Final 2024 Photovoltaic (PV) Forecast

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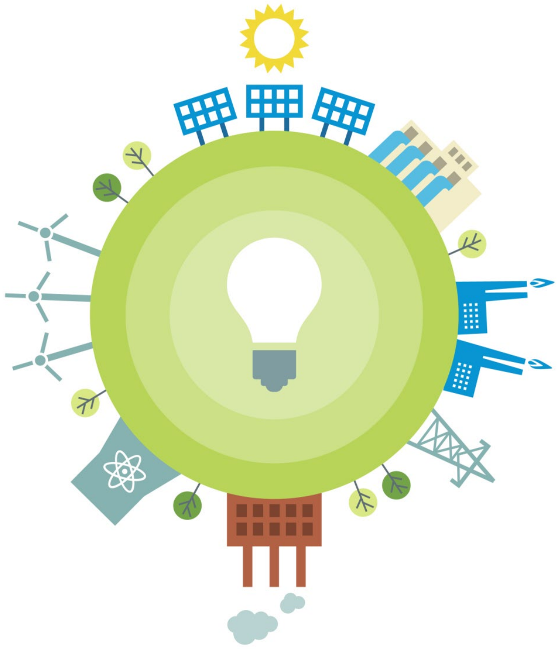


Acronyms

BTM	Behind-the-meter	**IOU**	Investor-owned utility
CBI	Capacity-based incentive	**ITC**	Investment tax credit
CELT	Capacity, Energy, Load, and Transmission report	**NEB**	Net energy billing (ME)
C&I	Commercial and industrial	**NM, NEM**	Net metering, net energy metering
DER	Distributed energy resource	**NREL**	National Renewable Energy Laboratory
DG	Distributed generation	**NRES**	Non-residential Renewable Energy Solutions (CT)
DGFWG	Distributed Generation Forecast Working Group	**PBI**	Performance-based incentive
dGEN™	Distributed Generation Market Demand Model	**PV**	Photovoltaic
EOR	Energy only resources	**REF**	Renewable Energy Fund (RI)
FCM	Forward Capacity Market	**REG**	Renewable Energy Growth program (RI)
FITs	Feed-in-tariffs	**RRES**	Residential Renewable Energy Solutions (CT)
IBI	Investment-based incentive	**SCEF**	Shared Clean Energy Facility program (CT)
ICR	Installed Capacity Requirement	**SMART**	Solar Massachusetts Renewable Target

CELT 2024 Stakeholder Process

- The ISO hosted 4 Distributed Generation Forecast Working Group (DGFWG) meetings during the 2024 forecast cycle:
  1. October 27, 2023
     - Introduction to the 2024 Forecast Cycle
     - Overview of the Distributed Generation Market Model
  2. December 4, 2023
     - State DG policy updates from MA, CT, RI, VT, NH, and ME
     - PV Forecast Preliminary Policy Modeling
  3. February 16, 2024
     - Draft 2024 PV forecast
     - December 2023 distributed generation survey results
  4. March 25, 2024
     - Final 2024 PV forecast

INTRODUCTION

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)

Similar to energy efficiency (EE), behind-the-meter PV is reconstituted into historical loads*

The 2024 gross load forecast reflects loads without PV load reductions

**Existing BTM PV decreases the historical metered loads, which are an input to the gross load forecast*

PV Forecast Focuses on Distributed Generation

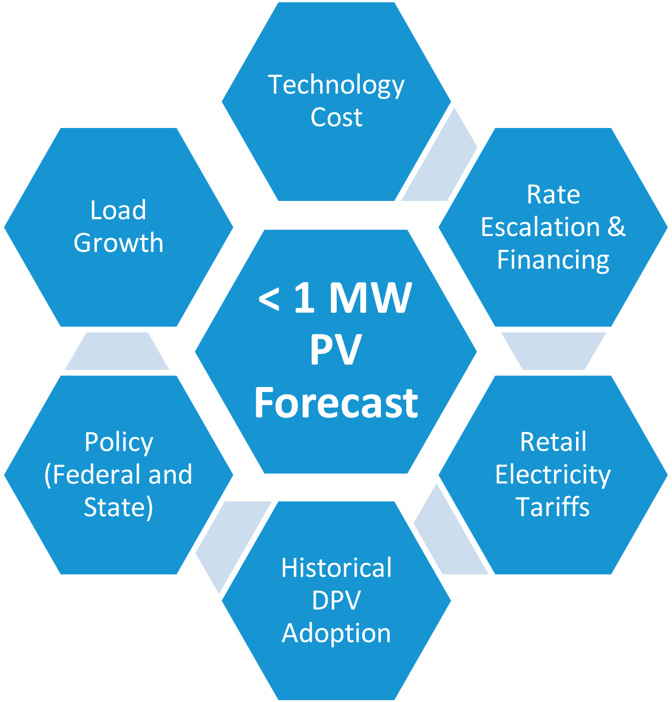
- The focus of the DGFWG is distributed generation (DG) projects:
  - "…defined as those that are typically 5 MW or less in nameplate capacity and are interconnected to the distribution system (typically 69 kV or below) according to state-jurisdictional interconnection standards."
  - Note that the industry has evolved since the formation of the DGFWG, and today DG is often referred to as a distributed energy resource (DER)
    - DER is defined in this context as *a source of electric power that is interconnected to the distribution system*
      - DER includes both generators and energy storage technologies
      - DER does <u>not</u> include demand response, controllable loads, or other load modifiers
- Therefore, the forecast does not consider policy drivers supporting larger-scale projects (i.e., those >5 MW)
- Large projects are generally accounted for as part of ISO's interconnection process and participate in wholesale markets

PV Forecast Methodology

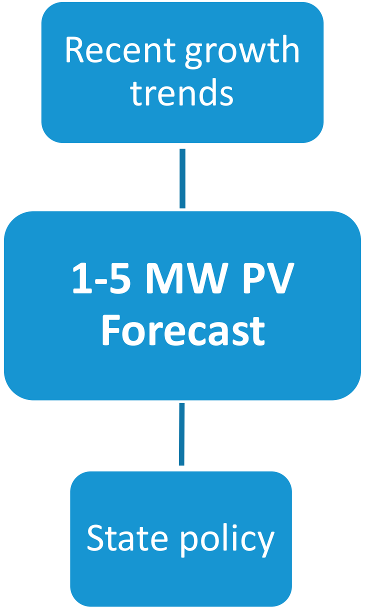
- The PV forecast is a projection of distributed PV resources to be used in ISO-NE System Planning studies, consistent with its role to ensure prudent planning assumptions for the bulk power system.
- For 2024 PV forecast, the ISO updated its methodology to include the Distributed Generation Market Demand Model (dGen^{TM}), an agent-based simulation tool developed and open-sourced by the National Renewable Energy Laboratory (NREL)
- The distributed PV nameplate forecast is now developed as two additive processes:
  1. For < 1 MW systems: Use residential and commercial dGen^{TM} modeling
  2. For 1-5 MW systems: Use a policy-based approach
- The ISO used a policy-based forecasting approach to generate forecast for all PV systems in the New England states that are equal or greater than one megawatt, but less than five megawatts.

PV Forecast Inputs

PV Systems < 1 MW



PV Systems 1-5 MW



FINAL 2024 PV FORECAST

Total Nameplate Capacity

Final 2024 PV Forecast

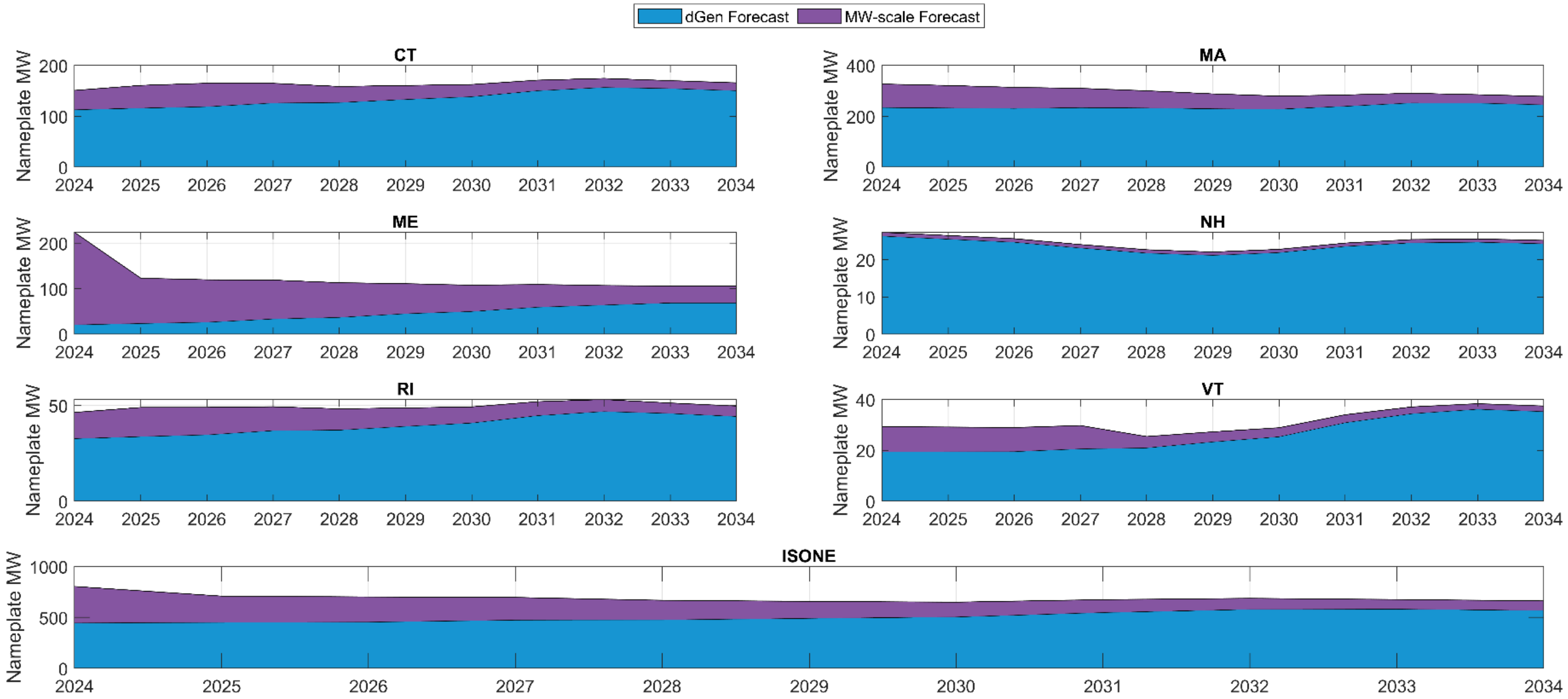
Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
CT	1,090.5	150.8	160.6	164.9	164.7	158.5	160.4	162.4	170.9	174.4	170.0	**2,728.1**
MA	3,712.0	326.5	320.9	313.6	309.7	300.1	288.0	279.2	283.7	290.5	284.9	**6,709.1**
ME	588.0	223.6	123.0	119.6	118.9	113.0	111.0	107.6	109.3	107.0	105.8	**1,826.9**
NH	244.0	27.3	26.5	25.6	24.0	22.7	22.0	22.8	24.4	25.4	25.6	**490.3**
RI	400.0	46.4	49.0	49.0	49.3	48.2	48.7	49.2	52.0	53.1	51.3	**896.1**
VT	507.0	29.3	29.2	29.0	29.8	25.4	27.3	28.9	34.0	37.1	38.3	**815.3**
Regional - Annual (MW)	**6,541.5**	**803.9**	**709.1**	**701.7**	**696.5**	**667.9**	**657.5**	**650.2**	**674.3**	**687.5**	**675.8**	**13,465.8**
Regional - Cumulative (MW)	**6,541.5**	**7,345.4**	**8,054.5**	**8,756.2**	**9,452.6**	**10,120.5**	**10,778.0**	**11,428.2**	**12,102.5**	**12,790.0**	**13,465.8**	**13,465.8**

Notes:

