APRIL 28, 2023

Final 2023 Photovoltaic (PV) Forecast

Outline

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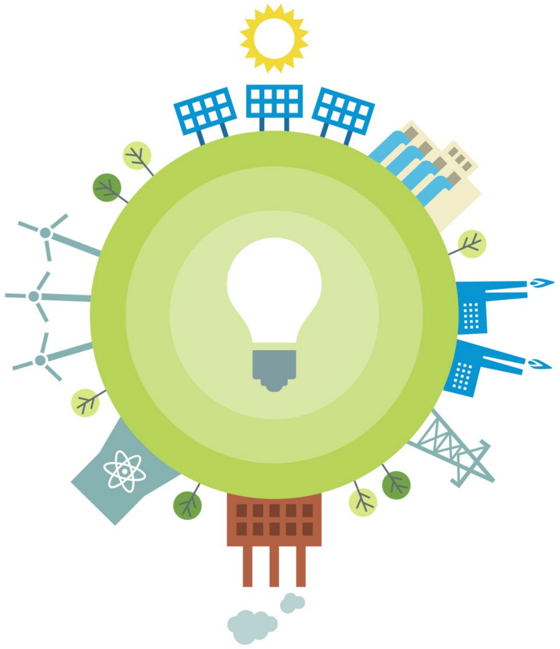
- Distribution Owner Survey Results
- 2022 PV Growth: Forecast and Actual
- Forecast Assumptions and Inputs
- 2023 PV Forecast - Nameplate MW
- 2023 PV Energy Forecast
- Classification of PV Forecast
  - Background & Methods
- Classification of 2023 PV Forecast
- 2023 Behind-the-meter PV (BTM PV) Forecast
- Geographic Distribution of PV Forecast
- Appendix: Example Calculation of Estimated Summer Peak Load Reductions from BTM PV



Forecast Review Process

- The ISO discussed the draft 2023 PV forecast with the DGFWG at the February 17, 2023 meeting
- Stakeholders provided comments on the draft forecast
  - Don Walters, Opus21
- The only change implemented for the forecast was to update the end of 2022 PV installed capacity in Vermont to correct an error in the utility data processing

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 2023 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."
- 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 Incorporates State Policies

- 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
- A policy-based forecasting approach is used to reflect the observation that trends in distributed PV development have tracked policy support by the New England states
- The ISO makes no judgment regarding state policies, but considers state policy information provided by the states in developing the forecast

Factors Influencing Development of Distributed PV

Policy Drivers	Other Drivers
Feed-in-tariffs (FITs)/Long-term procurement	Role of private investment in PV development
State Renewable Portfolio Standards (RPS) programs	Future equipment and installation costs
Net energy metering (NEM) and retail rate structure	Future wholesale and retail electricity costs
Federal investment tax credit (ITC) and federal depreciation	Costs and issues associated with grid infrastructure constraints and needed upgrades
Federal trade policy	Siting issues

2022 INSTALLED PV

Forecast vs. Reported

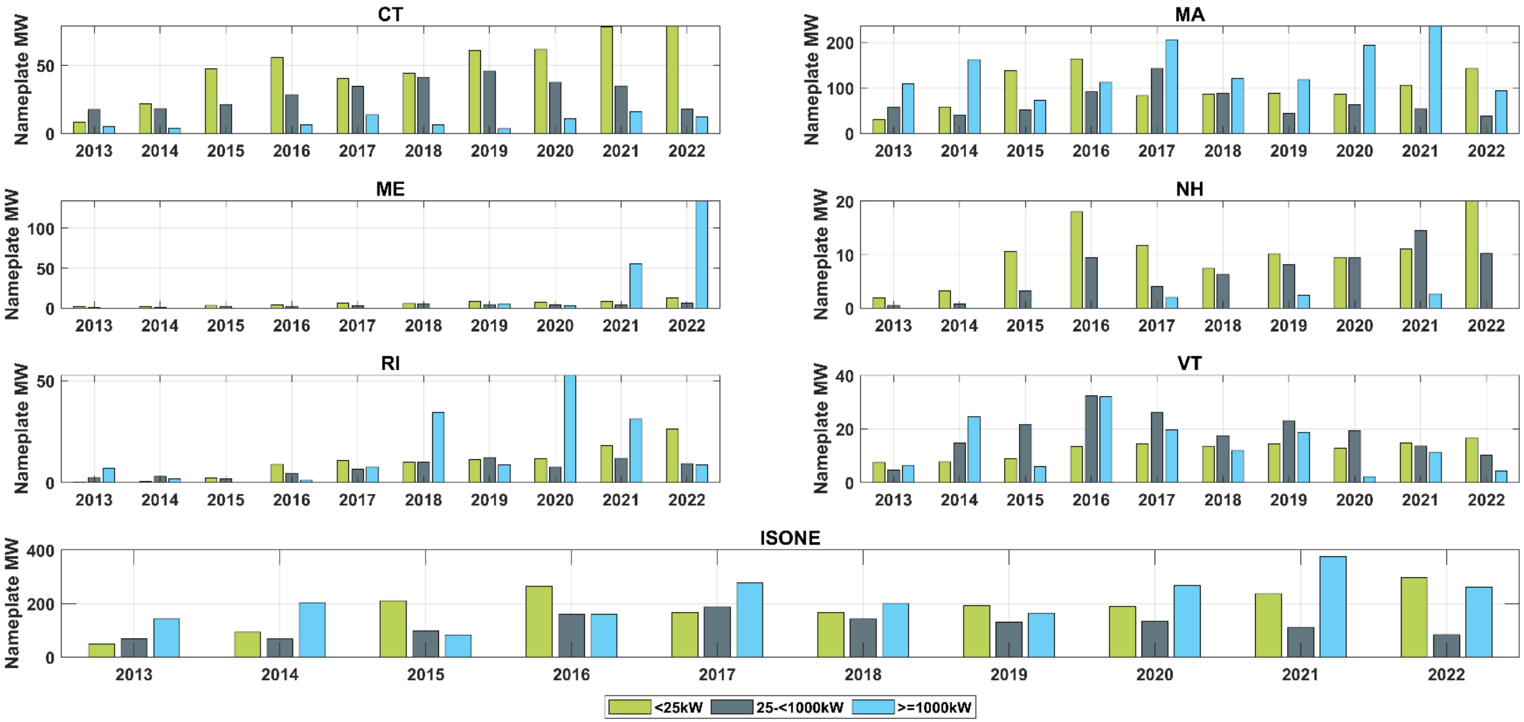
2022 PV Nameplate Capacity Growth

- Comparison of the state-by-state 2022 forecast PV growth and the growth for 2022 reported by utilities is tabulated below
  - Values include FCM, EOR, and BTM PV projects
- Regionally, 2022 growth reported by utilities totaled 705.6 MW, which is 75 MW lower than the forecast growth
  - Results vary by state as tabulated
- "Over the past year, uncertainty related to solar tariffs, energy policy, supply chain bottlenecks and rising project costs due to inflation has resulted in delayed, or even cancelled, projects" – Woods Mackenzie

State	2022 Reported Growth	2022 Forecast Growth	Error
CT	102.7	113.4	-10.7
MA	335.8	448.8	-113.0
ME	169.5	107.8	61.7
NH	26.5	30.0	-3.5
RI	37.2	52.1	-14.9
VT	33.9	28.5	5.4
Region	**705.6**	**780.6**	**-75.0**

Nameplate Capacity of Reported Annual PV Growth

Small (<= 25kW), Medium (25-<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	4	81.4
MA	-	-
ME	3	34.0
NH	-	-
RI	16	124.0
VT	-	-
Total	**23**	**239.4**

DISTRIBUTION OWNER SURVEY RESULTS

Installed Distributed PV – December 2022

Determining Cumulative PV Totals

December 2022 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, 2022
  - 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 2022 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 12/31/22.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	3,289	150,020
Connecticut	912	73,553
Vermont*	468	19,348
New Hampshire	183	14,427
Rhode Island	326	17,034
Maine	295	8,583
New England	**5,473**	**282,965**

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

December 2022- 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	711	54,496
	Connecticut Municipal Electric Energy Co-op	15	9
	United Illuminating	186	19,048
	Total	**912**	**73,553**
MA	Braintree Electric Light Department	6	43
	Chicopee Electric Light	13	43
	Unitil (FG&E)	48	2,623
	National Grid	1,721	80,359
	NSTAR	993	49,378
	Reading Municipal Lighting Plant	4	224
	Shrewsbury Electric & Cable Operations	7	131
	SREC I	54	589
	SREC II	97	1,672
	Western Massachusetts Electric Company	346	14,958
	Total	**3,289**	**150,020**
ME	Central Maine Power	259	7,554
	Versant*	36	1,029
	Total	**295**	**8,583**

