APRIL 29, 2025 | HOLYOKE, MA

Final 2025 Photovoltaic (PV) Forecast

Outline

Forecast Review Process

- The ISO hosted 3 Distributed Generation Forecast Working Group (DGFWG) meetings during the 2025 forecast cycle:
  1. December 9, 2024
     - DER forecast improvements
  2. February 10, 2025
     - Draft 2025 PV forecast
  3. March 24, 2025
     - December 2024 DER Photovoltaic Interconnection Data Update
     - Final draft 2025 PV forecast
- The final PV forecast is published in the 2025 CELT (Section 3):
  - See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/

INTRODUCTION

Transitional Slide Subtitle

Introduction

- The majority of state-sponsored distributed PV does not participate in wholesale markets, but reduces the system load observed by ISO

- The long-term PV forecast helps the ISO determine future system load characteristics that are important for the reliable planning and operation of the system

- To properly account for PV in long-term planning, the finalized PV forecast will be categorized as follows:
  1. PV as a capacity resource in the Forward Capacity Market (FCM)
  2. Non-FCM Energy Only Resources (EOR) and Generators
  3. Behind-the-meter PV (BTM PV)

Behind-the-meter PV is reconstituted into historical loads*

The 2025 gross load forecast reflects loads without BTM PV load reductions

**Historical BTM PV reduces historical metered loads; historical loads reconstituted for BTM PV are used to model base load in developing the base load forecast*

PV Forecast Focuses on Distributed Generation

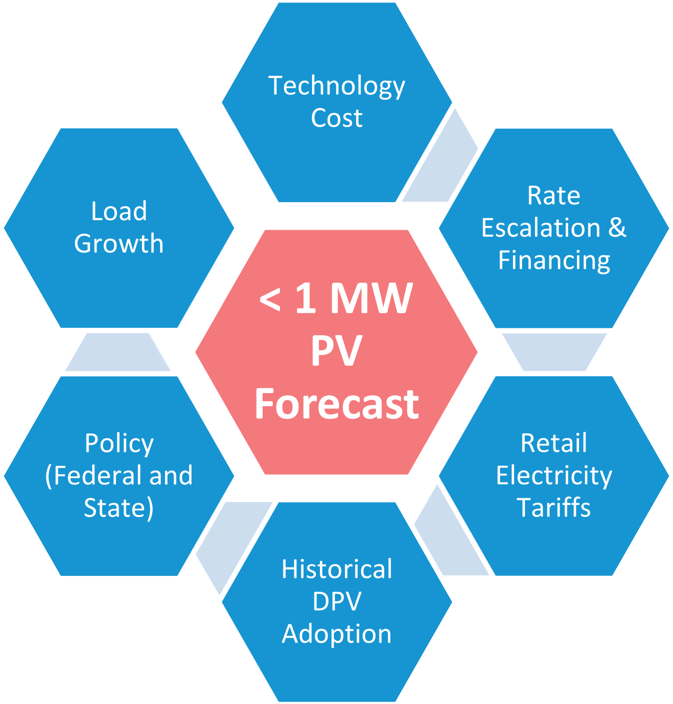
- The focus of the DGFWG is distributed generation (DG) projects:
  - "…defined as those that are typically 5 MW or less in nameplate capacity and are interconnected to the distribution system (typically 69 kV or below) according to state-jurisdictional interconnection standards."
  - Note that the industry has evolved since the formation of the DGFWG, and today DG is often referred to as a distributed energy resource (DER)
    - Per ISO's Planning Procedure 12, DER is defined *as any generator or energy storage facility located on the distribution system, any subsystem thereof, or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation or demand reduction*
      - DER does not include demand response, controllable loads, or other load modifiers
- While DER may include larger-scale DER projects greater than 5 MW in size, the forecast does not consider policy drivers and growth of larger-scale DER projects, since these projects are generally accounted for as part of ISO's interconnection process and participate in wholesale markets

PV Forecast Methodology

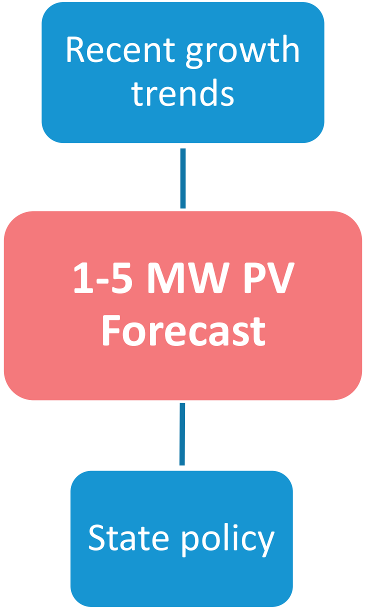
- The PV forecast is a projection of distributed PV resources to be used in ISO-NE System Planning studies, consistent with its role to ensure prudent planning assumptions for the bulk power system
- Beginning with the 2024 PV forecast, the ISO's methodology includes use of the Distributed Generation Market Demand Model (dGen™), an agent-based simulation that was developed and open-sourced by the National Renewable Energy Laboratory (NREL)
  – An overview of the dGen™ model was presented by the NREL team at the October 2023 DGFWG meeting
- The nameplate PV forecast is developed using the two following additive processes:
  1. For < 1 MW systems: Use residential and commercial dGen™ modeling
  2. For 1-5 MW systems: Use a policy-based approach
- For this year's forecast, the ISO is developing the forecast out through 2050

PV Forecast Inputs

PV Systems < 1 MW



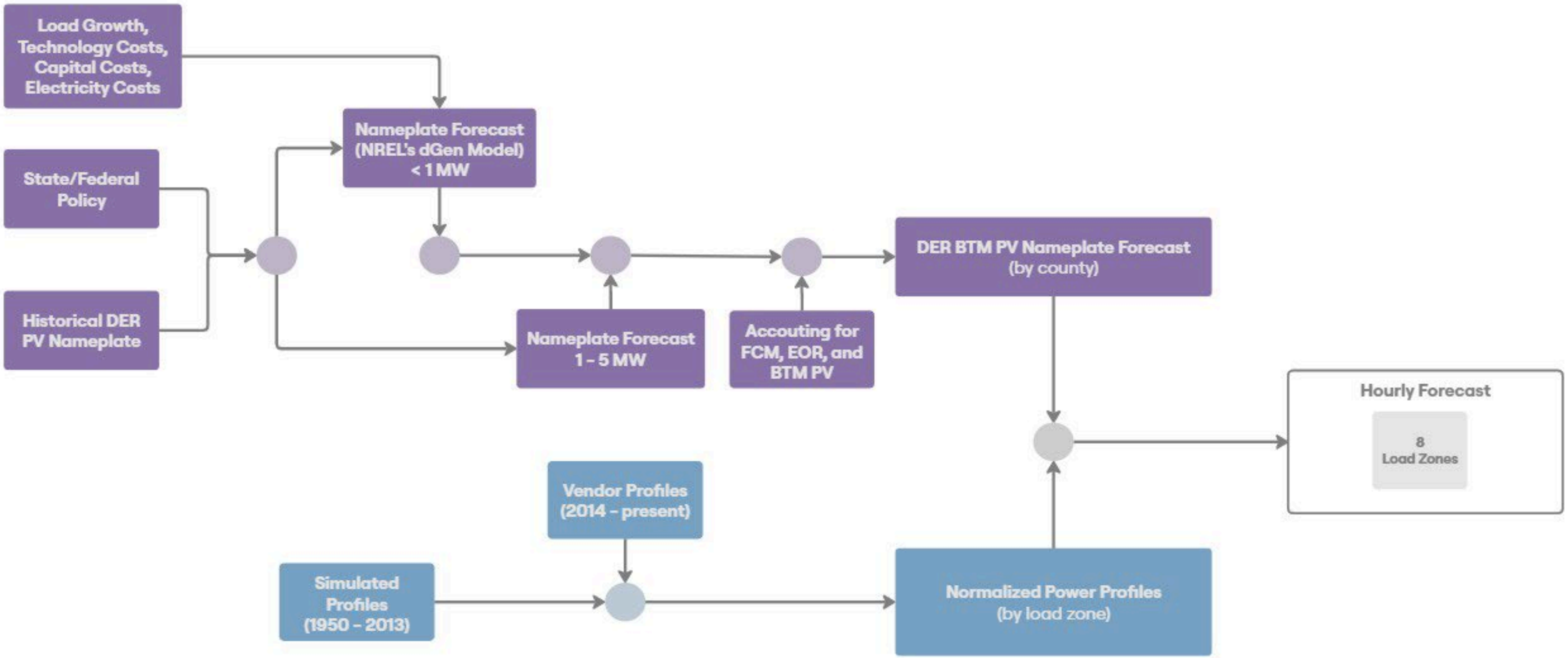
PV Systems 1-5 MW



2025 DER PV Forecast Improvements

- For CELT 2025, the ISO implemented the following improvements as part of the forecast cycle:
  1. Switch to hourly modeling of the BTMPV forecast at the load zone level, such that it aligns with ISO's new hourly load forecast methodology
  2. Advance the accounting for the nameplate forecast to county-level to help support efforts aimed to improve the spatial accounting of the forecast in the future
- The ISO also shared the results of its research and planning about implementing a DER storage forecast for CELT 2026 (included in Appendix IV)

CELT 2025 DER PV Forecast Process Flow



2025 PV FORECAST - NAMEPLATE CAPACITY

Final 2025 PV Forecast – 10 Year Horizon

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
CT	1,289	180	178	179	173	169	162	164	164	145	124	**2,927**
MA	4,019	294	293	308	305	307	300	307	308	274	237	**6,952**
ME	1,053	72	58	59	57	66	69	76	78	72	64	**1,723**
NH	280	36	38	46	49	54	55	58	60	57	52	**785**
RI	465	67	66	73	77	72	60	52	52	46	39	**1,070**
VT	529	33	33	34	34	35	35	38	41	39	35	**886**
Regional - Cumulative (MW)	**7,634**	**8,315**	**8,982**	**9,681**	**10,376**	**11,080**	**11,762**	**12,457**	**13,159**	**13,793**	**14,343**	**14,343**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

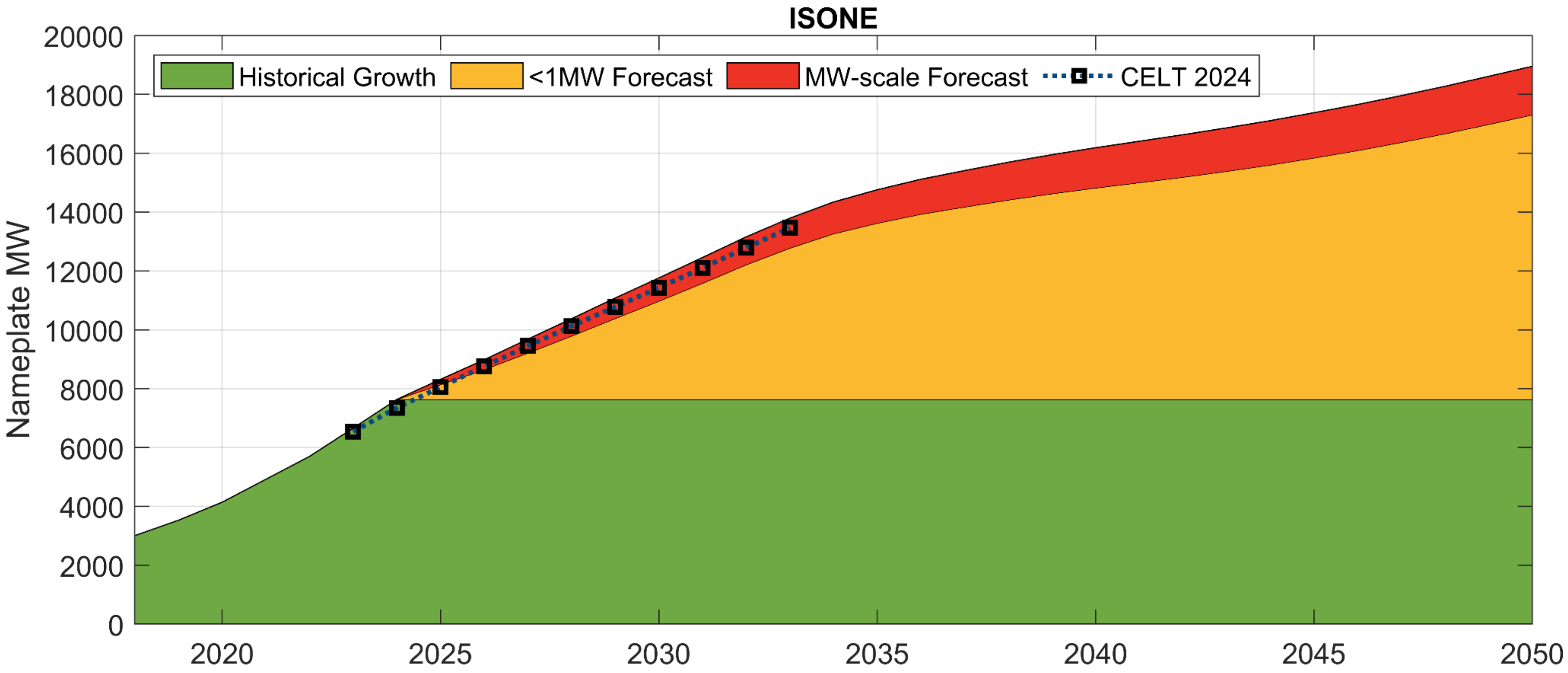
(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast

(3) All values represent end-of-year installed capacities

(4) Forecast does not include forward-looking PV projects > 5MW in nameplate capacity