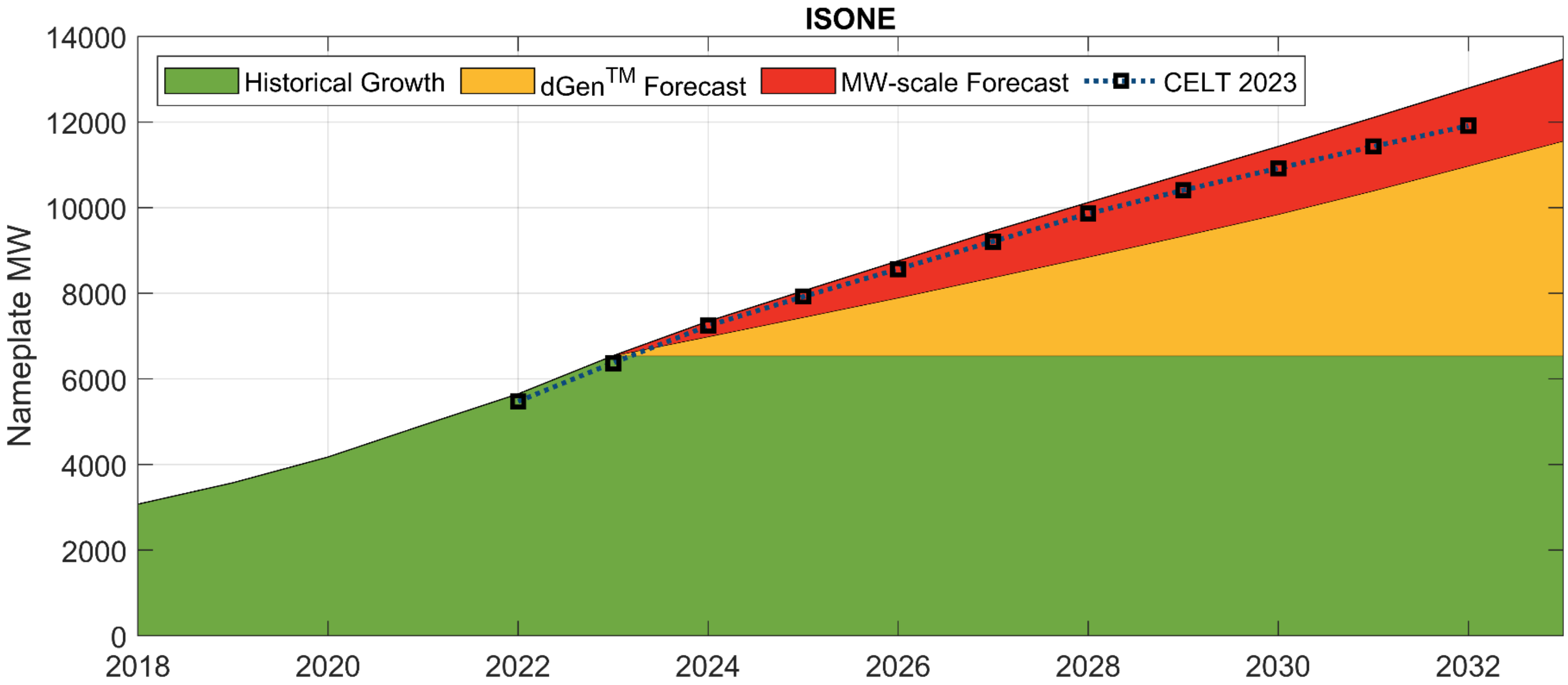
(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast values are net of the effects of discount factors applied to reflect a degree of uncertainty in the policy-based forecast
(3) All values represent end-of-year installed capacities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

Annual PV Nameplate Capacity Growth Breakdown



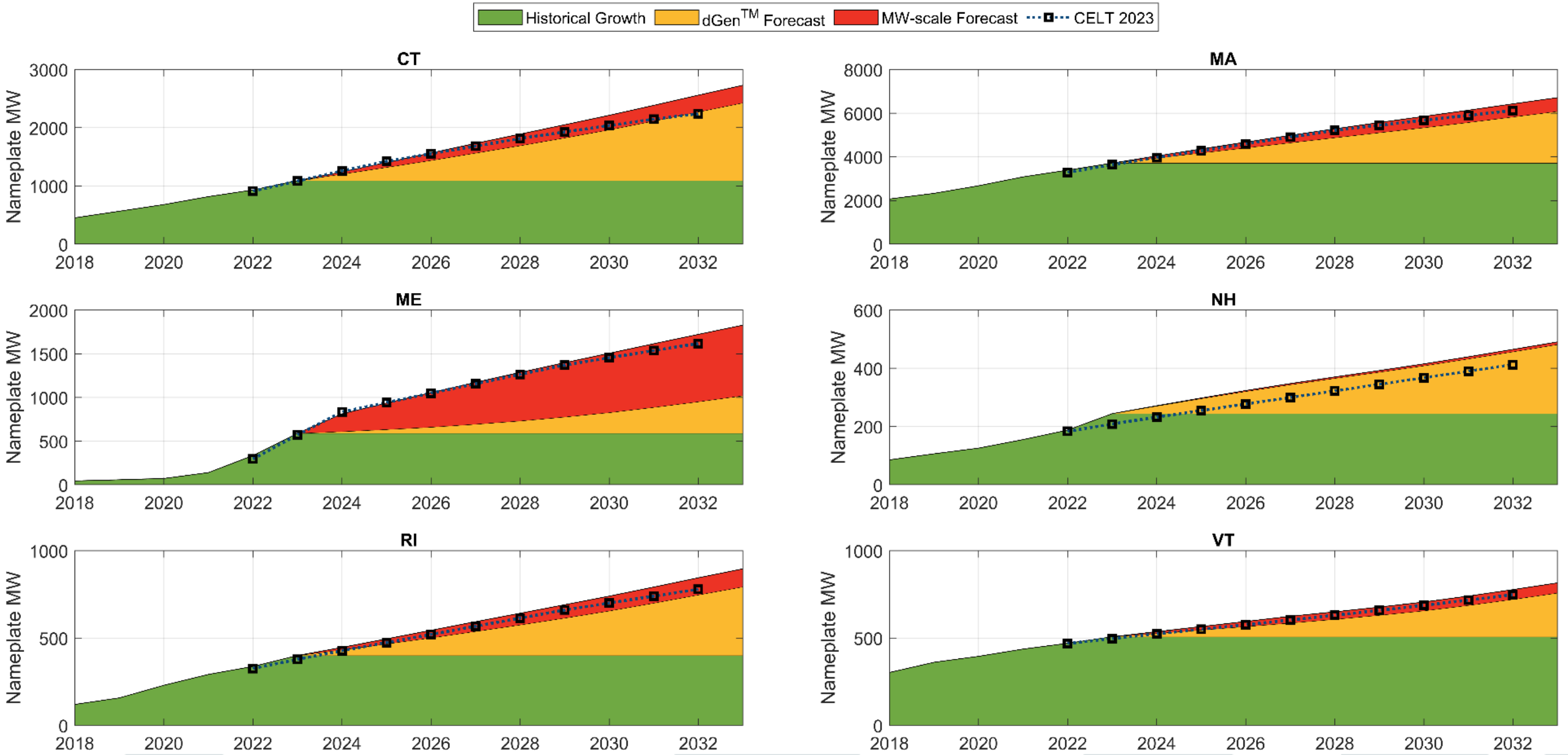
Regional PV Nameplate Capacity Growth

Historical vs. Forecast



State PV Nameplate Capacity Growth

Historical and Forecast



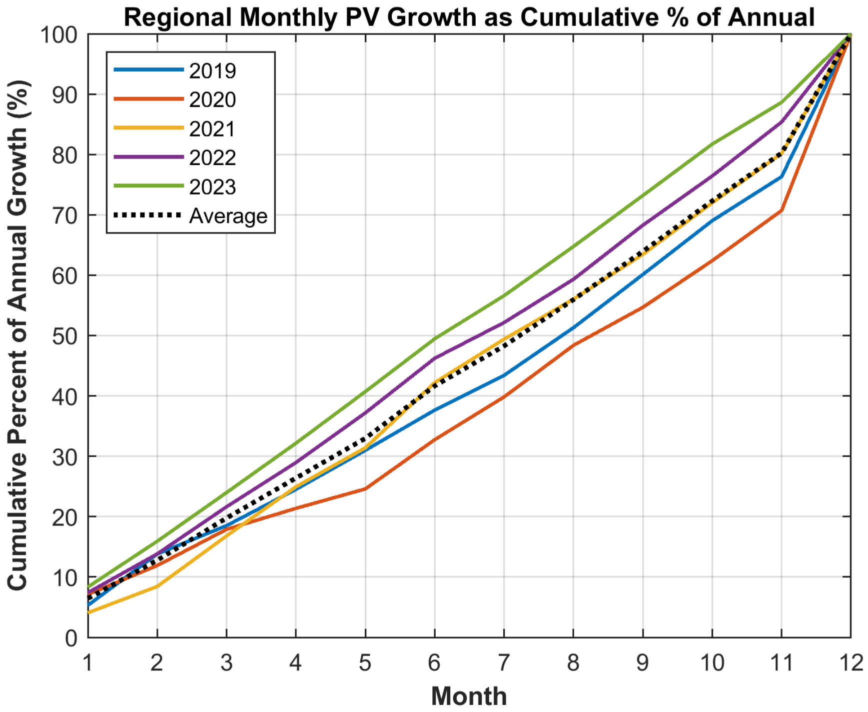
2024 PV ENERGY FORECAST

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 2019 and 2023 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 10 years of PV performance data (2014-2023)
  - Resulting state and regional CFs are tabulated to the right, and plots of individual monthly capacity factors in each state are shown on slide 45

State	Average CF, %
CT	14.7
ME	14.7
NH	14.2
RI	14.9
VT	13.8
MA	14.5
ISO-NE	**14.5**

Historical Monthly PV Growth Trends, 2019-2023



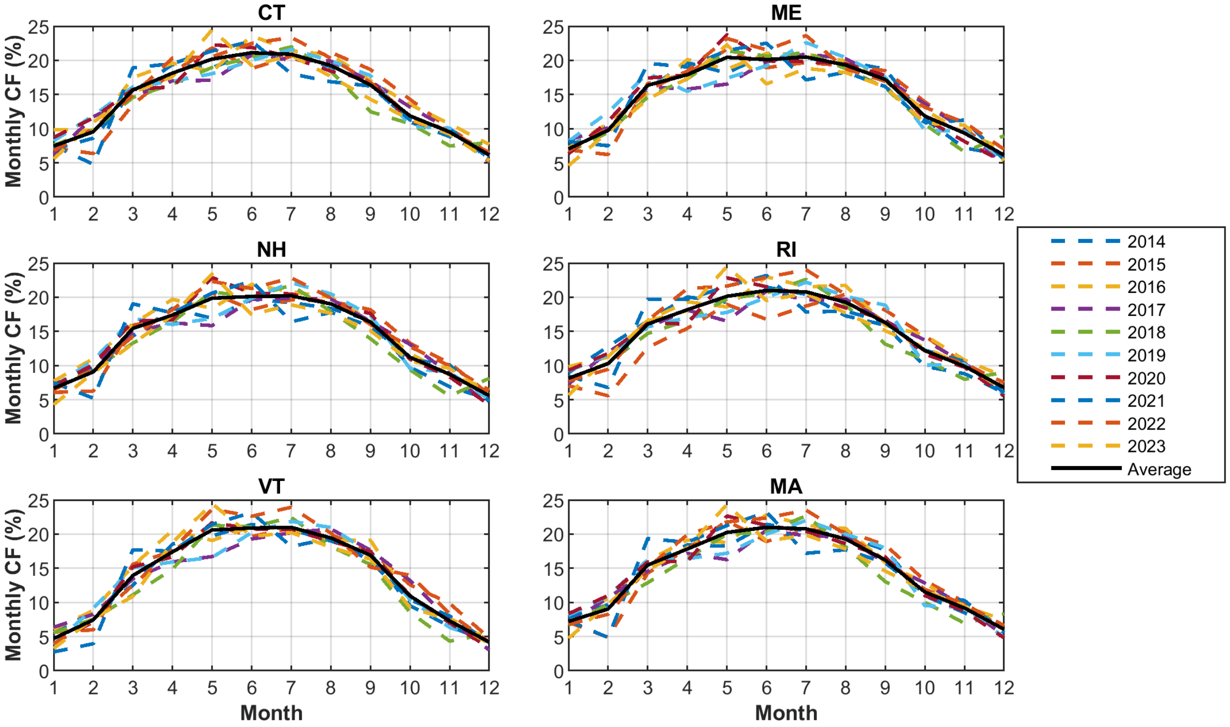
Average Monthly Growth Rates, % of Annual

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%

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, 2014-2023



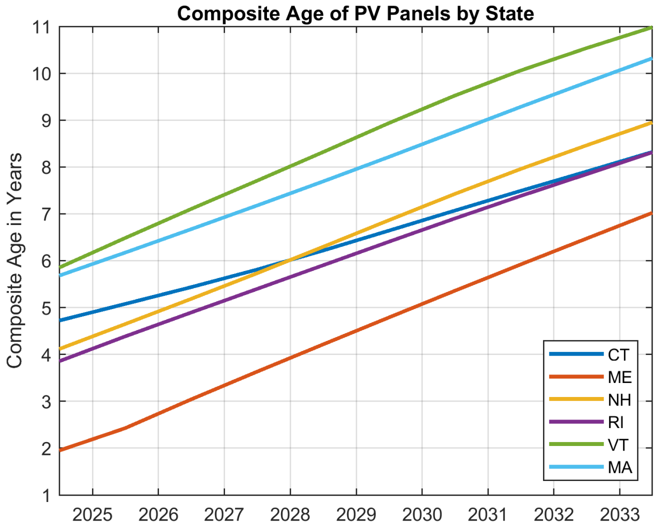
PV Panel Degradation Factors

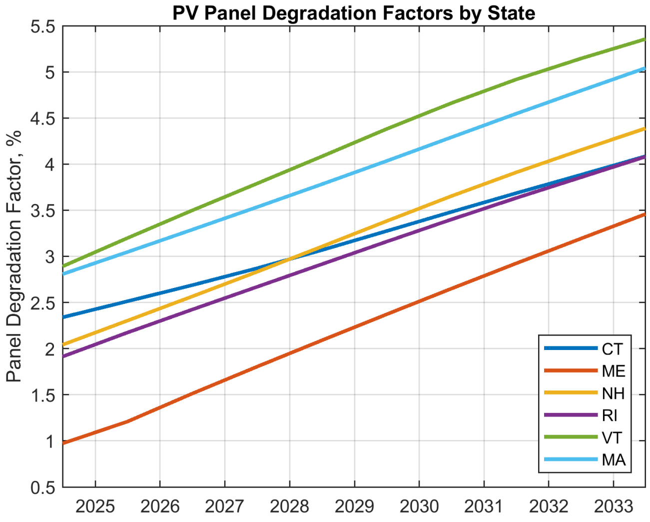
- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecasts of BTM PV energy and estimated summer peak load reductions include the effects of a 0.5%/year panel degradation rate to account for the expected declining conversion efficiency of solar panels 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 all 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 2024 PV Energy Forecast