* Does not include installations in Maine Public District

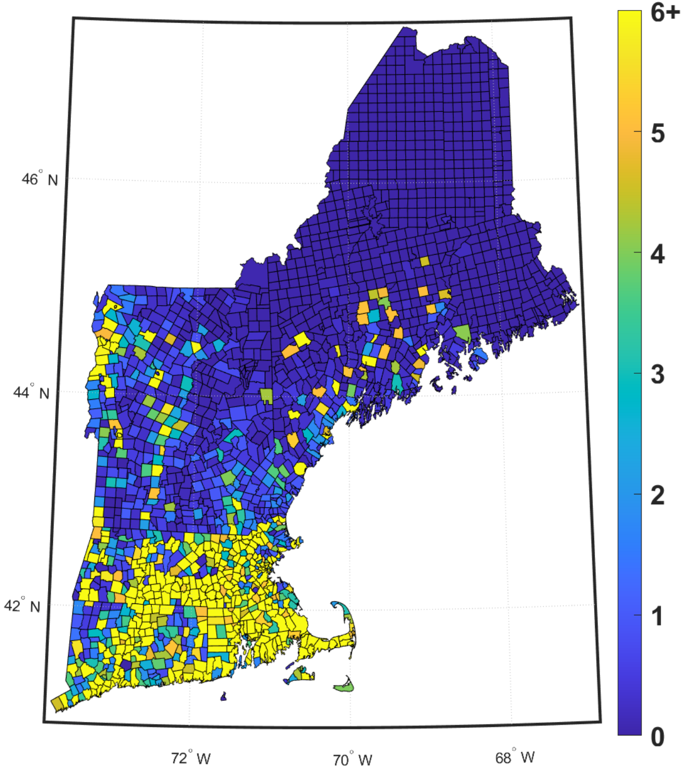
December 2022 Cumulative PV Totals (2 of 2)

Summary of Distribution Owner PV Data

State	Utility	Installed Capacity (MW_{AC})	No. of Installations
NH	Liberty Utilities	15	1,056
	New Hampshire Electric Co-op	18	1,573
	Public Service of New Hampshire	133	10,270
	Unitil (UES)	17	1,528
	Total	**183**	**14,427**
RI	National Grid	326	17,034
	Total	**326**	**17,034**
VT	Burlington Electric Department	9	376
	Green Mountain Power	384	15,047
	Stowe Electric Department	3	115
	Vermont Electric Co-op	42	2,311
	Vermont Public Power Supply Authority	22	709
	Washington Electric Co-op	7	790
	Total	**468**	**19,348**
New England		**5,473**	**282,965**

Installed PV Capacity as of December 2022

Regional Heat Map

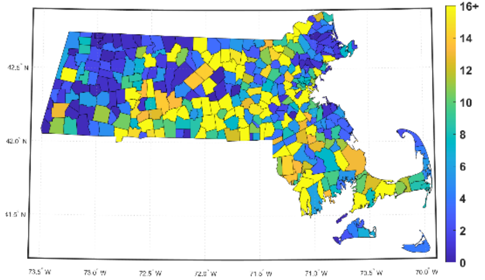


Note: Legend to the right of heat map shows color scale of nameplate megawatts per town

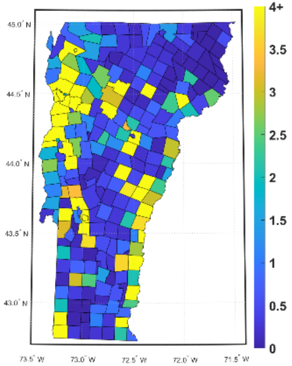
Installed PV Capacity as of December 2022

State Heat Maps

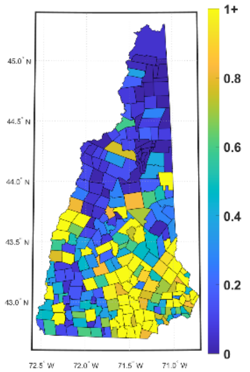
Massachusetts



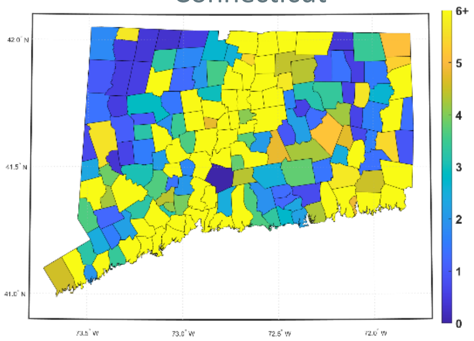
Vermont



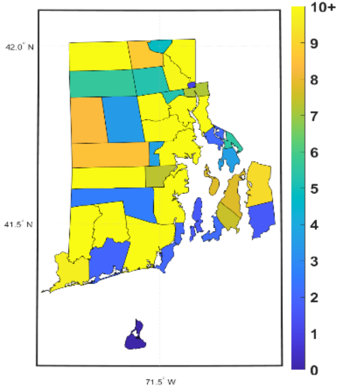
New Hampshire



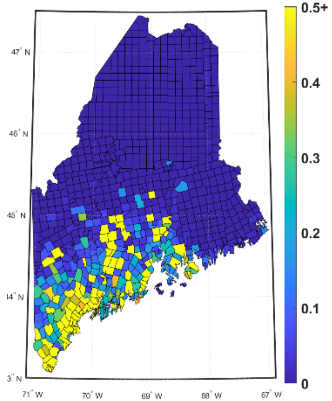
Connecticut



Rhode Island



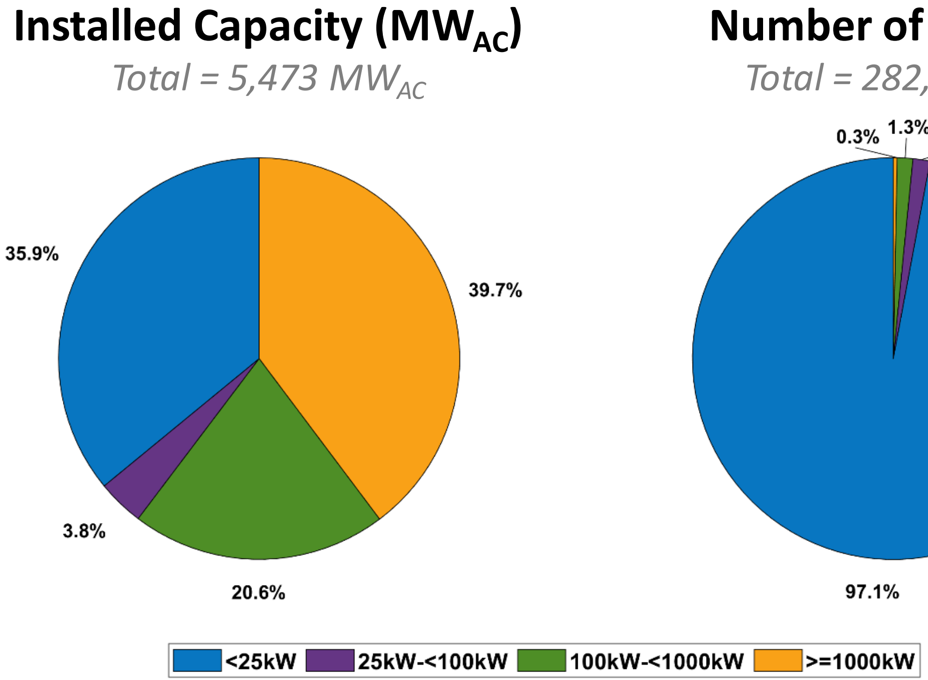
Maine



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

Installed PV Capacity as of December 2022

ISO-NE by Size Class



TOTAL PV NAMEPLATE CAPACITY FORECAST

Assumptions and Inputs

Federal Investment Tax Credit

- The federal Investment Tax Credit (ITC) has been a key driver of PV development in New England
- Business ITC
  - The federal Inflation Reduction Act (IRA) of 2022 (H.R. 5376) made several significant changes to this tax credit, including extending the expiration date, modifying the scheduled step-down in its value, providing for new bonus credits, and establishes procedures for other parties to monetize the credit (e.g., non-taxable entities).
  - The IRA also establishes new criteria to qualify for the full credit.
- Residential ITC
  - The IRA extended the expiration date and modified the phase down of the tax credit.

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

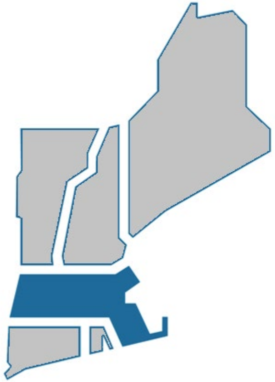
Overall Outlook

Tailwind Factors	Headwind Factors
Federal Inflation Reduction Act (IRA) extension of ITC for projects that begin construction before 2034, bringing longer-term certainty to renewables development	Hosting infrastructure constraints are becoming more prevalent as PV penetrations increase, especially for larger projects
State-level policy incentives	For larger projects in more rural areas, availability of land in proximity to adequate distribution infrastructure
Higher retail electric rates	Higher prices due to supply-chain constraints, high commodity and labor inflation, and increasing demand for clean energy
Corporations' increasing focus on environmental, social, and governance (ESG)	Finance in a time of inflation, higher interest rates, and a possible recession

Sources:

Opportunity and Complexity: U.S. Clean Energy Financing in 2023, CohnReznick and CohnReznick Capital, 2023.
U.S. Solar Surge Collides With Higher Rates and Shifting Economics, via Bloomberg LP, accessed February 15, 2023.

