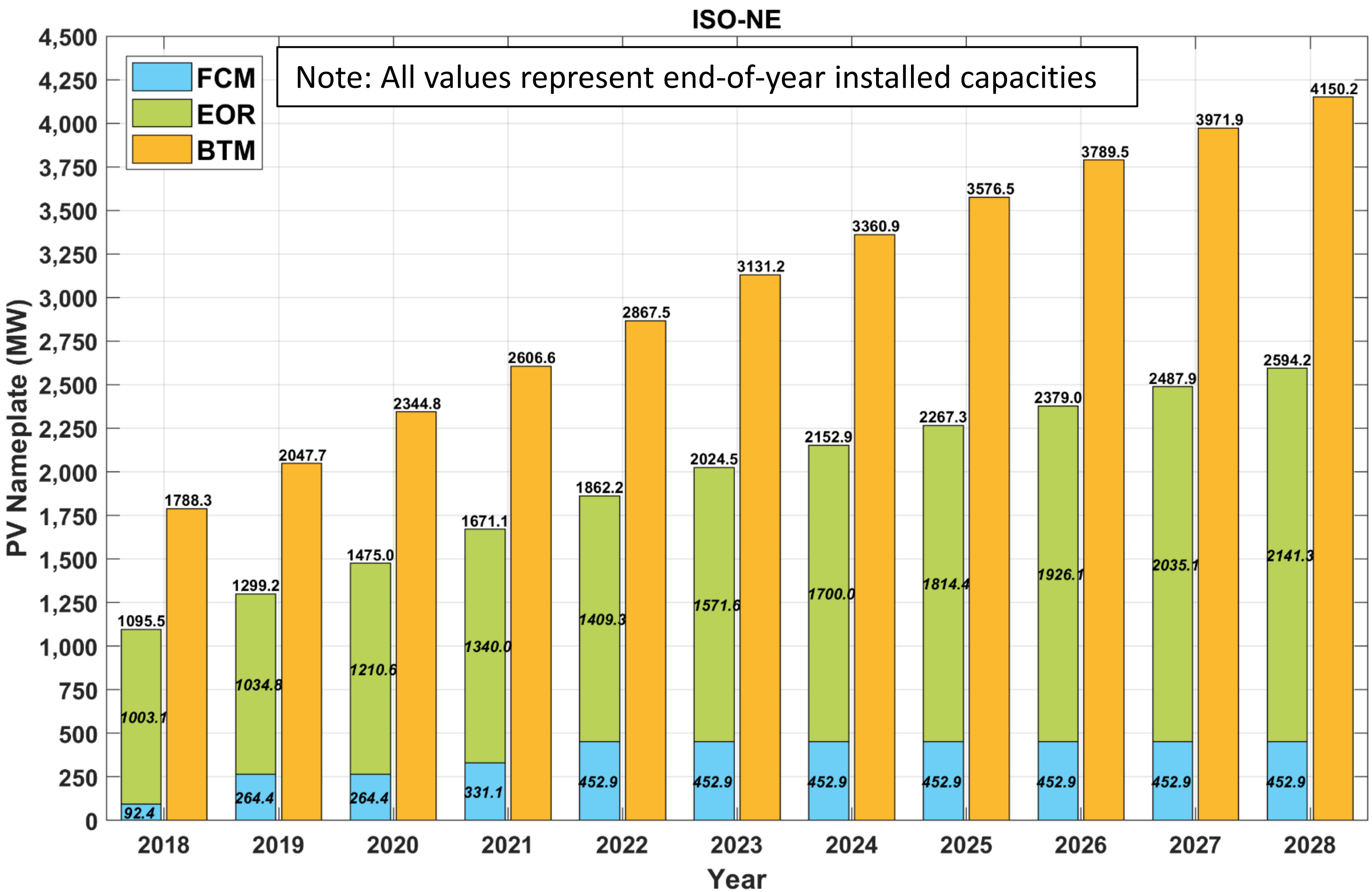
States	Cumulative Total MW (AC nameplate rating)										
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	464.3	532.8	623.9	721.4	818.8	890.5	962.1	1033.7	1105.3	1148.8	1190.9
MA	1871.3	2163.2	2451.2	2723.2	2995.2	3267.2	3471.2	3647.2	3817.9	3983.2	4143.2
ME	41.4	48.5	55.7	62.4	69.2	75.9	82.7	89.4	96.2	102.9	109.7
NH	83.8	96.6	109.3	121.4	133.4	145.4	157.5	169.5	181.6	193.6	205.6
RI	116.7	168.0	219.3	267.8	310.2	352.6	395.0	437.4	479.8	522.2	564.6
VT	306.3	337.8	360.3	381.6	402.8	424.1	445.3	466.6	487.8	509.1	530.3
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3819.8**	**4277.8**	**4729.7**	**5155.7**	**5513.8**	**5843.8**	**6168.5**	**6459.8**	**6744.4**