All Forecast PV (FCM+EOR+BTM), GWh

States	Total Estimated Annual Energy (GWh)										
	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
CT	1,355	1,547	1,748	1,961	2,176	2,390	2,591	2,798	3,011	3,237	3,450
MA	4,667	5,059	5,461	5,861	6,251	6,642	6,994	7,342	7,684	8,045	8,379
ME	628	931	1,167	1,327	1,482	1,636	1,778	1,918	2,056	2,197	2,327
NH	279	331	364	396	427	456	483	510	538	569	599
RI	513	573	635	700	764	830	891	955	1,020	1,089	1,154
VT	598	646	679	713	747	780	808	840	876	918	960
Regional - Annual Energy (GWh)	**8,040**	**9,086**	**10,054**	**10,958**	**11,848**	**12,734**	**13,545**	**14,362**	**15,184**	**16,054**	**16,869**

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% to reflect avoided transmission and distribution losses

CLASSIFICATION OF PV FORECAST

Background & Methods

Classification Needed to Determine BTM PV

- For resource adequacy studies, 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
- 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 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 2023
  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

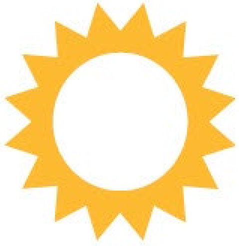
- FCM
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 18
    - Maintain separate accounting for FCM_{supply} and FCM_{DR}
  - Assume aggregate total PV in FCM as of FCA 18 remains constant from 2027-2033

- Non-FCM Gen/EOR
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/23
  - Assume the ($EOR+FCM_{supply}$) share of total PV at the end of 2023 in each state ***except Maine*** remains constant throughout the forecast horizon
    - For Maine, assume ($EOR+FCM_{supply}$) share is 75% over the forecast horizon to reflect how new policies prompting the majority of future PV growth require participation in wholesale markets

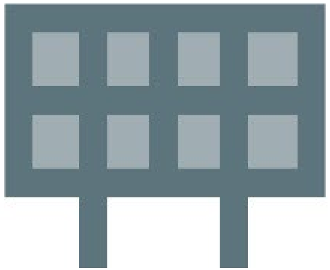
- Other assumptions
  - FCM_{supply} PV resources operate as EOR/Gen prior to their first FCM commitment period (this has been observed in MA and RI)
  - Planned PV projects known to be > 5 MW_{ac} nameplate are assumed to trigger OP-14 requirement to register in ISO energy market as a Generator

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 gross 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 2024 PV FORECAST

Results

Final 2024 PV Forecast

Cumulative Nameplate Capacity, MW_{ac}

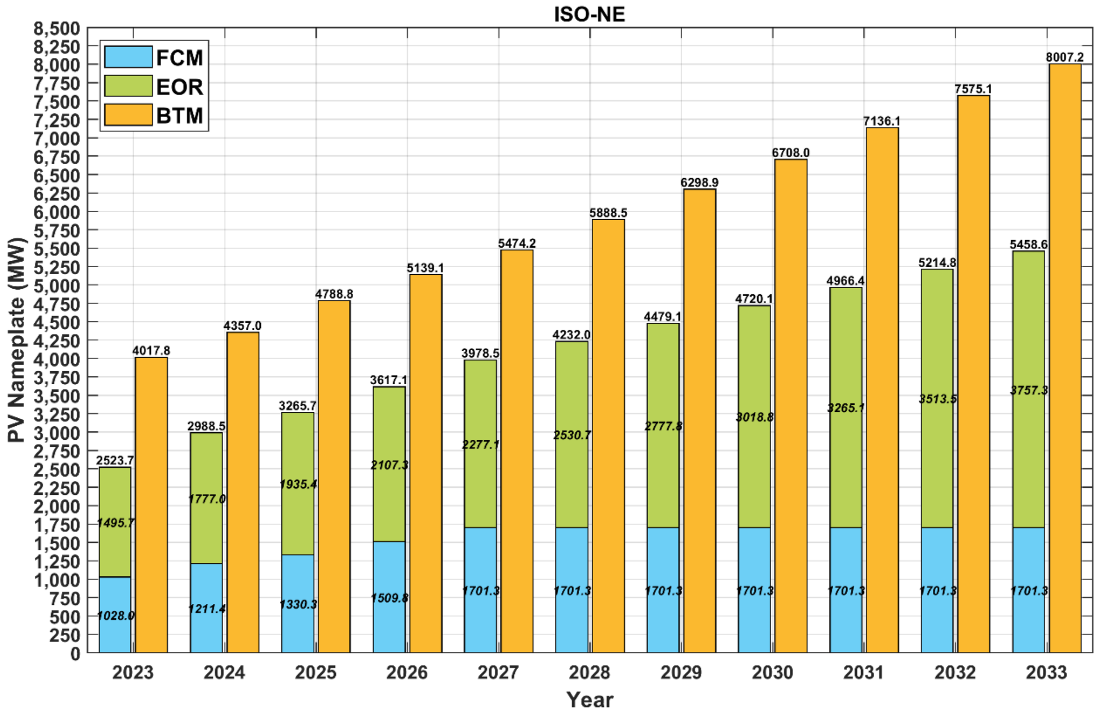
States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
CT	1,090.5	150.8	160.6	164.9	164.7	158.5	160.4	162.4	170.9	174.4	170.0	**2,728.1**
MA	3,712.0	326.5	320.9	313.6	309.7	300.1	288.0	279.2	283.7	290.5	284.9	**6,709.1**
ME	588.0	223.6	123.0	119.6	118.9	113.0	111.0	107.6	109.3	107.0	105.8	**1,826.9**
NH	244.0	27.3	26.5	25.6	24.0	22.7	22.0	22.8	24.4	25.4	25.6	**490.3**
RI	400.0	46.4	49.0	49.0	49.3	48.2	48.7	49.2	52.0	53.1	51.3	**896.1**
VT	507.0	29.3	29.2	29.0	29.8	25.4	27.3	28.9	34.0	37.1	38.3	**815.3**
Regional - Cumulative (MW)	**6,541.5**	**7,345.4**	**8,054.5**	**8,756.2**	**9,452.6**	**10,120.5**	**10,778.0**	**11,428.2**	**12,102.5**	**12,790.0**	**13,465.8**	**13,465.8**