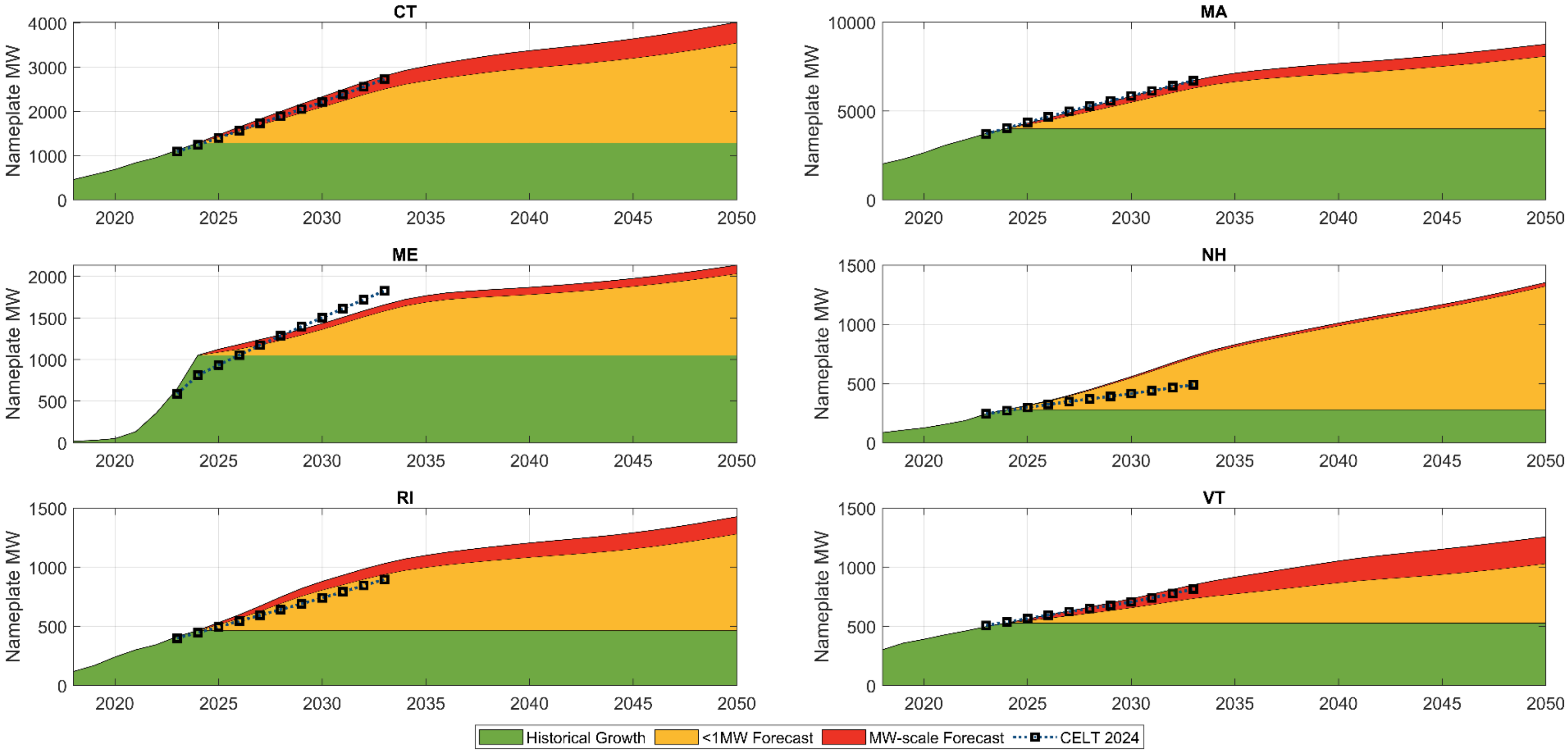
Regional PV Nameplate Capacity Growth

Historical vs. Forecast



State PV Nameplate Capacity Growth

Historical and Forecast

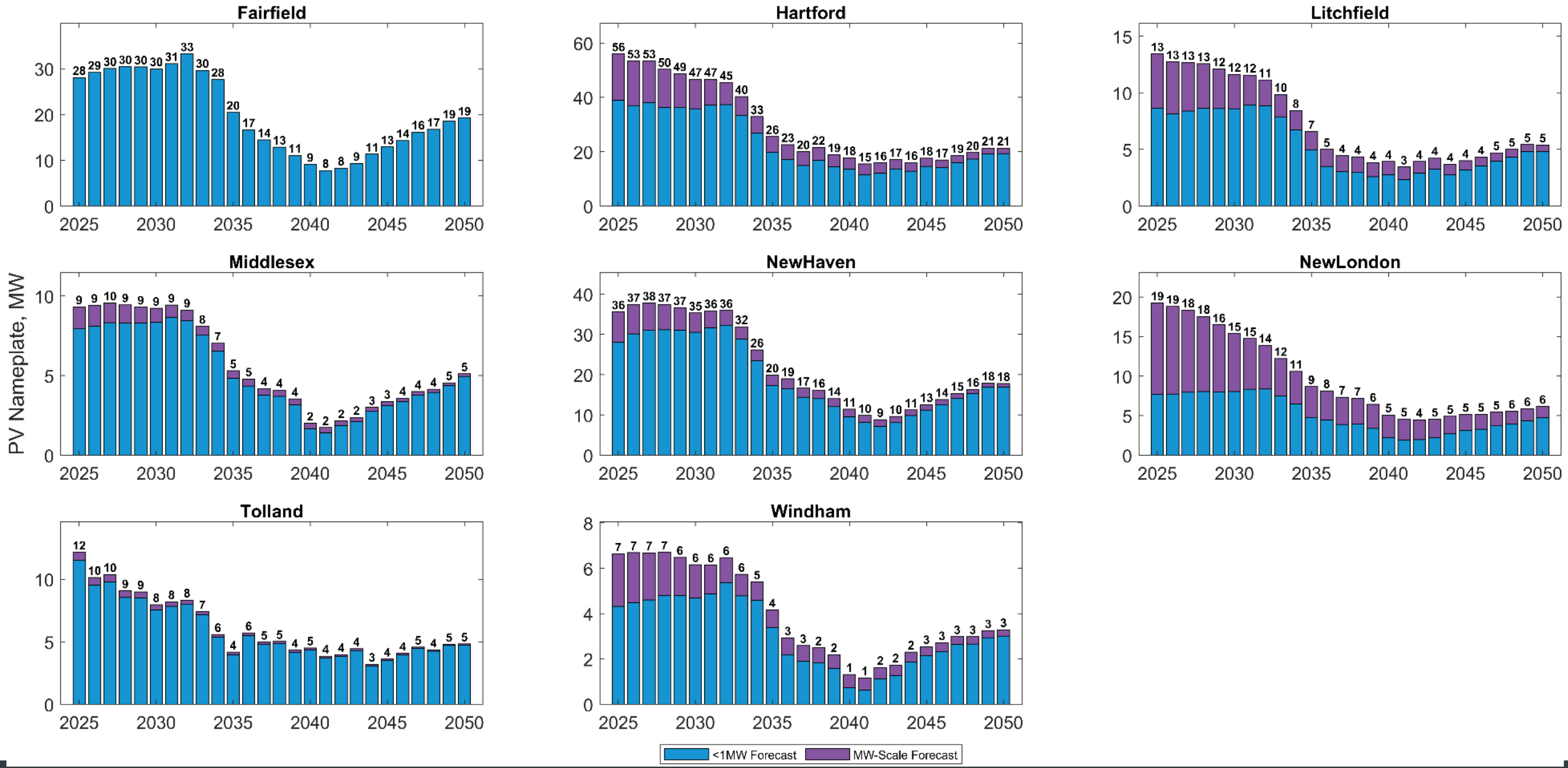


COUNTY-LEVEL 2025 PV NAMEPLATE CAPACITY FORECAST

Development of County-Level Forecasts

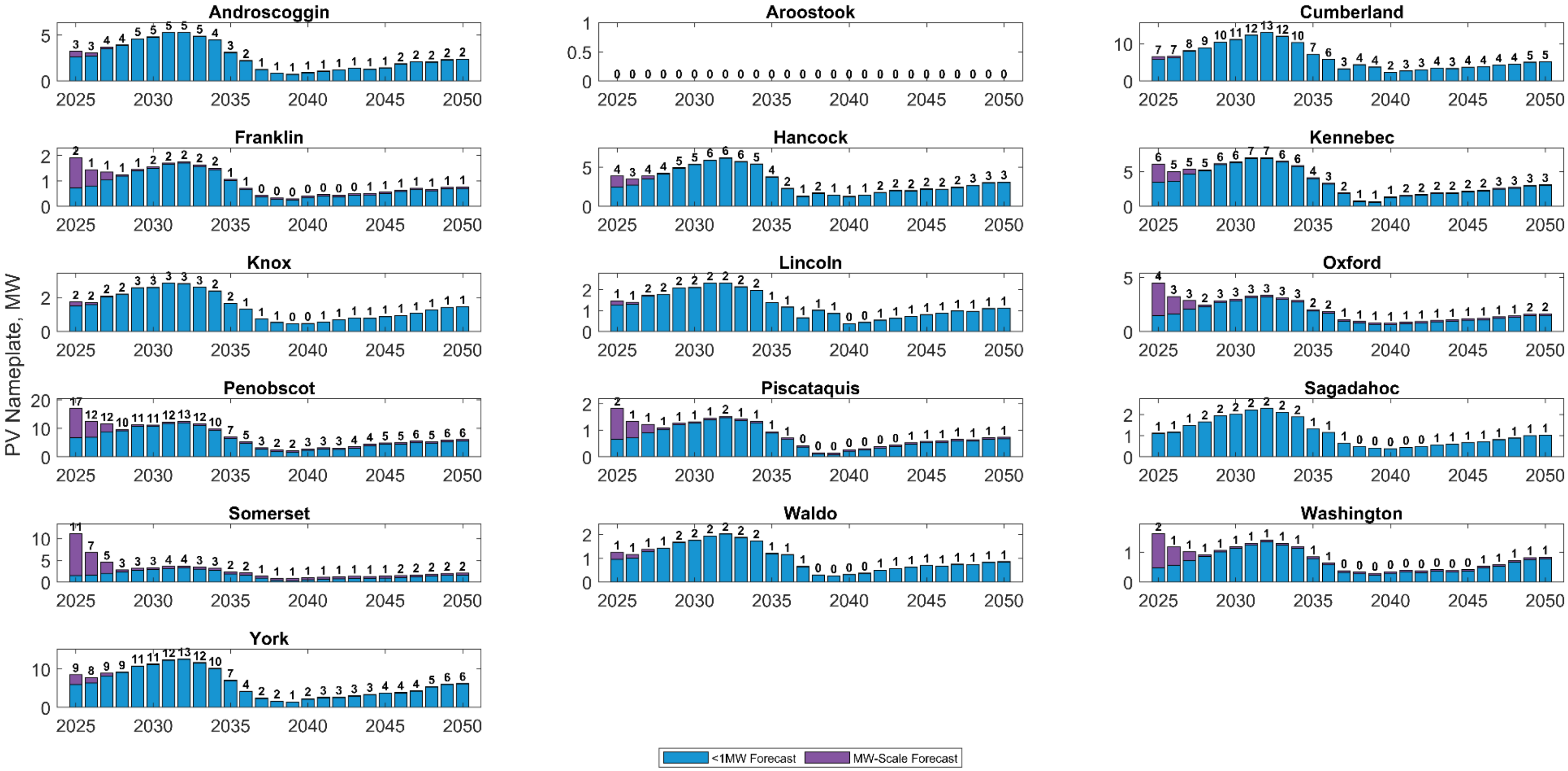
- County-level PV forecast for systems with nameplate capacity less than 1 MW is generated by dGen™
- County-level allocations of forecast for MW-scale systems are developed based on:
  - Historical share of MW-scale system in each county of each state
  - Land availability (using county population density as proxy)
  - Land value (using county median income as proxy)
  - Remaining area hosting capacity (estimated using substation electricity demand data)
- County-level forecast results are shown on the next slides for each New England state

