Final 2016 PV Forecast Details

Outline

- Background & Overview
- Distribution Owner Survey Results
- Forecast Assumptions and Inputs
- Final 2016 PV Forecast - Nameplate MW
- Final 2016 PV Energy Forecast
- Breakdown of PV Forecast into Resource Types
- Final 2016 Behind-the-meter (BTM) PV Forecast – Energy and Estimated Summer Peak Load Reductions
- Geographic Distribution of PV Forecast
- Appendix: PV's Reduction of Future Summer Peak Loads Analysis

BACKGROUND & OVERVIEW

Background

- Many factors influence the future commercialization potential of PV resources, some of which include:
  - Policy drivers:
    - Feed-in-tariffs (FITs)/Long-term procurement
    - State RPS programs
    - Net energy metering (NEM)
    - Federal Investment Tax Credit (ITC)
  - Other drivers:
    - Role of private investment in PV development
    - PV development occurs using a variety of business/ownership models
    - Future equipment and installation costs
    - Future wholesale and retail electricity costs

The PV Forecast Incorporates State Public Policies and Is Based on Historical Data

- The PV forecast process is informed by ISO analysis and by input from state regulators and other stakeholders through the Distributed Generation Forecast Working Group (DGFWG)
- The PV forecast methodology is straightforward, intuitive, and rational
- The forecast is meant to be a reasonable projection of the anticipated growth of out-of-market, distributed PV resources to be used in ISO's System Planning studies, consistent with its role to ensure prudent planning assumptions for the bulk power system
- The forecast reflects and incorporates state policies and the ISO does not explicitly forecast the expansion of existing state policies or the development of future state policy programs

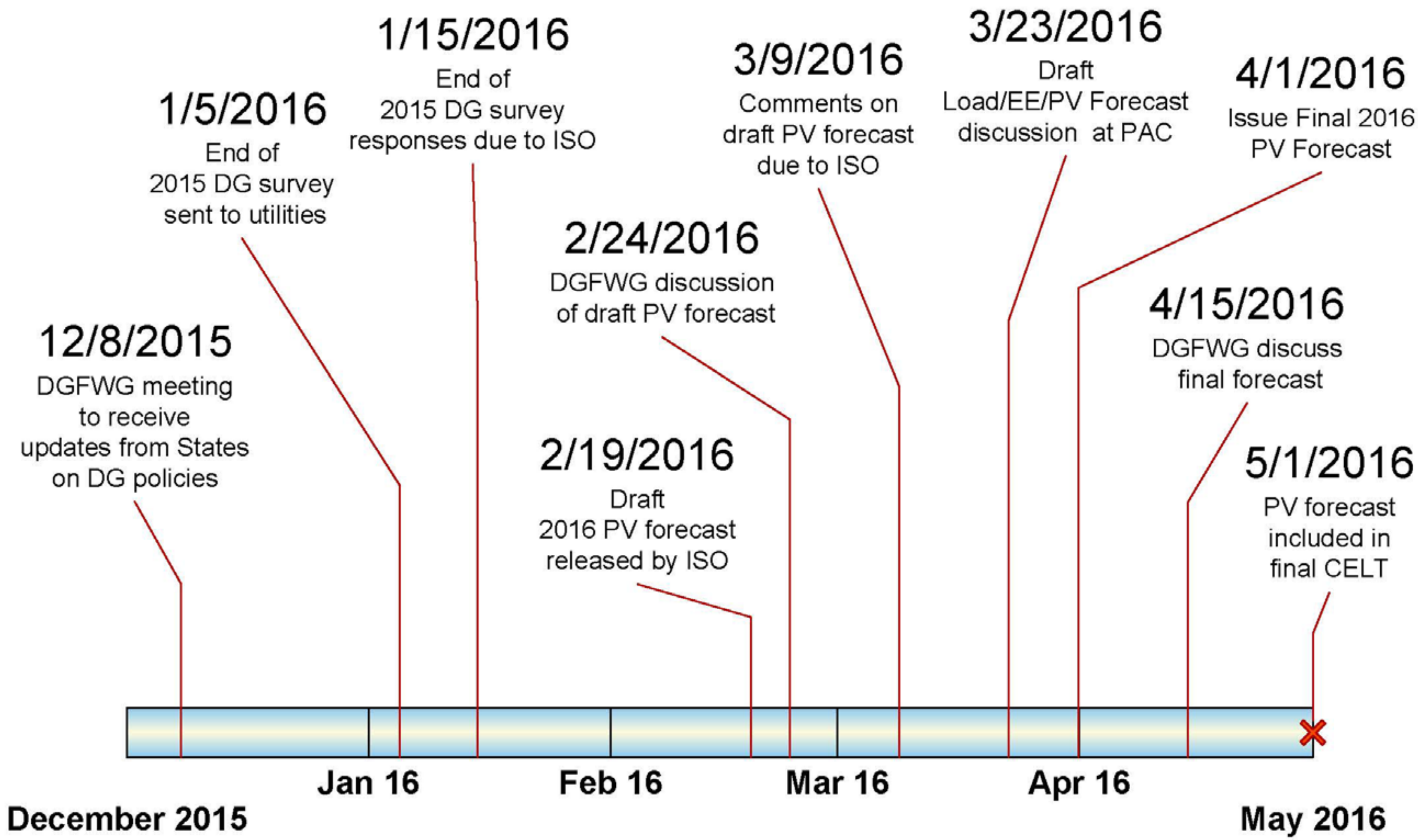
Forecast Focuses on State Policies in All Six New England States

- A policy-based forecasting approach has been chosen to reflect the observation that trends in distributed PV development are in large part the result of policy programs developed and implemented by the New England states
- The ISO makes no judgment regarding state policies, but rather utilizes the state goals as a means of informing the forecast
- In an attempt to control related ratepayer costs, states often factor anticipated changes in market conditions directly into policy design, which are therefore implicit to ISO's policy considerations in the development of the forecast

Background and Forecast Review Process

- The ISO discussed the draft PV forecast with the DGFWG at the February 24, 2016 meeting
  - See: http://www.iso-ne.com/static-assets/documents/2016/03/2016_draftpvforecast_20160224revised.pdf
- Stakeholders provided many helpful comments on the draft forecast
  - See: http://www.iso-ne.com/committees/planning/distributed-generation/?eventId=129509
- The final PV forecast is published in the 2016 CELT (Section 3): http://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls

KEY DATES: 2016 DG Forecast Development



DISTRIBUTION OWNER SURVEY RESULTS

Installed PV – December 2015

Determining Total PV Installed Through December 2015

- ISO requested distribution owners to provide the total nameplate PV (in MW_{ac}) that is already installed and operational within their respective service territories as of December 31, 2015
- The following Distribution Owners responded:
  - CT: CL&P, CMEEC, UI
  - ME: CMP, Emera Maine,
  - MA: Braintree, Chicopee, National Grid, NSTAR, Reading, Shrewsbury, Unitil, WMECo
  - NH: Liberty, NHEC, PSNH, Unitil
  - RI: National Grid
  - VT: Burlington, GMP, Stowe, VEC, VPPSA, WEC
- Based on respondent submittals, installed and operational PV resource totals by distribution owner and state are listed on the next slides

December 2015 Year-To-Date PV Installed Capacity

State-by-State

The table below reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. The values represent installed nameplate as of 12/31/15.

State	Installed Capacity (MW_{ac})
Connecticut	188.01
Maine	15.34
Massachusetts	947.11*
New Hampshire	26.36
Rhode Island	23.59
Vermont	124.57*
New England Total	**1,325.00**

Notes:
*Includes values based on MA SREC data associated with 43 MA munis and VT SPEED data for 3 VT munis that did not provide individual responses

December 2015 Year-to-Date Installed PV by Utility

State & Utility	Installed Capacity (MW_{ac})
Connecticut	**188.01**
Connecticut Light & Power	158.99
Connecticut Municipal Electric Energy Co-op	0.45
United Illuminating	29.03
Maine	**15.34**
Central Maine Power	13.44
Emera	1.91
Massachusetts	**947.11**
Braintree Electric Light Dept	1.75
Chicopee Electric Light	7.83
National Grid	457.7
NSTAR	338.03
Shrewsbury Electric & Cable Operations	2.76
Unitil (FG&E)	10.71
Reading Municipal Lighting Plant	1.14
Western Massachusetts Electric Company	61.72
Other Municipals (Per MA SREC data)	65.40

December 2015 Year-to-Date Installed PV by Utility

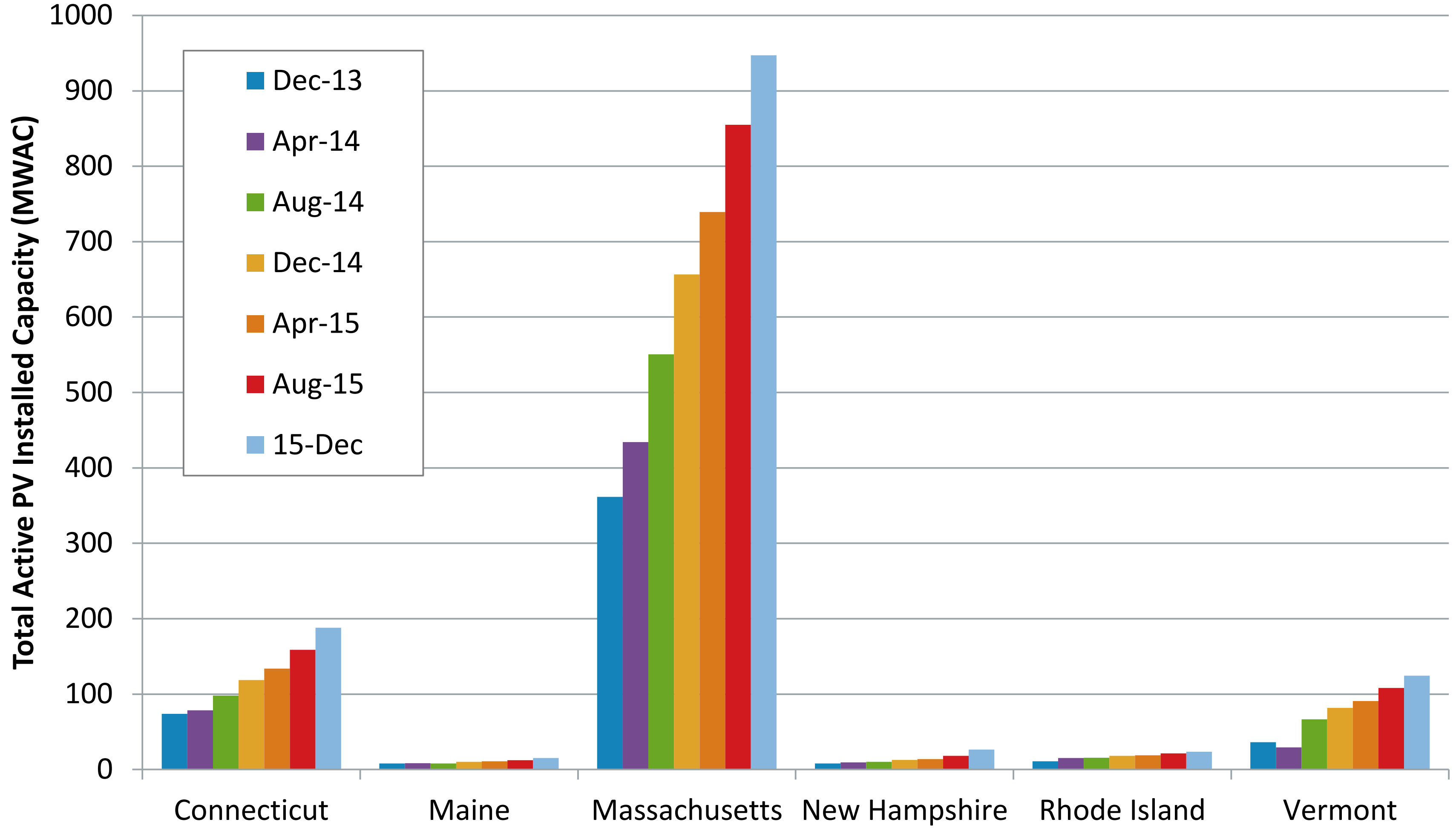
State & Utility	Installed Capacity (MW_{ac})
New Hampshire	**26.36**
Liberty	1.92
New Hampshire Electric Co-op	3.46
Public Service of New Hampshire	17.79
Unitil	3.12
Rhode Island	**23.59**
National Grid	23.59
Vermont	**124.57**
Burlington Electric Department	2.08
Green Mountain Power	104.41
Vermont Electric Co-op	11.25
Vermont Public Power Supply Authority	2.88
Stowe Electric Department	0.31
Washington Electric Co-op	3.64
Other Municipals (per VT SPEED data)	0.10
New England Total	**1,325.00**

Total Active PV Installed Capacity Survey Results

Reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. Values represent installed megawatt AC (MW_{ac}) nameplate

	Dec 2013	Apr 2014	Aug 2014	Dec 2014	Apr 2015	Aug 2015	Dec 2015
Connecticut	73.75	78.416	98.02	118.80	133.83	158.73	188.01
Maine	8.12	8.512	8.16	10.38	11.04	12.43	15.34
Massachusetts	361.55	434.39	550.54	656.73	739.48	855.03	947.11
New Hampshire	8.22	9.35	10.17	12.74	13.93	18.37	26.36
Rhode Island	10.9	15.29	15.52	18.21	19.08	21.51	23.59
Vermont	36.13	29.40	66.55	81.85	90.76	108.27	124.57
Total	**498.67**	**575.37**	**748.95**	**898.71**	**1,008.11**	**1,174.34**	**1,325.00**

Total Active PV Installed Capacity Survey Results 2013-2015 YTD *(MW_{ac})*



2016 FORECAST ASSUMPTIONS AND INPUTS

Introduction

- The PV forecast acknowledges the significant trend in PV development and its potential impact on the New England process
- All federal and state-by-state assumptions and inputs to the PV forecast are listed on the following slides
  - Includes discount factors