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

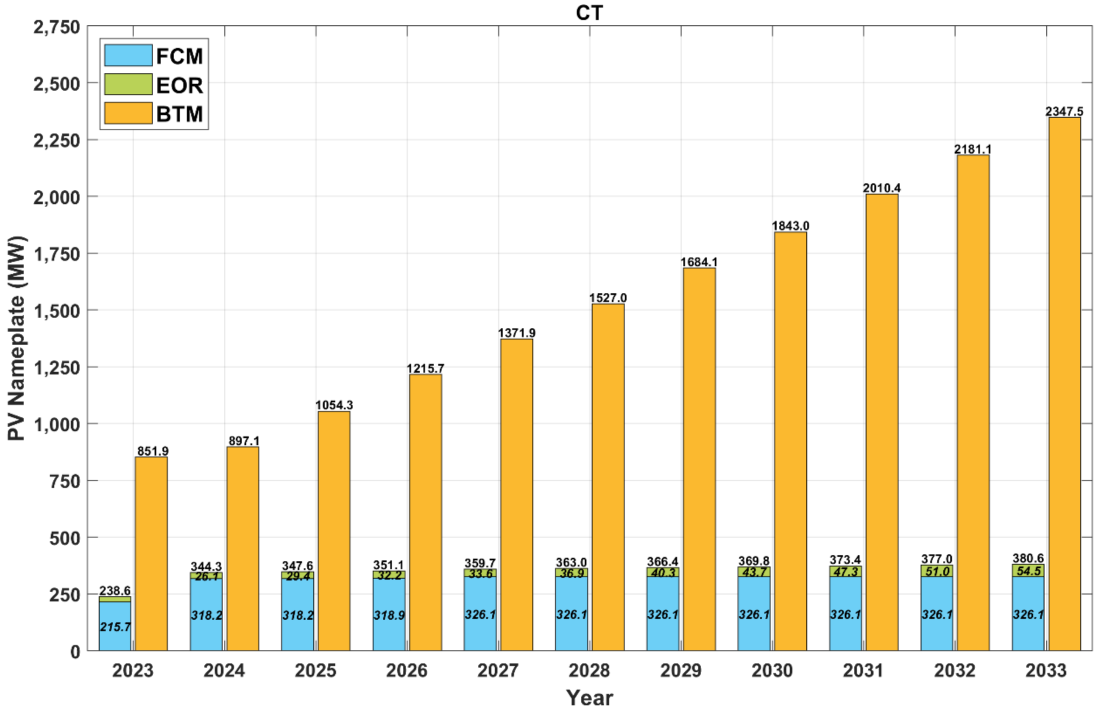
Final 2024 PV Forecast – New England

Cumulative Nameplate by Category, MW_{ac}



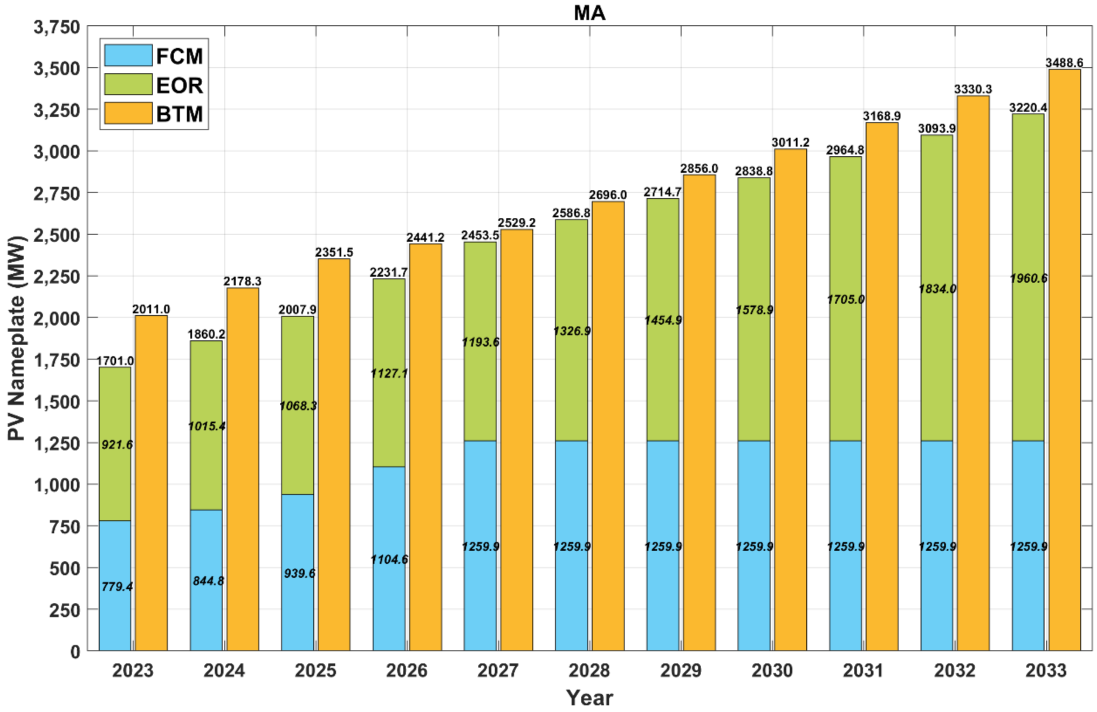
Final 2024 PV Forecast – Connecticut

Cumulative Nameplate by Category, MW_{ac}



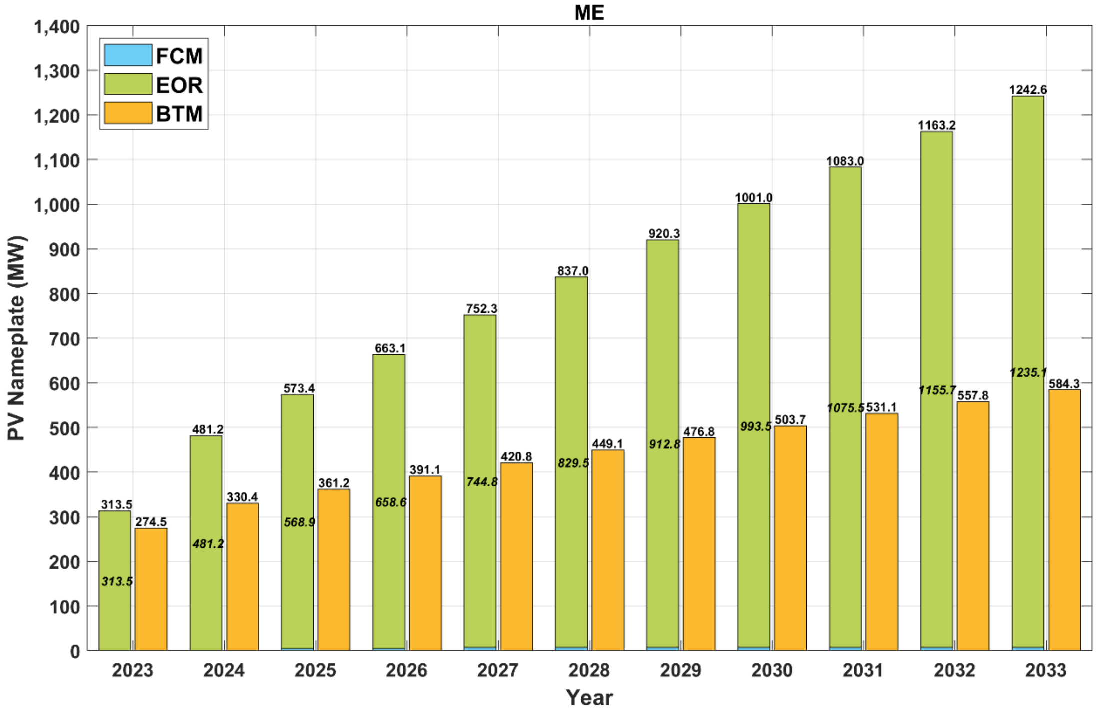
Final 2024 PV Forecast – Massachusetts

Cumulative Nameplate by Category, MW_{ac}



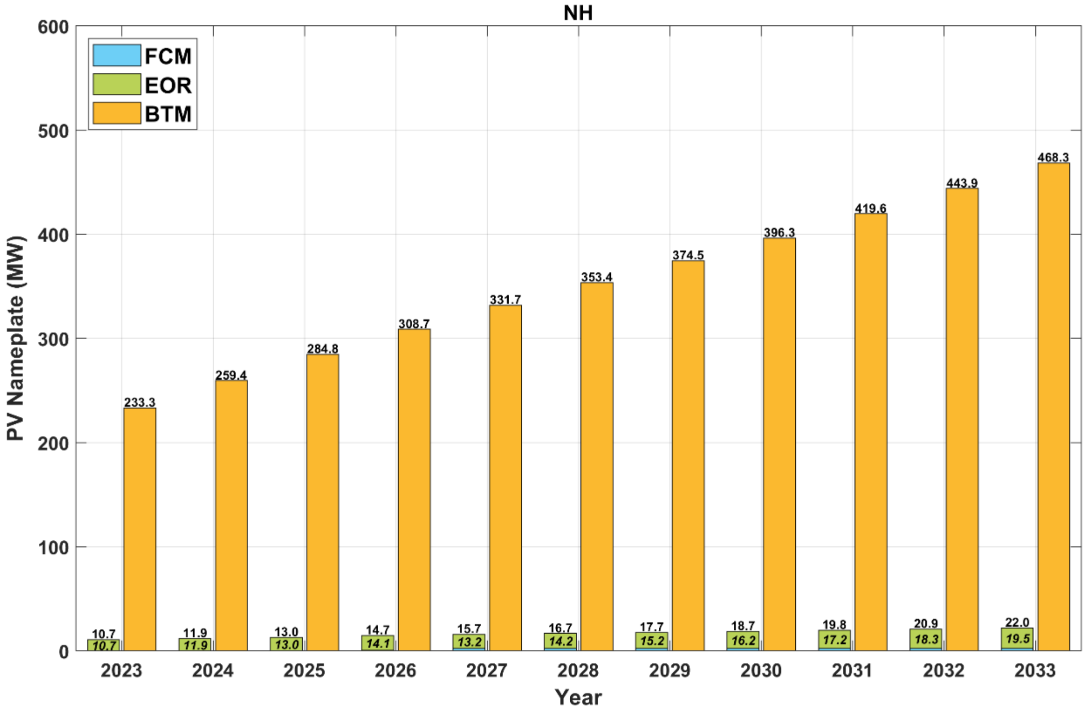
Final 2024 PV Forecast – Maine

Cumulative Nameplate by Category, MW_{ac}



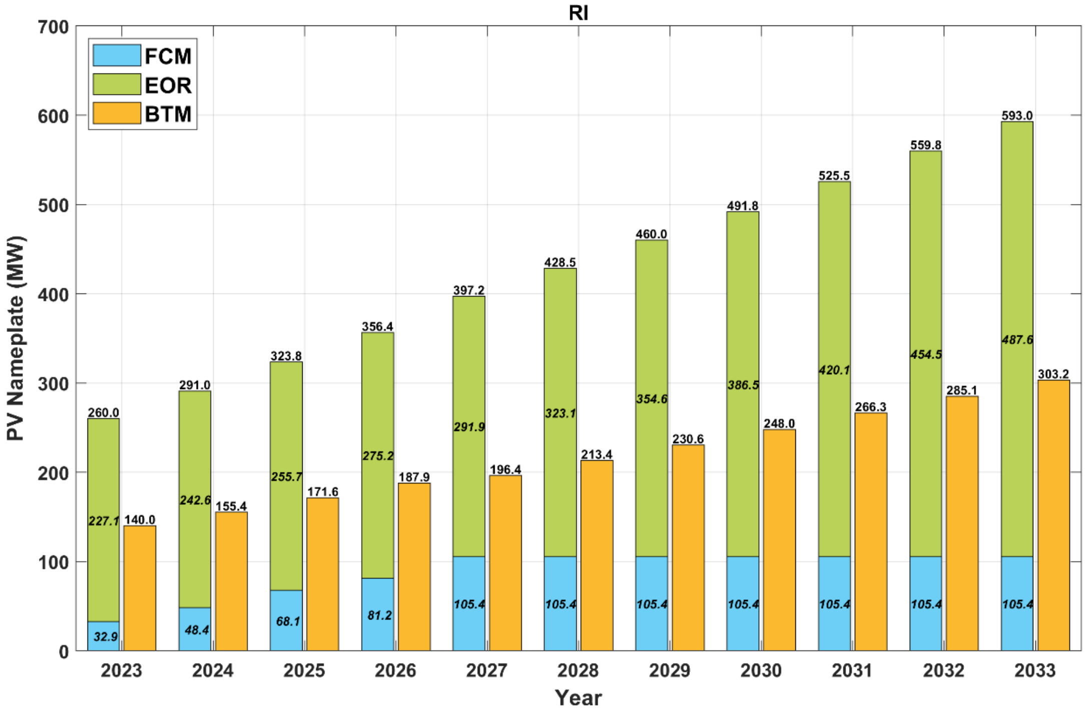
Final 2024 PV Forecast – New Hampshire

Cumulative Nameplate by Category, MW_{ac}



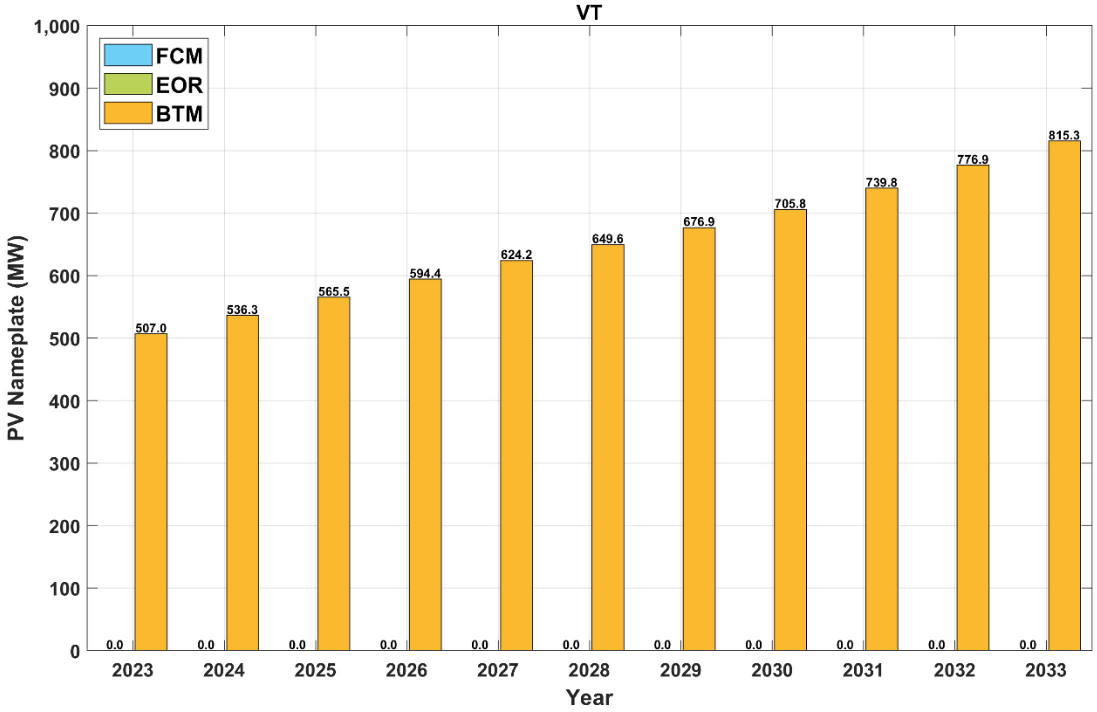
Final 2024 PV Forecast – Rhode Island

Cumulative Nameplate by Category, MW_{ac}



Final 2024 PV Forecast – Vermont

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



2024 BEHIND-THE-METER PV FORECAST

BTM PV Forecast Used in CELT Net Load Forecast

- The 2024 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 2024 CELT
  - PV does not reduce winter peak loads, which occur after sunset
- The methodology used to estimate summer peak load reduction associated with BTM PV over the forecast horizon is described here
- The final PV forecast is published in the 2024 CELT (Section 3):
  - See: https://www.iso-ne.com/system-planning/system-plans-studies/celt/

Final 2024 BTM PV Energy Forecast

GWh

Category	States	Estimated Annual Energy (GWh)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Behind-the-Meter PV	CT	955	1,144	1,288	1,497	1,704	1,911	2,110	2,313	2,522	2,743	2,954
	MA	2,147	2,732	2,945	3,098	3,206	3,380	3,577	3,771	3,962	4,163	4,350
	ME	208	405	464	503	541	580	614	649	683	718	750
	NH	250	316	348	378	408	436	461	487	514	543	572
	RI	130	200	220	242	257	275	297	319	342	367	390
	VT	595	646	679	713	747	780	808	840	876	918	960
Behind-the Meter Total	**Regional Total**	**4,284**	**5,444**	**5,943**	**6,431**	**6,863**	**7,361**	**7,867**	**8,379**	**8,899**	**9,452**	**9,975**

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% to reflect avoided transmission and distribution losses

Final 2024 BTM PV Forecast

July 1st Estimated Coincident Summer Peak Load Reductions

Category	States	Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Behind-the-Meter PV	CT	222.3	217.3	242.5	267.5	288.3	306.6	322.1	336.6	350.4	363.7	375.5
	MA	538.9	554.3	564.1	554.2	543.0	549.1	552.9	555.3	556.9	558.3	559.2
	ME	65.7	80.9	87.5	89.9	91.6	92.8	93.5	94.0	94.4	94.7	94.8
	NH	58.9	65.9	68.4	70.4	71.9	72.7	73.1	73.6	74.1	74.7	75.4
	RI	35.7	39.4	40.9	42.6	42.1	43.4	44.6	45.7	46.8	47.8	48.7
	VT	137.4	138.8	137.5	136.7	135.7	134.0	132.1	130.7	130.0	130.0	130.3
Total	**Cumulative**	1,059.0	1,096.7	1,140.9	1,161.3	1,172.6	1,198.6	1,218.3	1,235.9	1,252.5	1,269.2	1,283.8
Corresponding % of BTM PV AC nameplate capacity		27.3%	25.5%	24.0%	22.7%	21.5%	20.4%	19.3%	18.4%	17.6%	16.8%	16.1%

Notes:

(1) Forecast values reflect New England coincident summer peak reductions associated with 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; details of the methodology used to determine the estimated peak demand reductions are available at: http://www.iso-ne.com/static-assets/documents/2020/04/final_btm_pv_peak_reduction.pdf