Final 2025 County PV Forecast – Connecticut

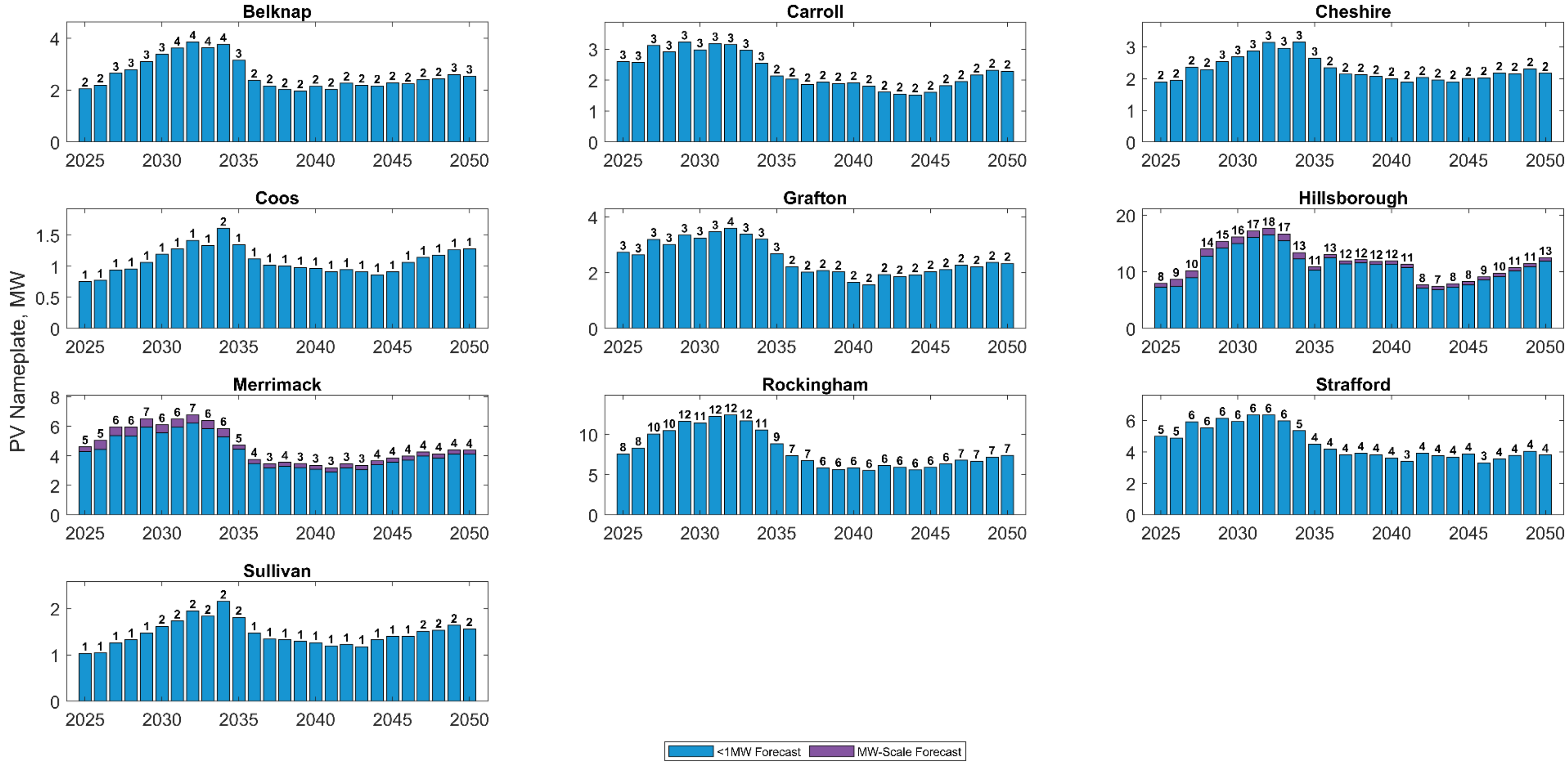


Final 2025 County PV Forecast – Massachusetts

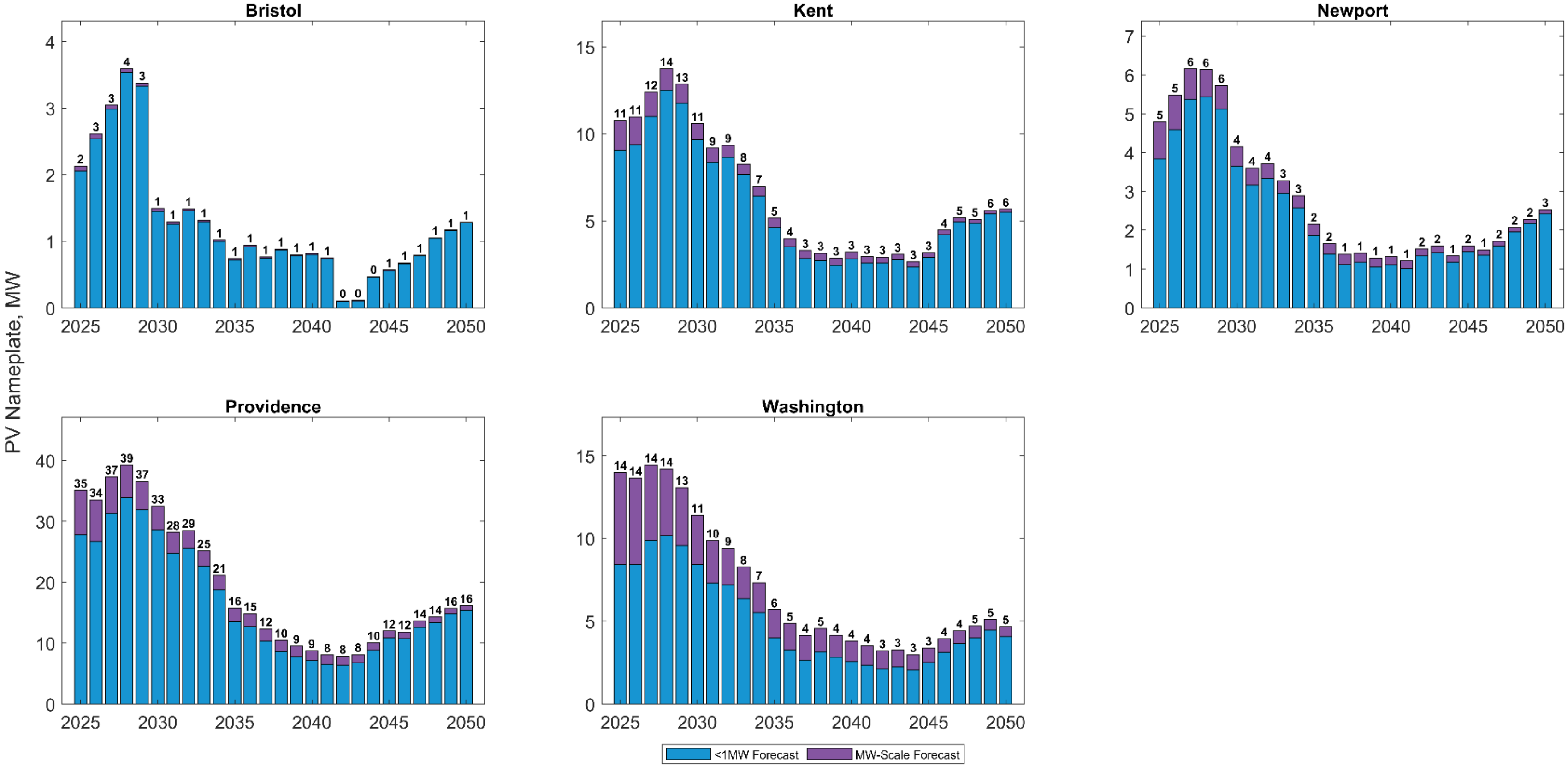
Final 2025 County PV Forecast – Maine



Final 2025 County PV Forecast – New Hampshire



Final 2025 County PV Forecast – Rhode Island



Final 2025 County PV Forecast – Vermont

CLASSIFICATION OF PV FORECAST

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 is reflected in the long-term load forecast
- 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 and estimates of hourly energy production (historical and forecast), and is important for the ISO's use of the PV forecast in 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

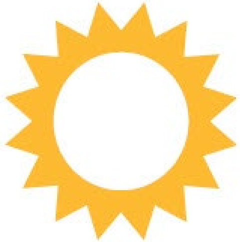
- Classification varies by state
  - Market disposition of PV projects can be influenced by state policies (*e.g.*, net metering requirements)
- The following steps were used to determine PV resource types for each state over the forecast horizon:
  1. FCM
     - Identify all Generation and Demand Response FCM PV resources for each Capacity Commitment Period (CCP) through FCA 18
  2. Non-FCM EOR/Gen
     - Determine the % share of non-FCM PV participating in energy market at the end of 2024
  3. BTM
     - Net the values from steps 1 and 2 from the annual state PV forecast according to assumptions detailed on the next slide; the remainder is the BTM PV

PV in ISO New England Markets

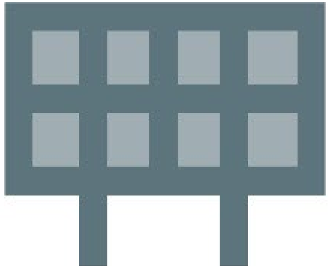
Data and Assumptions

- FCM
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 18
    - Maintain separate accounting for FCM_{supply} and FCM_{DR}
  - Assume aggregate total PV in FCM as of FCA 18 remains constant from 2027-2050
- Non-FCM Gen/EOR
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/24
  - Assume the (EOR+FCM_{supply}) share of total PV at the end of 2024 in each state *except Maine* remains constant throughout the forecast horizon
    - For Maine, assume (EOR+FCM_{supply}) share is 40% over the forecast horizon to reflect how updated assumptions about NEB programs no longer reflect as much future MW-scale growth, resulting in less participation in wholesale markets than assumed in the 2024 forecast
- Other assumptions
  - FCM_{supply} 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



- Historical BTM PV production estimates are developed at the hourly level for reconstitution in the development of the long-term load forecast
  – Estimates cover the historical period starting January 1, 2012



- The ISO estimates historical hourly BTM PV using:
  – Historical BTM PV performance data
  – Installed capacity data submitted by utilities
  – Historical energy production of market-facing PV
- BTM PV data and supporting documentation are available here on the ISO New England website

CLASSIFICATION OF 2025 PV FORECAST

Results

Final 2025 PV Forecast – 10 Year Horizon

Cumulative Nameplate Capacity, MW_{AC}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
CT	1,289	180	178	179	173	169	162	164	164	145	124	**2,927**
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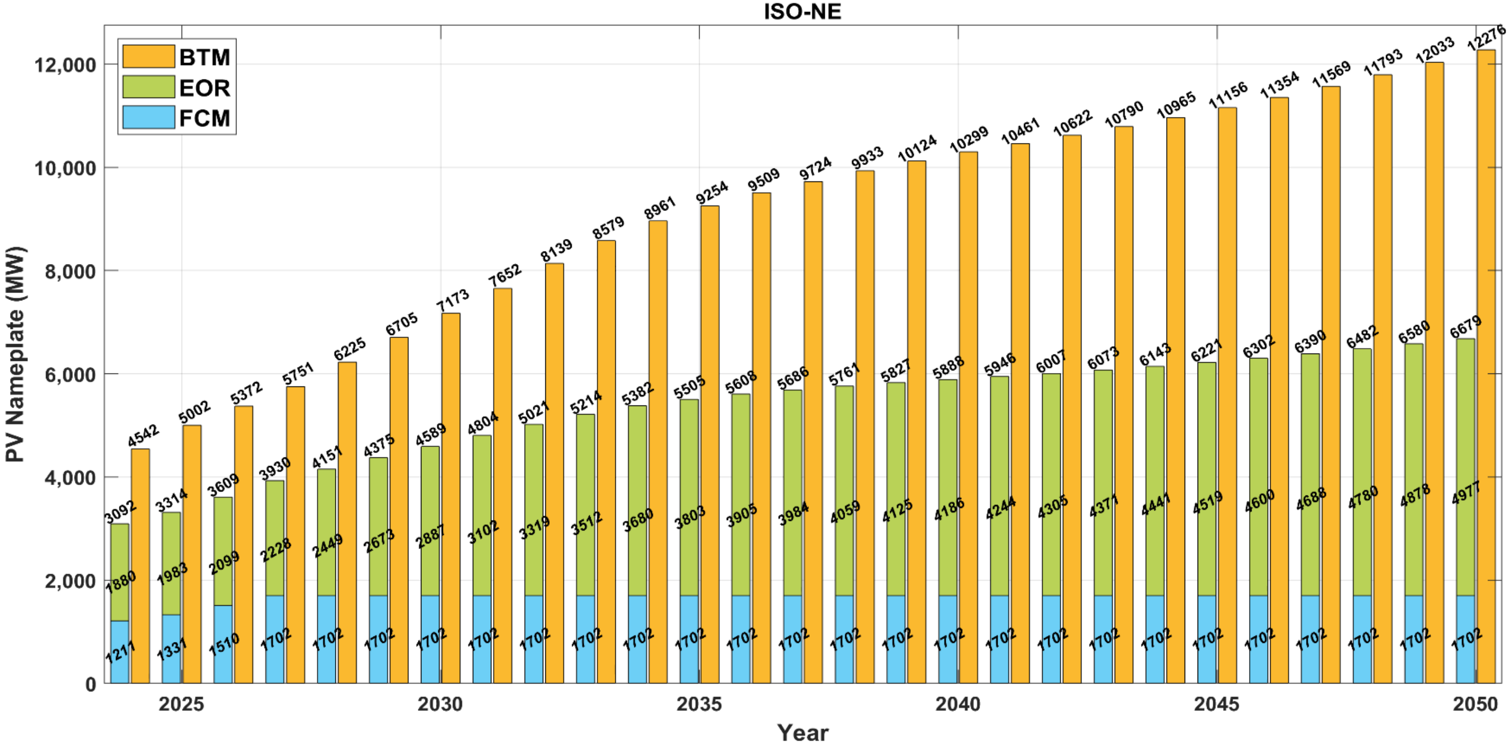
Notes:

(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

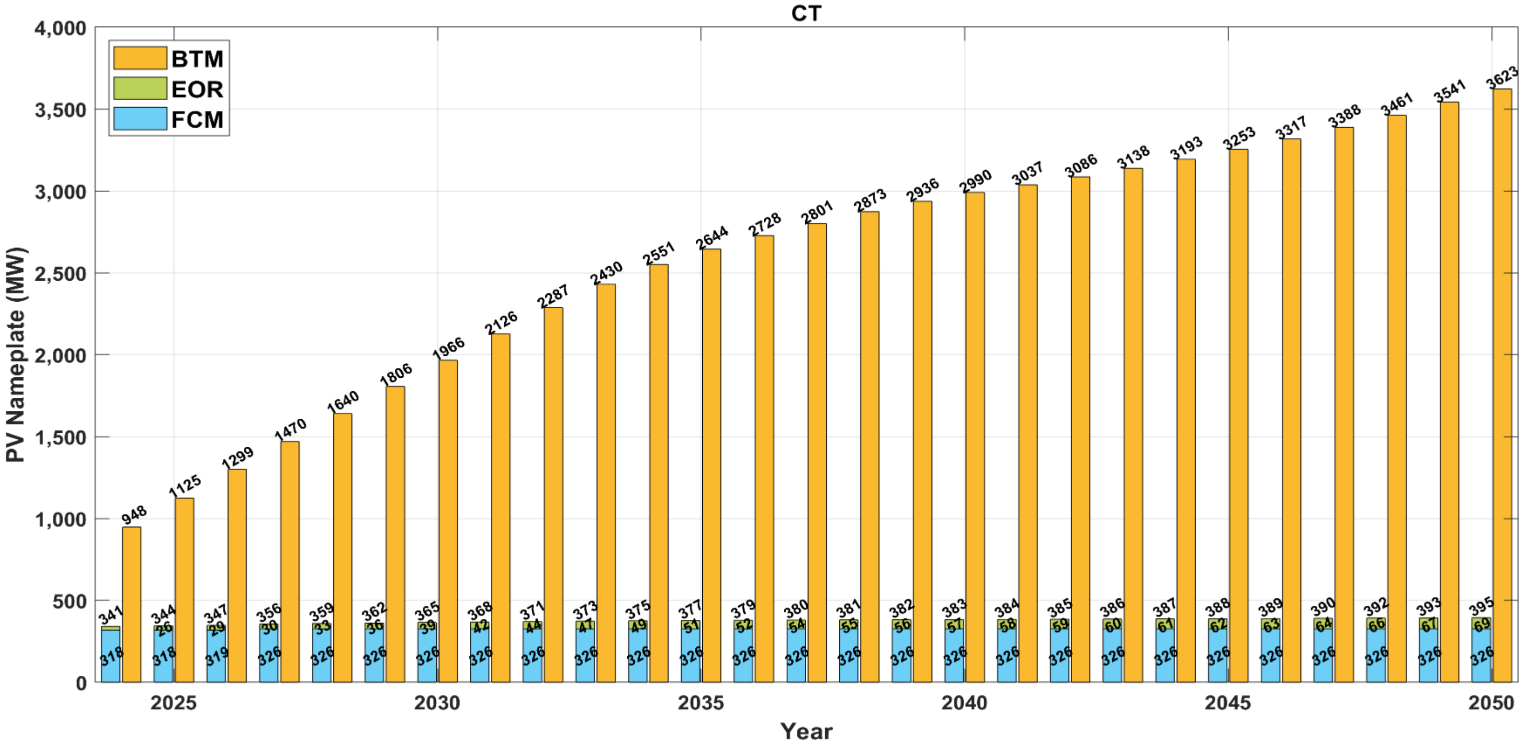
Final 2025 PV Forecast – New England

Cumulative Nameplate by Category, MW_{ac}



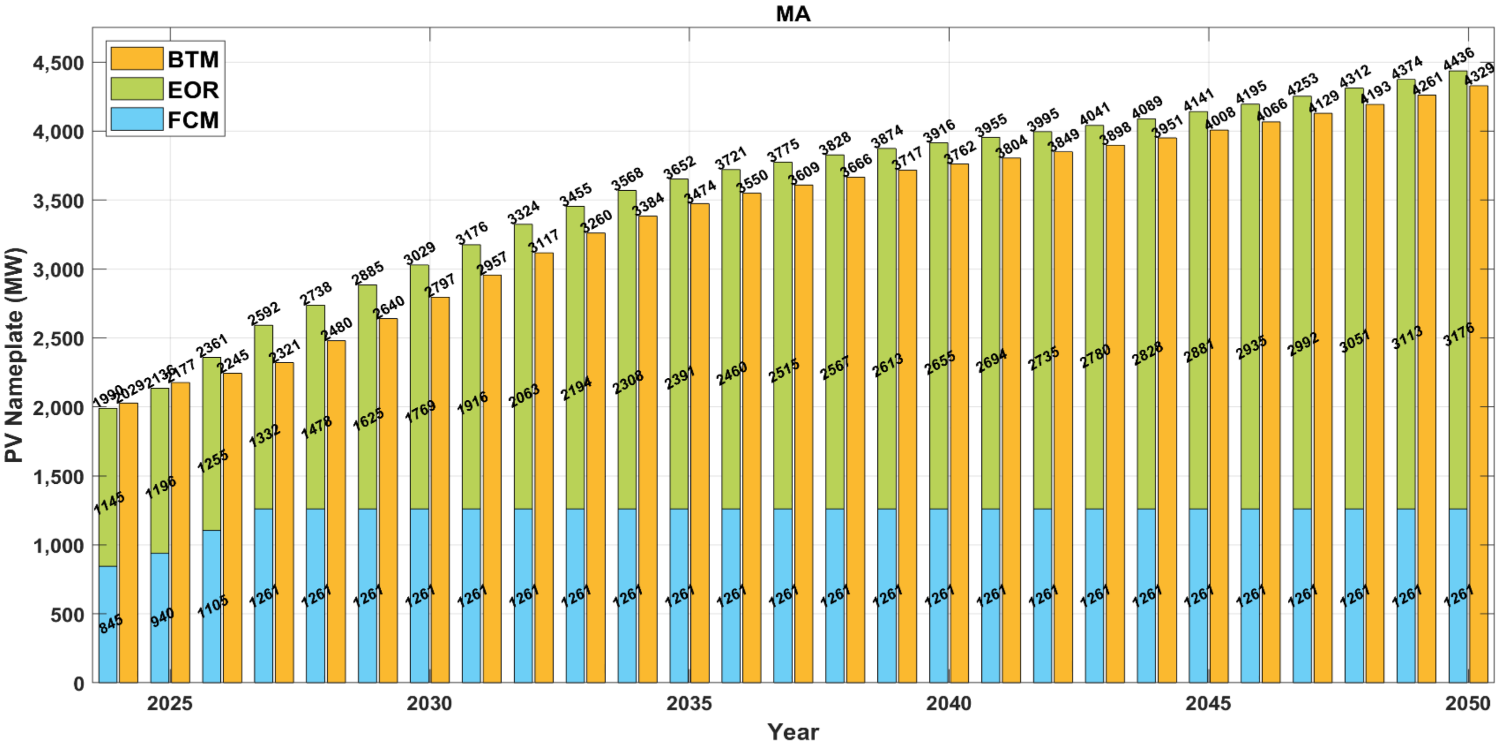
Final 2025 PV Forecast – Connecticut

Cumulative Nameplate by Category, MW_{ac}



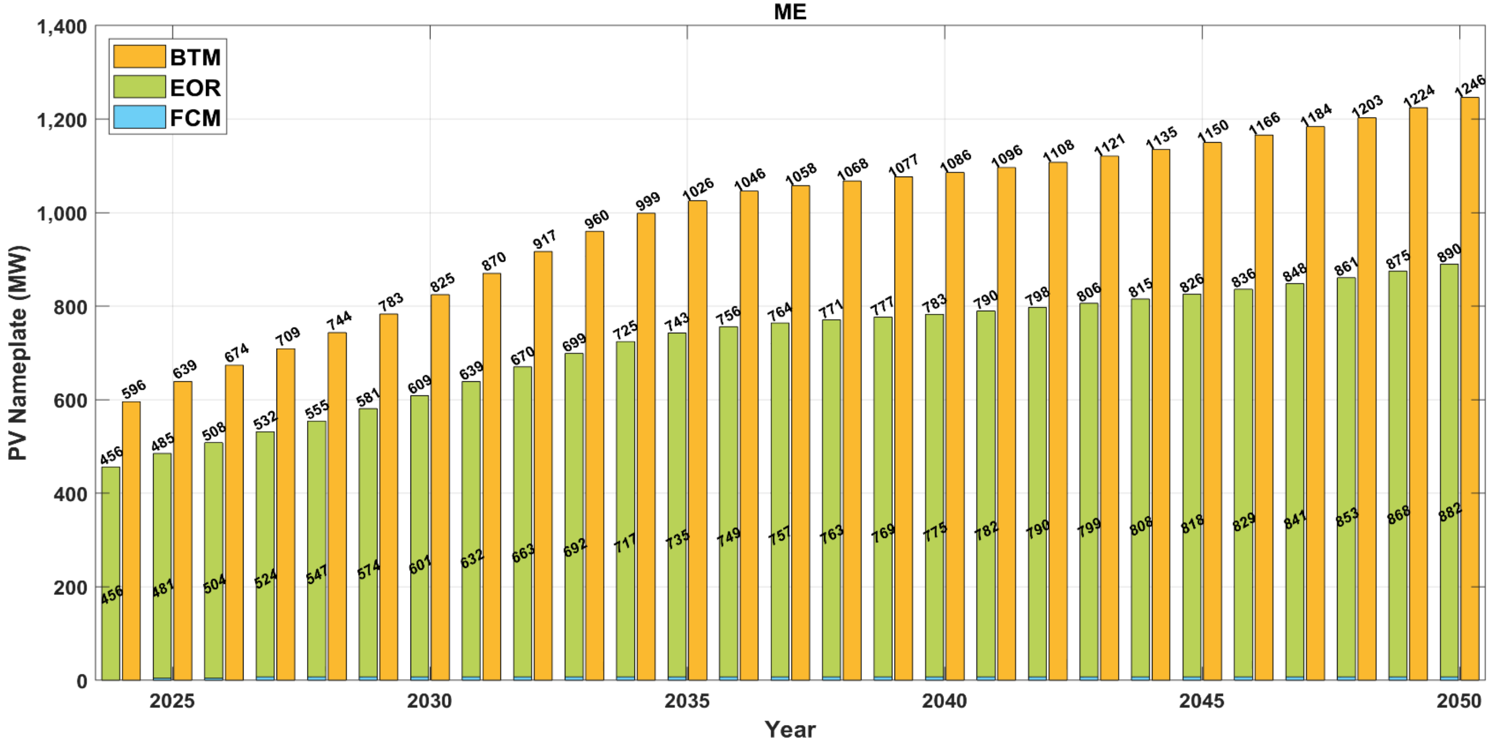
Final 2025 PV Forecast – Massachusetts

Cumulative Nameplate by Category, MW_{ac}



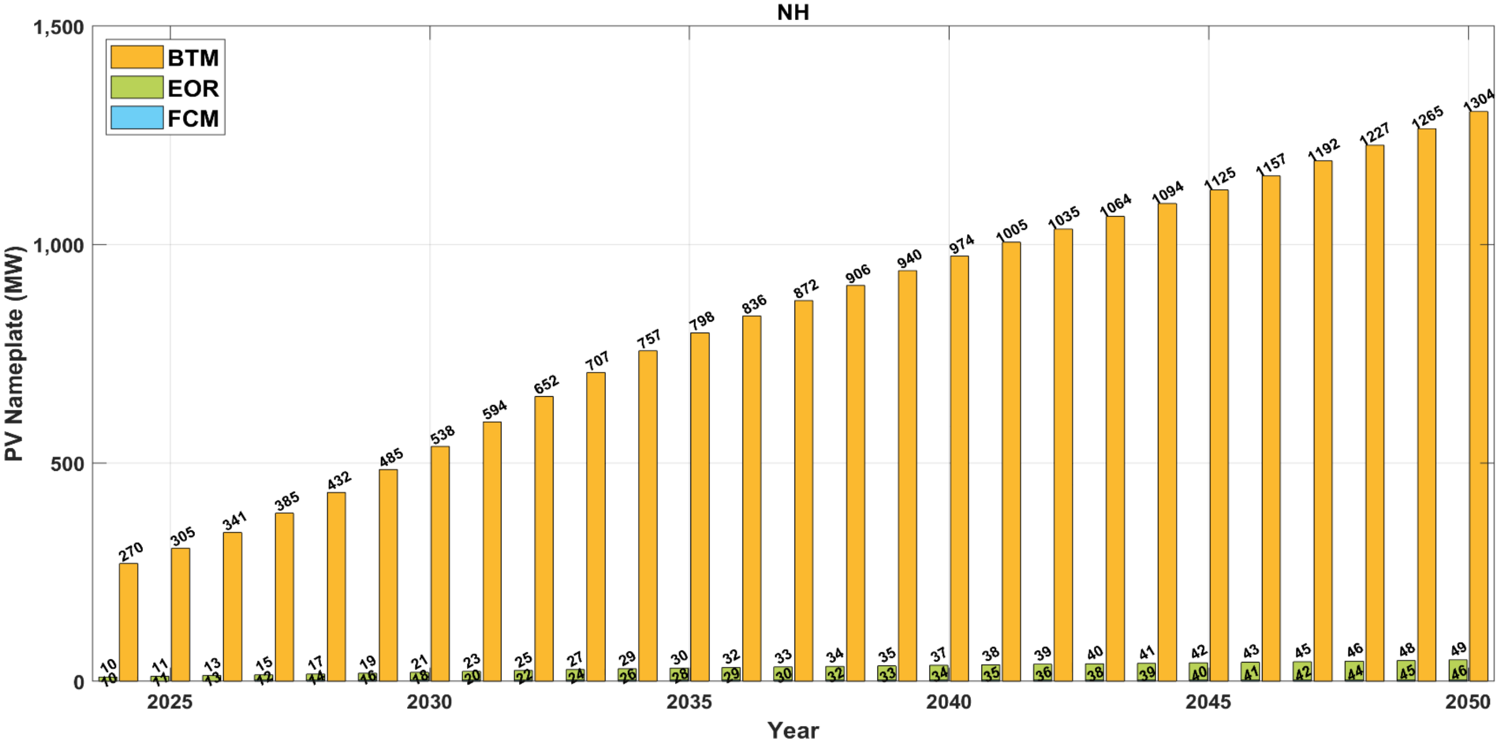
Final 2025 PV Forecast – Maine

Cumulative Nameplate by Category, MW$_{ac}$



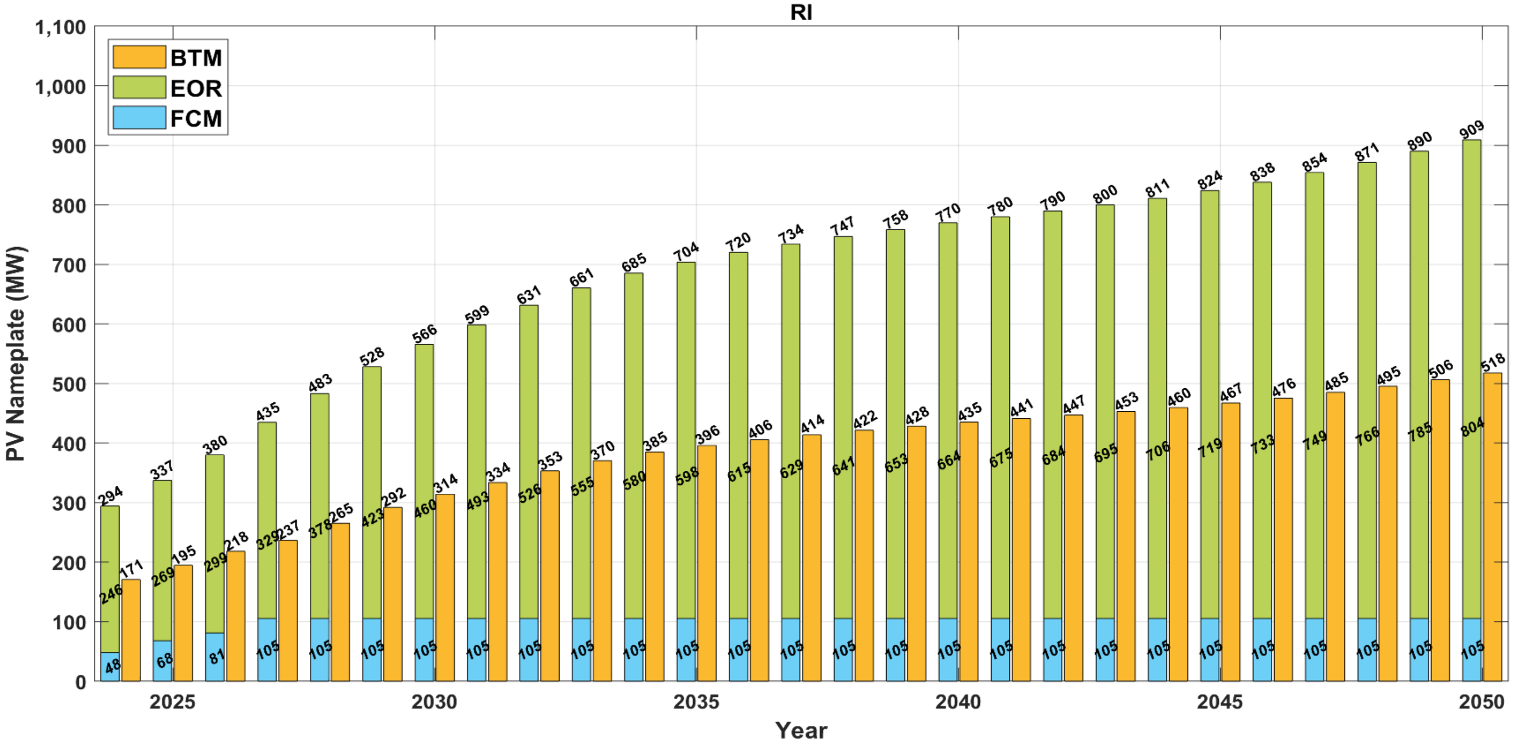
Final 2025 PV Forecast – New Hampshire

Cumulative Nameplate by Category, MW_{ac}



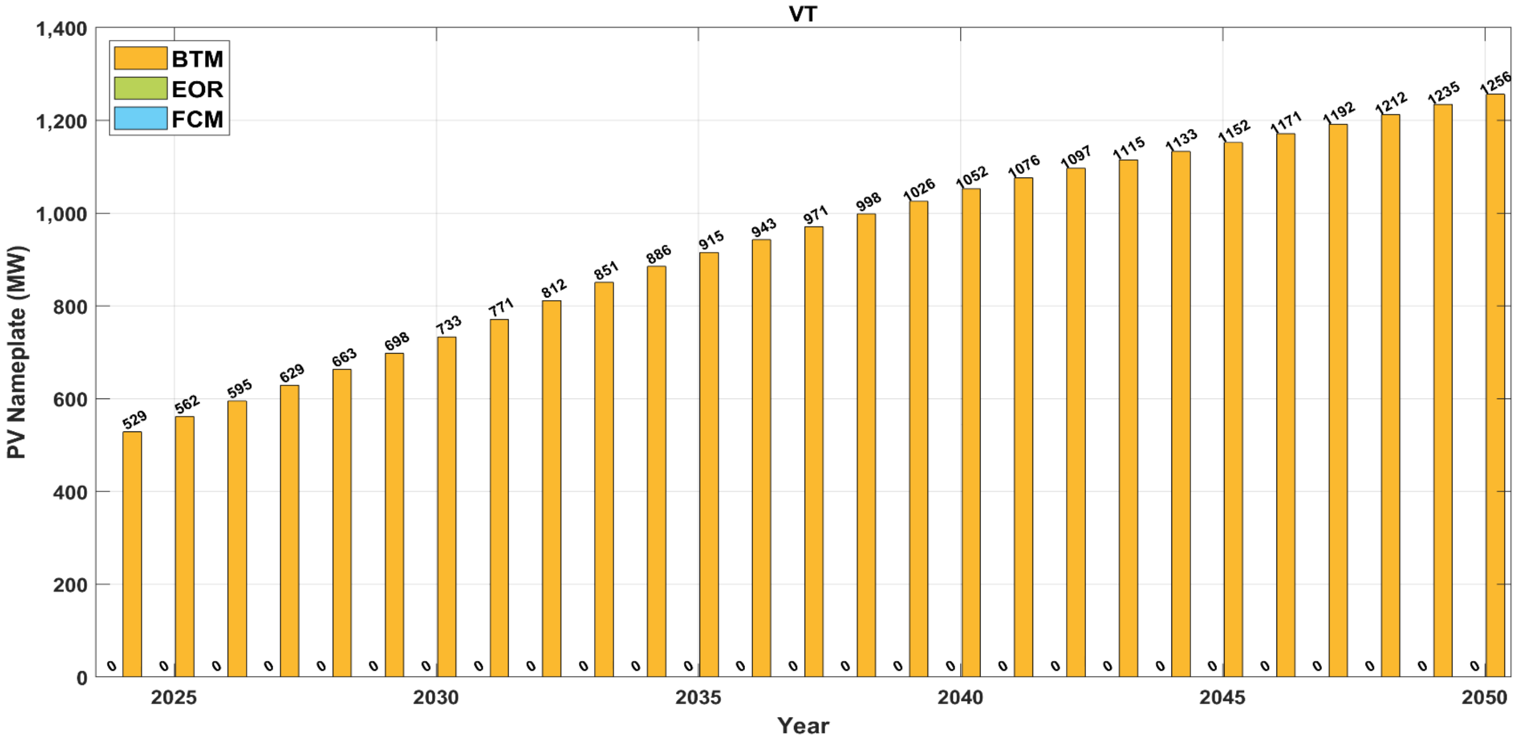
Final 2025 PV Forecast – Rhode Island

Cumulative Nameplate by Category, MW_{ac}



Final 2025 PV Forecast – Vermont

Cumulative Nameplate by Category, MW_{ac}

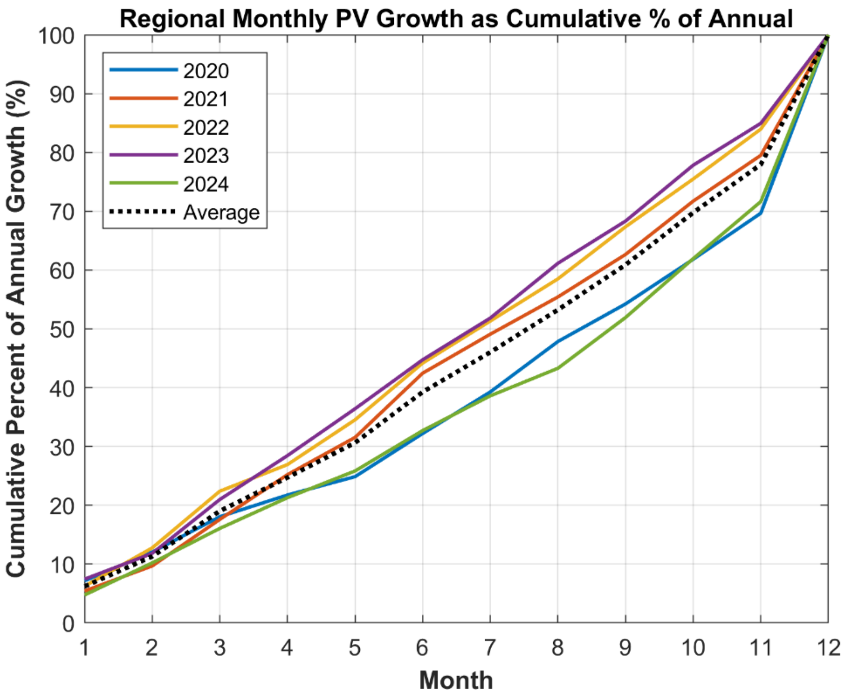


2025 BEHIND-THE-METER PV (BTM PV) ENERGY FORECAST

Development of BTMPV Energy Forecast

- The BTM PV nameplate forecast reflects end-of-year values
- Energy estimates in the BTM PV forecast are inclusive of incremental growth during a given year
- ISO assumes historical BTM PV growth trends across the region are indicative of future intra-annual growth rates
  - Growth trends between 2020 and 2024 were used to estimate intra-annual incremental growth over the forecast horizon (see next slide)
- For CELT 2025, monthly derated nameplate forecasts are used with historical hourly capacity factor profiles to generate the 70 years (11/1/1953 – 10/31/2023) of hourly forecasts, for each load zone and forecast year
- Monthly energy forecasts are the averages of the 70 monthly energy values of simulations performed for each forecast year
  - For example, January energy forecast is the average of all 70 January energy values withing the 70-year simulation period for a given forecast year