Update on Federal Investment Tax Credit

- ITC is a key driver of PV development in U.S., and was slated to be significantly reduced or eliminated at the end of 2016
  - Tax credit for a percent of "qualified expenditures" on PV installations
  - Eligible expenditures include labor costs for on-site preparation, assembly, installation, and for piping or interconnection wiring to interconnect
- The *Consolidated Appropriations Act*, signed in December 2015, extended the expiration date of the ITC, with a gradual step down after 2019

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

Update on Federal Business ITC *continued*

- Gradual step down of Business ITC shown on right
- Based on when construction begins
- No limit on maximum incentive for PV

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

Source: http://programs.dsireusa.org/system/program/detail/658

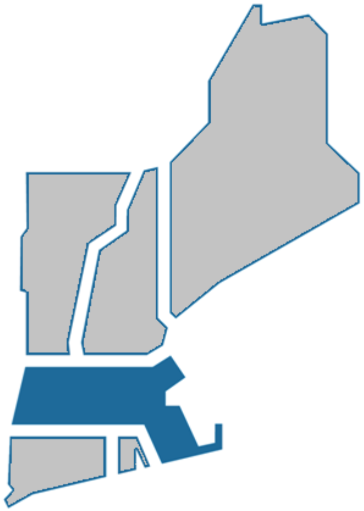
Update on Federal Residential ITC *continued*

Maximum Allowable Residential ITC	
Year	**Credit**
2016	30%
2017	30%
2018	30%
2019	30%
2020	26%
2021	22%

- Gradual step down of Residential ITC shown on left
- Based on when the system is "placed in service"
- Systems must be placed in service between January 1, 2006, and December 31, 2021
- The home served by the system does not have to be the taxpayer's principal residence

Source: http://programs.dsireusa.org/system/program/detail/1235

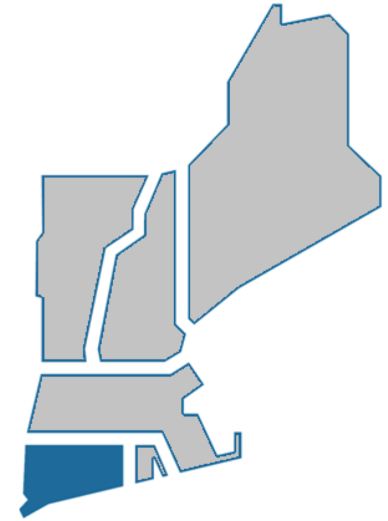
Massachusetts Forecast Methodology and Assumptions



- MA DPU's 12/8/15 DGFWG presentation serves as primary source for MA policy information
- A DC-to-AC derate ratio of 83% is applied to the MA SREC goal to determine AC nameplate of state goal
  – PV system designers/developers typically choose to oversize their solar panel array with respect to their inverter(s) by a factor of 1.2**
  – Converted MA 2020 goals: 1,600 MW_{DC} = **1,358 MW_{AC}**
- MA SREC I/II programs successfully achieve 2020 state goal
  – Since SREC program is already close to fully subscribed, application of remaining SREC MWs reflect achievement of the SREC policy goal assumed in 2018
- Post-SREC (after 2018) forecast values are kept at 2018 growth level, but are more significantly discounted

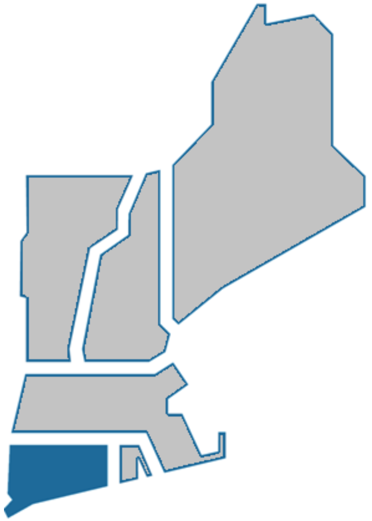
**Source: J. Fiorelli and M.Z. Martinson, *How Oversizing Your Array-to-Inverter Ratio Can Improve Solar-Power System Performance*, Solar Power World, July 2013, available at: http://www.solren.com/articles/Solectria_Oversizing_Your_Array_July2013.pdf

Connecticut Forecast Methodology and Assumptions



- CT DEEP's 9/30/13 DGFWG presentation serves as primary source for CT policy information
  - Policy updates provided at the 12/8/15 DGFWG meeting
- ZREC program will be satisfied entirely with PV
  - 288 MW CL&P + 72 MW UI = 360 MW total
  - Assumed 65 MW of ZREC projects in service by 12/31/15
    - Remaining 295 MW were divided and applied evenly during 5-year program duration, from 2015-2020
  - Post-ZREC (after 2020) forecast values are kept at 2020 growth level, but are more significantly discounted

Connecticut Forecast Methodology and Assumptions *continued*

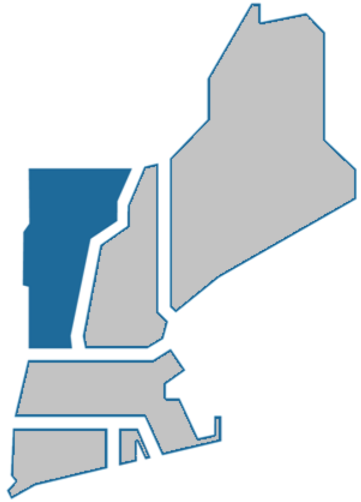


- Expanded CEFIA/Green Bank residential program
  - 107 MW approved as of 2015 and 300 MW goal by 2022
  - Assumed 80 MW installed by 2015; 31 MW/year from 2016-2022
- 20 MW project in Sprague/Lisbon assumed to be commissioned in 2017

Vermont Forecast Methodology and Assumptions

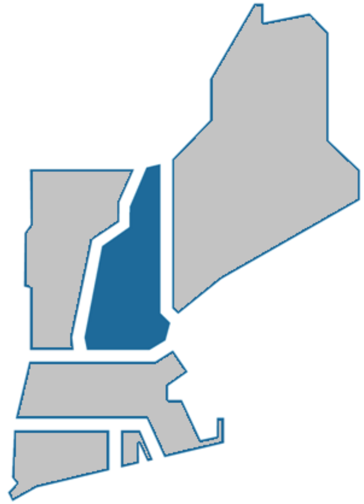
- VT DPS’ 12/8/15 DGFWG presentation serves as primary source for VT policy information
- PV comprises 110 MW of Standard Offer Program goal of 127.5 MW goal is reached by 2022
  - Assume 42 MW of SOP projects in-service by end of 2015, remaining MWs applied evenly over years 2016-2023
- Assume net metering projects will promote 135 MW of PV until 15% cap is reached
  - Assume 60 MW net metered PV projects in-service at end of 2015

Vermont Forecast Methodology and Assumptions *continued*



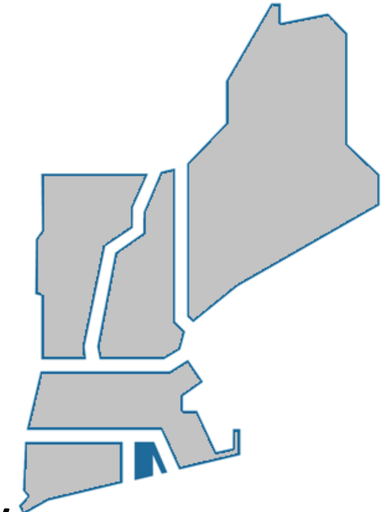
- Assume 75% of existing PPA projects reported last year by DPS go into service
  - Thru-2015: 6.7 MW
  - 2016: 2.95 MW
- The DG carve-out of the new Renewable Energy Standard (RES) will subsume both Standard Offer Program and net metering projects beginning in 2017
  - Assume ~85% of eligible resources will be PV and a total of 25 MW/year will develop

New Hampshire Forecast Methodology and Assumptions



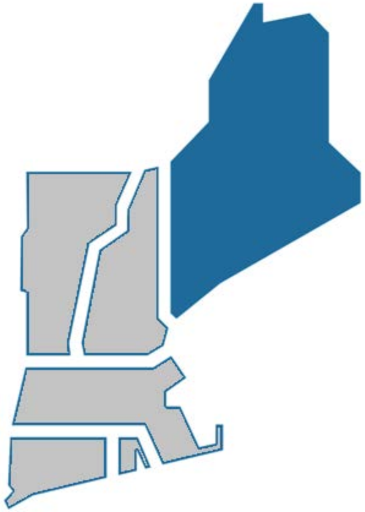
- NH PUC's 12/8/15 DGFWG presentation serves as primary source for NH policy information
- Based on distribution owner survey results, net metering and other state rebate/grants resulted in 13.7 MW of PV growth in 2015
- Post-2020, annual forecast values are kept constant, but are more significantly discounted
- Net metering – existing 50 MW cap
- November 2015 EIA Form 826 data suggests 28 MW of net metered capacity installed, 24.3 MW of which is PV (~87%)
- Assume remaining 22 MW is all PV, and 50 MW net metering cap reached by 2017

Rhode Island Forecast Methodology and Assumptions



- RI OER's 12/8/15 DGFWG presentation serves as primary source for RI policy information
- 30 MW of DG Standards Contract projects will be PV
- Renewable Energy Growth Program (REGP), 2015-2019
  - Total of 144 MW PV (90% of goal) anticipated, applied from 2016-2020 in proportion to phased-in timeline with one year commercialization period assumed
- 2.7 MW/year over the forecast horizon resulting from Renewable Energy Fund & Net Metering
- Post-2021 (after REGP ends), annual forecast values are kept constant, but are more significantly discounted

Maine Forecast Methodology and Assumptions



- ME PUC's 12/8/15 DGFWG presentation serves as primary source for ME policy information
- Based on Distribution Owner survey results, net metering and other state grants/incentives resulted in 4.9 MW of PV growth in 2015
- Growth carried forward at constant rate throughout forecast period
- EIA Form 826 data from November 2015 indicates 16.7 MW of net metered PV (~83% of all net metered capacity)

Discount Factors

- Discount factors were developed and incorporated into the forecast, and reflect a degree of uncertainty in future PV commercialization
- Discount factors were developed for two types of future PV inputs to the forecast (and all discount factors are applied equally in all states)

Policy-Based *PV that results from state policy*	**Post-Policy** *PV that may be installed after existing state policies end*
Discounted by values that increase annually up to a maximum value of 20%	**Discounted by 50% due to the high degree of uncertainty associated with possible future expansion of state policies and/or future market conditions required to support PV commercialization in the absence of policy expansion**

2016 PV Forecast Reflects Significant Policy Achievement over Next 10 Years

- Policy-based discount factors (shown on next slide) were reduced relative to those used last year
  - These discount factors are meant to account for a degree of uncertainty associated with the various factors impacting the commercialization of future PV
- Reduced policy-based discount factors used in 2016 forecast reflect:
  1. The recent extension of federal policy support (i.e., the ITC) that will create a more favorable environment for PV development nationally
  2. An additional year of utility-provided PV interconnection data verifying significant PV growth and measured achievement of state policy goals
- The ISO's post-policy discount factor is meant to be a simple means of capturing uncertainty associated with future expansion of state policies and/or future market conditions while acknowledging some degree of PV growth is expected when policies end

Policy-Based Discount Factors

Forecast Year	Policy-Based Discount Factor
Thru 2015	0%
2016	5%
2017	5%
2018	10%
2019	10%
2020	10%
2021	15%
2022	20%
2023	20%
2024	20%
2025	20%

Summary of State-by-State 2016 Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
CT	188.0	90.0	110.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	**1,108.0**
MA	947.1	309.9	129.1	77.5	77.5	77.5	77.5	77.5	77.5	77.5	77.5	**2,005.9**
ME	15.3	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	**64.5**
NH	26.4	14.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	**112.4**
RI	23.6	22.8	40.8	40.0	40.0	28.8	10.8	10.8	10.8	10.8	10.8	**249.6**
VT	124.6	31.8	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	**381.4**
Pre-Discount Annual Policy-Based MWs	**1325.0**	**473.3**	**317.8**	**237.4**	**159.9**	**148.7**	**71.7**	**64.9**	**33.9**	**33.9**	**33.9**	**2,900.4**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**8.0**	**85.5**	**85.5**	**144.5**	**151.2**	**182.2**	**182.2**	**182.2**	**1,021.3**
Pre-Discount Annual Total (MW)	**1325.0**	**473.3**	**317.8**	**245.4**	**245.4**	**234.1**	**216.1**	**216.1**	**216.1**	**216.1**	**216.1**	**3,921.7**
Pre-Discount Cumulative Total (MW)	**1325.0**	**1,798.3**	**2,116.1**	**2,361.5**	**2,606.9**	**2,841.0**	**3,057.2**	**3,273.3**	**3,489.4**	**3,705.6**	**3,921.7**	**3,921.7**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 13-27 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 2016 SOLAR PV FORECAST