Massachusetts Forecast Assumptions

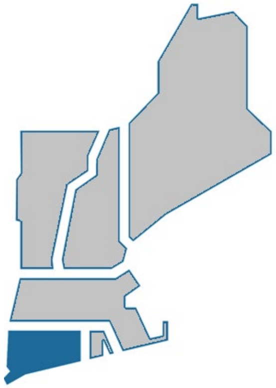


- Policy information is contained in the MA Department of Public Utilities (MA DPU) presentation to the DGFWG on December 5, 2022
- MA Distribution Owners reported a total of 3,289.2 MW_{AC} installed through 12/31/2022, including 335.8 MW_{AC} in 2022
- Solar Massachusetts Renewable Target (SMART) Program has a program goal of 3,200 MW_{AC}
  - 1,000 MW_{AC} installed by end of 2022
  - Additional 2,200 MW_{AC} installed to reach program goal by 2028 as tabulated below
- Post-policy development (i.e., red cells below) assumed to occur such that a total of 366.7 MW is carried forward from 2029 onward at constant rate throughout the remaining years of the forecast period, and post-policy discount factors are applied

MA Forecast Inputs

Year	Thru 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual % of SMART Program	31.3%	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	0%	0%	0%	0%
Annual SMART Program MW	1000	366.7	366.7	366.7	366.7	366.7	366.7	366.7	366.7	366.7	366.7

Connecticut Forecast Assumptions

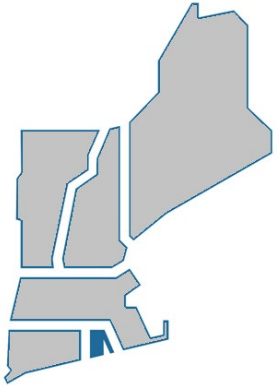


- Policy information is contained in the CT Department of Energy & Environmental Protection (CT DEEP) presentation to the DGFWG on December 5, 2022
- CT Distribution Owners reported a total of 911.8 MW_{AC} installed through 12/31/2022, including 102.7 MW_{AC} in 2022 (totals do not include projects > 5MW)
- Annual state MW forecast inputs tabulated below result from the following state programs:
  - Existing Low- & Zero-Emission Renewable Energy Credits (LREC/ZREC) program
  - Shared Clean Energy Facilities (SCEF) program
  - Renewable Energy Tariff, Residential Renewable Energy Solutions (RRES) program
  - Renewable Energy Tariff, Non-Residential Renewable Energy Solutions (NRES) program
- At the end of SCEF, RRES, and NRES programs, all MWs from last year of each program are carried forward until 2032 at a constant rate, and post-policy discount factors are applied

CT Forecast Inputs

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Existing ZREC/LREC	40.0	40.0	40.0							
SCEF (incl. Successor)	25.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
RRES	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
NRES	54.8	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3

Rhode Island Forecast Assumptions



- Policy information is contained in the RI Office of Energy Resources (RI OER) presentation to the DGFWG on December 5, 2022
- RI Distribution Owner reported a total of 325.6 MW_{AC} installed through 12/31/2022, including 32.7 MW_{AC} in 2022
  - Totals do not include projects > 5MW
- Annual state MW forecast inputs tabulated below result from the following state programs:
  - Renewable Energy Growth Program (REGP)
  - Renewable Energy Fund (REF) program
  - Virtual New Metering (VNM) program
- At the end of REGP, all MWs from last year of the program are carried forward until 2032 at a constant rate, and post-policy discount factors are applied

RI Forecast Inputs

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REGP	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
REF/VNM	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0

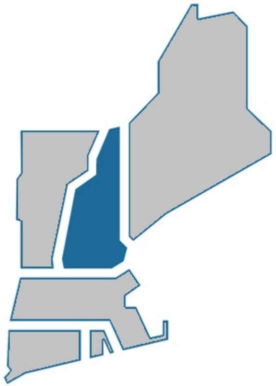
Vertmont Forecast Assumptions

- Policy information is contained in the VT Department of Public Service (VT PSD) presentation to the DGFWG on December 5, 2022
- VT Distribution Owner reported a total of 468.2 MW_{AC} installed through 12/31/2022, including 33.9 MW_{AC} in 2022
- 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
  - Load growth is assumed to reflect 2022 CELT net energy forecast (tabulated below)

VT Forecast Inputs

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Net Energy Growth (% of 2022)	0.1%	0.7%	1.3%	2.7%	4.6%	7.2%	9.7%	12.9%	16.2%	19.5%
Renewable Energy Standard	30.0	30.2	30.4	30.8	31.4	32.2	32.9	33.9	34.9	35.8

New Hampshire Forecast Assumptions

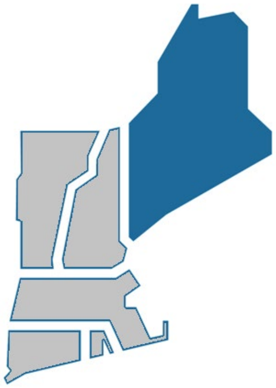


- Policy information is contained in the NH Department of Energy (NH DOE) presentation to the DGFWG on December 5, 2022
- NH Distribution Owners reported a total of 183.4 MW_{AC} installed through 12/31/2022, including 26.5 MW_{AC} in 2022
- Assume the Net Energy Metering Tariff continues to support the 2022 rate of growth throughout the forecast horizon as tabulated below

NH Forecast Inputs

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Net Metering MW	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5

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 294.6 MW_{AC} installed through 12/31/2022, including 169.5 MW_{AC} in 2022
- Annual state MW forecast inputs tabulated below result from the following state programs:
  - Net Energy Billing (NEB), 2-5 MW projects
    - Assume 750 MW total, minus 178.8 MW installed through 12/31/2022
  - NEB Successor, 2-5 MW projects
    - Assume 560 MW total program goal, minus 5% of program capacity assumed to be installed in Maine Public District (i.e., outside of ISO New England)
  - NEB, < 2MW projects
- At the end of NEB (2-5 MW), all MWs from last year of the program are carried forward until 2032 at a constant rate, and post-policy discount factors are applied

ME Forecast Inputs

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NEB (2-5 MW)	271.3	271.3								
NEB (2-5 MW) - Successor			106.4	106.4	106.4	106.4	106.4	106.4	106.4	106.4
NEB <2MW	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

Discount Factors

- Discount factors are:
  - Developed and incorporated into the forecast to consider a degree of expected uncertainty
  - Developed for two types of future PV inputs to the forecast, and all discount factors are applied equally in all states
  - Applied to the forecast inputs (see slide 32) to determine total nameplate capacity for each state and forecast year

Policy-Based *PV that results from state policy*	**Post-Policy** *PV that may be installed after existing state policies are fulfilled*
Discounts for uncertainty associated with future market and grid conditions (maximum value of 15%)	**Generally higher discounts due to the greater uncertainty associated with future state policies, in addition to future market and grid conditions**

Discount Factors Used

Policy-Based

Forecast Year	Final 2022 Forecast	Final 2023 Forecast
2023	10%	5%
2024	15%	10%
2025	15%	15%
2026	15%	15%
2027	15%	15%
2028	15%	15%
2029	15%	15%
2030	15%	15%
2031	15%	15%
2032	N/A	15%

Post-Policy

Forecast Year	Final 2022 Forecast	Final 2023 Forecast
2023	31.1%	30.0%
2024	32.2%	31.1%
2025	33.3%	32.2%
2026	34.4%	33.3%
2027	35.6%	34.4%
2028	36.7%	35.6%
2029	37.8%	36.7%
2030	38.9%	37.8%
2031	40.0%	38.9%
2032	N/A	40.0%

Draft 2023 Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
CT	911.8	180.3	193.8	193.8	153.8	153.8	153.8	153.8	153.8	153.8	153.8	**2,556.4**
MA	3289.2	366.7	366.7	366.7	366.7	366.7	366.7	366.7	366.7	366.7	366.7	**6,955.9**
ME	294.6	291.3	291.3	126.4	126.4	126.4	126.4	126.4	20.0	20.0	20.0	**1,569.2**
NH	183.4	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	26.5	**448.2**
RI	325.6	54.9	54.9	54.9	54.9	54.9	54.9	54.9	54.9	54.9	54.9	**874.4**
VT	468.2	30.0	30.2	30.4	30.8	31.4	32.2	33.0	34.0	35.0	36.0	**791.4**
Pre-Discount Annual Policy-Based MWs	**5472.7**	**949.7**	**963.4**	**798.6**	**759.1**	**759.7**	**760.5**	**306.1**	**170.8**	**171.8**	**107.5**	**11,219.8**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**455.2**	**591.4**	**591.4**	**656.8**	**2,294.8**
Pre-Discount Annual Total (MW)	**5472.7**	**949.7**	**963.4**	**798.6**	**759.1**	**759.7**	**760.5**	**761.3**	**762.2**	**763.3**	**764.3**	**13,514.6**
Pre-Discount Cumulative Total (MW)	**5472.7**	**6,422.3**	**7,385.7**	**8,184.4**	**8,943.5**	**9,703.1**	**10,463.6**	**11,224.9**	**11,987.1**	**12,750.3**	**13,514.6**	**13,514.6**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 15-20 for details)
(2) Yellow highlighted cells indicate that values contain post-policy MWs
(3) All values include FCM Resources, non-FCM Settlement Only Generators and Generators (per OP-14), and load reducing PV resources
(4) All values represent end-of-year installed capacities