(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

APPENDIX I

2023 Forecast and Actual PV Growth

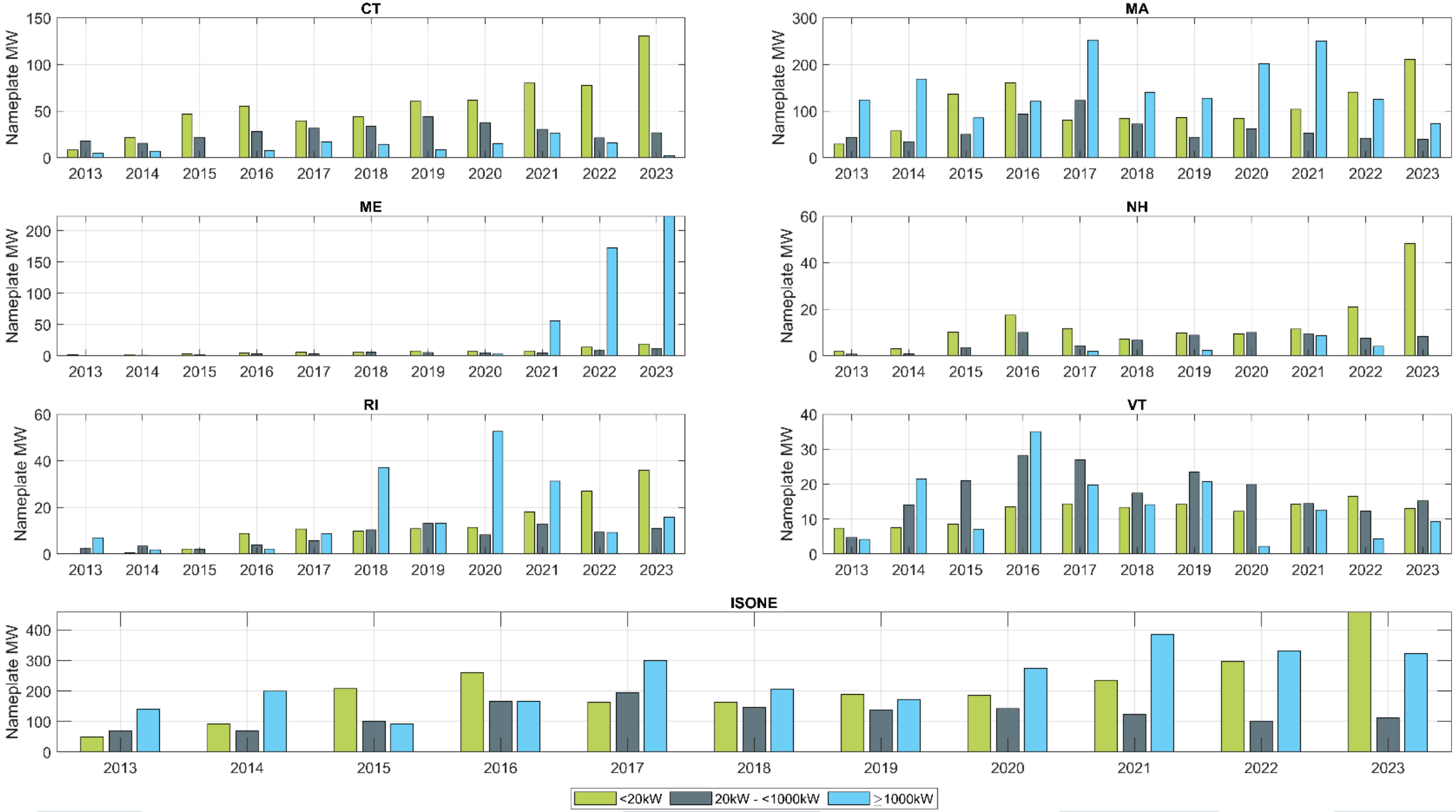
2023 PV Nameplate Capacity Growth

- Comparison of the state-by-state 2023 forecast PV growth and the growth for 2023 reported by utilities is tabulated
  - Values include FCM, EOR, and BTM PV projects
- Regionally, 2023 growth reported by utilities totaled 892.4 MW, which is 9.8 MW lower than the forecast growth
  - Results vary by state as tabulated

State	2023 Reported Growth	2023 Forecast Growth	Error
CT	159.4	171.3	-11.9
MA	322.6	348.3	-25.7
ME	253.7	276.8	-23.1
NH	56.4	25.2	31.2
RI	62.7	52.1	10.6
VT	37.5	28.5	9.0
Region	**892.4**	**902.2**	**-9.8**

Nameplate Capacity of Reported Annual PV Growth

Small (<= 20kW), Medium (20-<1,000kW), and Large (>=1,000kW) Projects



Larger-Scale PV

Projects >5 MW_{ac}

- Tabulated is a summary of in-service, larger-scale (i.e., non-DG) PV projects included as part of Distribution Owner survey data responses
- These projects are not included in the PV forecast accounting, and are excluded from installed PV totals reported herein

State	# Projects Listed	Total Nameplate (MW_{ac})
CT	5	97.4
MA	-	-
ME	3	34.0
NH	-	-
RI	21	169.9
VT	-	-
Total	**29**	**301.2**

APPENDIX II

Distribution Owner Survey Results

Determining Cumulative PV Totals

December 2023 Distribution Owner Survey Data

- 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, 2023
  - PV projects include FCM, EOR, and BTM PV projects
- The following Distribution Owners responded:

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

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

December 2023 Cumulative PV Totals

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 12/31/23.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	3,712	179,362
Connecticut	1,091	91,290
Vermont*	507	21,179
New Hampshire	244	21,234
Rhode Island	400	22,769
Maine	588	11,506
New England	**6,542**	**347,341**

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

December 2023 Cumulative PV Totals (1 of 2)

Summary of Distribution Owner PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
CT	Connecticut Light & Power	869	69,543
	Connecticut Municipal Electric Energy Co-op	13	7
	United Illuminating	208	21,740
	Total	**1,091**	**91,290**
MA	Braintree Electric Light Department	6	50
	Chicopee Electric Light	13	51
	Unitil (FG&E)	52	3,162
	National Grid	1,923	96,614
	NSTAR	1,144	59,090
	Reading Municipal Lighting Plant	9	283
	Shrewsbury Electric & Cable Operations	7	156
	SREC I	54	589
	SREC II	97	1,672
	Western Massachusetts Electric Company	408	17,695
	Total	**3,712**	**179,362**
ME	Central Maine Power	517	9,816
	Versant*	71	1,690
	Total	**588**	**11,506**

* Does not include installations in Maine Public District

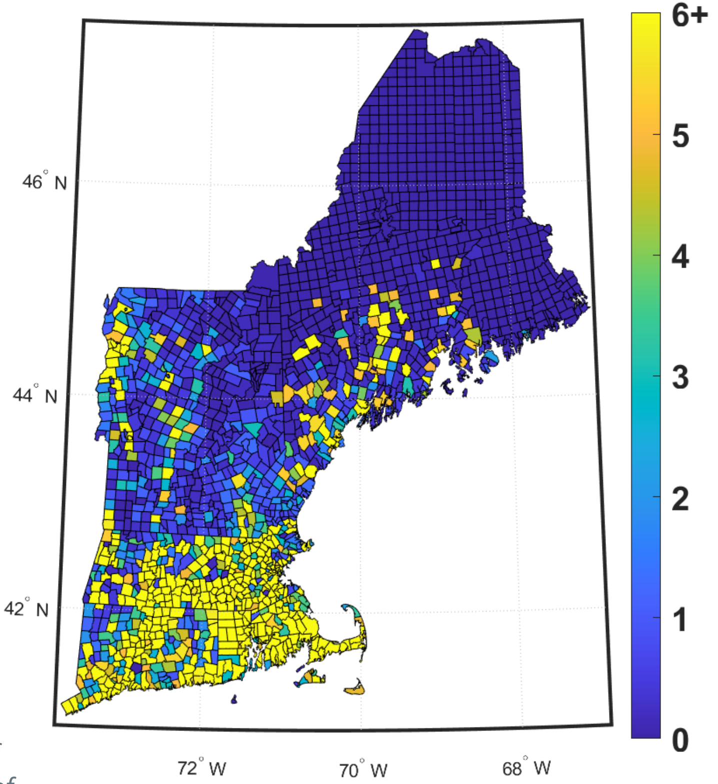
December 2023 Cumulative PV Totals (2 of 2)

Summary of Distribution Owner PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	20	1,550
	New Hampshire Electric Co-op	22	1,950
	Public Service of New Hampshire	179	15,518
	Unitil (UES)	23	2,216
	Total	**244**	**21,234**
RI	Rhode Island Energy	400	22,769
	Total	**400**	**22,769**
VT	Burlington Electric Department	9	409
	Green Mountain Power	418	16,326
	Stowe Electric Department	3	138
	Vermont Electric Co-op	47	2,609
	Vermont Public Power Supply Authority	22	829
	Washington Electric Co-op	8	868
	Total	**507**	**21,179**
New England		**6,542**	**347,341**

Installed PV Capacity as of December 2023

Regional Heat Map

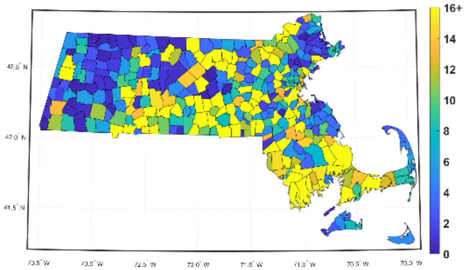


<u>Note</u>: Legend to the right of heat map shows color scale of nameplate megawatts per town

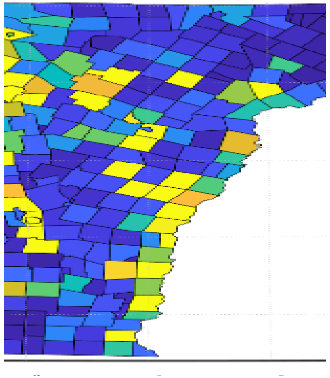
Installed PV Capacity as of December 2023

State Heat Maps

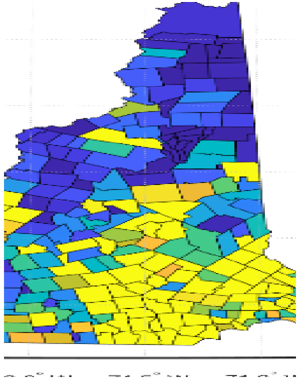
Massachusetts



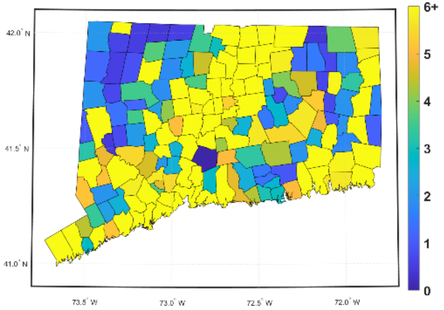
Vermont



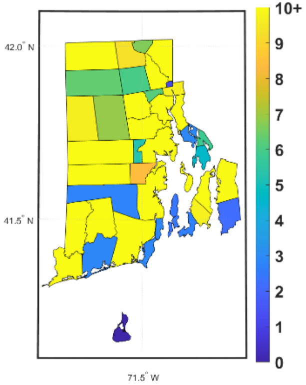
New Hampshire



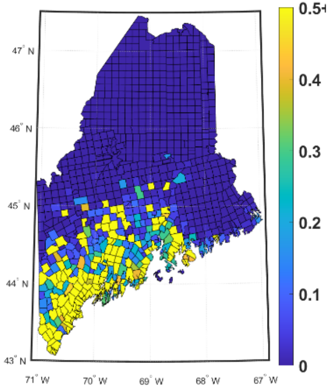
Connecticut



Rhode Island



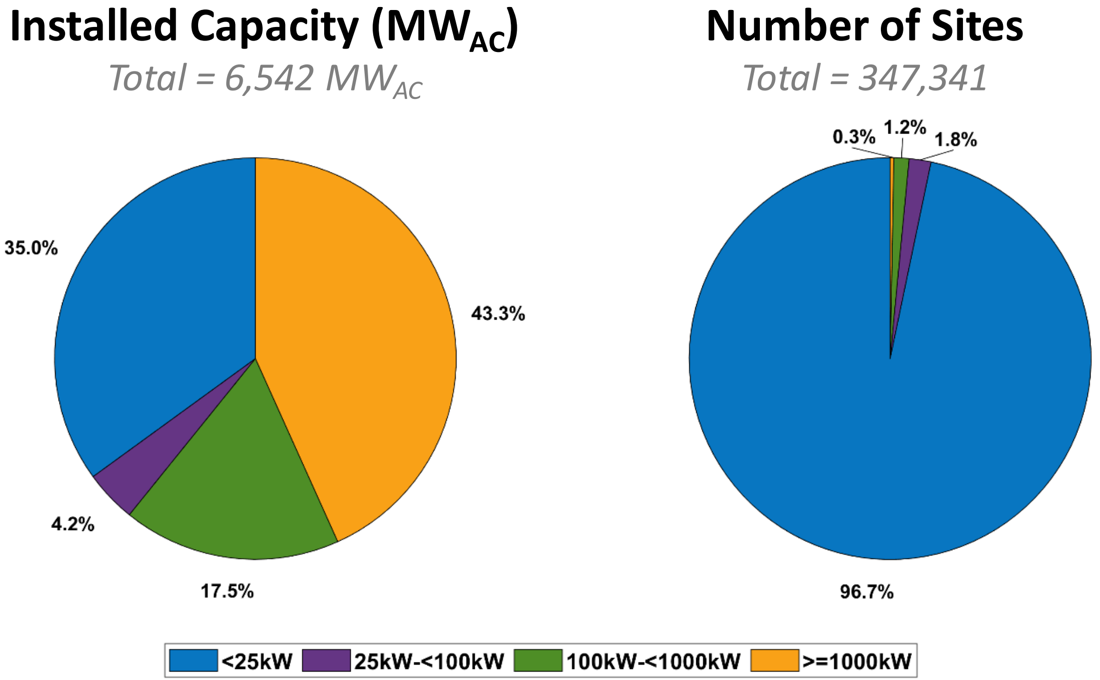
Maine



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

Installed PV Capacity as of December 2023

ISO-NE by Size Class



APPENDIX III

dGen^{TM} Modeling Assumptions

dGen™ Economic Modeling Informs Adoption

- To determine adoption, dGen™ considers the economic feasibility of a PV project by calculating its net present value
- The net present value calculation includes a detailed cash flow analysis based on the following:
  - System costs
  - Financial incentives (federal and state level)
  - Electric rates and rate structures
  - Electric energy consumption cost
  - Solar energy generation revenue
  - Others (taxes, inflation rate, etc.)
- The subsequent slides focus on ISO's preliminary assumptions to translate current policies to **financial incentive inputs** within dGen™

dGen™ Assumptions

- The ISO used the federal and state policy assumptions described in this Appendix as inputs to the dGen™ modeling
- NREL's 2023 Electricity Annual Technology Baseline (ATB) forecast are also used as an input regarding future PV technology costs
  - NREL's forecast assumes a decline in technology cost at an increasing rate toward the end of the forecast horizon