Nameplate MW

Final 2016 PV Forecast

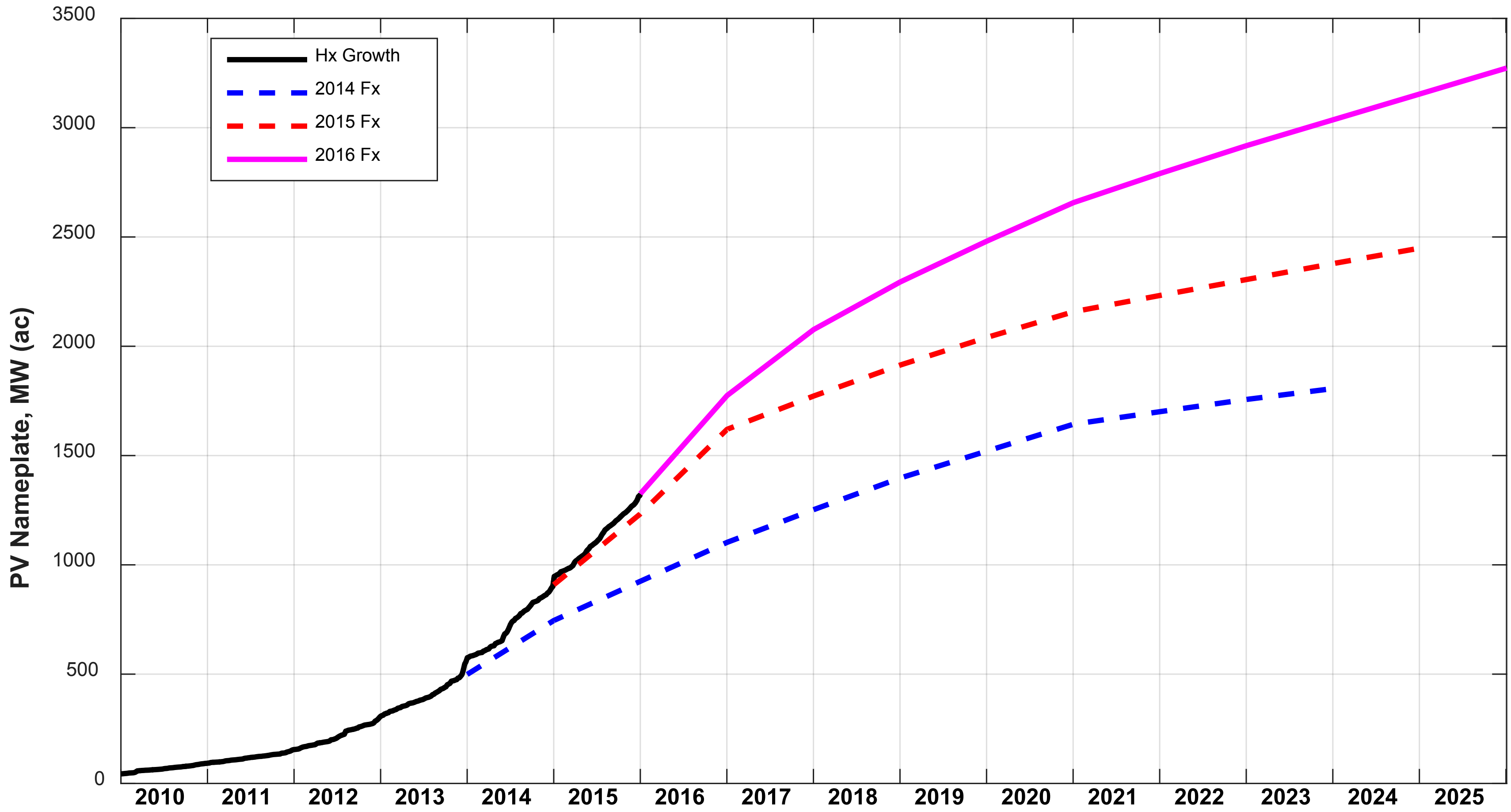
Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
CT	188.0	85.5	104.5	81.0	81.0	81.0	55.8	54.3	45.0	45.0	45.0	**866.1**
MA	947.1	294.4	122.7	69.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	**1,705.0**
ME	15.3	4.7	4.7	4.4	4.4	4.4	4.2	3.9	3.9	3.9	3.9	**57.9**
NH	26.4	13.3	7.6	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	**79.3**
RI	23.6	21.6	38.7	36.0	36.0	25.9	9.1	6.6	6.6	6.6	6.6	**217.2**
VT	124.6	30.2	23.8	22.5	22.5	22.5	21.3	20.0	20.0	20.0	20.0	**347.3**
Regional - Annual (MW)	**1325.0**	**449.6**	**301.9**	**217.7**	**186.7**	**176.5**	**133.2**	**127.5**	**118.2**	**118.2**	**118.2**	**3,272.8**
Regional - Cumulative (MW)	**1325.0**	**1774.7**	**2076.5**	**2294.2**	**2480.9**	**2657.4**	**2790.6**	**2918.1**	**3036.3**	**3154.6**	**3272.8**	**3,272.8**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast reflects discount factors described on slides 25-26
(3) All values represent end-of-year installed capacities
(4) ISO is working with stakeholders to determine the appropriate use of the forecast

PV Growth: Reported Historical vs. Forecast

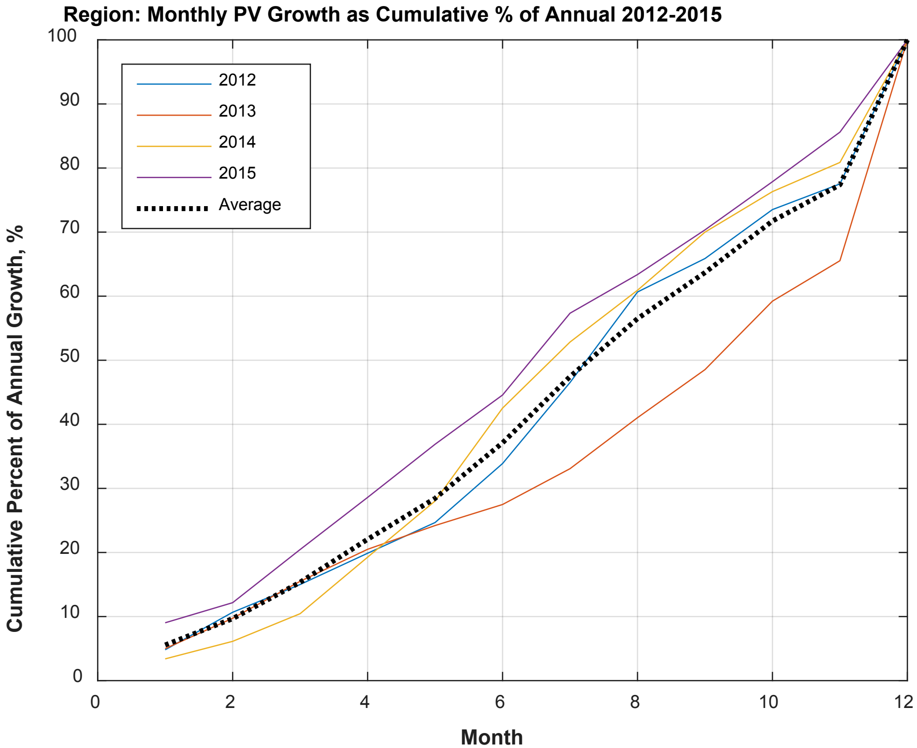


2016 PV ENERGY FORECAST

Development of PV Energy Forecast

- The 2016 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 2012 and 2015 were used to estimate intra-annual incremental growth over the forecast horizon (*see next slide*)
- The PV energy forecast was developed using a monthly nameplate forecast along with average monthly capacity factors from Yaskawa-Solectria data (*see slide 39*)
  - Annual capacity factor = 14.1%
  - Yaskawa-Solectria data is described further (*see slide 48*)

Historical Monthly PV Growth Trends, 2012-2015



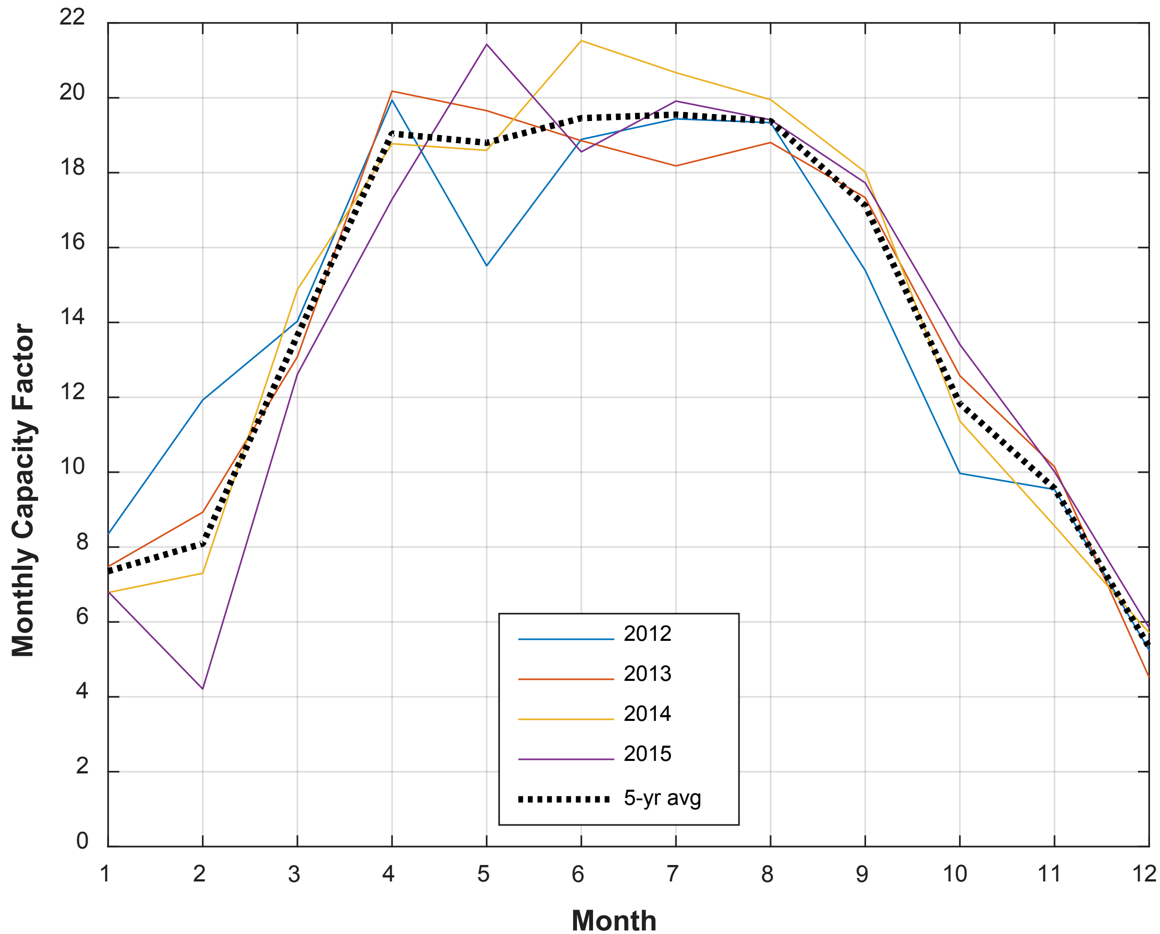
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6%	6%
2	4%	10%
3	6%	15%
4	7%	22%
5	6%	28%
6	9%	37%
7	10%	47%
8	9%	56%
9	7%	64%
10	8%	72%
11	6%	77%
12	23%	100%

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

Monthly PV Capacity Factors

Yaskawa-Solectria PV Site Data, 2012-2015



Source: http://www.solrenview.com/

Final 2016 PV Energy Forecast

All Resource Types, GWh

States	Total Estimated Annual Energy (GWh)									
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
CT	287	409	535	642	749	844	917	984	1,043	1,103
MA	1383	1,692	1,829	1,907	1,958	2,009	2,060	2,111	2,162	2,213
ME	22	28	35	40	46	52	57	62	68	73
NH	41	56	64	69	75	80	85	91	96	101
RI	41	77	127	175	217	244	255	263	272	281
VT	178	215	246	275	305	334	361	388	414	440
Regional - Annual Energy (GWh)	**1953**	**2,477**	**2,836**	**3,109**	**3,350**	**3,563**	**3,735**	**3,899**	**4,055**	**4,211**

***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) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

BREAKDOWN OF PV NAMEPLATE FORECAST INTO RESOURCE TYPES

Forecast Includes Classification by Resource Type

- In order to properly account for existing and future PV in planning studies and avoid double counting, ISO classified PV into three distinct types related to the resources assumed market participation/non-participation
- These market distinctions are important for the ISO's use of the PV forecast in a wide range of planning studies
- The classification process requires the estimation of hourly PV production that is behind-the-meter (BTM), i.e., PV that does not participate in ISO markets
  - This requires historical hourly BTM PV production data to reconstitute PV into the historical load data used to develop the long-term load forecast

Three Mutually Exclusive PV Resource Types

1. **PV as a resource in the Forward Capacity Market (FCM)**
   – Qualified for the FCM and have acquired a capacity supply obligations
   – Size and location identified and visible to the ISO
   – May be supply or demand-side resources

2. **Non-FCM Settlement Only Resources (SOR) 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

***Notes*:**
For 2015 CELT, BTM was further subdivided into two categories, behind-the-Meter PV embedded in load (BTMEL) and behind-the-meter PV not embedded in load (BTMNEL); Full PV reconstitution allowed ISO to combine these two categories into one (BTM)

Determining PV Resource Type By State

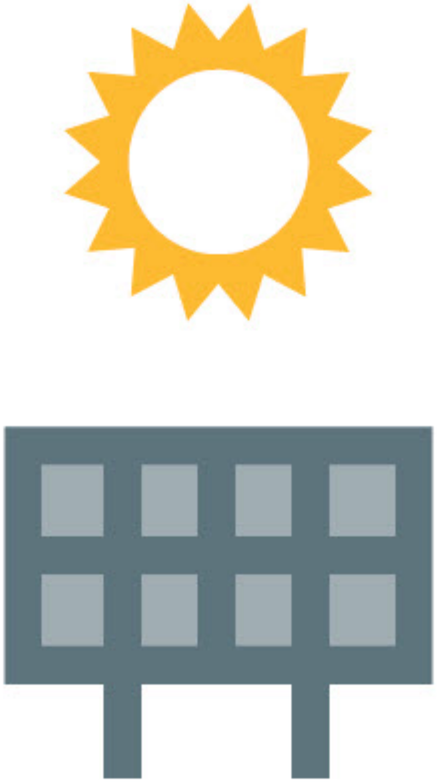
- Resource types vary by state
  - Can be influenced by state regulations and policies (*e.g.*, net metering requirements)
- The following steps were used to determine PV resource types for each state over the forecast horizon:
  1. **FCM**
     - Identify all Generation and Demand Response FCM PV resources for each Capacity Commitment Period (CCP) through FCA 10
  2. **Non-FCM SOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2015 and assume this share remains constant throughout the forecast period
  3. **BTM**
     - Subtract the values from steps 1 and 2 from the annual state PV forecast, the remainder is the BTM PV