FINAL 2023 PV NAMEPLATE CAPACITY FORECAST

Final 2023 PV Forecast

Nameplate Capacity, MW_{ac}

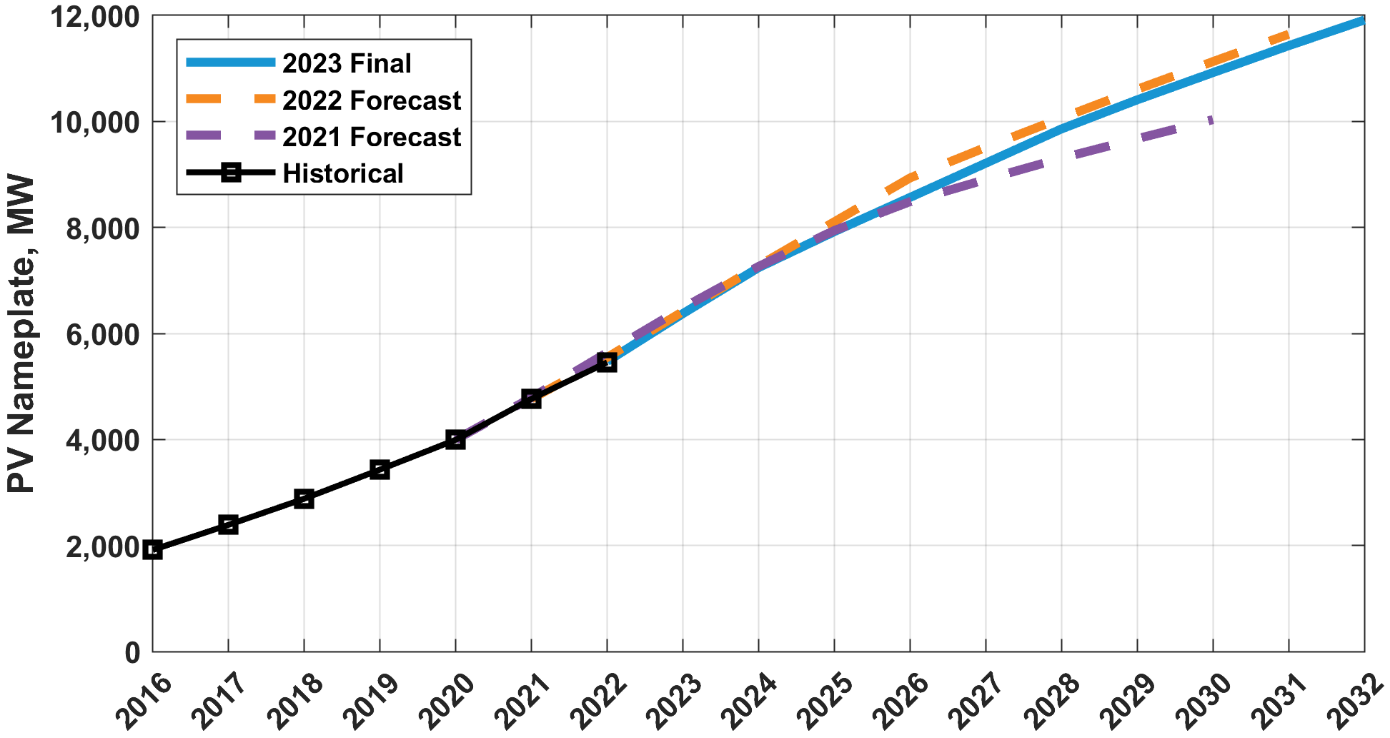
States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
CT	911.8	171.3	174.4	164.7	130.7	130.7	130.7	111.6	110.6	109.6	92.3	**2,238.5**
MA	3289.2	348.3	330.0	311.7	311.7	311.7	311.7	232.2	228.1	224.1	220.0	**6,118.7**
ME	294.6	276.8	262.2	107.4	107.4	107.4	107.4	107.4	83.2	82.0	80.8	**1,616.8**
NH	183.4	25.2	23.8	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	**412.5**
RI	325.6	52.1	49.4	46.6	46.6	46.6	46.6	46.6	39.8	39.5	39.2	**778.9**
VT	468.2	28.5	27.2	25.8	26.2	26.7	27.4	28.1	28.9	29.8	30.6	**747.4**
Regional - Annual (MW)	**5472.7**	**902.2**	**867.0**	**678.8**	**645.2**	**645.7**	**646.4**	**548.4**	**513.2**	**507.5**	**485.5**	**11,912.7**
Regional - Cumulative (MW)	**5472.7**	**6374.9**	**7241.9**	**7920.7**	**8566.0**	**9211.7**	**9858.1**	**10406.5**	**10919.7**	**11427.2**	**11912.7**	**11,912.7**

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

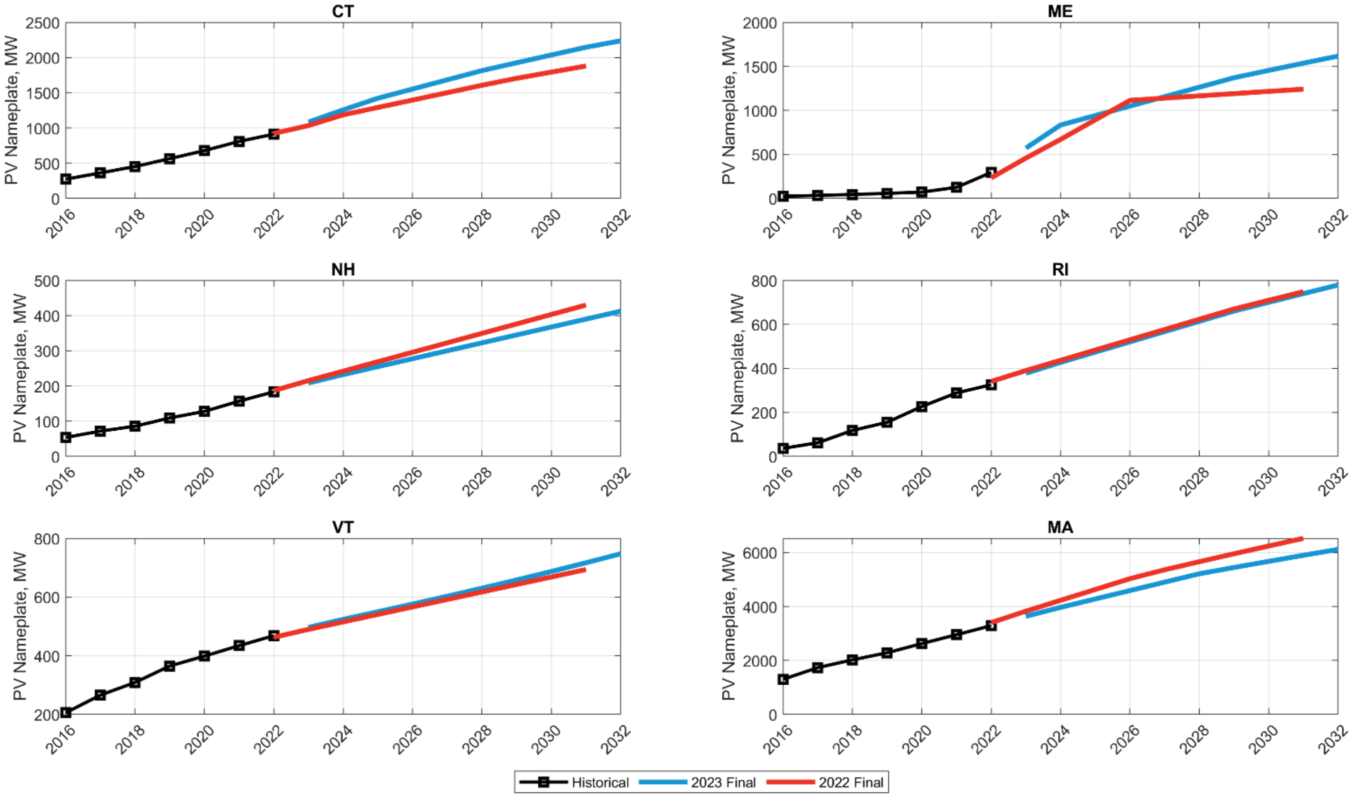
Regional PV Nameplate Capacity Growth

Historical vs. Forecast



State PV Nameplate Capacity Growth

Historical vs. Forecast



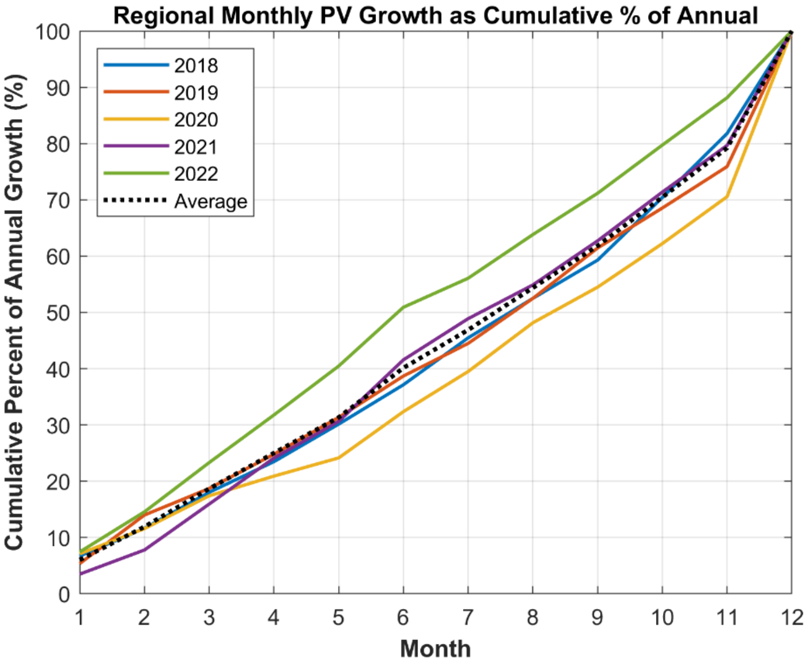
2023 PV ENERGY FORECAST

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 2018 and 2022 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 9 years of PV performance data (2014-2022)
  - Resulting state and regional CFs are tabulated to the right, and plots of individual monthly capacity factors in each state are shown on slide 40