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

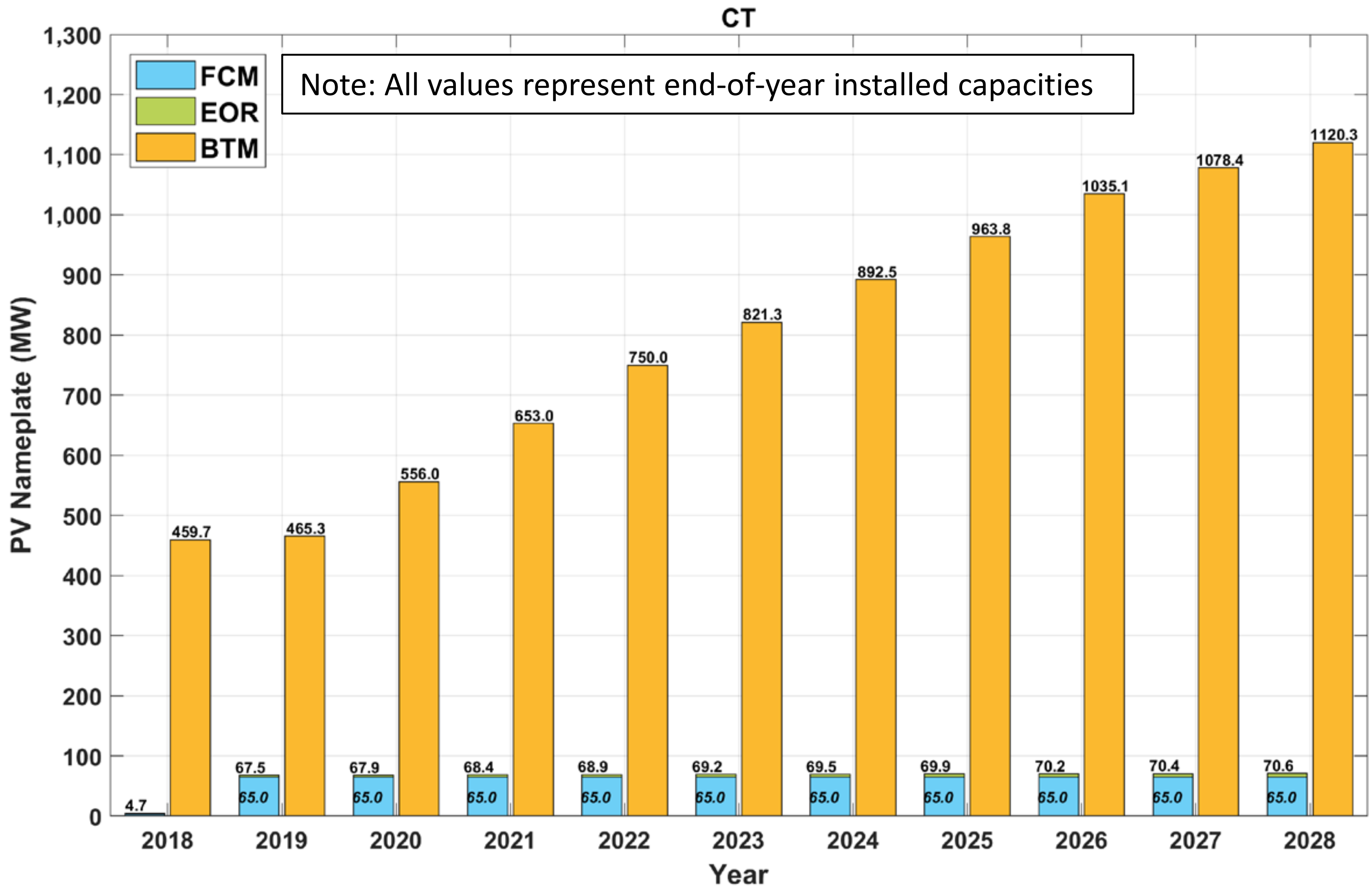
Final 2019 PV Forecast

Cumulative Nameplate, MW_{ac}