- Annual energy forecast is calculated as the sum of monthly energy forecasts for each forecast year

Historical Monthly PV Growth Trends, 2020-2024



Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6%	6%
2	6%	12%
3	7%	19%
4	7%	26%
5	7%	33%
6	9%	42%
7	6%	48%
8	8%	56%
9	8%	64%
10	8%	72%
11	8%	80%
12	20%	100%

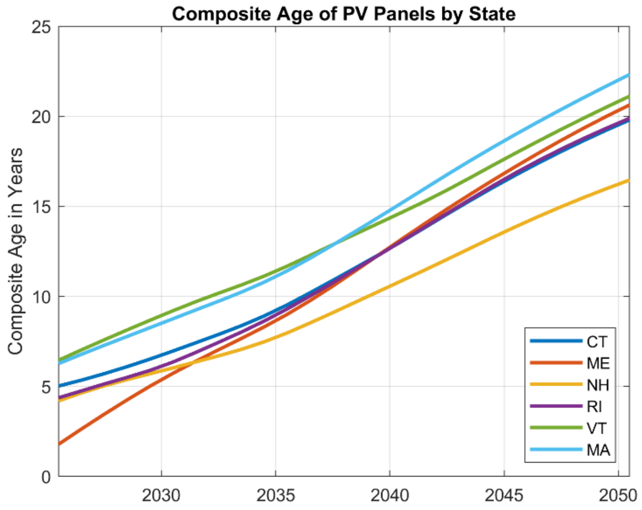
PV Panel Degradation Factors

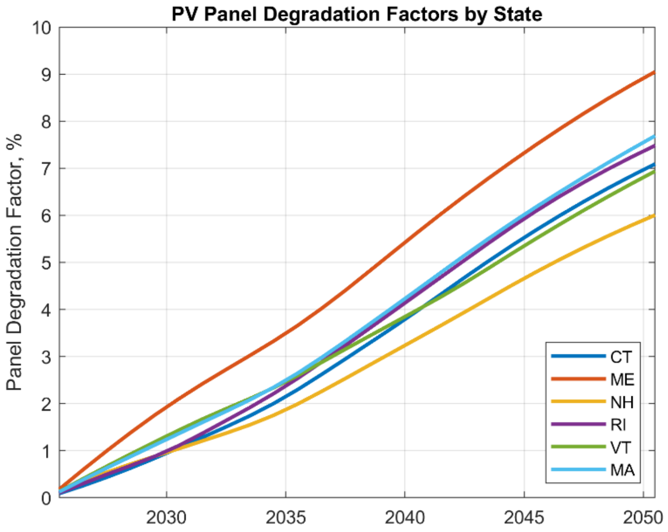
- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecast of BTM PV energy and summer peak load reductions include the effects of a 0.5%/year panel degradation rate to account for the expected declining conversion efficiency of solar panels over 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 all PV in each state (left plot) and corresponding degradation factors (right plot) over the forecast horizon are plotted below
- The degradation factors assumed precent reduction of PV performance over time that reflect the anticipated degradation of PV panels





Final 2025 BTM PV Energy Forecast – 10 Year Horizon

BTM PV, GWh

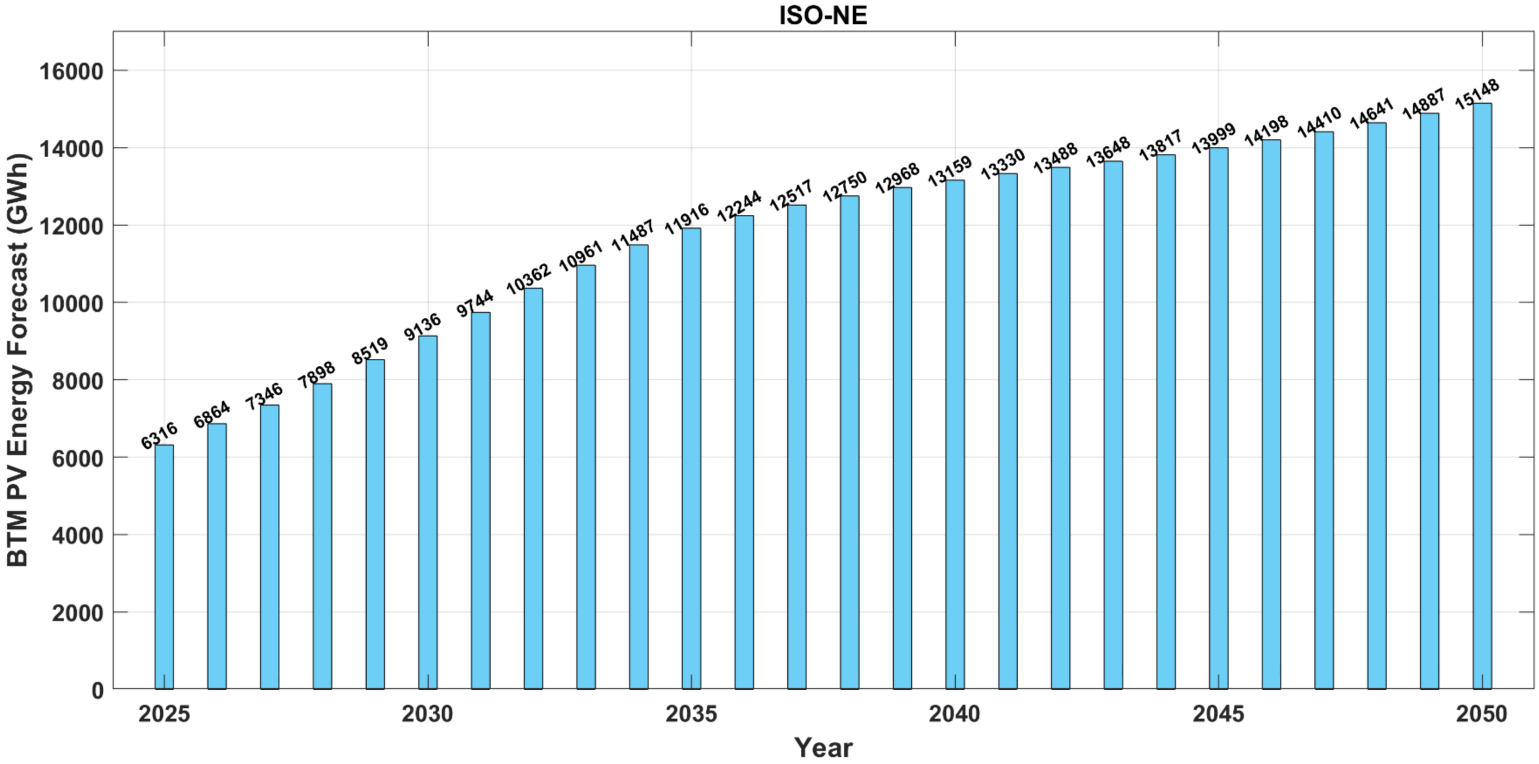
Category	States	Estimated Annual Energy (GWh)										
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Behind-the-Meter PV	CT	1,237	1,391	1,633	1,868	2,101	2,329	2,549	2,762	2,976	3,180	3,355
	MA	2,643	2,815	2,954	3,039	3,187	3,394	3,600	3,802	4,008	4,203	4,373
	ME	490	819	869	912	955	999	1,049	1,101	1,158	1,214	1,264
	NH	329	367	412	462	519	582	649	718	790	861	928
	RI	219	253	286	315	347	385	420	449	474	499	520
	VT	637	670	710	749	789	829	870	912	957	1,004	1,047
Behind-the Meter Total	**Regional Total**	**5,555**	**6,316**	**6,864**	**7,346**	**7,898**	**8,519**	**9,136**	**9,744**	**10,362**	**10,961**	**11,487**

Notes:

(1) Forecast values include energy 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% to reflect avoided transmission and distribution losses

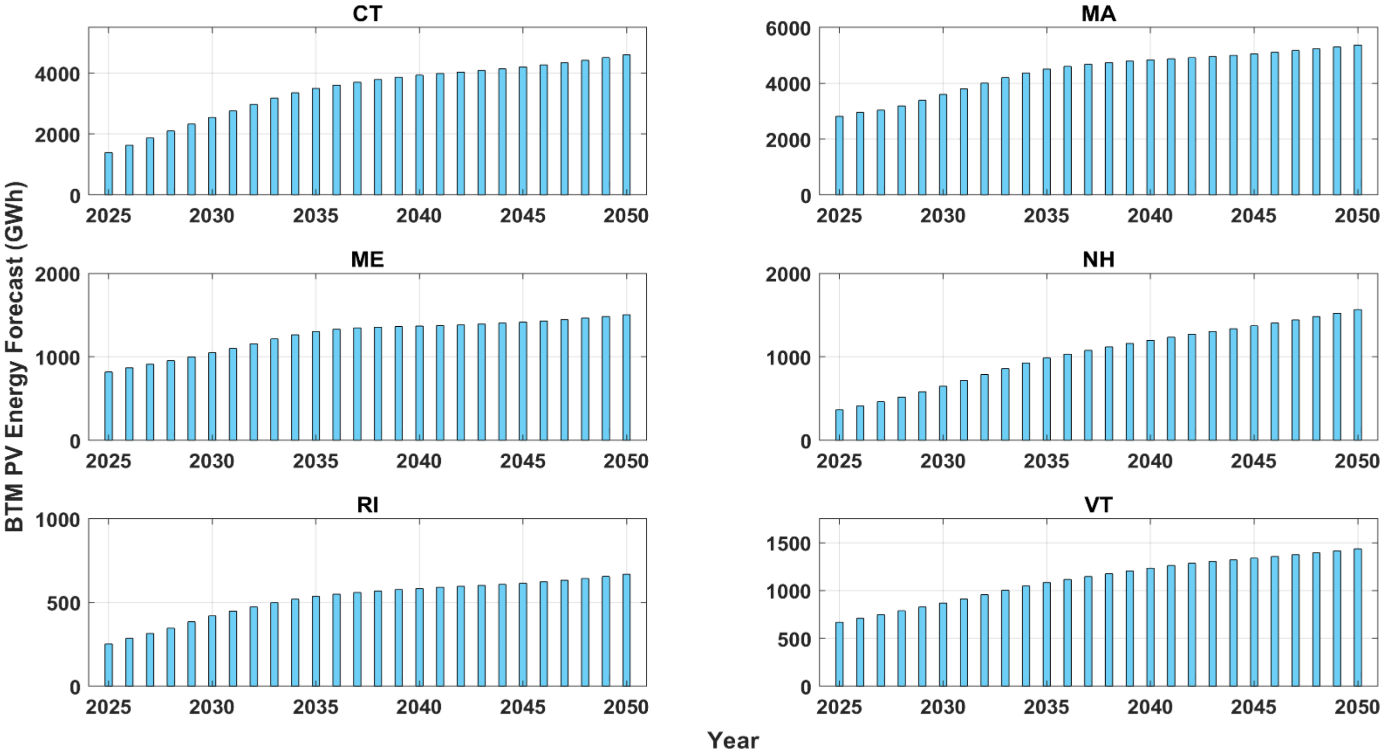
Final 2025 BTM PV Energy Forecast – New England