State	Average CF, %
CT	14.7
ME	14.8
NH	14.2
RI	14.9
VT	13.8
MA	14.5
ISO-NE	**14.5**

Historical Monthly PV Growth Trends, 2018-2022



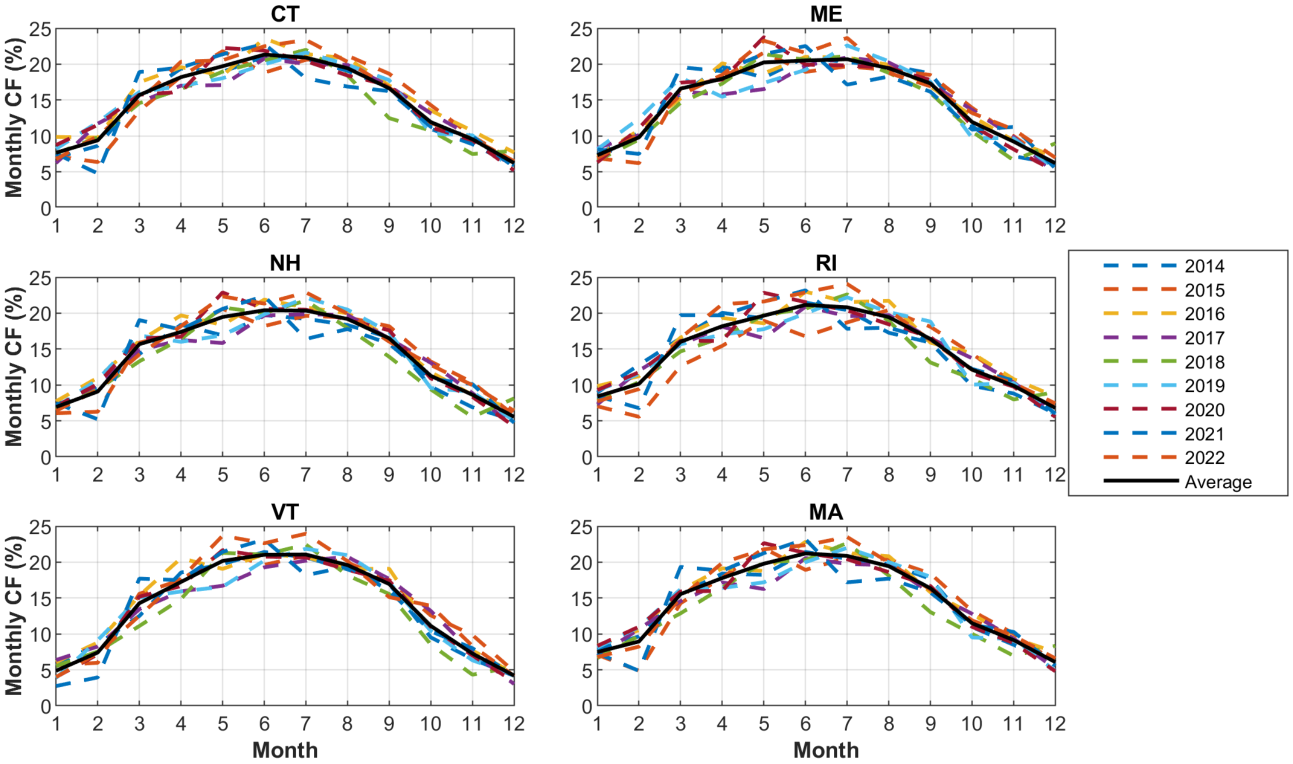
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6%	6%
2	6%	12%
3	7%	19%
4	6%	25%
5	6%	31%
6	9%	40%
7	7%	47%
8	7%	54%
9	7%	62%
10	9%	70%
11	9%	79%
12	21%	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, 2014-2022



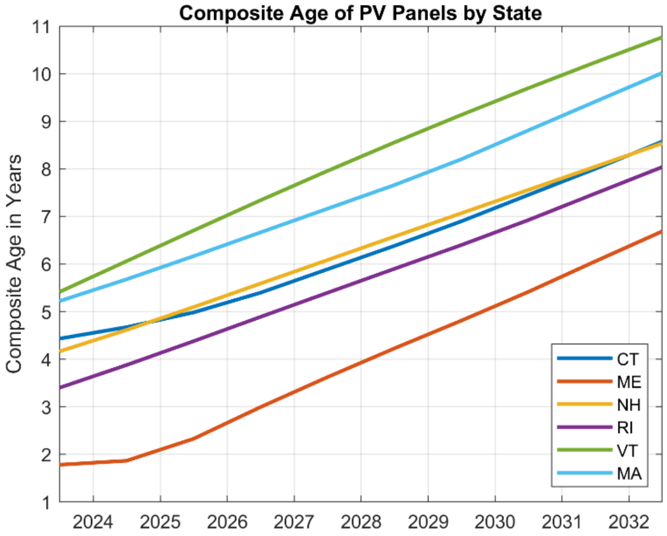
PV Panel Degradation Factors

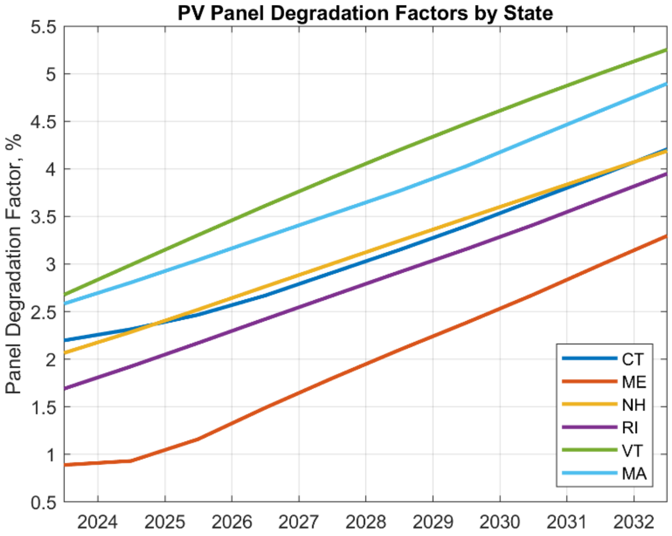
- No changes to the methodology to account for panel degradation were made since last year's forecast
- Forecasts of BTM PV energy and estimated summer peak load reductions include the effects of a 0.5%/year panel degradation rate to account for the expected declining conversion efficiency of solar panels 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 2023 PV Energy Forecast

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

States	Total Estimated Annual Energy (GWh)										
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	1,156	1,321	1,553	1,775	1,971	2,140	2,312	2,464	2,604	2,742	2,873
MA	4,132	4,525	4,969	5,371	5,764	6,156	6,556	6,887	7,163	7,433	7,709
ME	329	564	934	1,195	1,336	1,477	1,620	1,756	1,881	1,985	2,090
NH	218	251	283	312	340	368	396	424	451	479	507
RI	415	475	544	607	669	730	793	852	908	959	1,010
VT	566	599	633	663	693	723	755	786	819	852	888
Regional - Annual Energy (GWh)	**6,814**	**7,736**	**8,916**	**9,923**	**10,773**	**11,594**	**12,433**	**13,168**	**13,826**	**14,449**	**15,077**

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

- 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
- 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 17
  2. Non-FCM EOR/Gen
     - Determine the % share of non-FCM PV participating in energy market at the end of 2022
  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

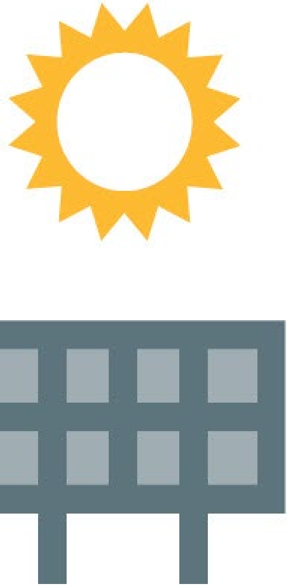
PV in ISO New England Markets

Data and Assumptions

- FCM
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 17
    - Maintain separate accounting for FCM_{supply} and FCM_{DR}
  - Assume aggregate total PV in FCM as of FCA 17 remains constant from 2026-2032
- Non-FCM Gen/EOR
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/22
  - Assume the ($EOR+FCM_{supply}$) share of total PV at the end of 2022 in each state *<u>except Maine</u>* 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 2023 PV FORECAST