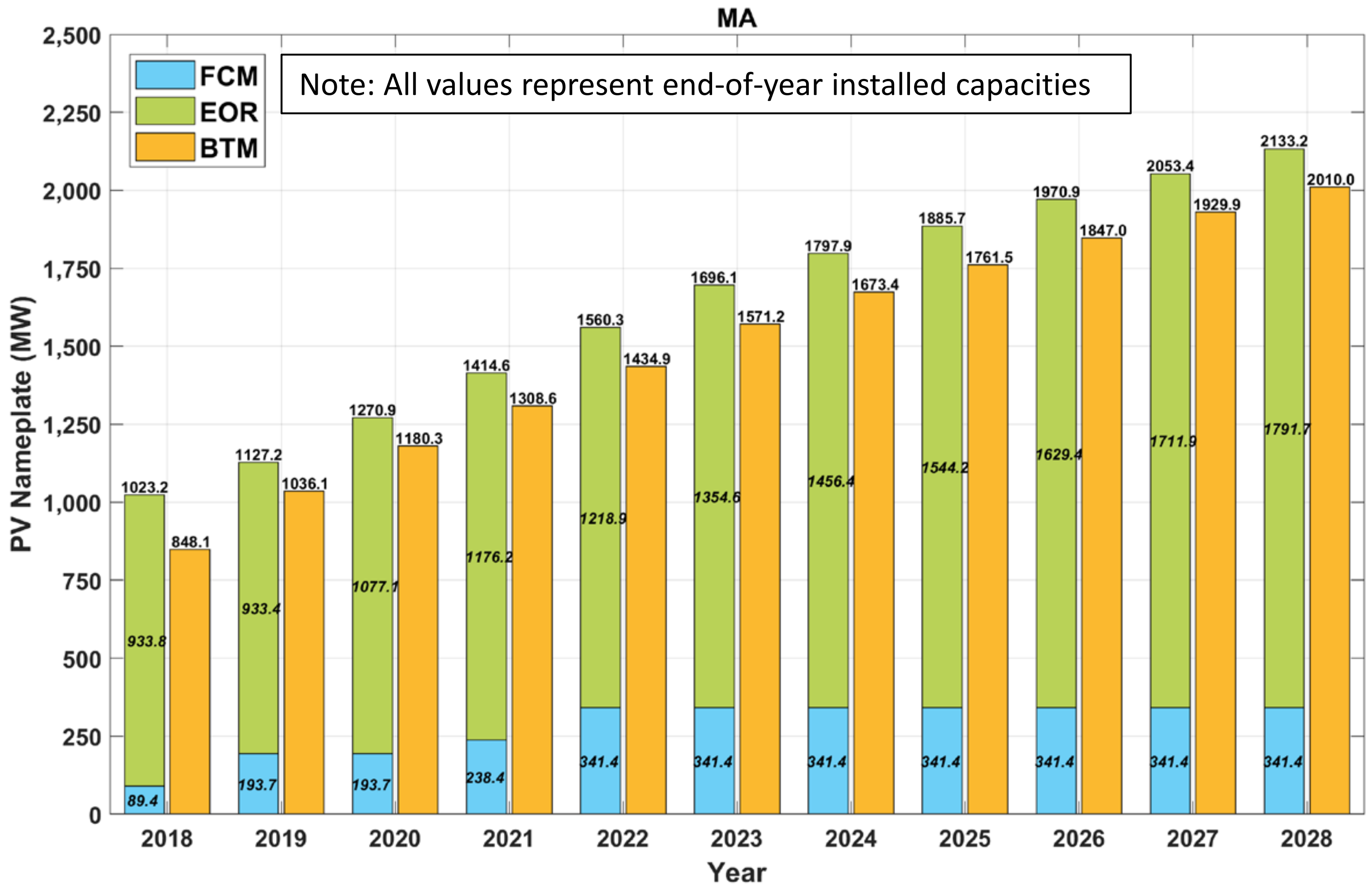


Cumulative Nameplate by Resource Type, MW_{ac}

Connecticut

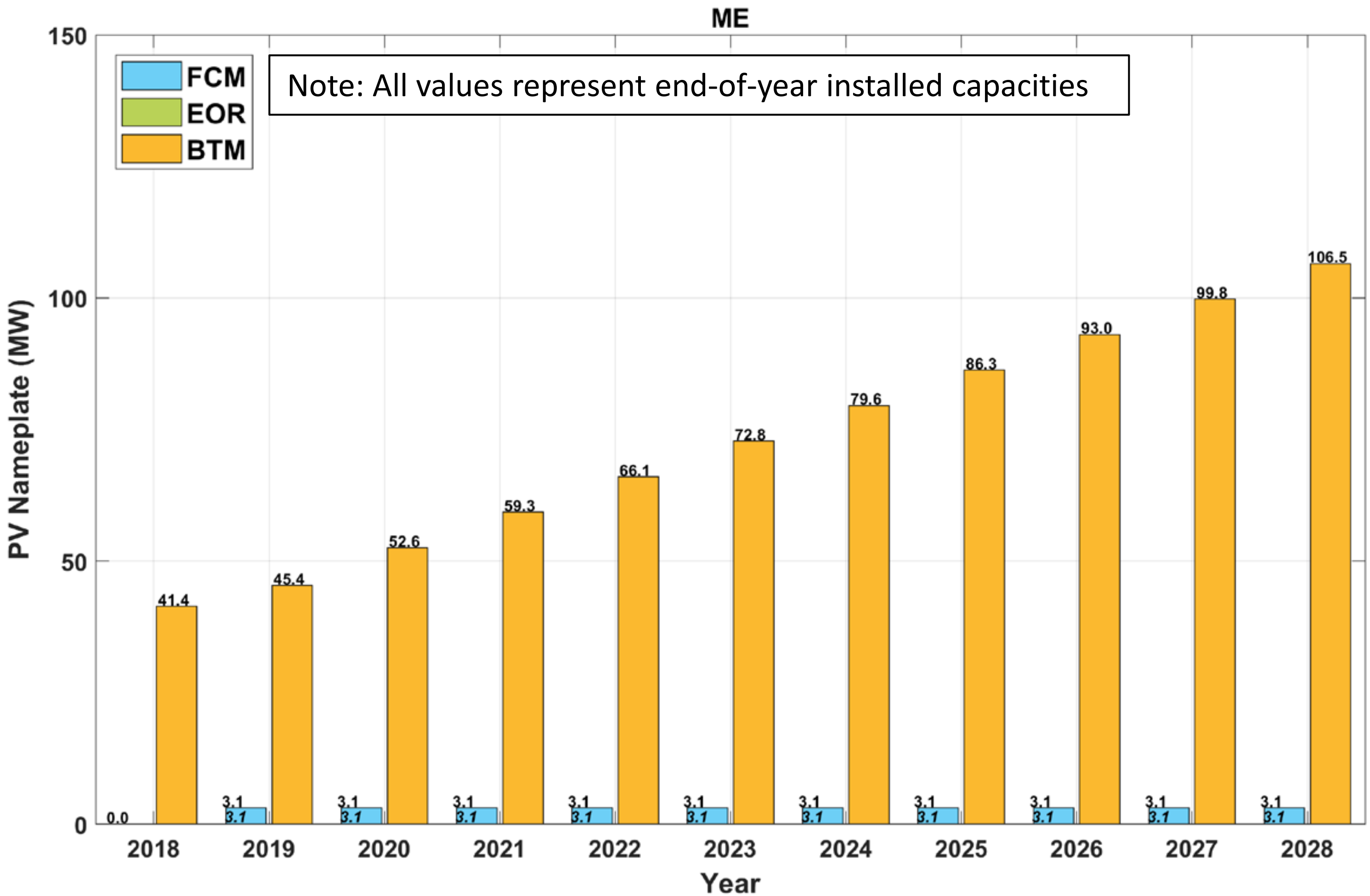