BTM PV, GWh



Final 2025 BTM PV Energy Forecast – State Level

BTM PV, GWh



2025 BTM PV PEAK DEMAND REDUCTION FORECAST

Long-Term Forecast Components for CELT 2025

- For CELT 2025, ISO is implementing a new hourly forecast methodology for which BTMPV and 3 other load components shown to the right are all modeled independently
- Additional details about these methodological changes are under discussion at the Load Forecast Committee
  - September 27th LFC materials
  - November 8th LFC materials
- Interested stakeholders are encouraged to attend future LFC meetings to learn more
  - Next LFC meeting is December 8th

Base Load Forecast

- Statistically modeled based on historical load reconstituted for BTM PV
- Is combined with electrification forecasts to yield the gross and net load forecasts

DER (BTM PV) Forecast

- Adoption forecasting based on NREL's dGen™ tool
- Demand reductions derived using zonal, historical hourly capacity factors

Heat Pump (HP) Forecast

- Adoption forecast along possible heating pathways
- Demand derived from simulated weather-dependent building heating needs and HP coefficient of performance (COP) curves

Electric Vehicle (EV) Forecast

- Policy-based adoption forecast (5 vehicle types)
- Demand derived from weather-sensitive battery efficiency curves and daily charging profiles

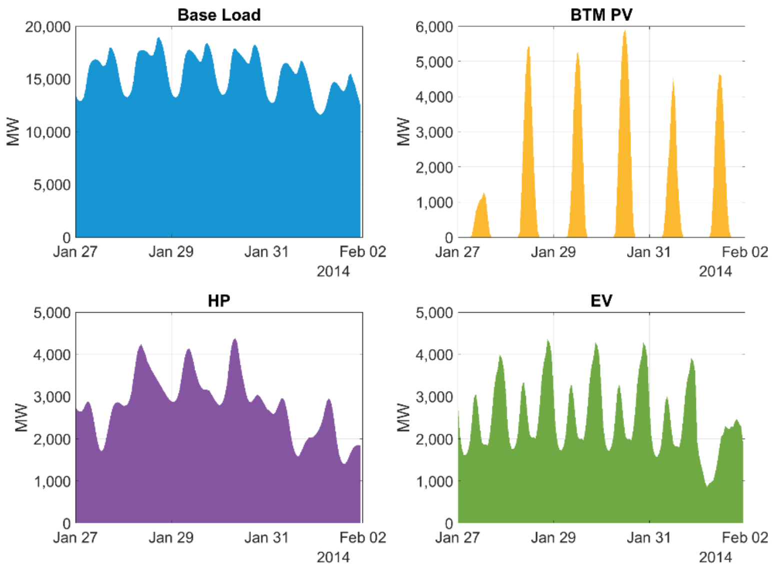
BTM PV Forecast Methodology Updates

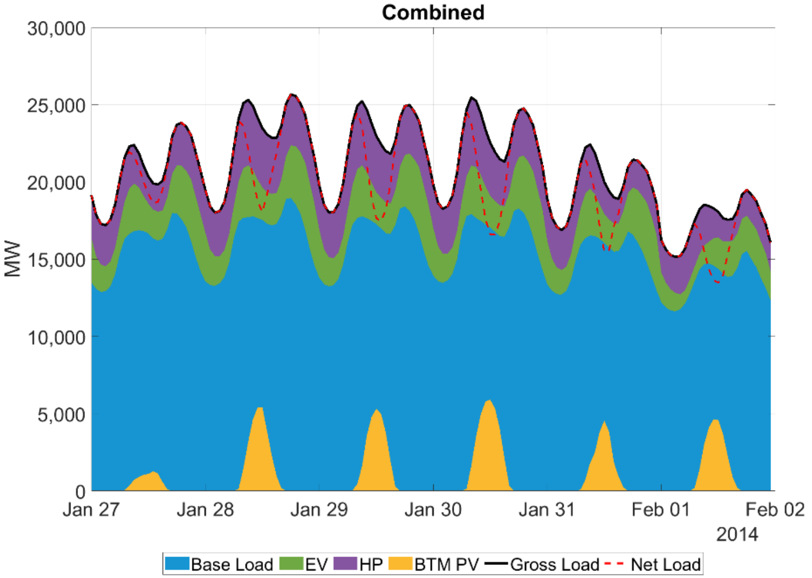
Switch to Hourly Modeling

- For CELT 2025, the BTM PV forecast will be converted into 73 years of hourly forecasts, at the load zone-level, based on historical profiles of hourly capacity factors
  - Example over recent years shown to the right
- Hourly capacity factor profiles will be scaled up based on the monthly nameplate capacity forecast to result in monthly hourly megawatt forecasts in each load zone
- Prior to CELT 2025
  - BTM PV energy forecasts were based on average historical monthly capacity factors
  - BTM PV summer peak load demand reductions

BTMPV Accounting in Hourly Load Forecast

- Each forecast component will be aggregated into load zones
- Zonal forecasts for base load, HPs, EVs, and BTM PV will be combined to yield forecasts of gross and load
  - Components are combined based on coincident weather over the historical simulation period





BTM PV Forecast Used in CELT Net Load Forecast

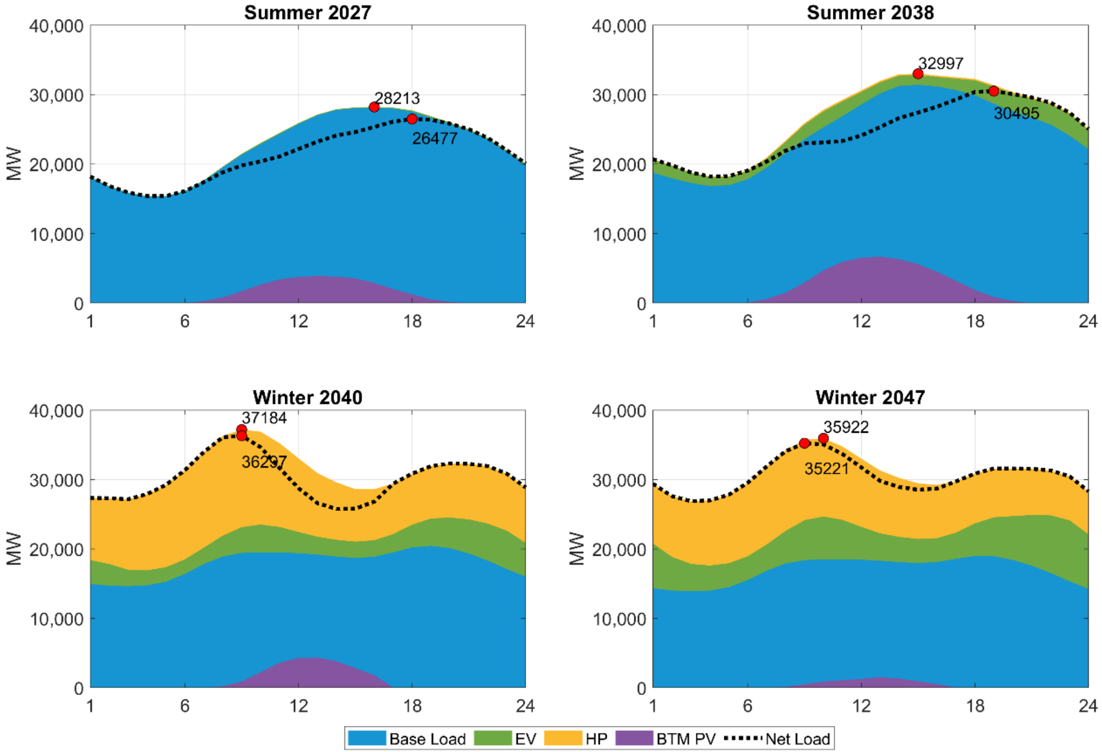
- The 2025 CELT net load forecast will reflect deductions associated with the BTM PV portion of the PV forecast
- Summer and winter peak load reductions associated with BTM PV over the forecast horizon are calculated using waterfall approach described in slide 14 of the February 21st LFC presentation

Seasonal Demand Impacts of BTM PV

- Example plots are shown for two summer and winter days to illustrate how BTM PV demand impacts are calculated for specific days
  - For each forecast year, probabilistic forecasts are based on the hourly results from 70 seasonal peak days
- Calculations are tabulated below

Calculations From Plots

Example Day	Gross Peak	Net Peak	Peak Load Reduction
Summer 2027	28,213	26,477	1,736
Summer 2038	32,997	30,495	2,502
Winter 2040	37,184	36,297	887
Winter 2047	35,922	35,221	701



Final 2025 BTM PV Forecast – Summer

Coincident "50-50" Summer Peak Load Reductions

Category	States	Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Behind-the-Meter PV	CT	330.0	338.0	352.0	376.0	403.0	421.0	434.0	440.0	444.0	437.0	423.0
	MA	750.0	880.0	887.0	905.0	928.0	955.0	975.0	989.0	996.0	997.0	993.0
	ME	81.0	169.0	170.0	170.0	169.0	164.0	156.0	146.0	135.0	123.0	109.0
	NH	104.0	106.0	109.0	116.0	129.0	141.0	148.0	149.0	149.0	150.0	152.0
	RI	101.0	89.0	91.0	93.0	95.0	96.0	97.0	96.0	95.0	93.0	91.0
	VT	155.0	153.0	151.0	149.0	144.0	138.0	128.0	120.0	116.0	114.0	111.0
Total	**Cumulative**	1,520.0	1,736.0	1,759.0	1,809.0	1,869.0	1,915.0	1,938.0	1,942.0	1,936.0	1,915.0	1,879.0
Corresponding % of BTM PV AC Nameplate Capacity		36.5%	36.3%	34.1%	32.7%	31.1%	29.6%	27.9%	26.2%	24.5%	22.9%	21.4%

Notes:

(1) Forecast values include energy 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 8% to reflect avoided transmission and distribution losses

Final 2025 BTM PV Forecast – Winter

Coincident "50-50" Winter Peak Load Reductions

Category	States	Cumulative Total MW - Estimated Winter Seasonal Peak Load Reduction										
		2024/2025	2025/2026	2026/2027	2027/2028	2028/2029	2029/2030	2030/2031	2031/2032	2032/3203	2033/2034	2034/2035
Behind-the-Meter PV	CT	0.0	0.0	0.0	0.0	1.0	6.0	11.0	14.0	13.0	20.0	39.0
	MA	0.0	0.0	2.0	12.0	32.0	68.0	100.0	129.0	153.0	182.0	220.0
	ME	0.0	0.0	3.0	6.0	13.0	21.0	29.0	34.0	39.0	54.0	74.0
	NH	0.0	0.0	1.0	3.0	5.0	7.0	10.0	12.0	13.0	18.0	25.0
	RI	0.0	0.0	1.0	1.0	1.0	2.0	5.0	7.0	7.0	9.0	16.0
	VT	0.0	0.0	0.0	1.0	5.0	9.0	13.0	14.0	17.0	20.0	28.0
Total	**Cumulative**	0.0	0.0	7.0	24.0	58.0	113.0	168.0	208.0	243.0	304.0	402.0
Corresponding % of BTM PV AC Nameplate Capacity		0.0%	0.0%	0.1%	0.4%	0.9%	1.7%	2.3%	2.7%	3.0%	3.5%	4.5%

Notes:

(1) Forecast values include energy 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 8% to reflect avoided transmission and distribution losses

APPENDIX I

2024 Forecast and Actual PV Growth

2024 DER PV Nameplate Capacity Growth

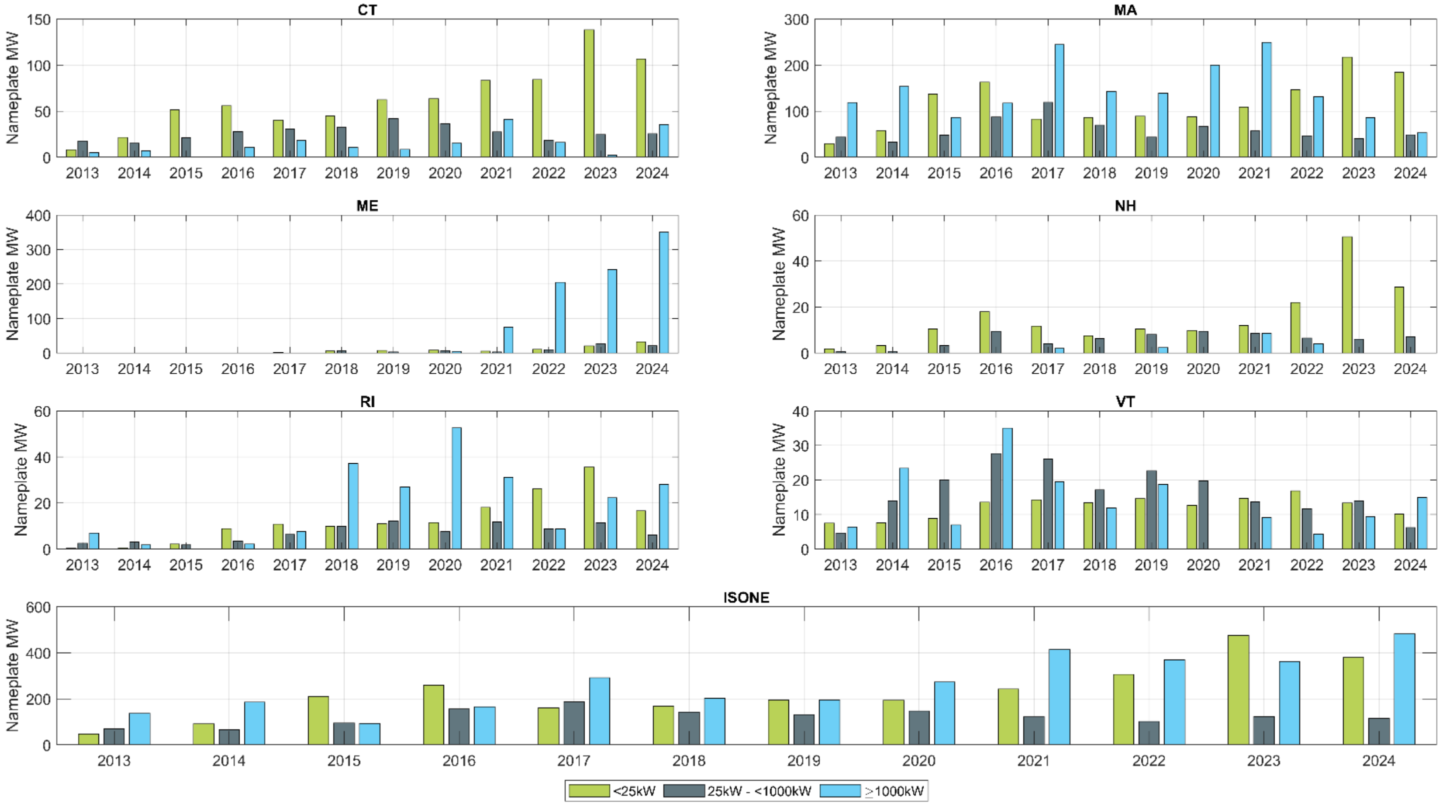
- End of 2024 DER interconnection data reported to ISO is draft
  - On-going data quality checks and improvements as part of ISO's first data collection per Planning Procedure 12
- A comparison of end-of-2024 and end-of-2023 total reported DER PV capacity is tabulated (top table)
  - Historical amounts of interconnected DER change with each vintage of data reported to ISO
  - The magnitude of changes are typically relatively small
  - Historical end-of-2023 totals reported at the end of 2024 were 116 MW higher than totals reported a year ago
    - Recent ME totals were 61 MW higher than a year ago
  - More significant changes in historical data are likely due to changes in reporting requirements as part of implementation of PP12
- For the annual long-term forecast, ISO is forecasting annual growth in DER PV
- A comparison of 2024 forecast PV growth (CELT 2024) and 2024 growth reported by DER data providers is tabulated (bottom table)
  - Reported growth is based on DER with interconnection dates in 2024
  - Regionally, 2024 reported growth exceeded the CELT 2024 forecast by 172 MW. The majority of the exceeded growth came from ME (180 MW)