Results

Final 2023 PV Forecast

Cumulative Nameplate Capacity, MW_{ac}

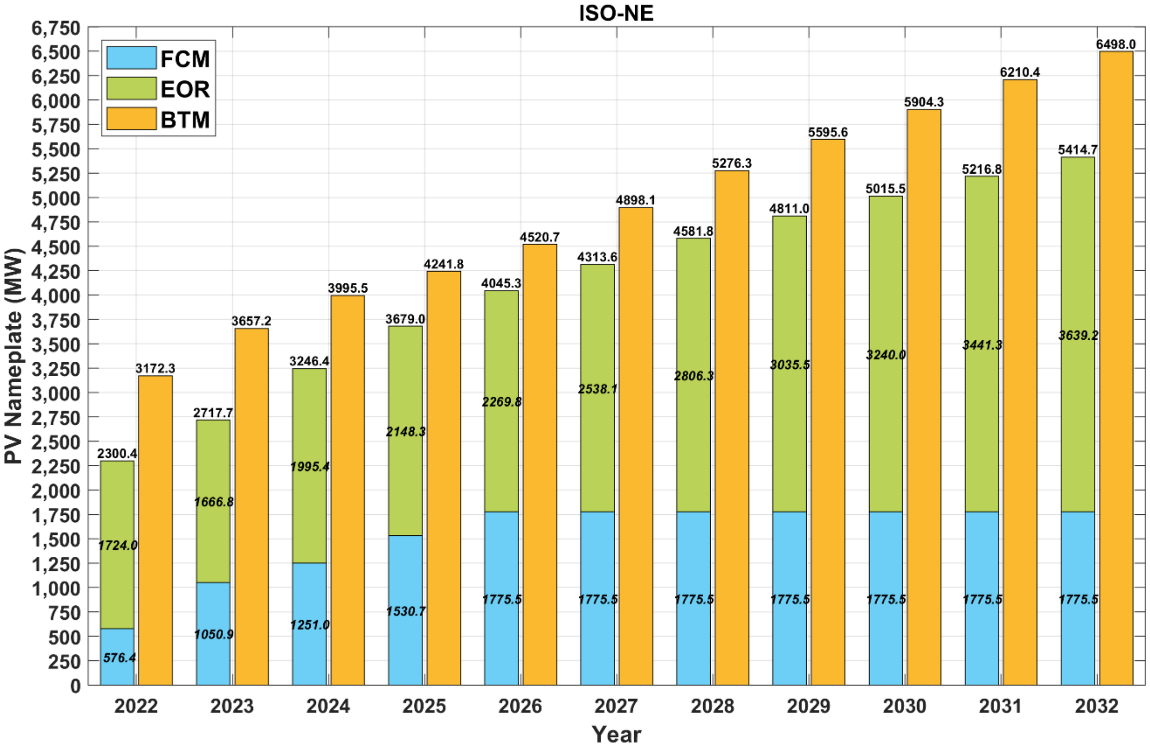
States	Cumulative Total MW (AC nameplate rating)										
	Thru 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CT	911.8	1,083.0	1,257.5	1,422.2	1,552.9	1,683.7	1,814.4	1,926.0	2,036.6	2,146.2	2,238.5
MA	3,289.2	3,637.6	3,967.6	4,279.2	4,590.9	4,902.6	5,214.2	5,446.5	5,674.6	5,898.7	6,118.7
ME	294.6	571.3	833.5	940.9	1,048.4	1,155.8	1,263.3	1,370.7	1,453.9	1,535.9	1,616.8
NH	183.4	208.5	232.4	254.9	277.4	299.9	322.4	344.9	367.4	389.9	412.5
RI	325.6	377.7	427.1	473.7	520.4	567.0	613.7	660.3	700.2	739.7	778.9
VT	468.2	496.7	523.9	549.7	576.0	602.7	630.1	658.1	687.0	716.8	747.4
Regional - Cumulative (MW)	**5,472.7**	**6,374.9**	**7,241.9**	**7,920.7**	**8,566.0**	**9,211.7**	**9,858.1**	**10,406.5**	**10,919.7**	**11,427.2**	**11,912.7**