FEDERAL INVESTMENT TAX CREDIT (ITC)

dGen^{TM} Federal Policy Modeling Assumptions

Federal Investment Tax Credit (ITC)

- The federal ITC allows residential and commercial tax payers to claim a federal income tax credit equivalent to a percentage of the total cost of a PV system
- ITC is modeled separately from net metering and other state incentives within dGen™
- Tabulated below are the modeling inputs for the federal ITC

Sector	Percent of total cost	Effective start date	Policy end date
Residential and Commercial	30	01/01/2006	12/31/2019
	26	01/01/2020	12/31/2021
	30	01/01/2022	12/31/2033
	22.5	01/01/2034	12/31/2034
	15	01/01/2035	12/31/2035
	0	Beyond 2035	

STATE POLICY MODELING

dGen^{TM} State Policy Modeling Inputs and Assumptions

Net Metering Modeling

- The default conceptual framework for net metering within dGen™ is:
  - Assumptions are based on the economics of a customer-owned project (i.e., not a “community” PV project), and leverage NREL’s end-use load shapes to represent electricity demand profiles
  - For months with PV generation in excess of demand, the excess is rolled over to next month’s billing period
  - Rolled over excess generation can continue to accumulate, and any net excess generation (kWh) at the end of the annual true-up period is credited to the bill as a monetary payment based on the compensation rate for net metering
    - Can be either the retail tariff or an adjusted retail tariff
- These default assumptions were used in the modeling of net metering and net energy billing programs in all states
  - ISO acknowledges these programs may operate differently in some states than modeled
  - Improvements to these default assumptions will be considered in subsequent forecast cycles, especially for states in which forecast adoption does not align with historical trends, and it is suspected that net metering modeling may be a contributing factor

MASSACHUSETTS

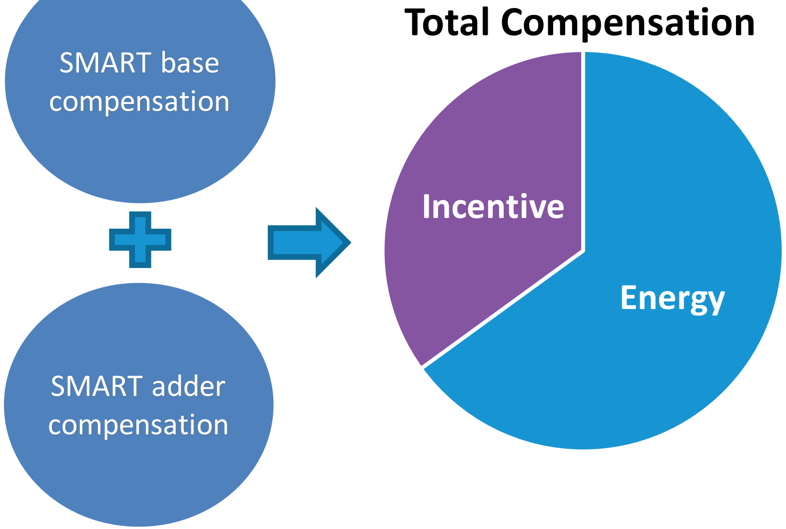
Current PV Policies in Massachusetts

1. Residential renewable energy income tax credit (RRITC)
   - Provides a investment-based incentive (IBI) of 15% (up to $1,000) against the state income tax for the net expenditure of a renewable energy system

Sector	Max. incentive ($)	Investment-based % of cost	Policy start date	Policy end date
Residential	1,000	15	1979-01-26	No end date

2. Solar Massachusetts Renewable Target (SMART)
   - Provides performance based incentive (PBI) for PV installed on residential and commercial properties within investor-owned utility (IOU) service territories
   - Total program capacity is 3,200 MW, divided into 16 capacity blocks with decreasing incentive rates
   - Provides additional incentives for qualifying "adders"
     - E.g., location, off-taker, energy storage, solar tracking and pollinator.

SMART Incentive Structure and Modeling



- Within dGen™, the incentive compensation and energy compensation are modeled separately
- Energy payment (value of energy)
  - Can be either net metering or alternative on-bill credit (AOBC)
  - In dGen™, modeled as net metering, which uses utility tariff rates
- Incentive payment
  - In dGen™, modeled as performance-based incentive

SMART Incentive Compensation Estimate

Estimate value of energy

Calculate average value of energy by sector and distribution company

Estimate adder compensation

Calculate a weighted average adder compensation (energy storage is currently excluded)

Estimate incentive compensation

Add estimated adder compensation and remove estimated value of energy

(by sector, capacity block, system class size and distribution company)

Calculate final weighted incentive inputs to dGen™

Weight average incentive by investor-owned utility and four capacity block groups (each block group includes four blocks)

SMART Incentive Compensation Estimate

Residential

- Tabulated below is the estimated incentive compensation for residential PV

Block Group	Capacity Blocks	Sector	System Class Size	Incentive Rate	Cumulative incentive capacity (MW)
1	1-4	Residential	<25kW	0.084	817
2	5-8			0.037	1,622
3	9-12			0.012	2,411
4	13-16			0*	3,200

*A zero incentive indicates that in block group four (i.e., capacity blocks 13-16), all payments from SMART come from energy compensation (i.e., net metering)

SMART Incentive Compensation Estimate

Commercial

- Tabulated below is the estimated incentive compensation for commercial facilities up to 250 kW

Block Group	Capacity Blocks	Sector	System Class Size	Incentive Rate ($/kWh)	Cumulative incentive capacity (MW)
1	1-4	Commercial	<25kW	0.139	817
2	5-8			0.091	1,622
3	9-12			0.066	2,411
4	13-16			0.047	3,200
1	1-4		25 – 250kW	0.064	817
2	5-8			0.029	1,622
3	9-12			0.009	2,411
4	13-16			0	3,200

SMART Incentive Compensation Estimate

Commercial

- Tabulated below is the estimated incentive compensation for commercial facilities in the size range of 250 kW to 1,000 kW

Block Group	Capacity Blocks	Sector	System Class Size	Incentive Rate ($/kWh)	Cumulative incentive capacity (MW)
1	1-4	Commercial	250 - 500kW	0.024	817
2	5-8			0.002	1,622
3	9-12			0	2,411
4	13-16			0	3,200
1	1-4		500 – 1,000kW	0.004	817
2	5-8			0	1,622
3	9-12			0	2,411
4	13-16			0	3,200

Resources

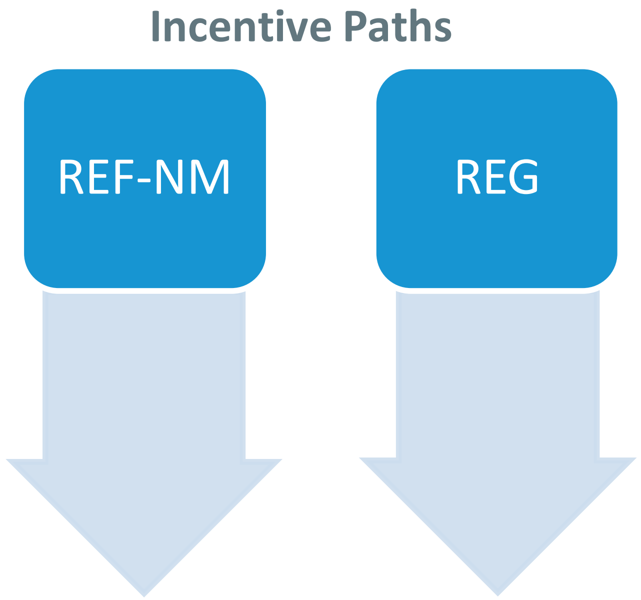
Program Related Information	References
SMART compensation rate	https://www.mass.gov/doc/capacity-block-base-compensation-rate-and-compensation-rate-adder-guideline-2
SMART program overview	https://www.mass.gov/doc/smart-launch-and-program-overview/
Value of energy workbook	https://www.mass.gov/doc/2023-btm-value-of-energy-workbook/download
Alternative on-bill credits	https://www.mass.gov/doc/alternative-on-bill-credit-faq/
SMART program data	https://www.mass.gov/doc/smart-solar-tariff-generation-units

RHODE ISLAND

Current PV Policies in RI – Two Incentive Paths

1. Renewable Energy Fund and net metering (REF-NM)
   - Renewable energy fund (REF)
     - Provides capacity-based incentive (CBI) grants for PV projects
     - Program fund is determined on an annual basis
   - Net metering
     - Enables customers to sell their PV generation at retail tariff rates
     - Net metering is modeled separately from incentive programs inside the dGen™ model

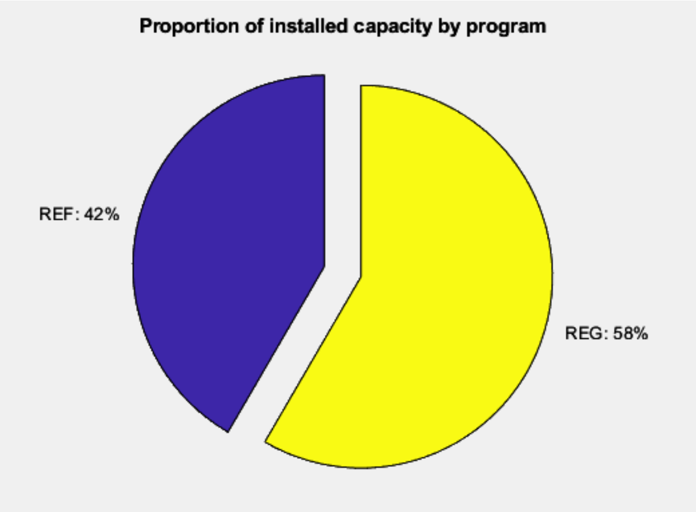
2. Renewable Energy Growth (REG) program
   - Provides a performance-based incentive (PBI) at fixed rates for 15-20 years
   - Each year the program is revised with new ceiling prices and a megawatt allocation plan



PV projects cannot participate in both incentive paths.

Modeling Adjustments

- dGen^{TM} is not able to model concurrent, mutually exclusive programs separately for a given forecast year
  - Therefore, steps are necessary to avoid double-counting of REF and REG within dGen^{TM}
- Solution → model as one program
  - Add total annual installed capacity from both programs
  - Adjust the incentive rates based on weights corresponding to the historical shares of installed capacity of each program



Unadjusted REG Incentives

- PBI rates tabulated below are net of the investor-owned utility (IOU) retail rates, which are modeled separately as a net metering incentive in dGen™
  - The IOU rate was obtained from the Utility Rate Database maintained by the U.S. Department of Energy's Energy Information Administration

- Rates below reflect incentives for the REG program only, prior to adjustments for modeling REF/REG as a combined program

Sector	System Capacity (kW)	Performance-based ($/kWh)	Incentive Duration	Effective start date	Policy end date
Residential	<= 15 kW	0.06	15	2015-01-01	Assumed a sunset date on 12/31/2029
	15 – 25 kW	0.04	20		
Commercial	<= 15 kW	0.14	15		
	15 – 25 kW	0.12	20		
	25 – 250 kW	0.12	20		
	250 – 1,000 kW	0.07	20		
	1,000 – 5,000 kW	0.01	20		

Unadjusted REF Incentives

- CBI rates tabulated below are based on published REF data for the two most recent years
- Rates reflect incentives for REF program only, prior to adjustments for modeling REF/REG as a combined program

Sector	System Capacity (kW)	Capacity-based ($/kW) *	Effective start date	Policy end date
Residential	<= 7.69	650	2014-01-01	Assumed a sunset date on 12/31/2029
Commercial	<= 50	700		
	50 – 100	400		
	100 – 150	300		
	150 – 5,000	200		

*Rate does not include energy storage adder

Adjustment Calculations

- Adjustments are calculated based on weighting factors applied to both the REG's PBI rate and REF's CBI rate to model both programs concurrently within dGen^{TM} as described below:

$$REG_{adj} = REG_{unadj} \times REG_{Weight}$$
$$REF_{adj} = REF_{unadj} \times REF_{Weight}$$

Where:

REG_{adj}	: adjusted PBI rate for REG program
REG_{unadj}	: unadjusted PBI rate for REG program
REG_{Weight}	: weighting factor for REG program, 0.58 (as mentioned in slide 3)
REF_{adj}	: adjusted CBI rate for REF program
REF_{unadj}	: unadjusted CBI rate for REF program
REF_{Weight}	: weighting factor for REF program, 0.42 (as mentioned in slide 3)

Adjusted REG and REF Incentives

Sector	System Capacity (kW)	Performance-based ($/kWh)	Incentive Duration	Policy start date	Policy end date
Residential	<= 15 kW	0.03	15	2015-01-01	Assumed a sunset date on 12/31/2029
	15 – 25 kW	0.02	20		
Commercial	<= 15 kW	0.08	15		
	15 – 25 kW	0.07	20		
	25 – 250 kW	0.07	20		
	250 – 1,000 kW	0.04	20		
	1,000 – 5,000 kW	0.003	20		

Sector	System Capacity (kW)	Capacity-based ($/kW) *	Policy start date	Policy end date
Residential	<= 7.69	270	2014-01-01	Assumed a sunset date on 12/31/2029
Commercial	<= 50	290		
	50 – 100	170		
	100 – 150	120		
	150 – 5,000	80		