State	**A** Total Reported Capacity, MW (End of 2023)	**B** Total Reported Capacity, MW (End of 2024)	**C** Total Capacity Change, MW **[B-A]**
CT	1,091	1,289	198
MA	3,712	4,019	307
ME	588	1,053	465
NH	244	280	36
RI	400	465	65
VT	507	529	22
ISO-NE	6,542	7,634	1,092

State	**D** 2024 Forecast Growth, MW (CELT 2024)	**E** 2024 Reported Growth, MW (End of 2024)	**C** Total Capacity Change, MW **[B-A]**
CT	151	168	17
MA	327	286	-41
ME	224	404	180
NH	27	36	9
RI	46	51	5
VT	29	31	2
ISO-NE	804	976	172

Capacity of Reported Annual DER PV Growth

Small (<= 25kW), Medium (25-<1,000kW), and Large (>=1,000kW) Projects



Larger-Scale DER PV

Projects >5 MW_{ac}

- Tabulated is a summary of in-service, larger-scale DER PV projects included as part of PP12 data submittals
- These projects are not included in the PV forecast accounting, and are excluded from installed DER PV totals reported herein

State	# Projects Listed	Total Nameplate (MW_{ac})
CT	7	128
MA	-	-
ME	8	88
NH	-	-
RI	28	244
VT	-	-
Total	**43**	**460**

APPENDIX II

End of 2024 DER Photovoltaic Installation Update

Updates Since February DGFWG

December 2024 DER PV Interconnection Data

- Starting this year, Distribution Owners and/or Transmission Owners are required to submit distributed energy resource (DER) interconnection data to satisfy requirements outlined in ISO-New England's Planning Procedure 12 (PP12)
  - The data reflected in this presentation represent cumulative DER solar photovoltaic (PV) interconnection data as of December 31, 2024
  - These data have been used to inform ISO New England's final draft 2025 long-term PV forecast
  - These data represent about 1% more installed capacity (76 MW) than the data presented at the February 2025 DGFWG
  - PV projects include FCM, EOR, and BTM PV projects

- Primary differences between these data and the data presented in February include:
  - Improved data quality resulting from several resubmittals
  - Data submitted by more than 70 data providers, compared to the 24 data providers reflected at the February DGFWG
  - SREC and SPEED data have been replaced by municipal supplied data

- Thank you to the data providers for your continued efforts to ensure timely and accurate data submittals

December 2024 Cumulative DER PV Totals

State-by-State

The table below reflects statewide aggregated PV data provided to ISO New England by regional Distribution Owners and/or Transmission Owners. The values represent installed nameplate as of 12/31/2024

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts	4,019	206,118
Connecticut	1,289	106,620
Vermont	529	22,166
New Hampshire	280	24,706
Rhode Island	465	25,395
Maine	1,053	12,100
New England	**7,634**	**397,105**

December 2024 Cumulative DER PV Totals (1 of 2)

Summary of PP12 DER PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
CT	Connecticut Light & Power	1,024	82,351
	United Illuminating	230	23,332
	Municipal Electric Companies	35	937
	Total	**1,289**	**106,620**
MA	National Grid	2,131	111,428
	NSTAR	1,241	67,077
	Wester Massachusetts Electric Co.	413	20,015
	Municipal Electric Companies	234	7,598
	Total	**4,019**	**206,118**
ME	Central Maine Power	840	9,869
	Versant*	213	2,231
	Total	**1,053**	**12,100**

* Does not include installations in Maine Public District

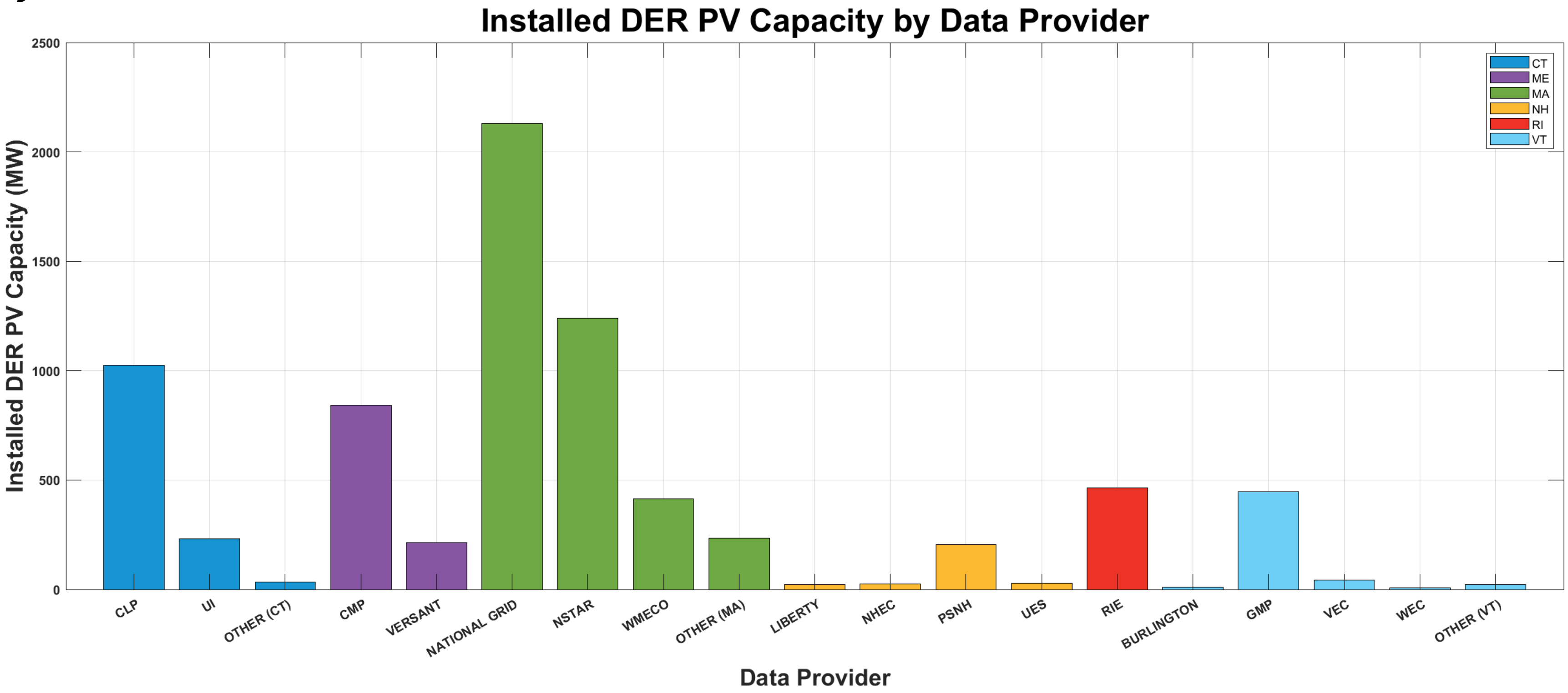
December 2024 Cumulative DER PV Totals (2 of 2)

Summary of PP12 DER PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	23	1,813
	New Hampshire Electric Co-op	24	2,204
	Public Service of New Hampshire	205	18,101
	Unitil (UES)	28	2,588
	Total	**280**	**24,706**
RI	Rhode Island Energy	465	25,395
	Total	**465**	**25,395**
VT	Burlington Electric Department	10	436
	Green Mountain Power	446	17,334
	Vermont Electric Co-op	43	2,413
	Washington Electric Co-op	8	957
	Municipal Electric Companies	22	1,026
	Total	**529**	**22,166**
New England		**7,634**	**397,105**

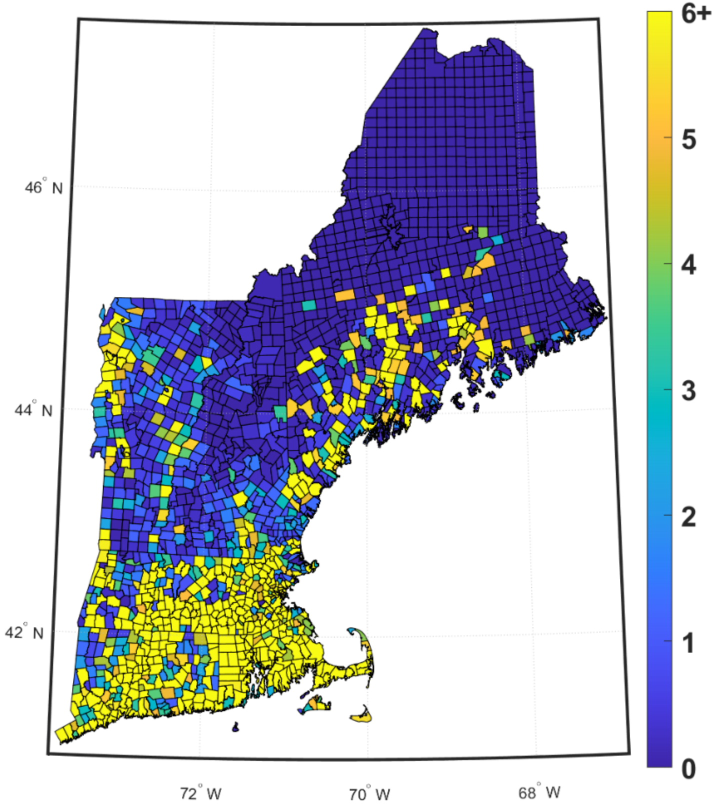
December 2024 Cumulative DER PV Totals

By Data Provider



Installed DER PV Capacity as of December 2024

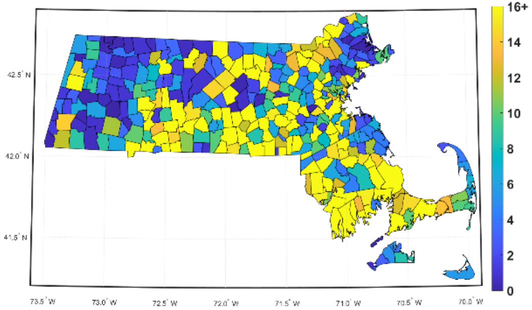
Regional Heat Map

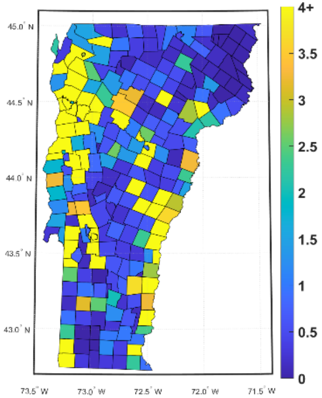


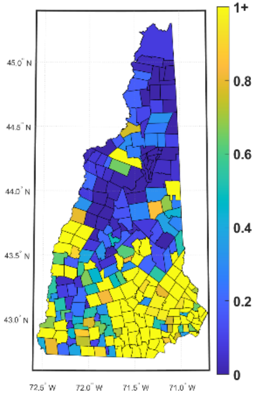
Note: Legend to the right of the heat map shows color scale of nameplate megawatts per town

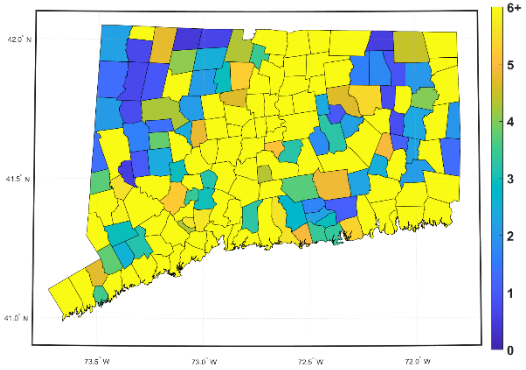
Installed DER PV Capacity as of December 2024

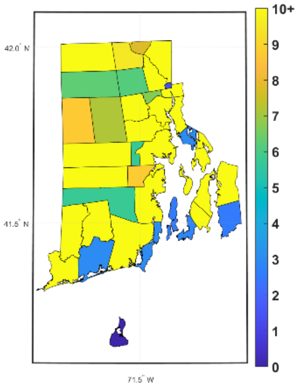
State Heat Maps

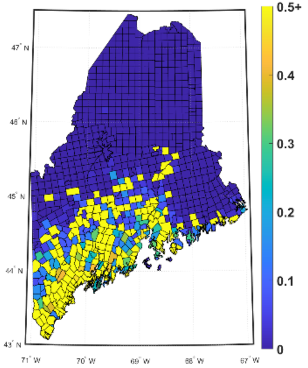








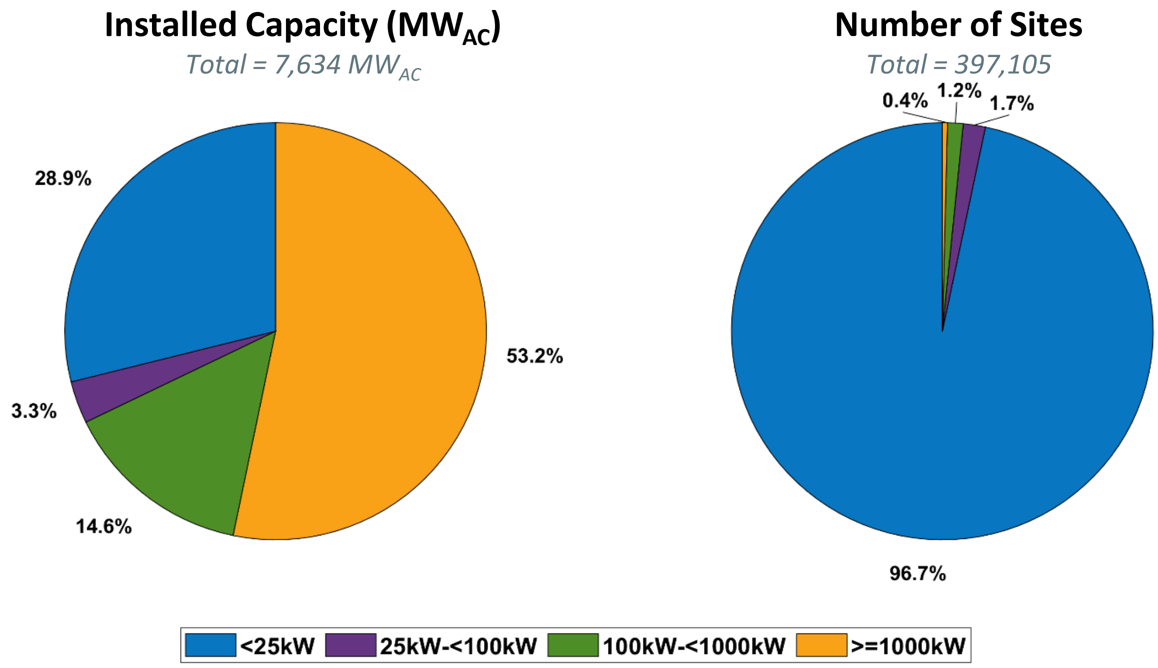




<u>Note</u>: Legend to the right of each state plot shows color scale of nameplate megawatts per town