PV in ISO New England Markets

- **FCM**
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 10
  - Assume aggregate total PV in FCM as of FCA 10 remains constant from 2019-2025
- **Non-FCM Gen/SOR (Energy Only Resources (EOR))**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/15
  - Assume % share of nameplate PV in energy market as of 12/31/15 remains constant throughout the forecast horizon
- Other assumptions:
  - Supply-side FCM PV resources operate as SOR/Gen prior to their first FCM commitment period (this has been observed in Massachusetts)
  - Planned PV projects known to be > 5 MW_{ac} nameplate are assumed to trigger OP-14 requirement to register in ISO energy market as a Generator

Estimation of Hourly BTM PV

- In order to estimate hourly BTM PV production, ISO developed hourly state PV profiles for the period 1/1/2012 –1/31/2015 using publicly-available historical production (*see slide 48*)
  - Data aggregated into normalized PV profiles for each state, which represent a per-MW-of-nameplate production profile for PV



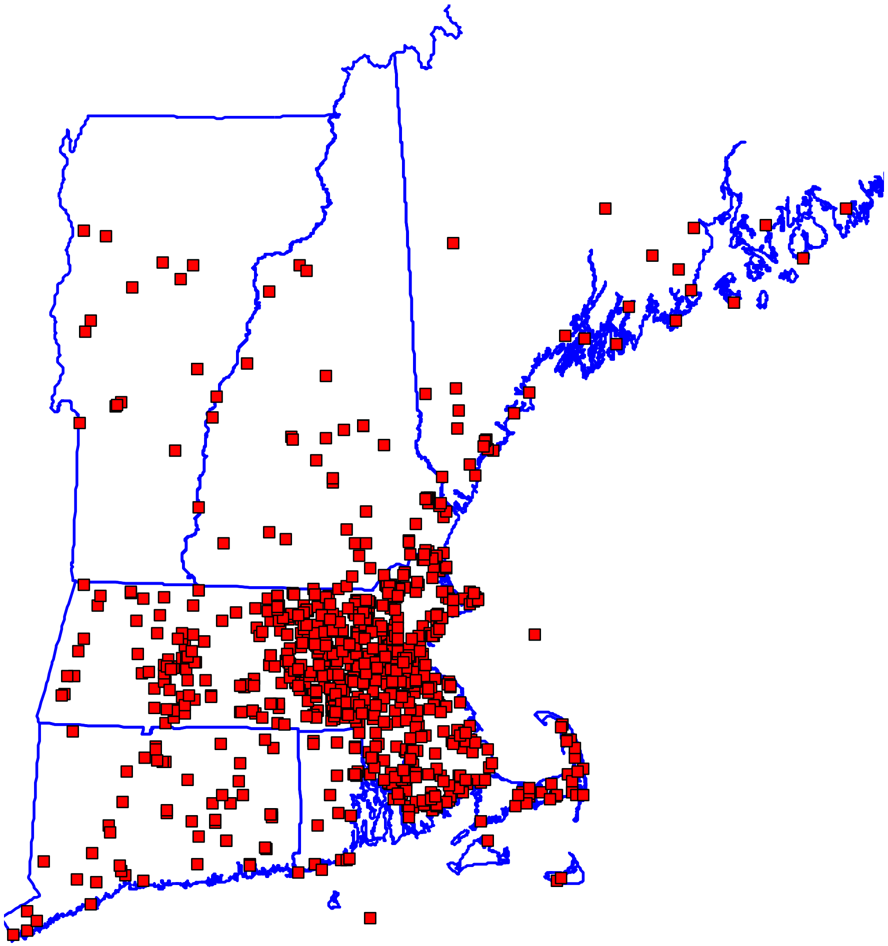
Estimation of Hourly BTM PV (*continued*)

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

Historical PV Profile Development and Analysis

- Hourly state PV profiles developed for four years (2012-2015) using production data using Yaskawa-Solectria Solar's web-based monitoring system, SolrenView*
  - Represents PV generation at the inverter or at the revenue-grade meter
- A total of more than 1,200 individual sites representing more than 125 MW_{ac} in nameplate capacity were used
  - Total nameplate capacity represents approximately 10% of installed PV capacity in the region as of 12/31/15
  - The site distribution throughout the region is sufficient for estimating profiles of all PV installations in New England
  - Site locations depicted on adjacent map

Yaskawa-Solectria Sites



Source: http://www.solrenview.com/

Final 2016 PV Forecast

Cumulative Nameplate, MW_{ac}

States	Cumulative Total MW (AC nameplate rating)										
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT	188.0	273.5	378.0	459.0	540.0	621.0	676.9	731.2	776.2	821.1	866.1
MA	947.1	1241.5	1364.2	1433.9	1472.6	1511.3	1550.1	1588.8	1627.6	1666.3	1705.0
ME	15.3	20.0	24.6	29.1	33.5	37.9	42.1	46.1	50.0	53.9	57.9
NH	26.4	39.7	47.3	51.3	55.3	59.3	63.3	67.3	71.3	75.3	79.3
RI	23.6	45.2	83.9	119.9	155.9	181.8	190.9	197.5	204.1	210.7	217.2
VT	124.6	154.8	178.5	201.0	223.5	246.0	267.3	287.3	307.3	327.3	347.3
Regional - Cumulative (MW)	**1325.0**	**1774.7**	**2076.5**	**2294.2**	**2480.9**	**2657.4**	**2790.6**	**2918.1**	**3036.3**	**3154.6**	**3272.8**

Notes:

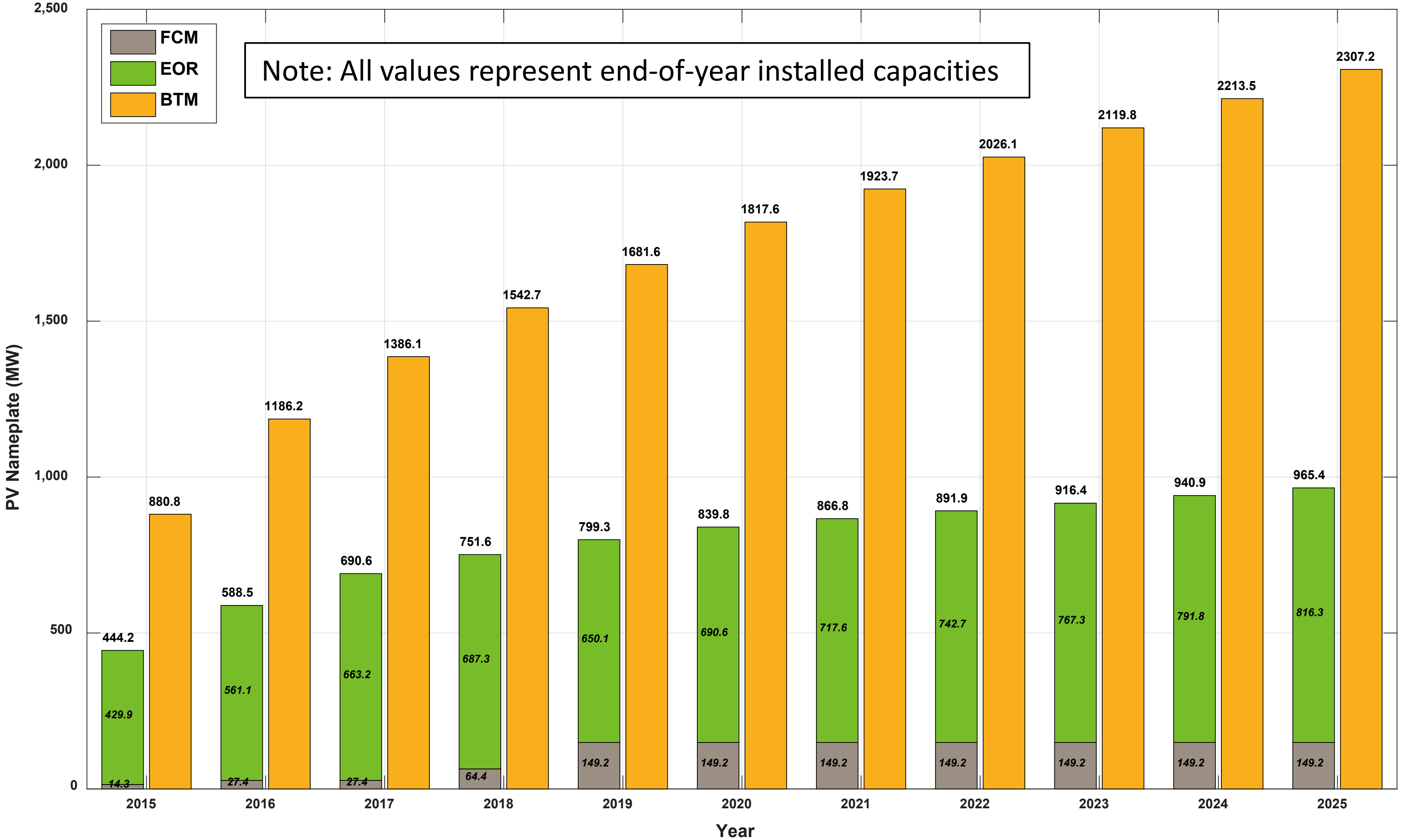
(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals

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

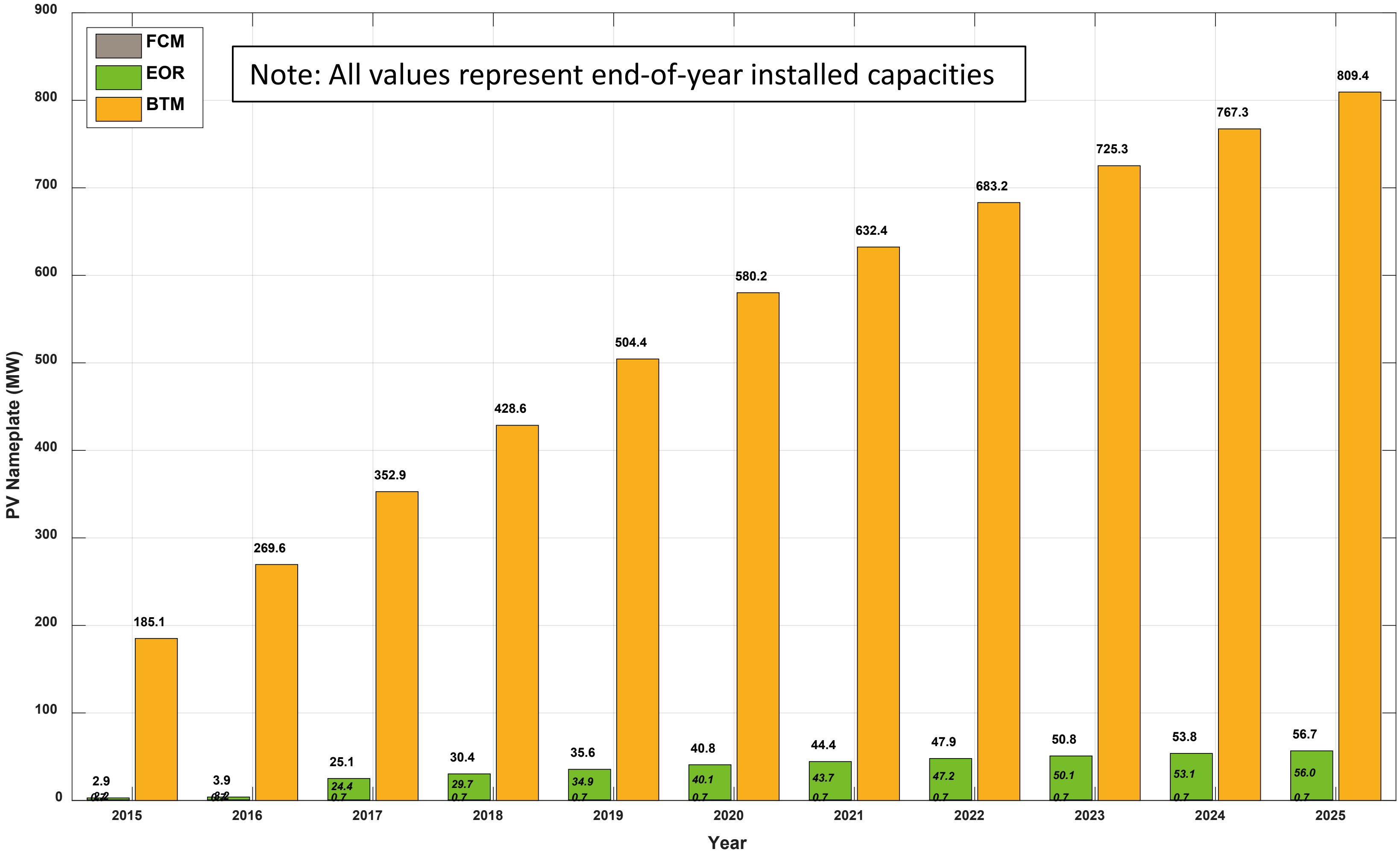
Final 2016 PV Forecast

Cumulative Nameplate, MW_{ac}



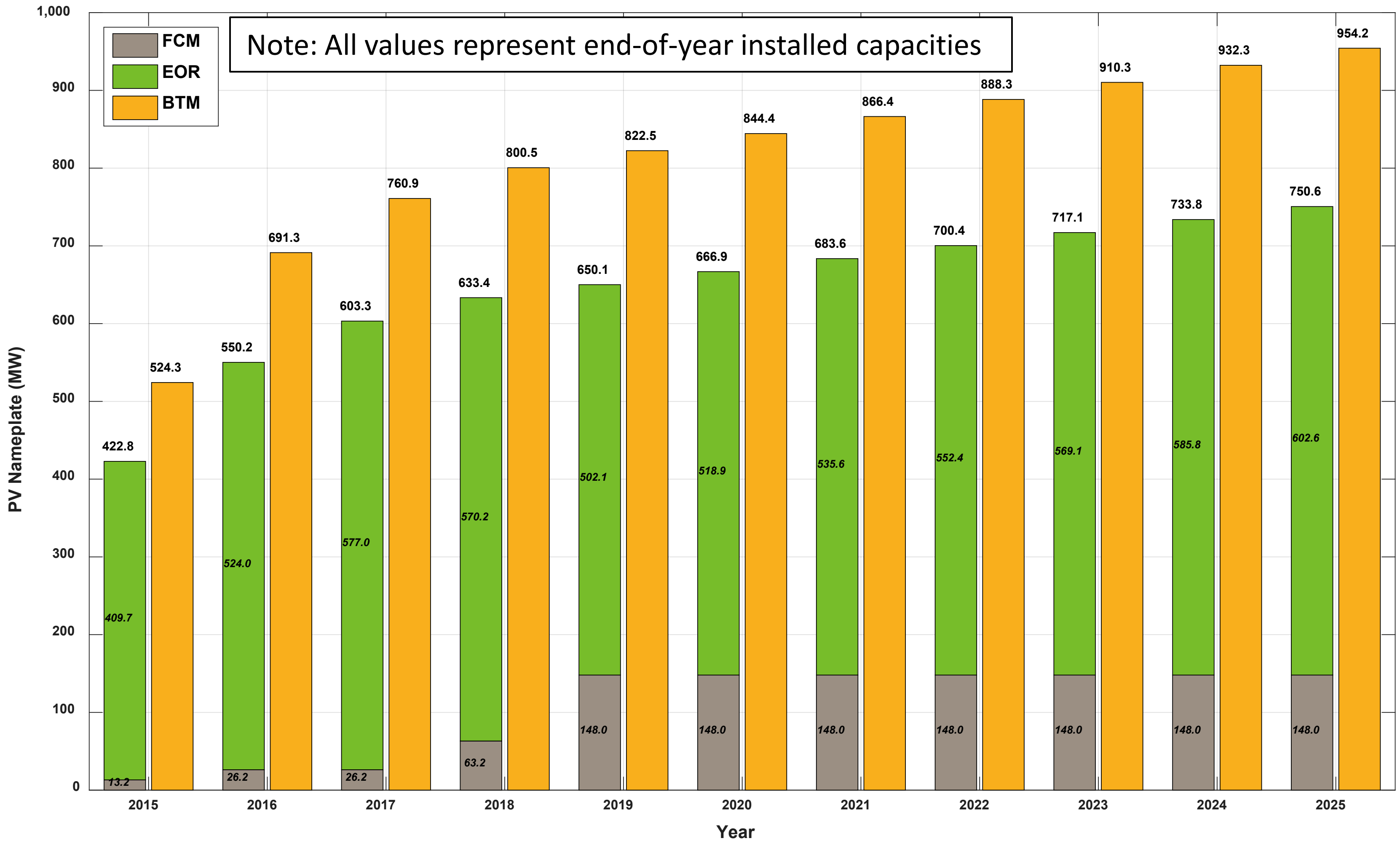
Cumulative Nameplate by Resource Type, MW_{ac}

Connecticut



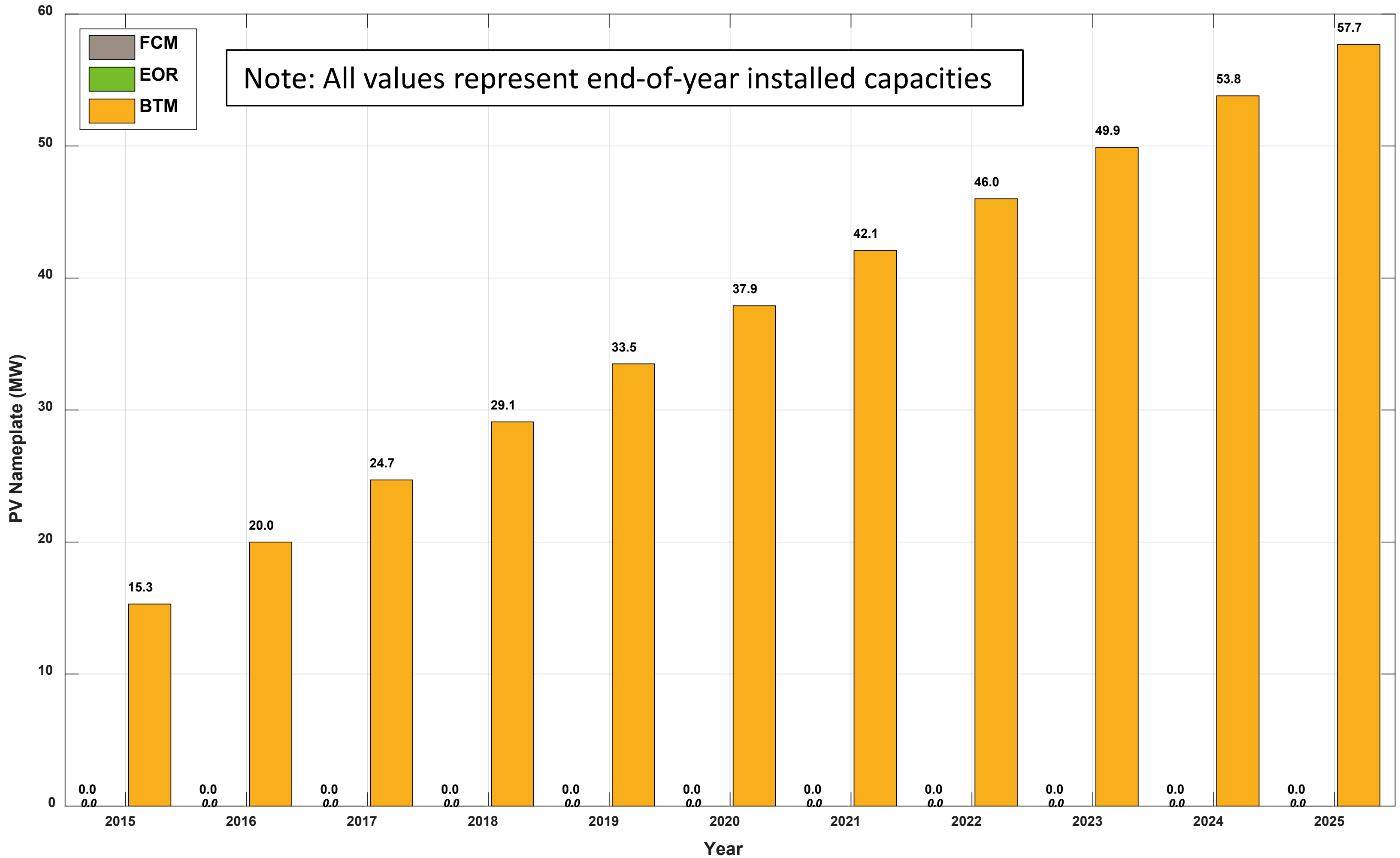
Cumulative Nameplate by Resource Type, MW_{ac}

Massachusetts



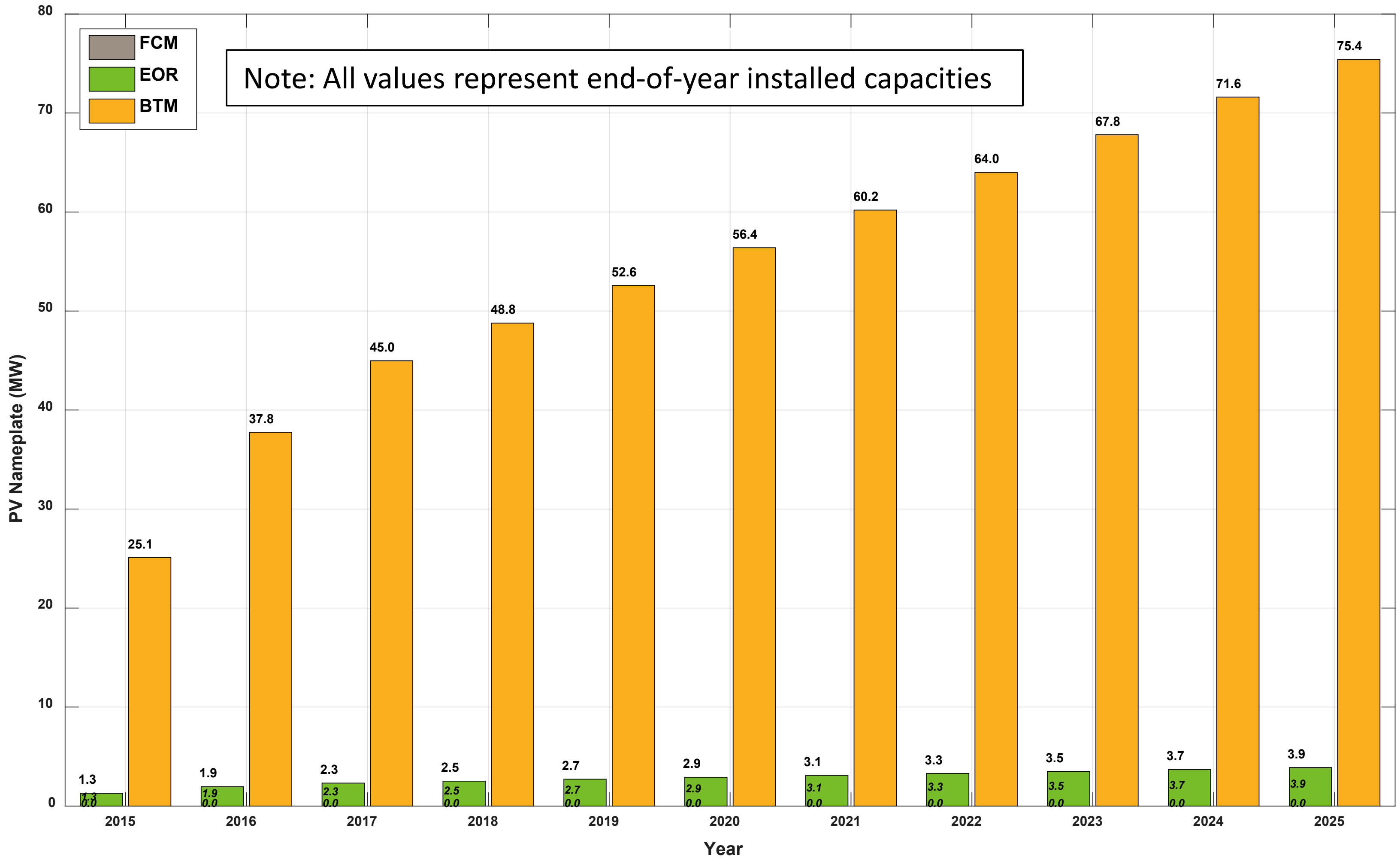
Cumulative Nameplate by Resource Type, MW_{ac}

Maine



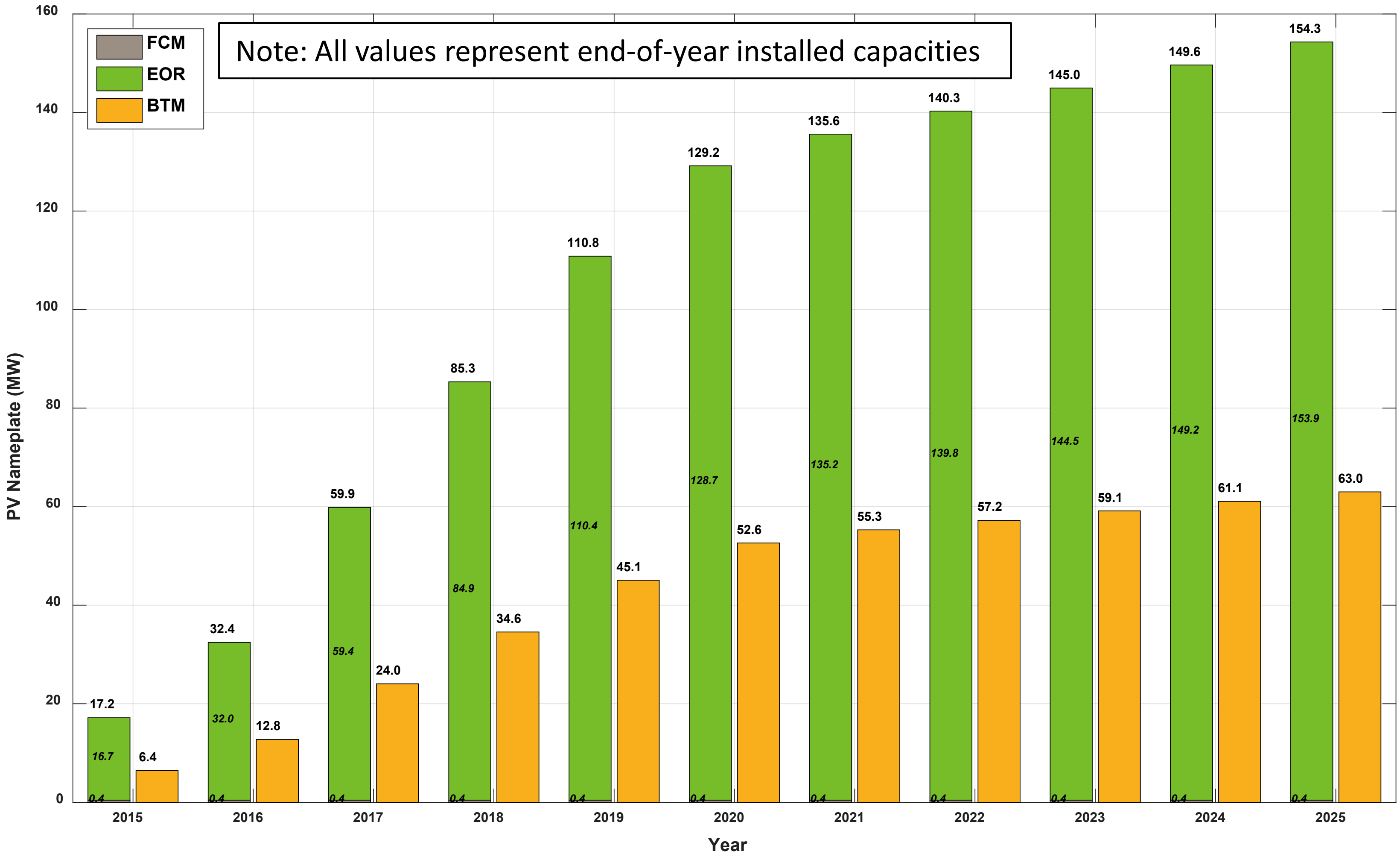
Cumulative Nameplate by Resource Type, MW_{ac}