*Rate does not include energy storage adder

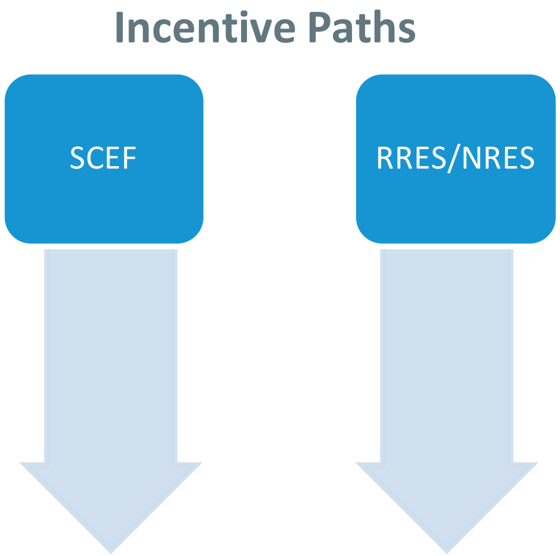
Resources

Program Related Information	References
REG	https://gridforce.my.site.com/RI/s/article/Rhode-Island-Renewable-Energy-Growth-Program https://energy.ri.gov/renewable-energy/wind/renewable-energy-growth-program-reg-program
REF	https://commerceri.com/financing/renewable-energy-fund/
Net metering	https://energy.ri.gov/renewable-energy/wind/net-metering

CONNECTICUT

Current PV Policies in Connecticut

- Shared Clean Energy Facility (SCEF) program
  - Provides incentives to customers who are not able to invest/lease an individual property PV installation.
  - Customers can subscribe to a shared PV system with no additional cost.
  - Eligible shared PV system must be between 100 kW and 5,000 kW capacity.
- Residential Renewable Energy Solutions (RRES)
  - Provides incentives to residential customers via net metering and renewable energy certificate (REC)
  - Two options:
    - Buy-all incentive rate, utilities purchase all generated energy and RECs at a fixed rate for 20 years.
    - Netting incentive rate, utilities purchase all generated RECs at a rate that is determined annually and issue on-bill credit for energy exported/not consumed on site.
- Non-residential Renewable Energy Solutions (NRES)
  - Similar to the RRES program but for commercial customers



PV projects cannot participate in both incentive paths.

SCEF Not Included in dGen™ Modeling

- The SCEF program is not modeled within dGen™ since it primarily supports MW-scale, “community” PV projects that are beyond the scope of the model
- The outlook for SCEF-supported PV growth is therefore included in the MW-scale forecast

RRES Assumptions

- RRES is modeled within dGen™ as a combination of net metering and an additional performance-based incentive (PBI)
  - This modeling approach “looks” like the netting incentive rate option
- The PBI rate is estimated using the investor-owned utility (IOU) average price cap per REC for residential customers
- Tabulated below is the PBI rate and associated information used

Sector	System Capacity (kW)	Performance-based ($/kWh)	Incentive duration	Effective start date	Policy end date
Residential	<= 25	0.0318	20	2022-01-01	Defaulted to 2029-12-31

NRES Assumptions

- NRES is modeled as a combination of net metering and an additional performance-based incentive (PBI) from NRES
- The PBI rate is estimated using the investor-owned utility (IOU) average price cap per REC for commercial customers

Sector	System Capacity (kW)	Performance-based ($/kWh)	Incentive Duration	Effective start date	Policy end date
Commercial	<= 5	0.012	20	2022-01-01	Defaulted at 2023-12-31
	5 – 200	0.054			
	200 – 1,000	0.043			
	1,000 – 5,000	0.012			

References

Program	References
SCEF	https://portal.ct.gov/DEEP/Energy/Shared-Clean-Energy-Facilities/Shared-Clean-Energy-Facilities
RRES	https://portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/residential-renewable-energy-solutions-program https://portal.ct.gov/-/media/PURA/electric/TRA/Eversource-Residential-Renewable-Energy-Solutions-FAQs.pdf
NRES	https://portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/non-residential-renewable-energy-solutions-program https://portal.ct.gov/-/media/PURA/electric/TRA/CAE-071-UI-Attachment-2.pdf https://www.eversource.com/content/docs/default-source/save-money-energy/nres-year-2-rfp.pdf?sfvrsn=9e649362_2

NEW HAMPSHIRE

Current PV Policies in New Hampshire

- Residential solar rebate program
  - Provide grants to residential scale PV projects.
  - Incentive rate is \$0.20/W with a maximum of \$1,000 or 30% of total cost (whichever is less).
  - Program is closed in 2023; future applications are selected on a lottery basis, depending on available funding
- Commercial and industrial (C&I) solar rebate program
  - Provide grants to C&I scale PV projects.
  - Incentive rate is \$0.2/W with a maximum of \$10,000 or 25% of total cost (whichever is lower).
- Net metering
  - Currently at NEM 2.0, which allows customers to sell their PV generation at a revised tariff rate (i.e., tariff rate less non-bypassable charges).
  - Net metering is modeled separately from other incentive programs inside the dGen™ model

Residential Solar Rebate Program Assumptions

- Modeled as a capacity-based incentive (CBI) with a total budget cap and project incentive cap, as tabulated below:

Sector	System Capacity (kW)	Capacity-based ($/kW)	Project incentive cap ($)	Total remaining program budget ($)	Policy start date	Policy end date
Residential	<= 25	200	1,000	2,136,200	10/01/2009	Assumed a sunset date on 01/01/2030

- Estimation of the total remaining program budget used for this forecasting cycle is based on the following equation:

$$Total_{budget} = fund_{FY23} + fund_{FY24} \times (Program\ End\ Year\ - 2024)$$

Where:

$Total_{budget}$: total estimated program budget
$fund_{FY23}$: available funding FY23 - $200,000
$fund_{FY24}$: available funding FY24 - $356,000
$Program\ End\ Year$: Assumed sunset year for the program - 2029

C&I Solar Rebate Program Assumptions

- Modeled as a capacity-based incentive (CBI) with a total budget cap and project incentive cap, as tabulated below:

Sector	System Capacity (kW)	Capacity-based ($/kW)	Project incentive cap ($)	Total remaining program budget ($)	Policy start date	Policy end date
Commercial	<= 500	200	10,000	3,250,000	10/01/2010	Assumed a sunset date on 01/01/2030

- Estimation of the total remaining program budget used for this forecasting cycle is based on the following equation:

$$Total_{budget} = fund_{FY23} + fund_{FY24} \times (Program\ End\ Year - 2024)$$

Where:

$Total_{budget}$: total estimated program budget
$fund_{FY23}$: available funding FY23 - $250,000
$fund_{FY24}$: available funding FY24 - $500,000
$Program\ End\ Year$: assumed sunset year for the program – 2030

References

Program Related Information	References
Residential solar rebate program	https://www.energy.nh.gov/renewable-energy/renewable-energy-rebates/residential-renewable-electrical-generation-rebate
C&I Solar Rebate Program	https://www.energy.nh.gov/renewable-energy/renewable-energy-rebates/commercial-industrial-solar-incentive-program
Program funding	https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/renewal-energy-fund-budget-allocation-approval-fy24_0.pdf https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-302/LETTERS-MEMOS-TARIFFS/15-302_2022-09-14_NHDOE_LTR-APPROVING-FY23-RENEWABLE-ENERGY-FUND-PROGRAM-BUDGET-ALLOCATION.PDF
Net metering	https://www.puc.nh.gov/sustainable%20energy/Group%20Net%20Metering/PUC-SE-NEM-Tariff-2020.pdf

VERMONT

Current PV Policies in Vermont

- Standard offer program
  - Under the program, Vermont distribution utilities purchases renewable power from an eligible generator at a specified price for a specified period of time
  - Eligible system's capacity must not exceed 2,200 kW
  - Program cap is 127.5 MW (113 MW for PV projects)
  - 73.95 MW of PV system online, 39.05 MW pending
- State tax credits for business
  - Provides state tax credit for projects that are eligible to receive federal tax credit.
  - Credit amount equals to 24% of the federal investment tax credit (ITC) attributable to the Vermont-property portion of the investment
- Net metering
  - Currently at NEM 2.5, which allows customers to sell their PV generation at the retail tariff rate with adjustors for REC disposition and siting
  - Net metering is modeled separately from incentive programs inside the dGen™ model

Standard Offer Program Modeling

- Model as a performance-based incentive program (PBI)
- The PBI rate is based on the price-cap rate from the program’s 2022 Request for Proposals (RFP)
- The pending total PV system capacity was used as a cap for the program within the model

Sector	System Capacity (kW)	Performance-based ($/kWh)	Remaining total program capacity (MW)	Effective start date	Policy end date
Residential	<= 2,200	0.098	39.05	09/30/2009	Assumed a sunset date of 12/31/2029
Commercial	<= 2,200	0.098			

State Tax Credit for Business Modeling

- Model the policy as an investment-based incentive (IBI) within dGen^{TM}, calculated as 24% of the federal ITC as tabulated below:

Effective period	Federal ITC	State ITC
2009 – 2033	30%	7.2%
2034	22.5%	5.4%
2035	15%	3.6%
Beyond 2035	0%	0%

- The table below describes the direct model inputs for this policy.

Sector	Investment based percent	Effective start date	Policy end date
Commercial	7.2	01/01/2009	12/31/2033
	5.4	1/1/2034	12/31/2034
	3.6	1/1/2035	12/31/2035

References

Program	References
Standard Offer Program	https://vermontstandardoffer.com/ https://vermontstandardoffer.com/standard-offer/request-for-proposals/2022-rfp/2022-standard-offer-program-request-for-proposals/
State Tax Credit for Business	https://tax.vermont.gov/business/tax-credits https://programs.dsireusa.org/system/program/detail/3428/investment-tax-credit
Net metering	https://puc.vermont.gov/electric/net-metering

MAINE

Current PV Policies in Maine

- Net energy billing (NEB) includes two distinct programs:
  1. kWh credit program
     - Available to all electric utility customers.
     - Customers may choose to have their own project, or participate in a larger “shared” project
     - Provides kWh credits on participating customers’ electricity bills. Customers will be charged only for their net energy import. The excess generation will be applied to the following billing period.
     - Customers may accumulate unused credits and apply them against total usage over a 12-month rolling period. Accumulated unused credits may not be applied against future usage and will not be compensated.
  2. Tariff rate program
     - Available to non-residential customers
     - Customers may choose to have their own project, or participate in a larger “shared” project
     - Provides bill credits on participating customers’ electricity bills. The tariff rates are determined annually by the Public Utilities Commission (PUC).
     - 2023 tariff rates are the standard offer rates plus 75% of transmission and distribution charges (rates differ by business classes and investor-owned utilities).
     - Customers may accumulate unused bill credits and apply them against total bill over a 12-month rolling period. Accumulated unused credits may not be applied against future usage and will not be compensated.

- NEB is modeled using the default net metering assumptions within dGen™

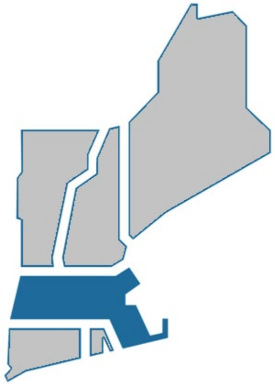
References

Program Related Information	References
NEB	https://www.maine.gov/mpuc/regulated-utilities/electricity/neb
Tariff rate	https://www.maine.gov/mpuc/regulated-utilities/electricity/delivery-rates https://www.maine.gov/mpuc/regulated-utilities/electricity/standard-offer-rates/

APPENDIX IV

Megawatt-Scale PV Forecast Assumptions

Massachusetts Forecast Assumptions

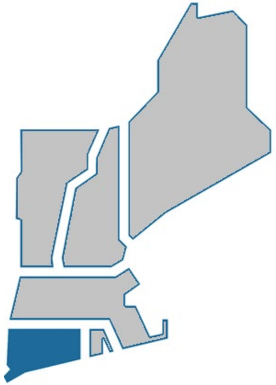


- Policy information is contained in in the MA Department of Public Utilities (MA DPU) presentation to the DGFWG on December 8, 2023
- MA Distribution Owners reported a total of 1,746 MW_{AC} of large systems (>= 1 MW) installed through 12/31/2023 with less growth observed in 2023 from large systems than that observed in 2021 and 2022
- Within Solar Massachusetts Renewable Target (SMART) Program, 1,013 MW_{AC} of large systems were installed by end of 2023
  - Assume an additional 412 MW_{AC} of large projects will be installed to reach program goal by 2029

MA Forecast Inputs

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW-scale Forecast	94	93	89	84	77	69	60	52	44	38

Connecticut Forecast Assumptions



- Policy information is contained in the CT Department of Energy & Environmental Protection (CT DEEP) presentation to the DGFWG on December 8, 2023
- Driving policies:
  - Low- & Zero-Emission Renewable Energy Credits (LREC/ZREC) program: 411.3 MW_{AC} are operational, assume 10.8 MW_{AC} of the remaining 123.8 MW are from large systems
  - Shared Clean Energy Facility (SCEF) program: 1.5 MW_{AC} of selected 118.3 are in service, assume all of the selected MW are large system and another 100 MW_{AC} will be installed under the program's 2024 and 2025 procurement
  - Non-Residential Energy Solution (NRES) program: 44.1 MW_{AC} of large systems were selected, assume an additional 148 MW_{AC} will be installed throughout the remaining period of the program
- Most recent historical data shows a 3-year average growth rate for large system was 14.8 MW_{AC} with 2 MW_{AC} installed last year
- Forecast inputs tabulated below reflect approximately 80% of total nameplate capacity from policies listed above