Installed DER PV Capacity as of December 2024

ISO-NE by Size Class



APPENDIX III

dGen™ Forecast Assumptions

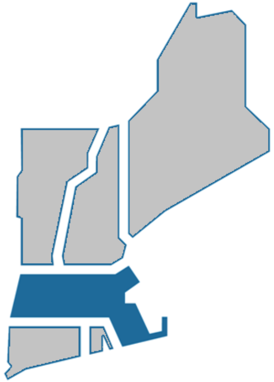
dGen^{TM} Assumptions

- The ISO presented the policy modeling assumptions used as inputs to dGen^{TM} at the December 8, 2023 DGFWG
- For 2025 PV forecast, the ISO updated the following inputs to the dGen^{TM} model
  - Historical PV nameplate capacity growth (up to 2022)
  - Tariff rate for each “agent” based on the utility rate from NREL’s Utility Rate Database (URDB)
  - Residential and non-residential incentive rates from the policies driving the PV nameplate capacity growth in the region
  - PV technology costs using NREL’s 2024 Electricity Annual Technology Baseline (ATB)
  - Calibrate the model parameters based on the most recent observed nameplate capacity growth (2024 data)

APPENDIX IV

Megawatt-Scale Forecast Assumptions

Massachusetts Forecast Assumptions

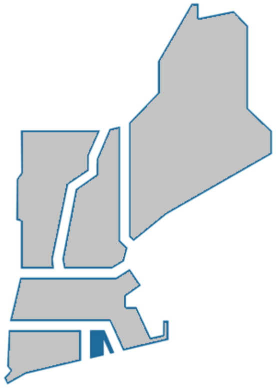


- Policy information is contained in in the MA Department of Public Utilities (MA DPU) presentation to the DGFWG on December 9, 2024
- PP12 reporting included a total of 1,978 MW_{AC} of MW-scale systems installed through 12/31/2024 with less observable growth from large systems since 2022.
- Within Solar Massachusetts Renewable Target (SMART) Program, approximately 1,021 MW_{AC} of large systems were installed by end of 2024
  - Assume an additional 312 MW_{AC} of large projects will be installed to reach program goal by 2029

Connecticut Forecast Assumptions

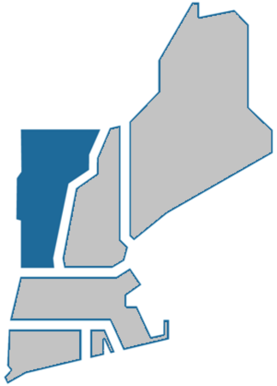
- Policy information is contained in the CT Department of Energy & Environmental Prote DEEP) [presentation] to the DGFWG on December 9, 2024
- A total of 435.5 MW_{AC} are operational under the existing Low- & Zero-Emission Renewa Energy Credits (LREC/ZREC) program, and 104.5 MW are assumed to remain.
  – Based on the historical share of large systems, assume 10.8 MW_{AC} to be from large systems
- 8 MW_{AC} are in service under the Shared Clean Energy Facility (SCEF) program, with another 132 MW selected
  – Assume all of the selected MW are large systems, and that another 50 MW_{AC} are expected to be installed under the program's 2025 procurement
  – In addition, Public Act 24-31 extended the SCEF program from 6 years to 8 years
- 56.7 MW_{AC} of MW-scale systems were selected under Non-Residential Energy Solution. An addition of 143 MW_{AC} are expected to be installed throughout the remaining period of the program
- PP12 reporting shows a 3-year average growth rate for MW-scale systems of 17.1 MW_{AC} with 33.4 MW_{AC} installed last year

Rhode Island Forecast Assumptions



- Policy information is contained in the RI Office of Energy Resources (RI OER) presentation to the
  DGFWG on December 9, 2024
- 215.8 MW_{AC} of large system were installed by the end of 2024. An addition of 75 MW_{AC} of large systems are planned from 2024-2026 according to the Renewable Energy Growth (REG) Program Drafted Megawatt Allocation Plan
- Historical data on Renewable Energy Fund (REF) does not include any large systems
- PP12 reporting shows a 3-year average growth rate for MW-scale systems of 21.4 MW_{AC} with 4.1 MW_{AC} installed last year

Vermont Forecast Assumptions

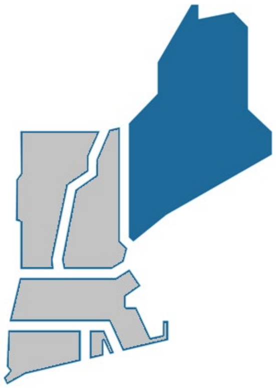


- Policy information is contained in the VT Department of Public Service (VT PSD) presentation to the DGFWG on December 9, 2024
- 85 MW_{AC} were installed under the Standard Offer program. An addition of 42 MW_{AC} are anticipated, all of which are large systems
- DG carve-out of the Renewable Energy Standard (RES) and its supporting policies (Standard Offer Program, net metering) drive distributed PV growth to match a growing share of VT's annual load energy, with the following assumptions:
  - All forward-looking renewable energy certificates (RECs) from Standard Offer and net metered projects will be sold to utilities and count towards RES DG carve-out
- PP12 reporting shows a 3-year average growth rate for MW-scale systems was 9.9 MW_{AC} with 16.2 MW_{AC} installed last year
- The forecast assumed a near-term increase in the adoption due to the increase in DG RES obligations for utilities in VT. The forecast considered recent DG RES policy changes in VT by increasing the assumed growth of MW-scale systems until 2035
- The ISO revisited the MW-scale PV forecast assumptions to include expectations about VT's future load growth based on the ISO's 2025 long-term load forecast

New Hampshire Forecast Assumptions

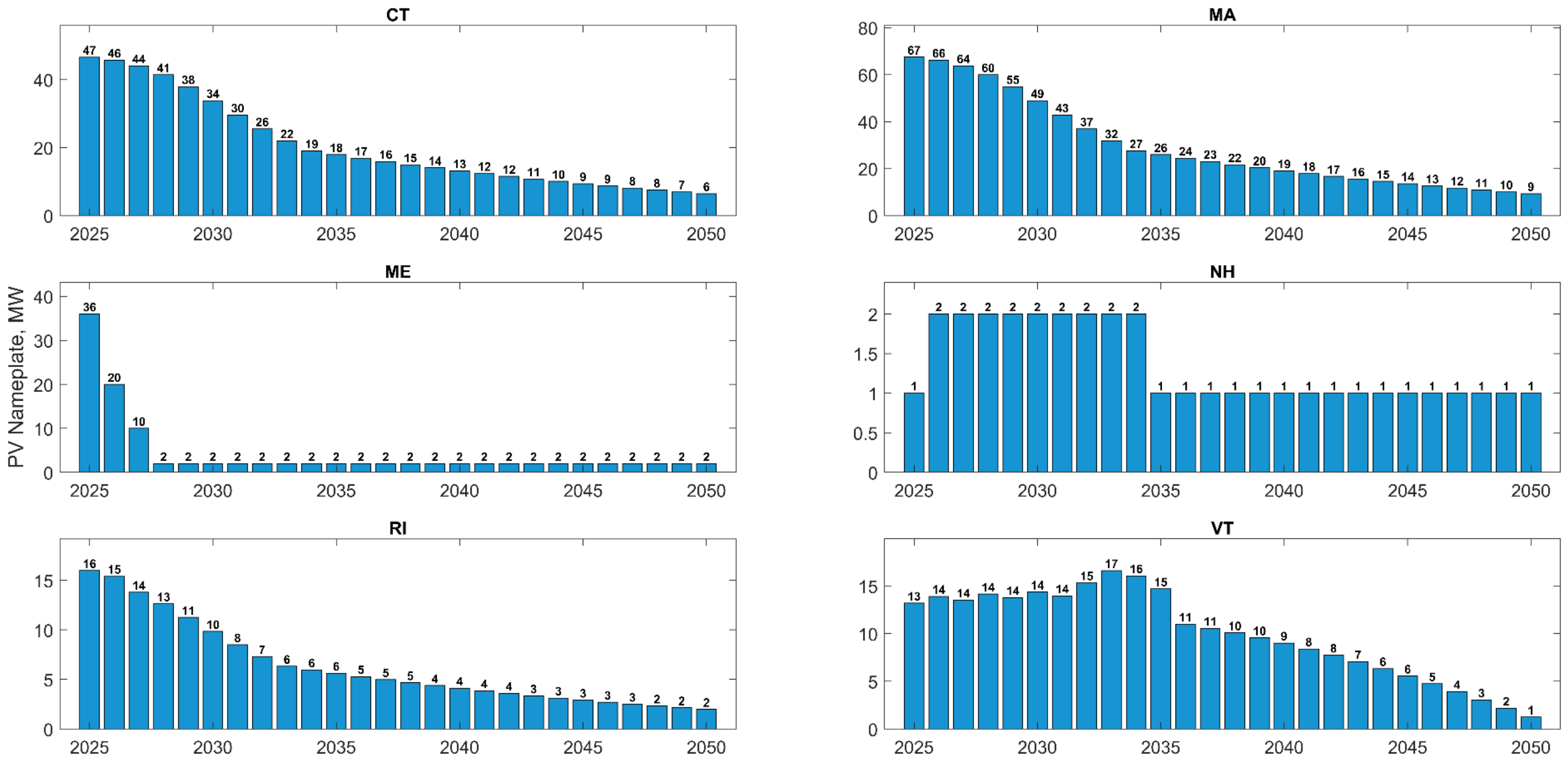
- Policy-based (large system):
  - Policy information is contained in the NH Department of Energy (NH DOE) presentation to the DGFWG on December 9, 2024
  - Per NH's net metering tariff, Municipal Hosts are permitted to install projects up to 5 MW
  - PP12 reporting suggests that growth in MW-scale systems in NH has been minimal and sporadic, with zero installed capacity in 2023 and 2024. The forecast assumed no change in policy supporting MW-scale systems

Maine Forecast Assumptions



- Based on Maine's DGFWG December, 2024 presentation, all NEB "kWh" projects betw MW must reach commercial operation by December 31, 2024. Moving forward, projec can participate in NEB programs must be less than 1MW
- All future projects in the C&I tariff NEB program must be collocated with 100% of the subscribed load in order to participate in the program
  - ISO has assumed that these projects are possible, but will be uncommon
- However, at the end of 2024, there were approximately 44 MW of MW-scale projects in queue based on the data submitted to ME PUC data
  - ISO assumed these will become operational
- All of the available information points toward a significant reduction of MW-scale projects in Maine in 2025 and onward

Megawatt-scale PV Forecast Inputs



APPENDIX V

Discount Factors

Discount Factors

- Discount factors are:
  - Developed and incorporated into the forecast to consider a degree of expected uncertainty
  - All discount factors are applied equally in all states
  - Applied to the forecast inputs (see slides 96-98) to determine total nameplate capacity for each state and forecast year

Policy-Based *PV that results from state policy*
Discounts for uncertainty associated with future market and grid conditions (maximum value of 15%)

Discount Factors Used

Policy-Based

Forecast Year	Final 2024 Forecast	Draft 2025 Forecast
2025	5%	2.5%
2026	7.5%	5%
2027	10%	7.5%
2028	12.5%	10%
2029	15%	12.5%
2030	15%	15%
2031	15%	15%
2032	15%	15%
2033	15%	15%
2034 - 2050	N/A	15%

2025 Forecast Inputs – 10-Year Horizon

Nameplate Capacity, PV Systems < 1 MW

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
CT	1,118	138	141	149	151	155	157	163	167	149	127	**2,616**
MA	2,228	234	242	269	279	296	304	319	325	291	251	**5,038**
ME	175	38	41	54	61	74	79	87	90	83	73	**855**
NH	263	36	38	47	53	60	62	67	69	65	59	**819**
RI	239	52	54	65	73	71	61	53	54	48	40	**812**
VT	359	21	21	23	24	26	27	31	33	30	25	**618**
ISONE	**4,382**	**519**	**538**	**609**	**641**	**682**	**691**	**719**	**737**	**665**	**575**	**10,758**

Notes:

(1) The above values **are not forecast values**, but rather pre-discounted inputs to the forecast (see slides 22-23 for details)

(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

2025 Forecast Inputs – 10-Year Horizon

Nameplate Capacity, PV Systems 1-5 MW

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
CT	170	47	46	44	41	38	34	30	26	22	19	**516**
MA	1,791	67	66	64	60	55	49	43	37	32	27	**2,291**
ME	877	36	20	10	2	2	2	2	2	2	2	**957**
NH	17	1	2	2	2	2	2	2	2	2	2	**36**
RI	226	16	15	14	13	11	10	8	7	6	6	**333**
VT	170	13	14	14	14	14	14	14	15	17	16	**314**
ISONE	**3,251**	**180**	**163**	**147**	**132**	**122**	**111**	**99**	**89**	**81**	**72**	**4,448**

Notes:

(1) The above values **are not forecast values**, but rather pre-discounted inputs to the forecast (see slides 22-23 for details)
(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

2025 Forecast Inputs – 10-Year Horizon

Pre-Discounted Nameplate Values, All PV Systems

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
CT	1,289	185	187	193	193	193	191	193	192	171	146	**3,132**
MA	4,019	301	308	333	339	351	353	361	362	323	279	**7,330**
ME	1,053	74	61	64	63	76	81	89	92	85	75	**1,812**
NH	280	37	40	49	55	62	64	69	71	67	61	**855**
RI	465	68	70	79	85	82	71	61	62	54	46	**1,144**
VT	529	34	35	37	38	40	42	44	48	46	41	**933**
Pre-Discount Cumulative Total (MW)	**7,634**	**8,333**	**9,034**	**9,790**	**10,563**	**11,367**	**12,169**	**12,987**	**13,813**	**14,559**	**15,206**	**15,206**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 23-24 for details)
(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

2025 Forecast Inputs – Forecast Horizon