Cumulative Nameplate by Resource Type, MW_{ac}
Massachusetts



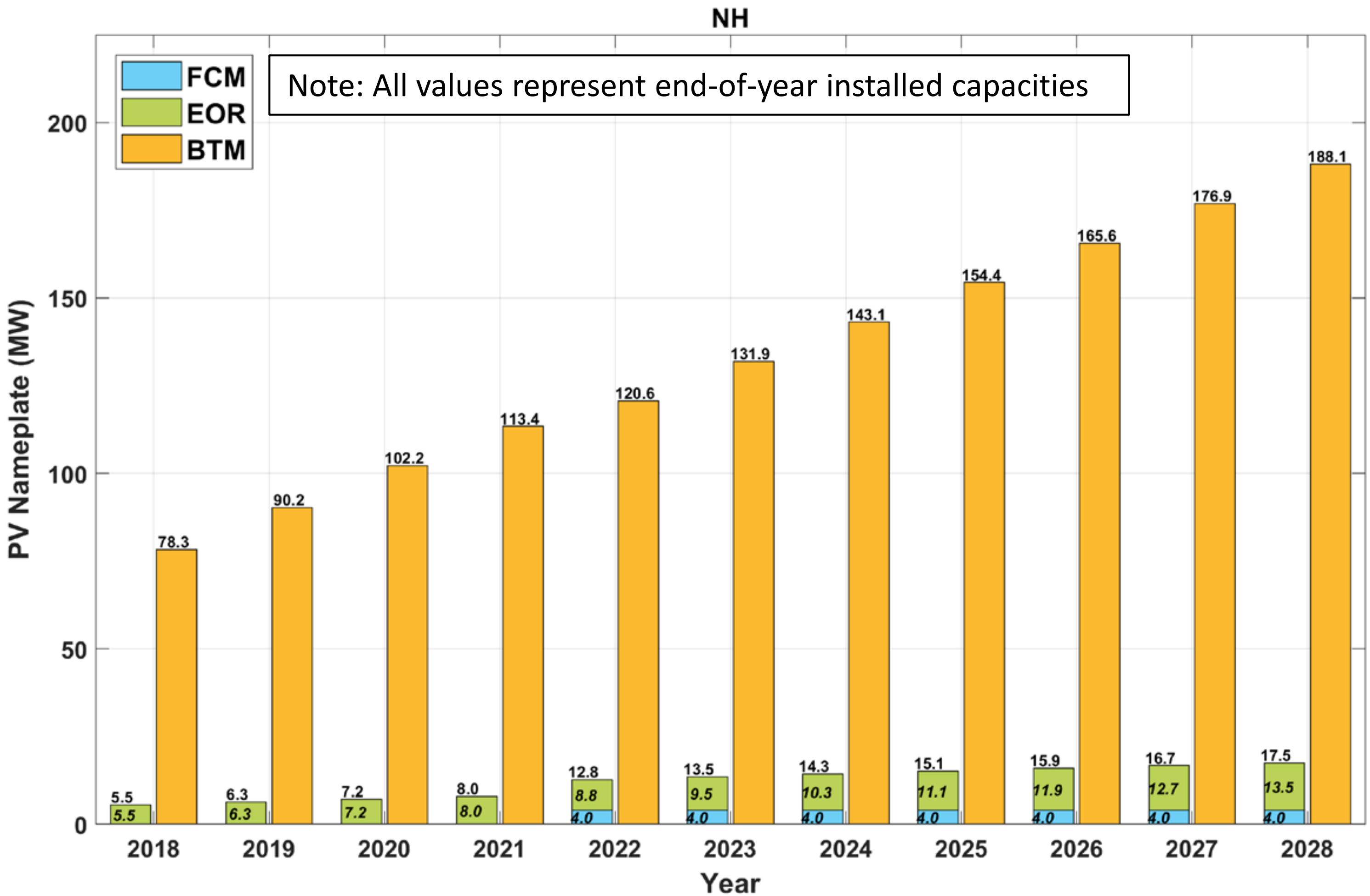
Cumulative Nameplate by Resource Type, MW_{ac}