New Hampshire



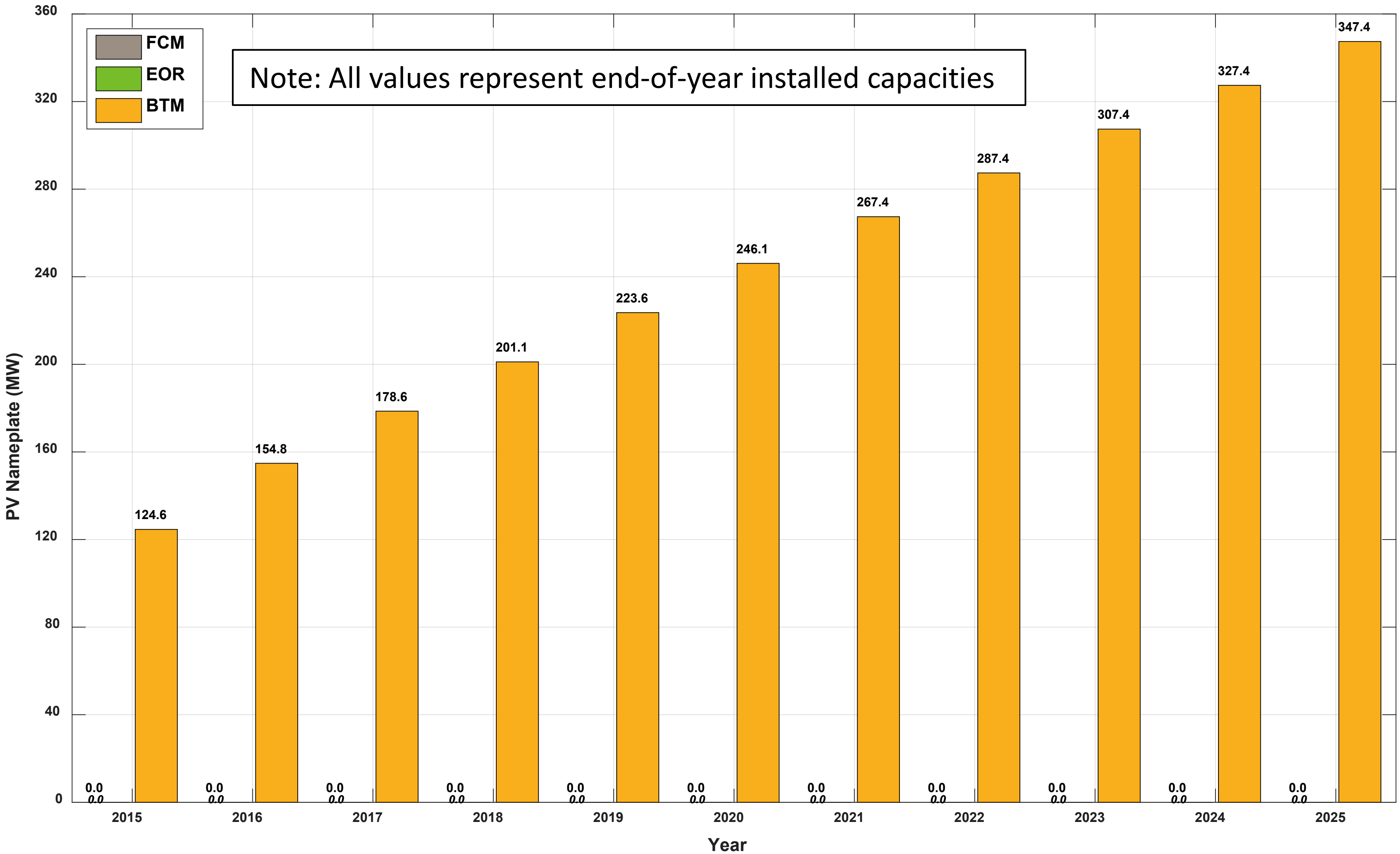
Cumulative Nameplate by Resource Type, MW_{ac}

Rhode Island



Cumulative Nameplate by Resource Type, MW_{ac}

Vermont



BTM PV: ESTIMATED ENERGY & SUMMER PEAK LOAD REDUCTIONS

BTM PV Forecast Used in CELT Net Load Forecast

- The 2016 CELT net load forecast reflects deductions associated with the BTM PV portion of the PV forecast
- The following slides show values for summer peak load reductions and annual energy anticipated from BTM PV included in the 2016 CELT net load forecast
  – PV does not reduce winter peak loads
- Values for expected summer peak load reductions from BTM PV incorporates the results of ISO's analysis included as an appendix at the end of this presentation, which was discussed with stakeholders at the February 24, 2016 DGFWG meeting

Final 2016 Forecast

BTM PV: July 1st Estimated Summer Peak Load Reductions

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Behind-the-Meter PV	CT	61.0	92.1	123.9	153.6	181.0	207.7	230.6	247.6	262.8	275.7	288.2
	MA	194.0	249.4	295.6	312.6	320.4	324.0	327.9	332.5	337.1	341.8	346.2
	ME	5.4	7.3	9.0	10.6	12.2	13.7	15.2	16.6	17.8	19.1	20.3
	NH	6.8	12.7	16.7	18.7	19.9	21.1	22.2	23.4	24.6	25.8	26.9
	RI	2.5	3.7	7.0	11.3	15.2	18.7	20.6	21.3	21.8	22.3	22.7
	VT	44.2	57.8	67.4	75.4	83.0	90.5	97.7	104.5	110.9	117.1	123.3
Total	**Cumulative**	313.9	422.9	519.5	582.2	631.6	675.6	714.3	745.9	775.0	801.7	827.6

Estimated Summer Seasonal Peak Load Reduction - % of BTM AC nameplate	40.0%	39.4%	38.2%	37.3%	36.7%	36.1%	35.6%	35.2%	34.8%	34.5%	34.1%

Notes:

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

(2) Percent of BTM AC nameplate values reflect the effect of diminishing PV production as increasing PV penetrations shift the timing of later in the day (see results of analysis in Appendix)

(3) All values represent anticipated July 1st installed PV, and are grossed up by 8% to reflect avoided transmission and distribution losses

(4) Different planning studies may use values different that these estimated peak load reductions based on the intent of the study

Final 2016 PV Energy Forecast

BTM PV, GWh

		Estimated Annual Energy (GWh)										
Category	**States**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Behind-the-Meter PV	CT	145	283	394	500	600	699	788	857	919	975	1030
	MA	584	768	943	1021	1065	1094	1123	1152	1181	1209	1238
	ME	15	22	29	35	40	46	52	57	62	68	73
	NH	17	39	53	61	66	71	76	81	86	91	96
	RI	6	11	22	37	50	63	71	74	76	79	81
	VT	115	178	215	246	275	305	334	362	388	414	441
Behind-the Meter Total		**882**	**1301**	**1655**	**1898**	**2097**	**2278**	**2444**	**2582**	**2713**	**2836**	**2959**

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) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

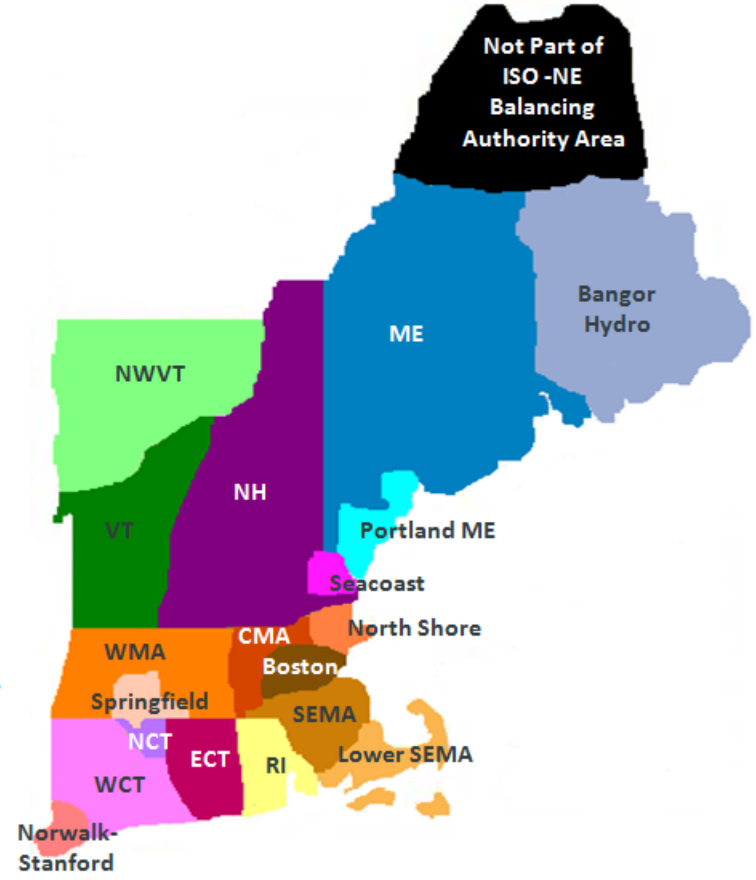
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

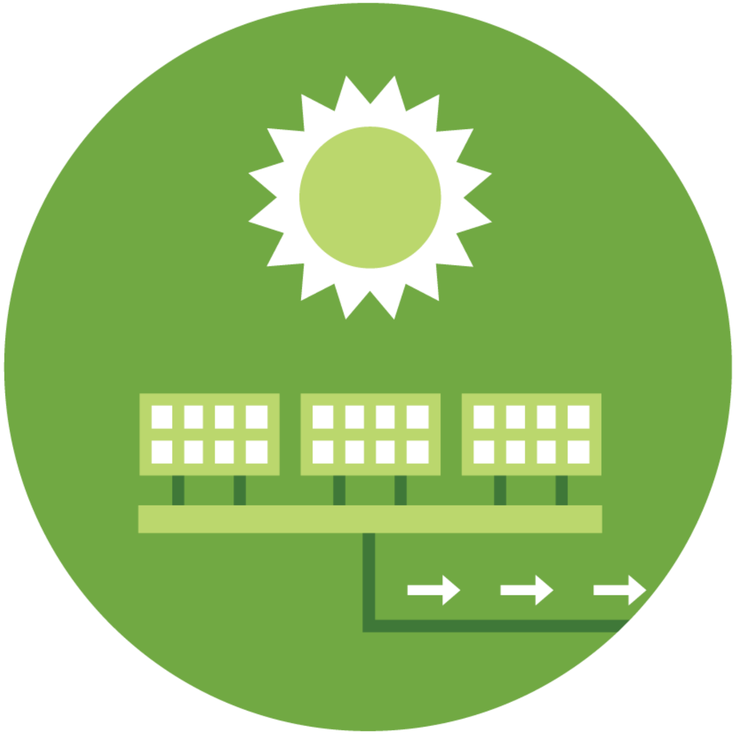
- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of most future PV resources are ultimately unknown
- Mitigation of some of this uncertainty (especially for near-term development) is possible via analysis of available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

Forecasting Solar By DR Dispatch Zone

- Demand Response (DR) Dispatch Zones were created as part of the DR Integration project
- These zones were created in consideration of electrical interfaces
- Quantifying existing and forecasted PV resources by Dispatch Zone (with nodal placement of some) will aid in the modeling of PV resources for planning and operations purposes



Geographic Distribution of PV Forecast



- Existing MWs:
  - Apply I.3.9 project MWs nodally
  - For remaining existing MWs, determine Dispatch Zone locations of projects already interconnected based on utility distribution queue data (town/zip), and apply MWs equally to all nodes in Zone
- Future MWs:
  - Apply I.3.9 project MWs nodally
  - For longer-term forecast, assume the same distribution as existing MWs

Dispatch Zone Distribution of PV

Based on December 31, 2015 Utility Data

State	Dispatch Zone	% Share
MA	SEMA	21.5%
	Boston	10.9%
	Lower SEMA	18.7%
	Central MA	15.3%
	Spfld	6.0%
	North Shore	4.9%
	Western MA	22.7%
CT	Eastern CT	18.8%
	Western CT	53.7%
	Northern CT	20.1%
	Norwalk-Stamford	7.5%
NH	New Hampshire	88.3%
	Seacoast	11.7%
VT	Northwest VT	62.9%
	Vermont	37.1%
RI	Rhode Island	100.0%
ME	Bangor Hydro	15.6%
	Maine	51.2%
	Portland	33.3%

APPENDIX:
PV'S REDUCTION OF FUTURE SUMMER PEAK LOADS

Summer Peak Period Considerations

- For summer peak load conditions, ISO is seeking to understand the anticipated reductions in future peak loads due to the aggregate influence of many PV installations that are interconnected “behind-the-meter” (BTM)
- For the 2014 and 2015 PV forecasts, ISO used Summer Seasonal Claimed Capability (SCC) to estimate PV’s aggregate performance under summer peak load conditions
  - For CELT 2015 this value was estimated to be 40% of AC nameplate based on 3 years of historical data
  - ISO noted that different values may be used for various System Planning studies, depending on the intent of the study

Summer Peak Period Considerations *continued*

- PV performance at the time of the peak is known to differ across the variety of possible peak load conditions due to varied weather and the exact timing of peak loads
- As PV penetrations grow, peak net loads (i.e., load net of PV) will shift later in the afternoon when PV output is diminishing
- The following slides summarize an ISO net load analysis meant to:
  1. Illustrate the interplay between PV growth and the timing/magnitude of summer peak loads based on available data; and
  2. Quantify the corresponding changes in PV's capability to serve the shifted peaks

Recall From 2015 PV Forecast
PV's Seasonal Claimed Capability *continued*

- In accordance with Market Rule 1, Section III.13.1.2.2.2.1(c), ISO uses Seasonal Claimed Capability (SCC) as a measure of a resource's capability to perform under specified summer and winter conditions
  – As an Intermittent Resource, PV's SCC is determined using the median of net output during Intermittent Reliability Hours, which are defined as follows:
    - Summer: June-September, 14:00 through 18:00 (Hours Ending 14 – 18)
    - Winter: October-May, 18:00 and 19:00 (Hours Ending 18 – 19)