CT Forecast Inputs

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW-scale Forecast	39	47	50	43	36	32	28	24	21	18

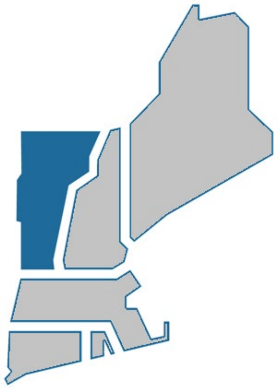
Rhode Island Forecast Assumptions

- Policy information is contained in the RI Office of Energy Resources (RI OER) presentation to the DGFWG on December 8, 2023
- Driving policies:
  - Renewable Energy Growth (REG): 178.8 MW_{AC} of large system were installed by the end of 2023, assume an additional 75 MW_{AC} (included in the program 2024-2026 Drafted Megawatt Allocation Plan) will be installed
  - Renewable Energy Fund (REF): Historical data does not include any large systems
- Most recent historical data shows a 3-year average growth rate for large system was 18.8 MW_{AC} with 15.8 MW_{AC} installed last year

RI Forecast Inputs

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW-scale Forecast	14	16	15	14	13	11	10	8	7	6

Vermont Forecast Assumptions

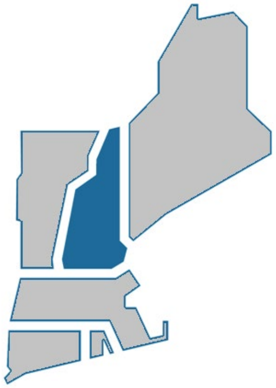


- Policy information is contained in the VT Department of Public Service (VT PSD) presentation to the DGFWG on December 8, 2023
- Driving policies:
  - Standard Offer program: 81.9 MW_{AC} were installed by the end of 2023, assume an additional 44.5 MW_{AC} (remaining of the program) will be installed, all of which are large systems
  - DG carve-out of the Renewable Energy Standard (RES) will drive distributed PV growth to match a growing share of VT's annual load energy, assume 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
- Most recent historical data shows a 3-year average growth rate for large system was 8.8 MW_{AC} with 9.3 MW_{AC} installed last year
- The forecast assumed a decline in the adoption of large systems beginning in 2028

VT Forecast Inputs

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW-scale Forecast	10	10	10	10	5	5	4	4	3	3

New Hampshire Forecast Assumptions



- Policy-based (large systems):
  - Policy information is contained in the NH Department of Energy (NH DOE) presentation to the DGFWG on December 8, 2023
  - Historical PV growth from large systems in has been minimal and sporadic, with zero installed capacity in 2023

NH Forecast Inputs

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW-scale Forecast	1	1	1	1	1	1	1	1	1	1

Maine Forecast Assumptions

- Policy information is contained in the ME Governor's Energy Office (ME GEO) presentation to the DGFWG on December 5, 2022
- ME Distribution Owners reported a total of 453.8 MW_{AC} of large systems installed through 12/31/2023, including 223.2 MW_{AC} in 2023
- Driving policies:
  - Net Energy Billing (NEB), 2-5 MW projects: 453.8 MWAC were installed by the end of 2023, assume an additional of 296.2 MWAC (total of 750 MW program goal) will be installed
  - NEB Successor, 2-5 MW projects: assume 560 MWAC total program goal, minus 5% of program capacity assumed to be installed in the Main Public District (i.e., outside of ISO New England), will be installed
  - NEB, <2MW projects, assume an annual growth of 5MW

ME Forecast Inputs

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW-scale Forecast	208	104	101	95	87	77	67	58	50	43

USE OF DISCOUNT FACTORS

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 106-108) 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 2023 Forecast	Final 2024 Forecast
2024	10%	2.5%
2025	15%	5%
2026	15%	7.5%
2027	15%	10%
2028	15%	12.5%
2029	15%	15%
2030	15%	15%
2031	15%	15%
2032	15%	15%
2033	N/A	15%

Draft 2024 Forecast Inputs

Nameplate Capacity, PV Systems < 1 MW

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
CT	972.0	115.9	122.3	128.7	140.3	145.4	156.8	163.1	177.0	184.5	182.0	**2,488.0**
MA	1,966.0	240.5	245.1	249.8	260.2	266.1	270.3	268.6	282.1	297.3	296.7	**4,642.7**
ME	134.0	21.5	25.2	28.8	37.5	42.6	53.4	59.2	70.3	75.7	81.2	**629.5**
NH	227.0	27.0	26.9	26.7	25.7	24.9	24.9	25.8	27.8	28.9	29.1	**494.6**
RI	221.0	33.6	35.6	37.5	41.0	42.5	46.1	48.1	52.7	55.2	54.0	**667.2**
VT	347.0	19.9	20.5	21.2	22.9	24.0	27.5	29.9	36.4	40.5	42.6	**632.4**
ISONE	**3,867.0**	**458.5**	**475.6**	**492.7**	**527.7**	**545.5**	**579.0**	**594.7**	**646.2**	**682.0**	**685.5**	**9,554.4**

Notes:

(1) The above values **are not forecast values**, but rather pre-discounted inputs to the forecast (see slides 64-65 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

Draft 2024 Forecast Inputs

Nameplate Capacity, PV Systems 1-5 MW

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
CT	118.0	38.8	46.7	49.6	42.8	35.8	31.9	27.9	24.1	20.7	17.9	**454.1**
MA	1,746.0	94.4	92.6	89.2	83.9	76.8	68.5	59.9	51.7	44.5	38.5	**2,446.0**
ME	454.0	207.8	104.3	100.5	94.5	86.5	77.2	67.5	58.2	50.1	43.3	**1,344.1**
NH	17.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	**27.0**
RI	179.0	14.0	16.0	15.4	13.8	12.6	11.3	9.8	8.5	7.3	6.3	**293.9**
VT	160.0	10.2	10.2	10.2	10.2	5.1	4.6	4.1	3.6	3.1	2.5	**223.6**
ISONE	**2,674.0**	**366.1**	**270.8**	**265.9**	**246.2**	**217.8**	**194.4**	**170.2**	**147.2**	**126.7**	**109.5**	**4,788.8**

Notes:

(1) The above values **are not forecast values**, but rather pre-discounted inputs to the forecast (see slides 64-65 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

Draft 2024 Forecast Inputs

Pre-Discounted Nameplate Values, All PV Systems

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
CT	1,090.5	154.7	169.0	178.3	183.0	181.1	188.7	191.0	201.1	205.2	200.0	**2,942.7**
MA	3,712.0	334.9	337.7	339.0	344.2	342.9	338.8	328.5	333.8	341.7	335.1	**7,088.7**
ME	588.0	229.3	129.5	129.3	132.1	129.1	130.6	126.6	128.6	125.8	124.5	**1,973.5**
NH	244.0	28.0	27.9	27.7	26.7	25.9	25.9	26.8	28.8	29.9	30.1	**521.6**
RI	400.0	47.5	51.5	52.9	54.8	55.1	57.3	57.9	61.1	62.5	60.3	**961.1**
VT	507.0	30.1	30.7	31.3	33.1	29.1	32.1	34.0	40.0	43.6	45.1	**856.1**
Pre-Discount Annual Total (MW)	**6,541.5**	**824.5**	**746.4**	**758.6**	**773.9**	**763.3**	**773.5**	**764.9**	**793.3**	**808.8**	**795.1**	**14,343.7**
Pre-Discount Cumulative Total (MW)	**6,541.5**	**7,366.1**	**8,112.4**	**8,871.0**	**9,644.9**	**10,408.2**	**11,181.7**	**11,946.5**	**12,739.9**	**13,548.7**	**14,343.7**	**14,343.7**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 64-65 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

APPENDIX VI

Geographic Distribution of PV Forecast

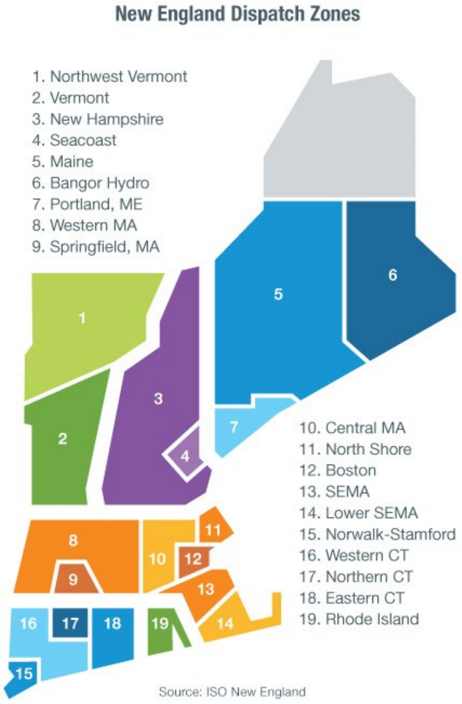
Overview

- 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 is possible via analysis of available data
- ISO geographically distributes forecasted PV according to existing geographical distribution at the end of the last historical year of data provided by Distribution Owners for the following sub-regions:
  - Load Zones
  - Dispatch Zones
  - RSP Subareas
- The breakdown of total PV reflected in Distribution Owner data submittals as of 12/31/2023 by Dispatch Zone is included on the next slide
- Note: Beginning with the 2020 forecast, all classification of PV (FCM, EOR, and BTM) has been performed uniquely for each sub-region to ensure proper accounting in various system planning studies

Dispatch Zone Distribution of PV

Based on December 31, 2023 Distribution Owner Data Submittals

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	17.7%
	CT	NorthernCT	18.0%
	CT	Norwalk_Stamford	7.8%
	CT	WesternCT	56.6%
ME	ME	BangorHydro	10.3%
	ME	Maine	68.3%
	ME	PortlandMaine	21.4%
MA	NEMA	Boston	11.7%
	WCMA	CentralMA	12.9%
	SEMA	LowerSEMA	16.5%
	NEMA	NorthShore	4.8%
	SEMA	SEMA	20.1%
	WCMA	SpringfieldMA	7.4%
	WCMA	WesternMA	26.6%
NH	NH	NewHampshire	88.5%
	NH	Seacoast	11.5%
RI	RI	RhodeIsland	100.0%
VT	VT	NorthwestVermont	60.8%
	VT	Vermont	39.2%



APPENDIX VII

Example Calculation of Estimated Summer Peak Load Reductions from BTM PV

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 2027

Description of Example Calculation Steps & Inputs

Massachusetts BTM PV July 2027 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 32
   - Input uses the conversion of cumulative end-of-year state nameplate forecast (slide 29) into monthly forecast using monthly capacity growth rates (slide 17)

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 20

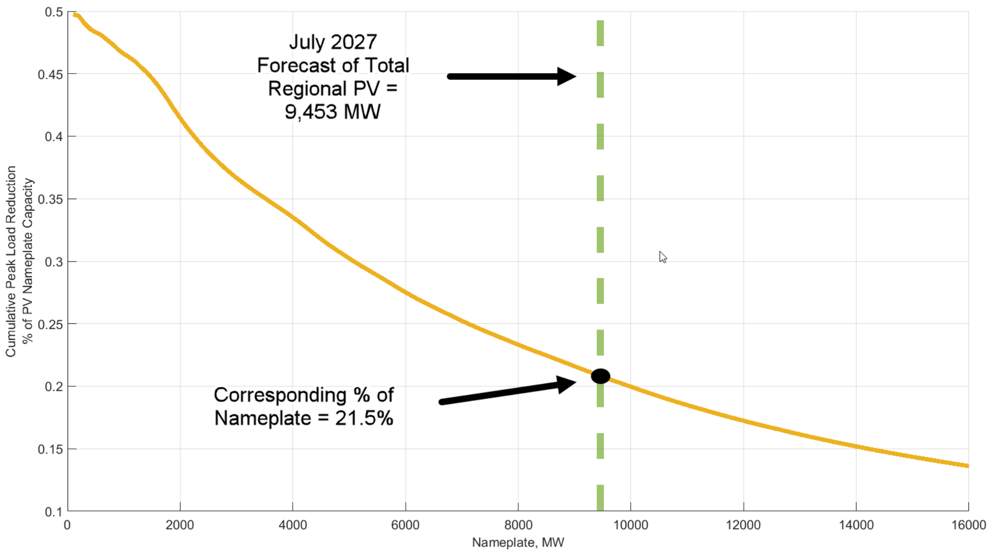
$$DegradeMultiplier = (1 - ADR)^{CA}$$

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

Estimated Summer Peak Load Reductions

July 2027 Example

- The orange line is the load-weighted peak load reduction as a percent of PV nameplate capacity
- These percent values are used to calculate BTM PV peak load reductions according to the equation below
- Details of underlying analysis used to develop the orange line is available at: http://www.iso-ne.com/static-assets/documents/2020/04/final_btm_pv_peak_reduction.pdf



BTM PV Peak Load Reduction, MW = (BTM PV Installed Capacity) * (% PV Nameplate)

Final Calculation

Massachusetts BTM PV July 2027 Summer Peak Load Reduction

Calculation Line Item	Relevant Region	
July 2027 Total Nameplate PV Forecast (MW)	ISO-NE	9046.3
July 2027 BTM PV Nameplate Forecast (MW)	MA	2428.8
% of Nameplate (from previous slide)	ISO-NE	0.215
Panel Degradation Multiplier	MA	0.96
Peak Gross Up Factor	ISO-NE	1.08
Final BTM PV Summer Peak Load Reduction (MW)	MA	543.0

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

Note: Tabulated values are rounded to the precision shown