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

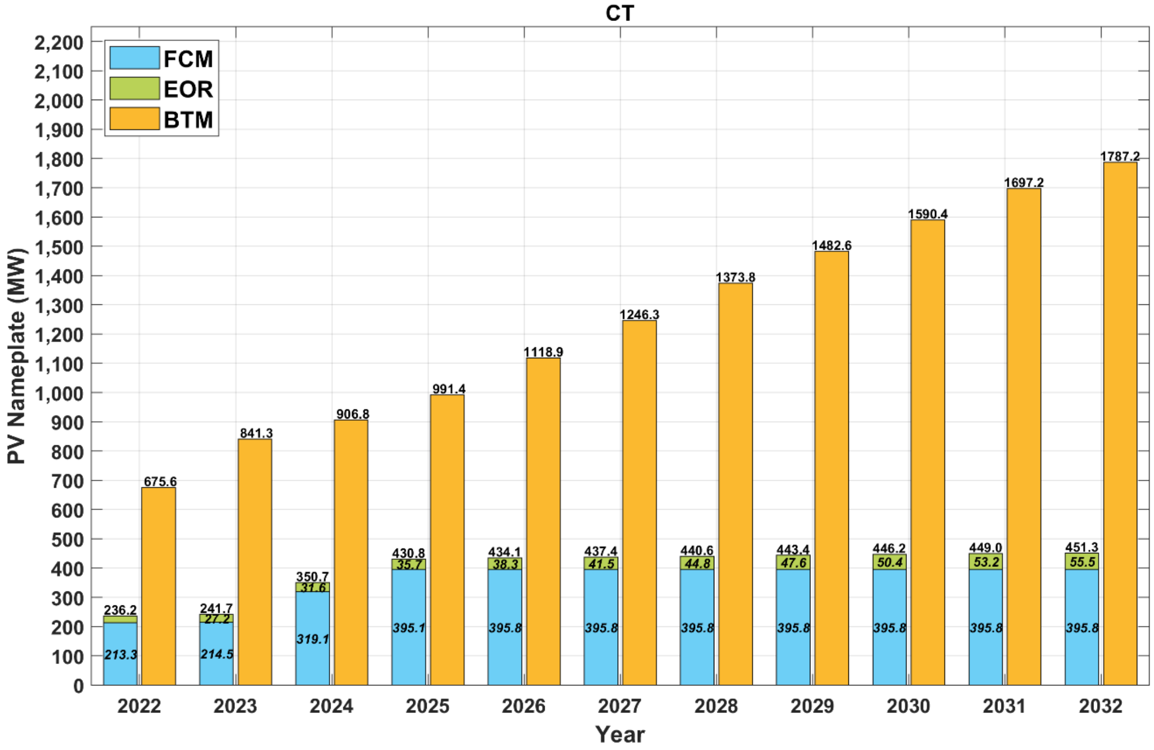
Final 2023 PV Forecast – New England

Cumulative Nameplate by Category, MW_{ac}



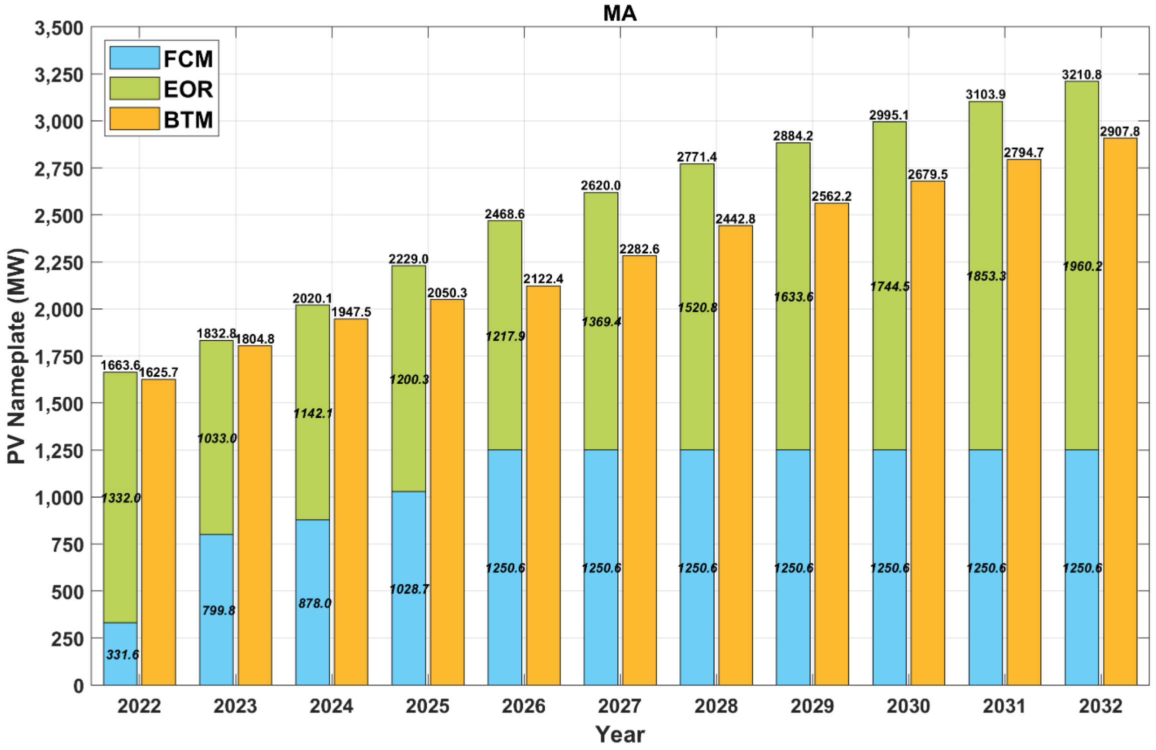
Final 2023 PV Forecast – Connecticut

Cumulative Nameplate by Category, MW_{ac}



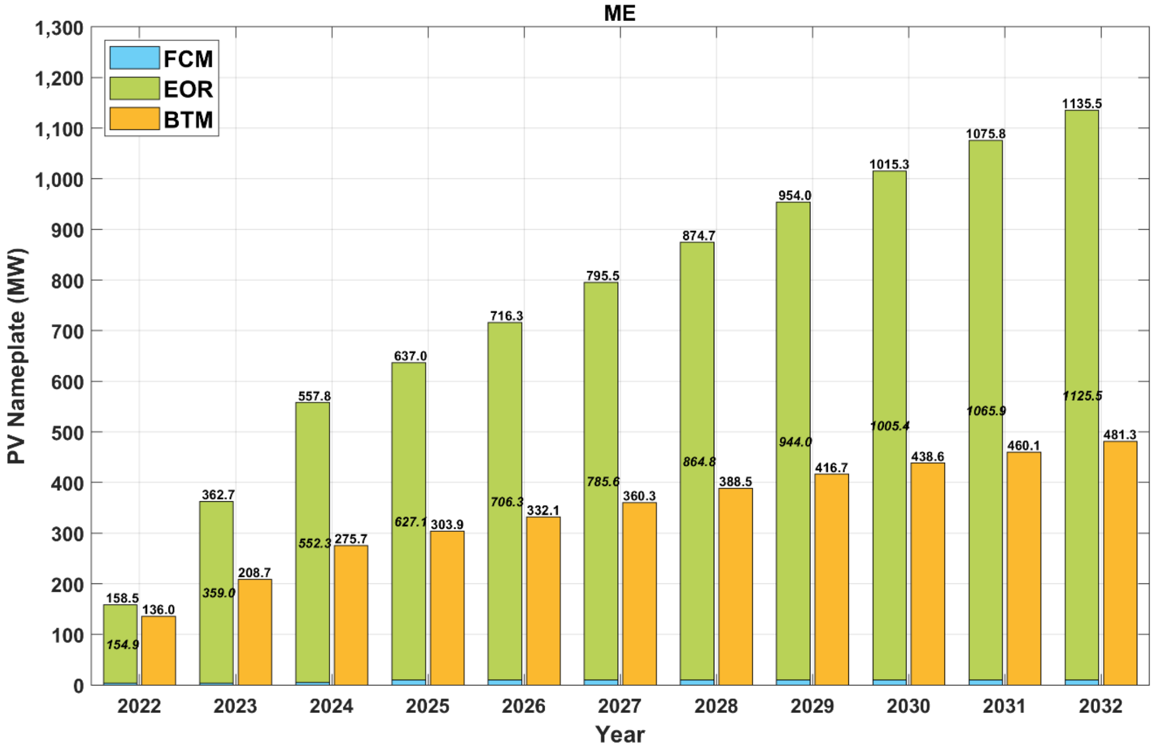
Final 2023 PV Forecast – Massachusetts

Cumulative Nameplate by Category, MW_{ac}



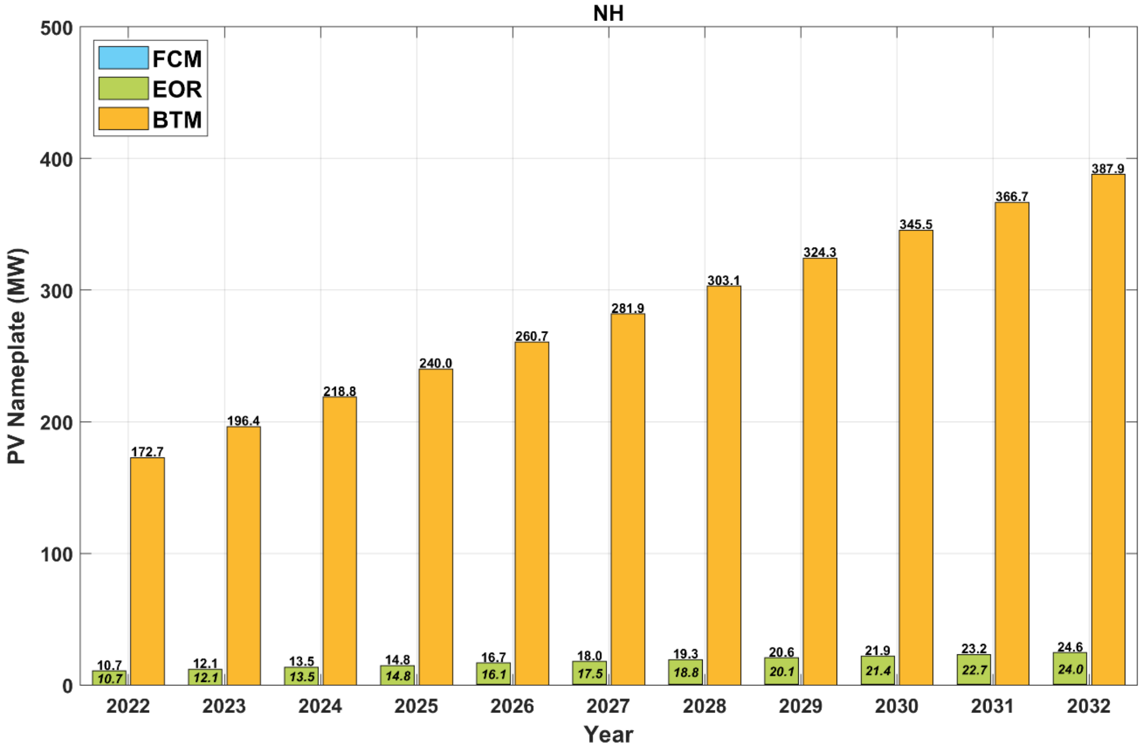
Final 2023 PV Forecast – Maine

Cumulative Nameplate by Category, MW_{ac}



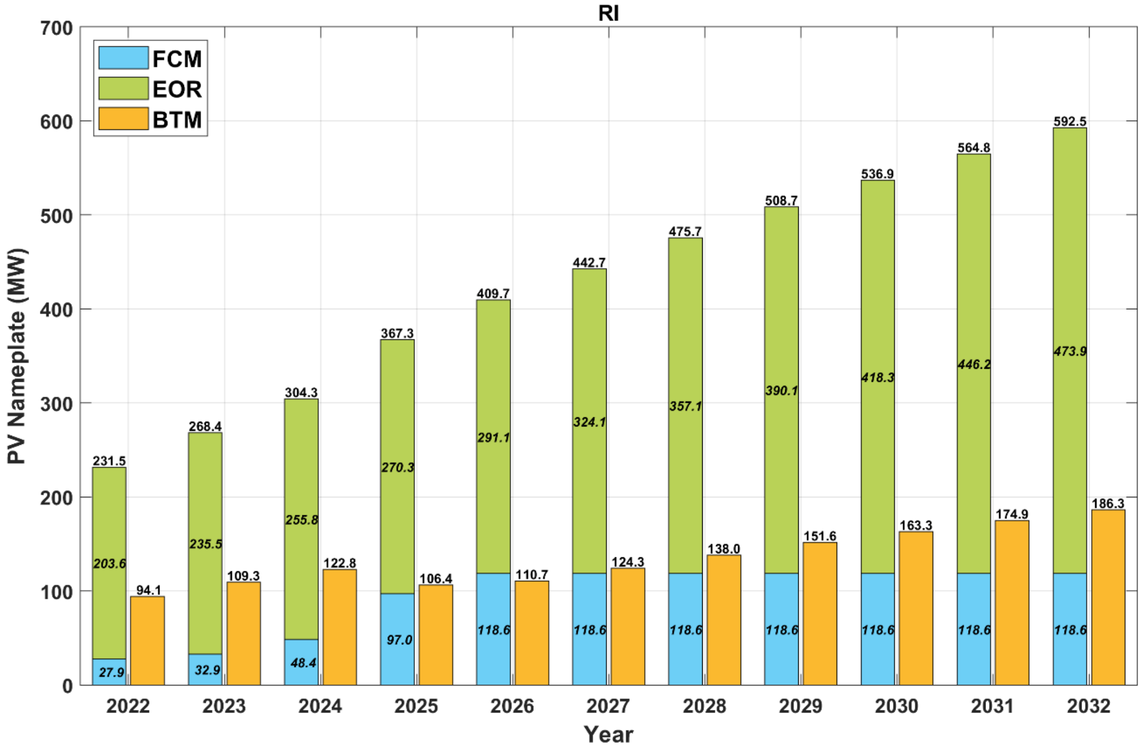
Final 2023 PV Forecast – New Hampshire

Cumulative Nameplate by Category, MW_{ac}



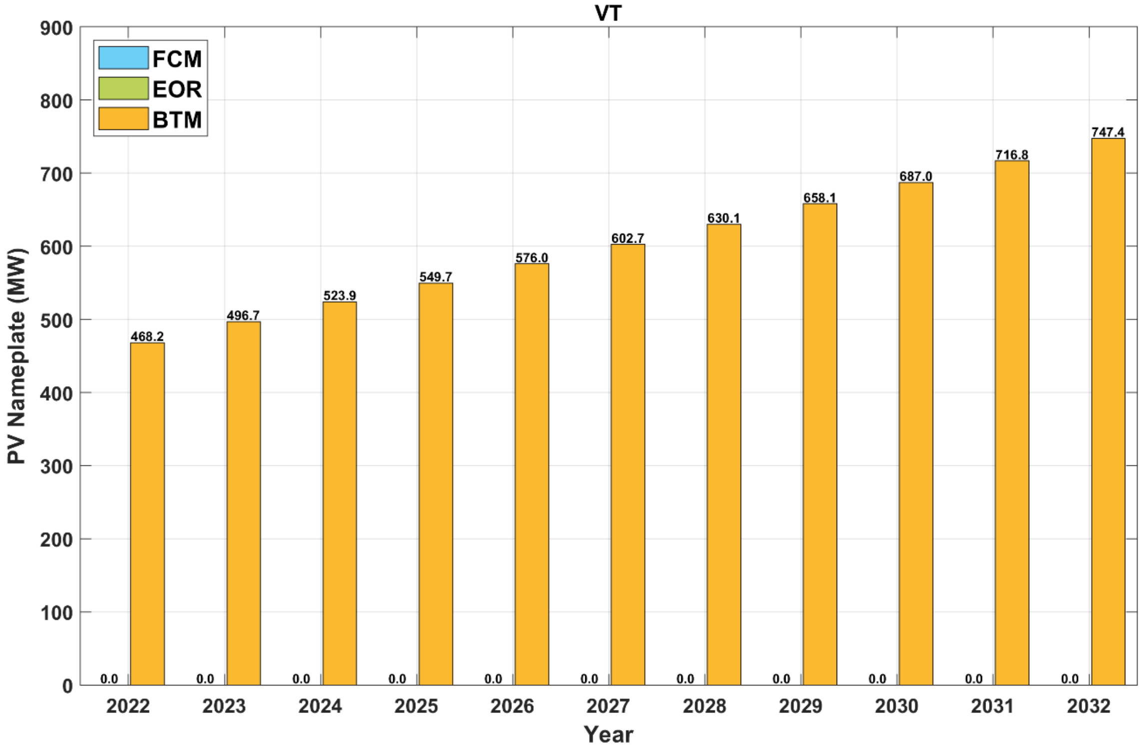
Final 2023 PV Forecast – Rhode Island

Cumulative Nameplate by Category, MW_{ac}



Final 2023 PV Forecast – Vermont

Cumulative Nameplate by Category, MW_{ac}



BTM PV Forecast Used in CELT Net Load Forecast

- The 2023 CELT net load forecast will reflect deductions associated with the BTM PV portion of the PV forecast
- The following slides show values for annual energy and summer peak load reductions anticipated from BTM PV that will be reflected in the 2023 CELT
  - PV does not reduce winter peak loads, which occur after sunset
- Documentation of the ISO's methodology for estimating summer peak load reduction associated with BTM PV over the forecast horizon is available here

Final 2023 BTM PV Energy Forecast

GWh

Category	States	Estimated Annual Energy (GWh)										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Behind-the-Meter PV	CT	861	1,001	1,142	1,243	1,395	1,561	1,729	1,880	2,017	2,153	2,281
	MA	1,921	2,240	2,448	2,595	2,699	2,855	3,061	3,232	3,376	3,515	3,657
	ME	138	228	324	391	428	464	502	537	570	597	624
	NH	216	237	267	294	320	346	373	398	424	450	477
	RI	90	137	157	150	144	157	176	193	210	225	240
	VT	584	599	633	663	693	723	755	786	819	852	888
Behind-the Meter Total	**Regional Total**	**3,811**	**4,442**	**4,970**	**5,336**	**5,679**	**6,107**	**6,596**	**7,027**	**7,415**	**7,792**	**8,168**

***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 2023 BTM PV Forecast

July 1st Estimated Coincident Summer Peak Load Reductions

Category	States	Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Behind-the-Meter PV	CT	194.2	216.5	216.8	225.6	249.2	265.8	279.9	290.6	298.4	304.6	307.9
	MA	482.0	493.7	495.3	490.2	480.6	492.6	501.8	506.0	505.3	503.1	499.3
	ME	44.5	48.7	64.0	73.3	76.1	78.7	80.7	82.5	83.7	83.8	83.6
	NH	49.2	53.4	55.6	57.5	59.4	61.2	62.6	63.8	65.0	66.0	66.6
	RI	26.2	29.4	31.0	24.7	24.4	26.3	27.9	29.4	30.5	31.3	31.9