Maine



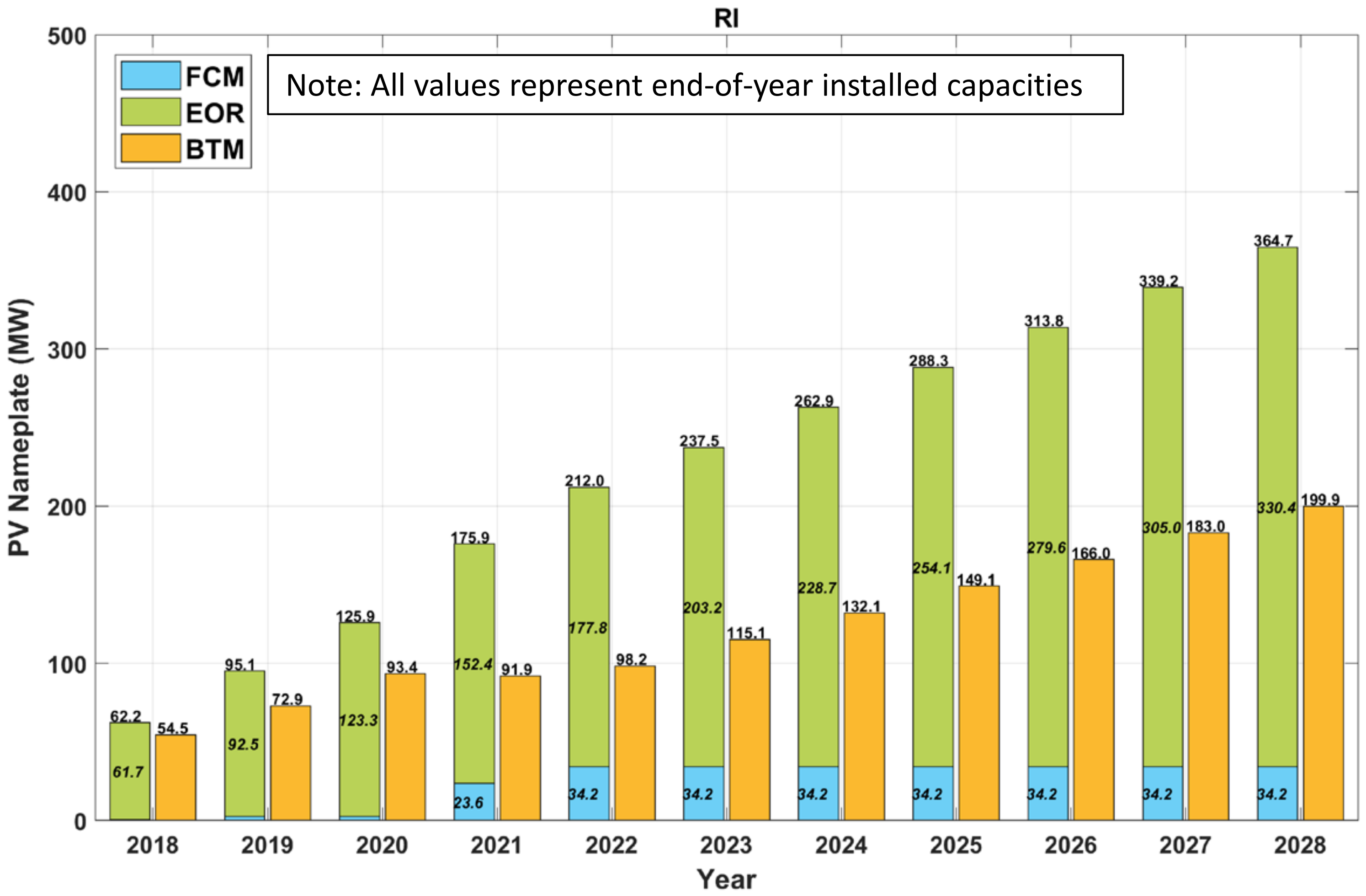
Cumulative Nameplate by Resource Type, MW_{ac}