Recall From 2015 PV Forecast
PV's Seasonal Claimed Capability

- Based on analysis of three years of PV performance data (2012-2014), the summer SCC for PV in the region is 40% of nameplate (and winter SCC is zero); however, it should be cautioned that:
  - PV performance often differs from its summer SCC during the variety of peak load conditions that occur
  - As PV penetrations grow across the region, PV will shift peak net loads later in the afternoon, decreasing PV's incremental contribution to serving peak loads

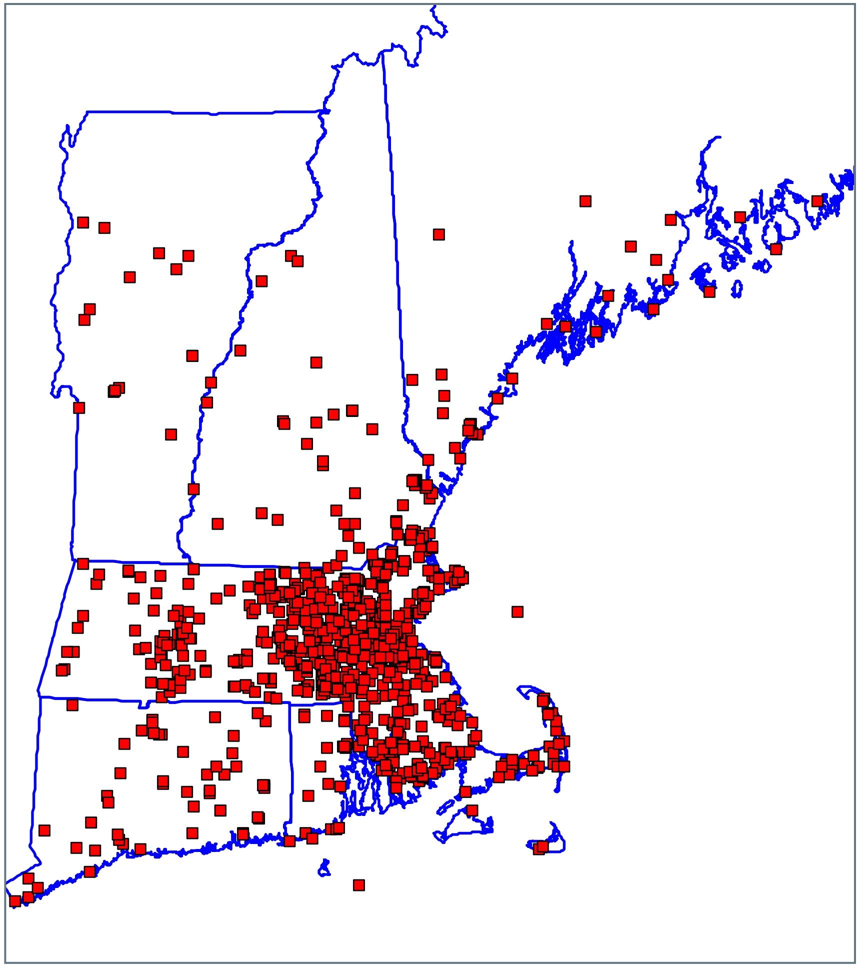
TOPIC ADDRESSED IN FOLLOWING SLIDES

- For these reasons, values that differ from the 40% summer SCC estimate may be more suitable for various planning studies, based on the assumptions (e.g., load level) and intent of each study in question

Net Load Simulation Method

- Future net load scenarios are based on coincident, historical hourly load and PV production data for the years 2012-2015
- PV production data accessed via Yaskawa-Solectria Solar's SolrenView*
  - >1k PV sites totaling > 125 MW_{ac}
- Normalized PV profiles developed for each New England state, blended into a regional profile which was then "upscaled" to each PV scenario

Yaskawa-Solectria Sites

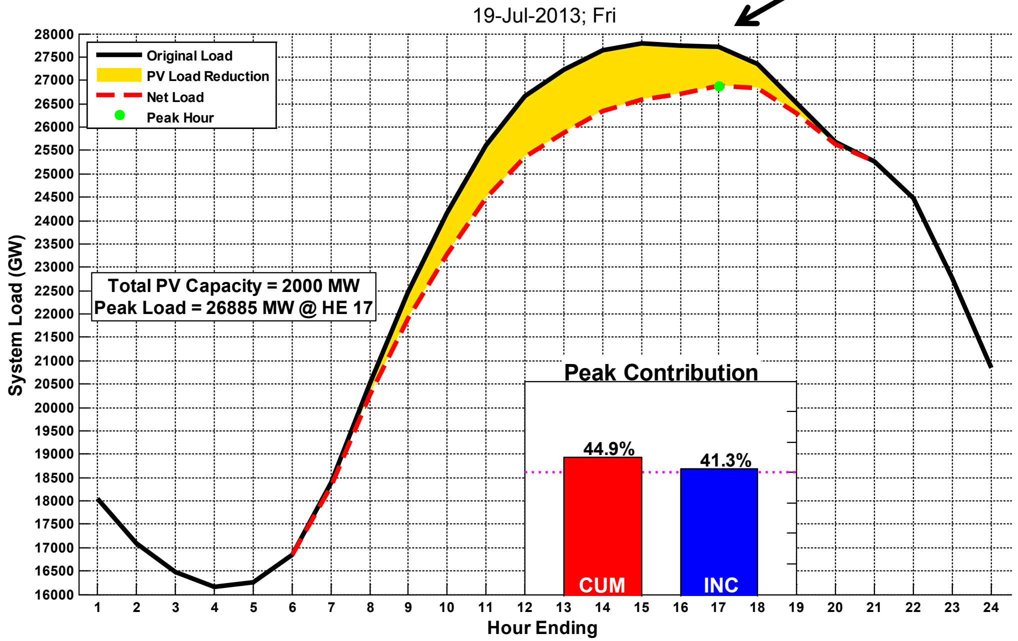


*Accessed via http://www.solrenview.com/

Net Load Simulation Method *continued*

- Existing PV system design and technology trends are not anticipated to change *significantly* over the next decade.
- It is assumed that upscaling of these profiles yields a reasonable estimate of future profiles associated with larger PV fleets that is adequate for simulation purposes
- Hourly load profiles net of increasing amounts of PV were developed in 200 MW (AC nameplate) increments up to 8,000 MW
- Eleven days with loads greater than 25,000 MW were selected for further analysis
  - These daily profiles reflect a variety of weather conditions and calendar effects that influence peak loads
- One of the eleven days (July 19, 2013) is used to illustrate the steps and process of the analysis on subsequent slides

Terms Defined



- The original load without PV is the top **black** curve
- The shaded yellow region represents PV's simulated load reduction
- The **dashed red line** is the new net load profile associated with the total PV capacity shown (2,000 MW on right)
- The **green dot** shows the peak net load

Terms Defined *continued*

- **INC** represents the incremental reduction of the new daily peak load, including associated time shifts, from adding the next MW of PV

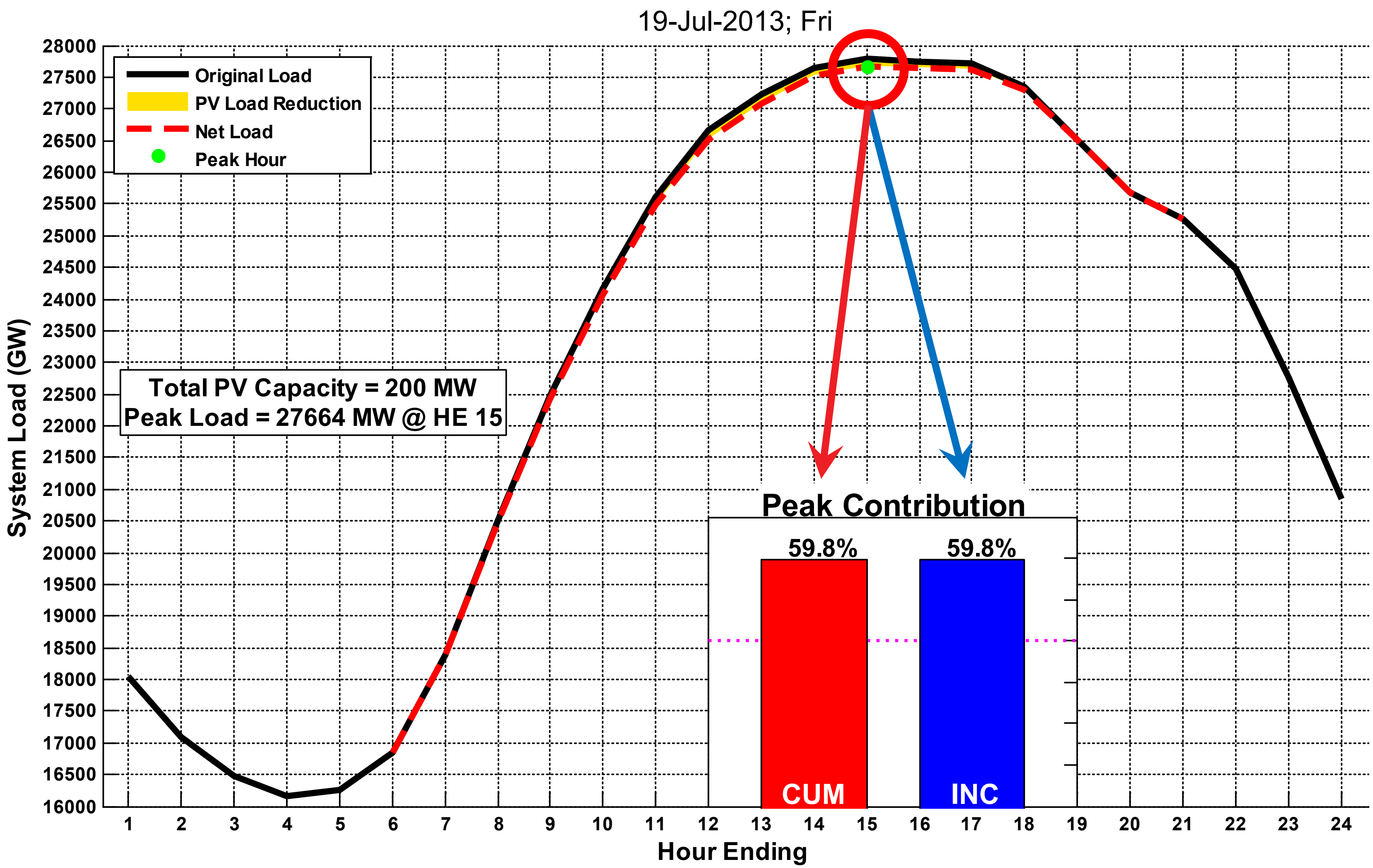
- **CUM** represents the total reduction of the original daily peak load (i.e., without PV) as a percentage of the total installed nameplate capacity of PV

$$\text{INC} = \%\ of\ PV\ nameplate\ at\ time\ of\ new\ peak\ load$$

$$\text{CUM} = \frac{(original\ peak\ load - new\ peak\ load)}{total\ installed\ PV\ nameplate}\ x\ 100$$