	VT	140.8	139.7	136.3	134.0	133.0	132.1	131.0	130.0	129.4	128.8	127.9
Total	**Cumulative**	936.9	981.4	998.9	1,005.3	1,022.7	1,056.7	1,084.0	1,102.3	1,112.3	1,117.5	1,117.1
Corresponding % of BTM PV AC nameplate capacity		29.5%	27.7%	25.6%	24.0%	22.8%	21.7%	20.6%	19.7%	18.8%	18.0%	17.1%

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

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

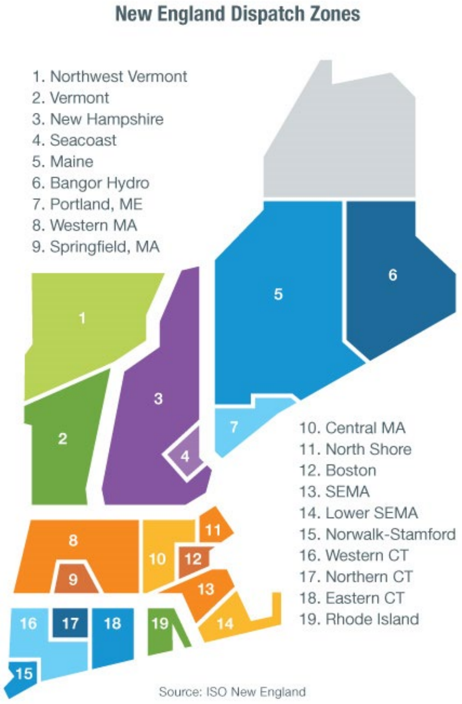
- The breakdown of total PV reflected in Distribution Owner data submittals as of 12/31/2022 by Dispatch Zone is included on the next slide

- 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, 2022 Distribution Owner Data Submittals

State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.2%
	CT	NorthernCT	18.4%
	CT	Norwalk_Stamford	7.2%
	CT	WesternCT	56.2%
ME	ME	BangorHydro	9.2%
	ME	Maine	67.1%
	ME	PortlandMaine	23.6%
MA	NEMA	Boston	11.5%
	WCMA	CentralMA	12.9%
	SEMA	LowerSEMA	16.2%
	NEMA	NorthShore	4.8%
	SEMA	SEMA	19.7%
	WCMA	SpringfieldMA	7.3%
	WCMA	WesternMA	27.5%
NH	NH	NewHampshire	89.0%
	NH	Seacoast	11.0%
RI	RI	RhodeIsland	100.0%
VT	VT	NorthwestVermont	62.6%
	VT	Vermont	37.4%



APPENDIX

Example Calculation of BTM PV Estimated Summer Peak Load Reduction

Introduction

- The following slides describe an example calculation of estimated summer peak load reductions published in CELT
- The example calculation shown is for Massachusetts in July 2026

Description of Example Calculation Steps & Inputs

Massachusetts BTM PV July 2026 Summer Peak Load Reduction

1. State monthly BTM PV nameplate forecast
   - Find BTM PV share of total end-of-year nameplate forecast based on state accounting for categories (FCM, non-FCM EOR, and BTM) – see slide 54
   - Input uses the conversion of cumulative end-of-year state nameplate forecast (slide 51) into monthly forecast using monthly capacity growth rates (slide 39)

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 42

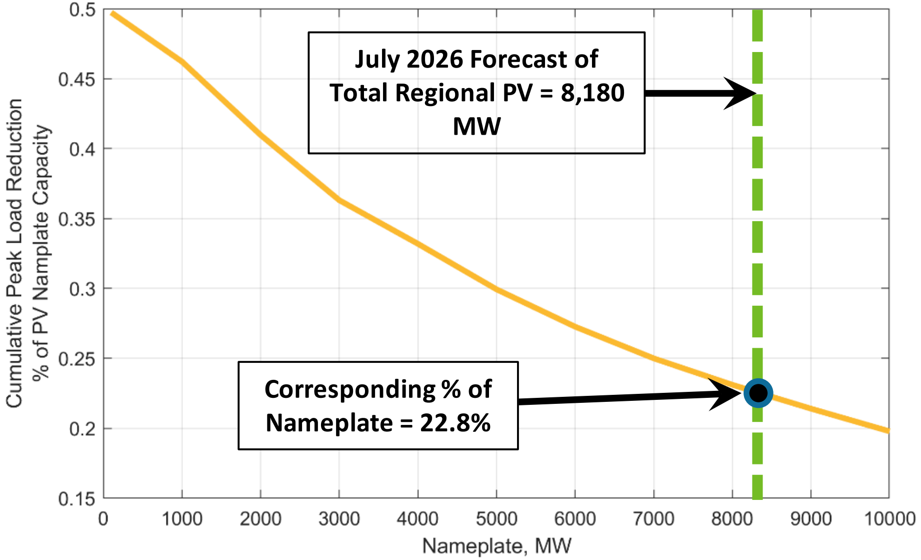
$$DegradeMultiplier = (1 - ADR)^{CA}$$

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

Estimated Summer Peak Load Reductions

July 2026 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 2026 Summer Peak Load Reduction

Calculation Line Item	Relevant Region	
July 2026 Total Nameplate PV Forecast (MW)	ISO-NE	8179.7
July 2026 BTM PV Nameplate Forecast (MW)	MA	2026.4
% of Nameplate (from previous slide)	ISO-NE	0.228
Panel Degradation Multiplier	MA	0.97
Peak Gross Up Factor	ISO-NE	1.08
Final BTM PV Summer Peak Load Reduction (MW)	MA	**480.6**

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

Note: Tabulated values are rounded to the precision shown.