New Hampshire



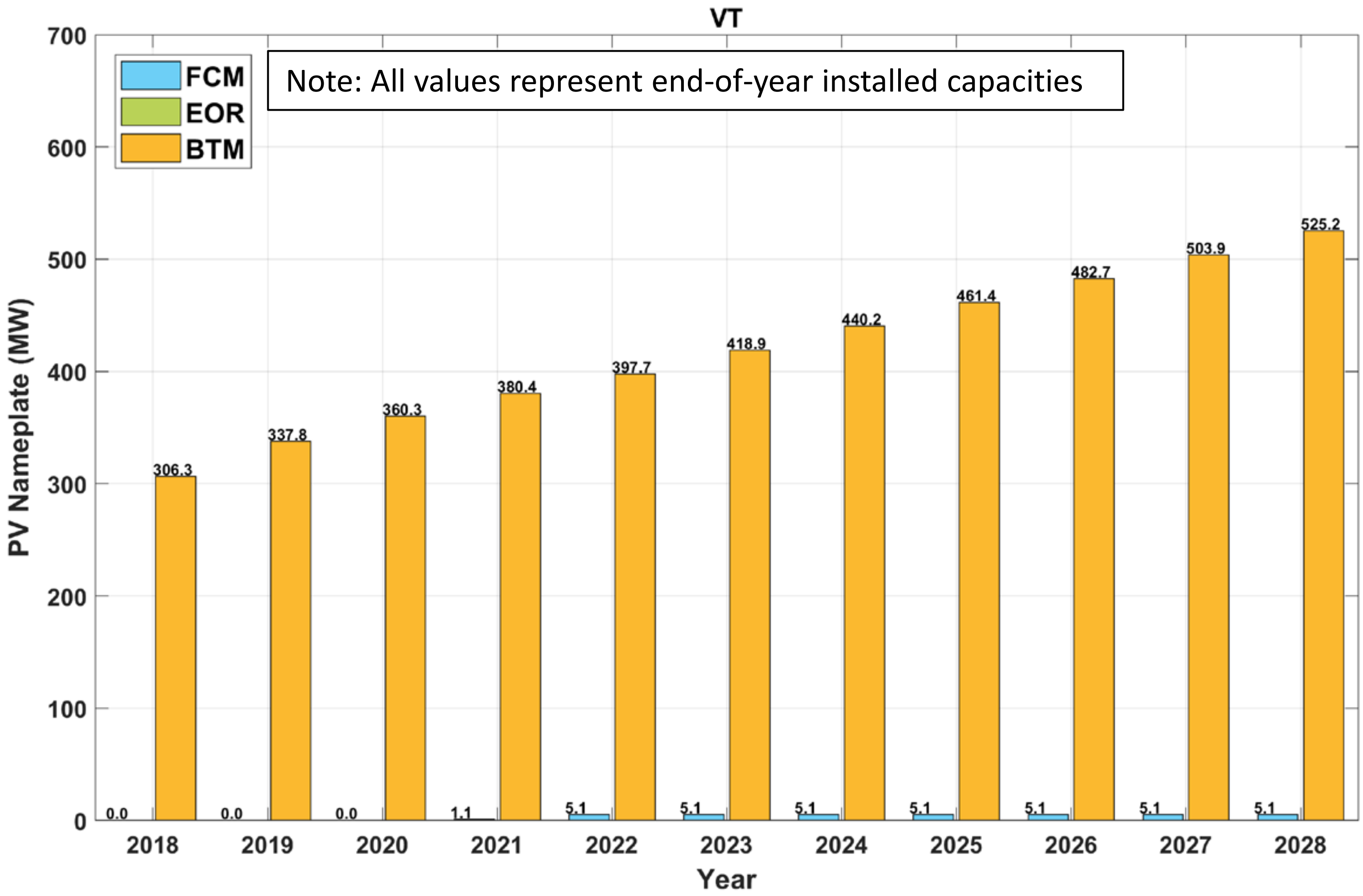
Cumulative Nameplate by Resource Type, MW_{ac}

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 2019 CELT net load forecast will reflect 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 2019 CELT
  - 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 2019 PV Energy Forecast

BTM PV, GWh

States	Total Estimated Annual Energy (GWh)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	623	672	794	922	1,037	1,131	1,220	1,311	1,388	1,441
MA	1218	1,445	1,621	1,785	1,951	2,111	2,228	2,334	2,436	2,538
ME	57	64	73	82	90	99	108	116	125	133
NH	107	122	137	149	159	174	187	201	215	229
RI	84	110	126	128	141	164	186	209	231	253
VT	402	437	462	484	505	531	555	579	603	628
Regional - Annual Energy (GWh)	**2490**	**2,849**	**3,213**	**3,549**	**3,884**	**4,210**	**4,483**	**4,749**	**4,996**	**5,222**

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 2019 Forecast

BTM PV: July 1st Estimated Summer Peak Load Reductions

States	Estimated Summer Peak Load Reductions - BTM PV (MW)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	172.8	180.0	204.6	227.9	245.3	256.8	267.9	278.0	284.1	285.1
MA	345.0	392.0	422.8	446.5	468.2	485.8	495.4	501.3	505.7	509.1
ME	16.1	17.3	19.0	20.4	21.7	22.8	23.9	24.9	25.9	26.7
NH	31.1	34.1	36.7	38.3	39.4	41.2	42.9	44.5	45.9	47.3
RI	23.3	29.3	32.1	31.3	33.3	37.1	40.7	44.0	47.0	49.8
VT	119.3	124.3	126.4	127.0	127.3	128.4	129.7	130.8	131.7	132.6
Regional - Cumulative Peak Load Reductions (MW)	**707.6**	**777.2**	**841.6**	**891.4**	**935.2**	**972.1**	**1000.5**	**1023.5**	**1040.3**	**1050.6**

% of BTM AC Nameplate	35.2%	33.9%	32.5%	31.2%	29.9%	28.8%	27.8%	26.8%	25.9%	25.1%

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

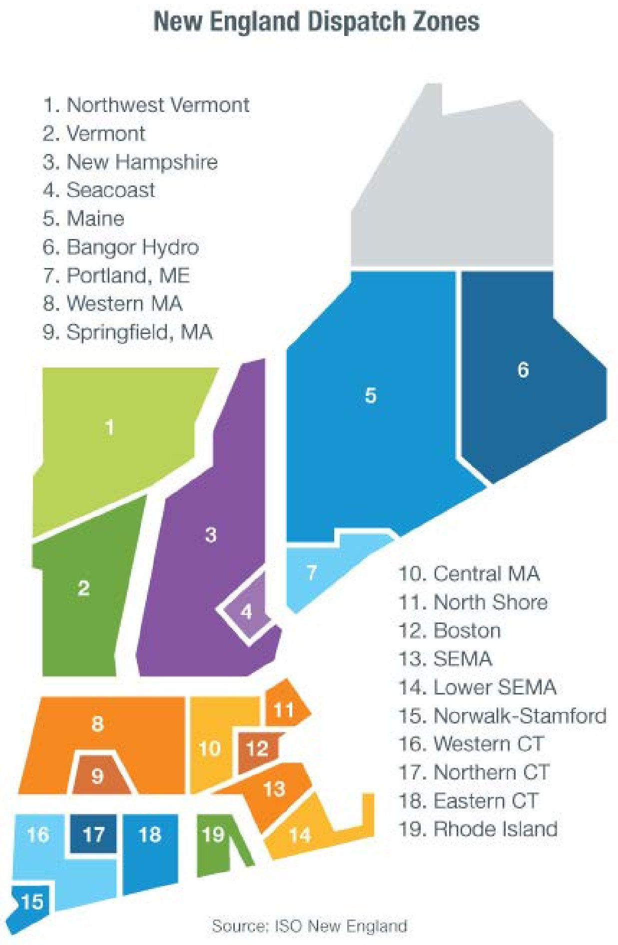
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

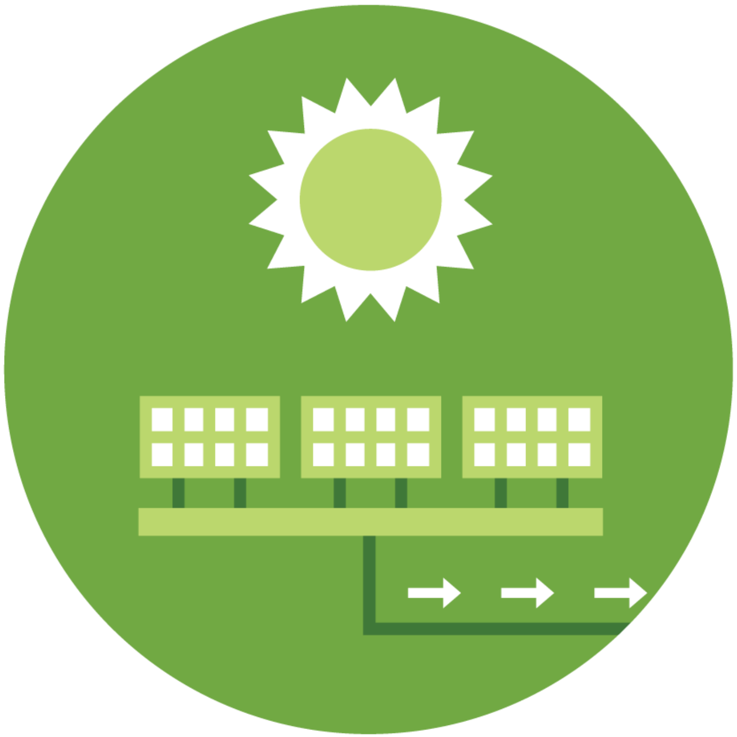
- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of most future PV resources are ultimately unknown
- Mitigation of some of this uncertainty (especially for near-term development) is possible via analysis of available 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, 2018 Utility Data

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.7%
	CT	NorthernCT	18.6%
	CT	Norwalk_Stamford	7.3%
	CT	WesternCT	55.4%
ME	ME	BangorHydro	14.6%
	ME	Maine	49.9%
	ME	PortlandMaine	35.5%
MA	NEMA	Boston	11.9%
	NEMA	NorthShore	5.8%
	SEMA	LowerSEMA	15.1%
	SEMA	SEMA	21.2%
	WCMA	CentralMA	14.0%
	WCMA	SpringfieldMA	7.1%
	WCMA	WesternMA	24.9%
NH	NH	NewHampshire	90.6%
	NH	Seacoast	9.4%
RI	RI	RhodeIsland	100.0%
VT	VT	NorthwestVermont	62.3%
	VT	Vermont	37.7%

SUMMARY AND NEXT STEPS

Summary and Next Steps

- The 2019 PV nameplate and energy forecasts have been finalized
- The ISO has categorized the 2019 state and regional PV forecasts according to the three PV resource categories
- The ISO has updated its geographic distribution assumptions based on recent data
- The final PV forecast will appear in the 2019 CELT, which will be published by May 1, 2019

Questions