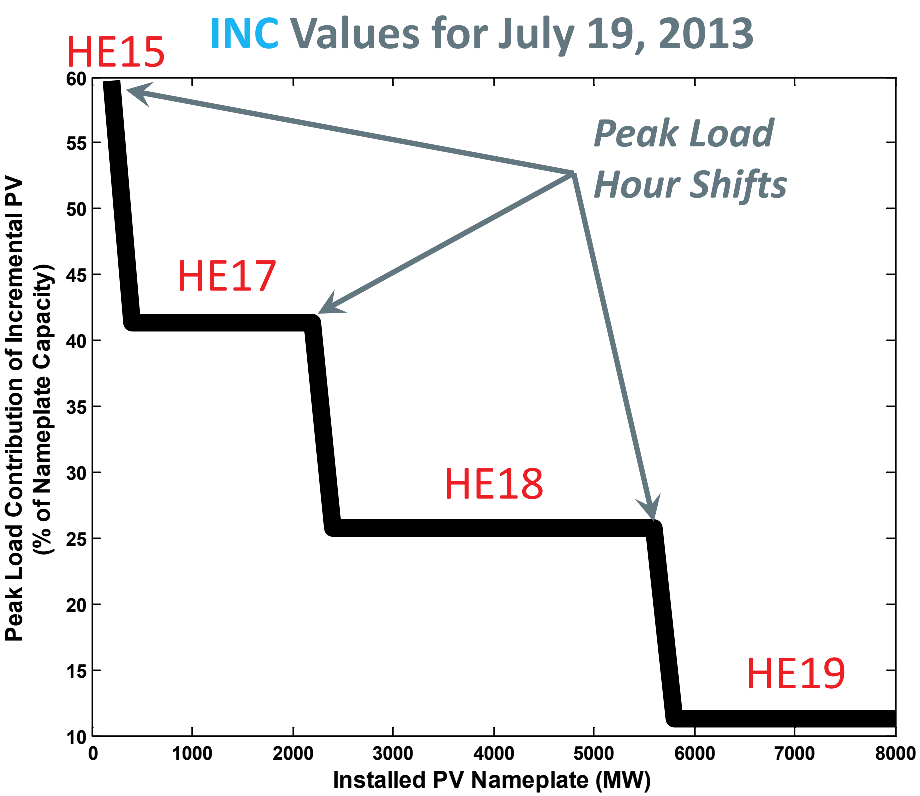
July 19, 2013 Net Load Profile

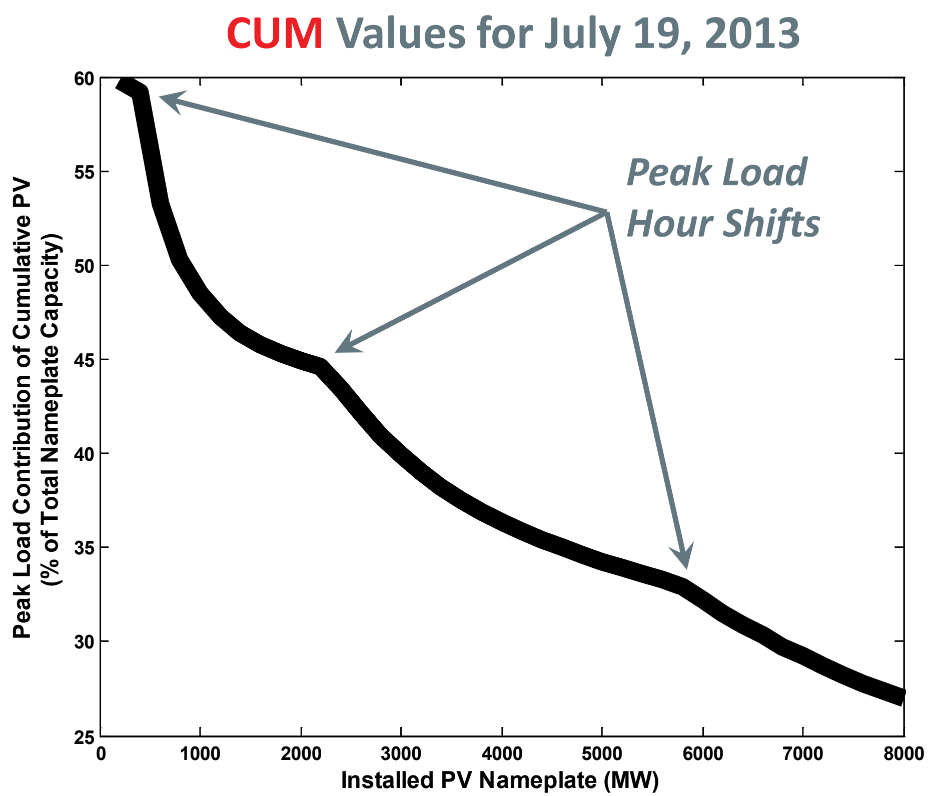
200 MW PV



July 19, 2013

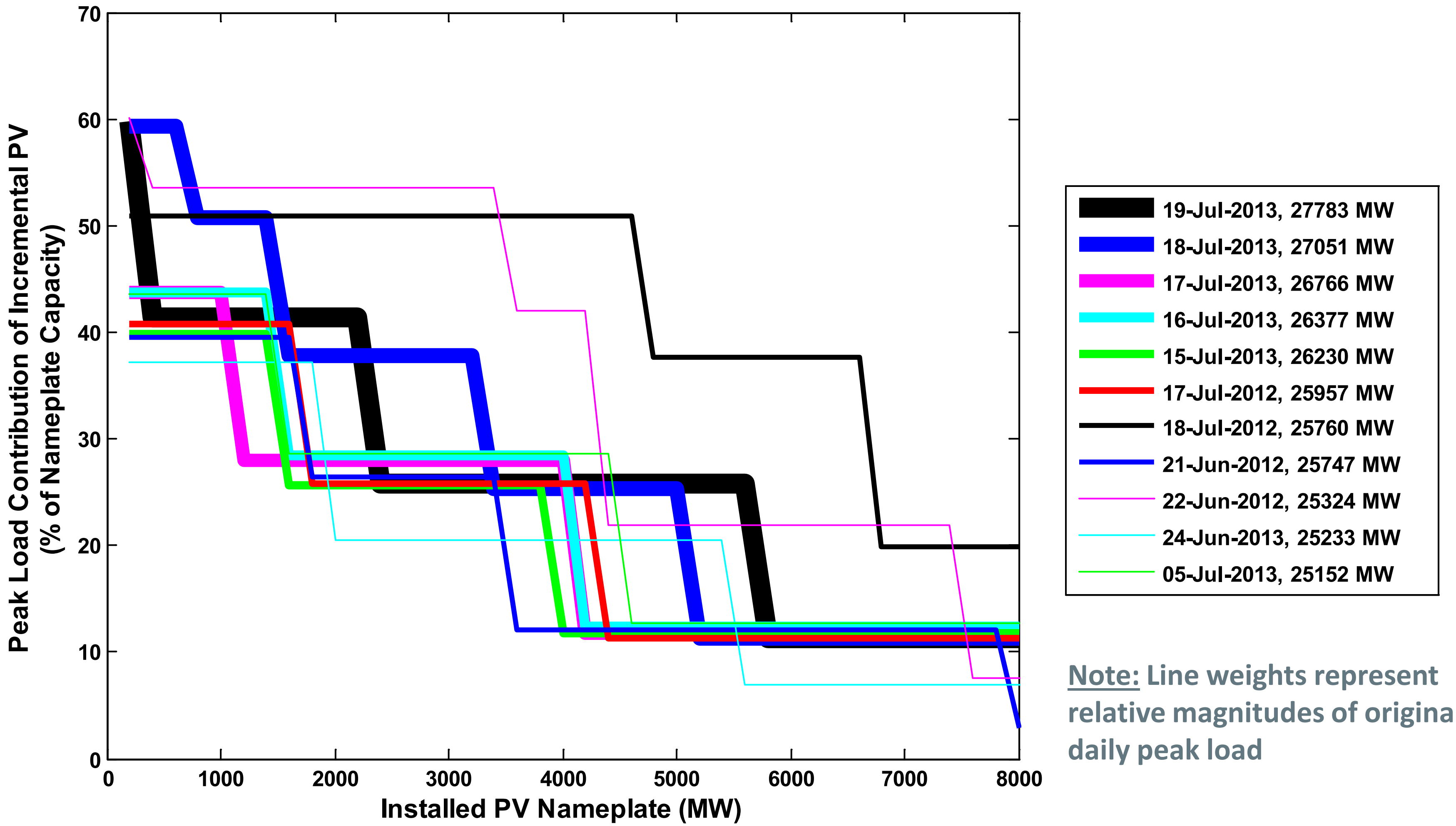
Resulting INC and CUM





All 11 Days: Incremental (INC) Peak Reduction

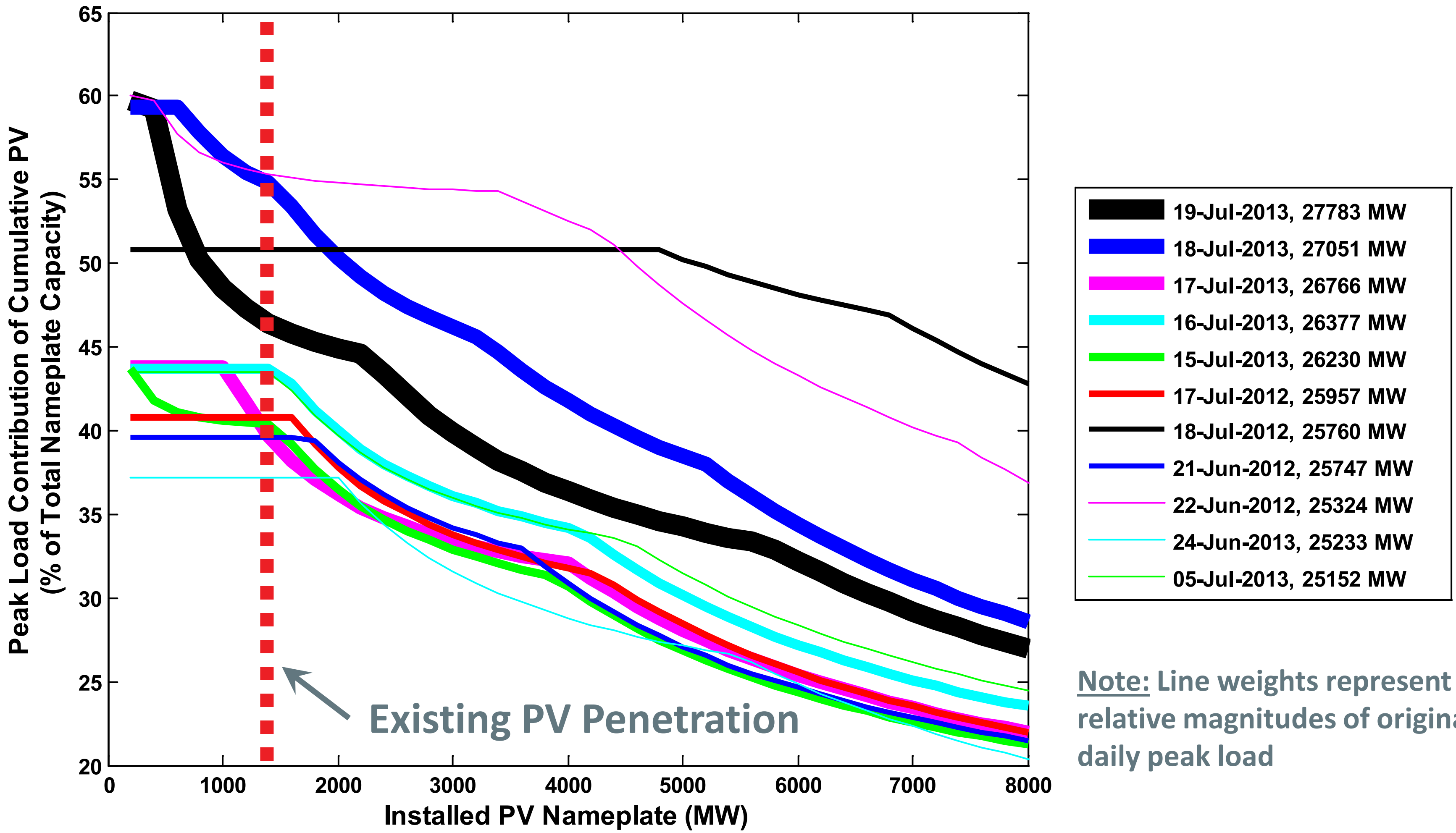
% of Incremental Nameplate Capacity



Note: Line weights represent relative magnitudes of original daily peak load

All 11 Days: Cumulative (CUM) Peak Reduction

% of Total Nameplate Capacity

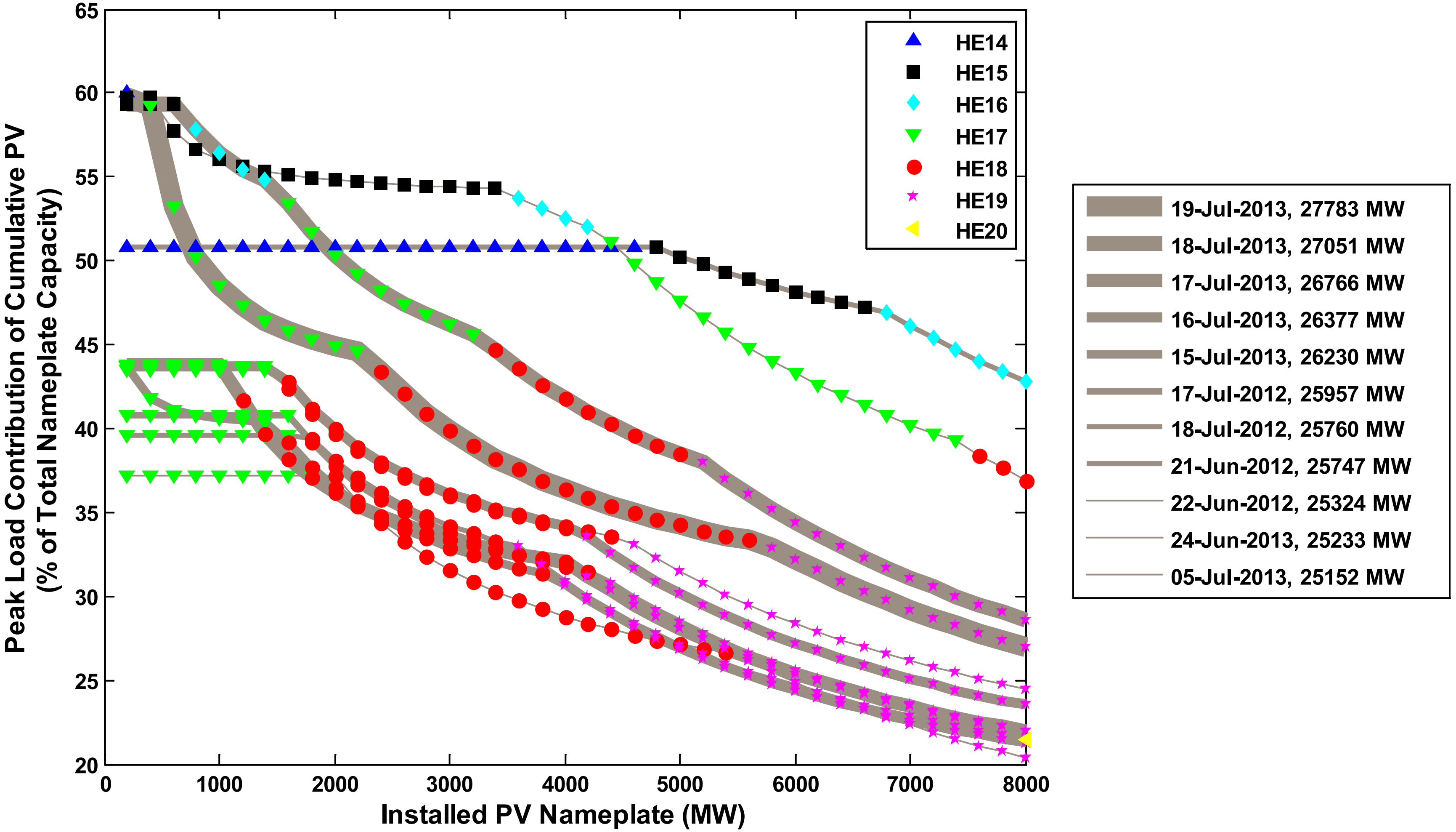


Note: Line weights represent relative magnitudes of original daily peak load

All 11 Days: Cumulative (CUM) Peak Reduction

Peak Net Load Hour Timing

Timing of peak net load shown by marker type/colors

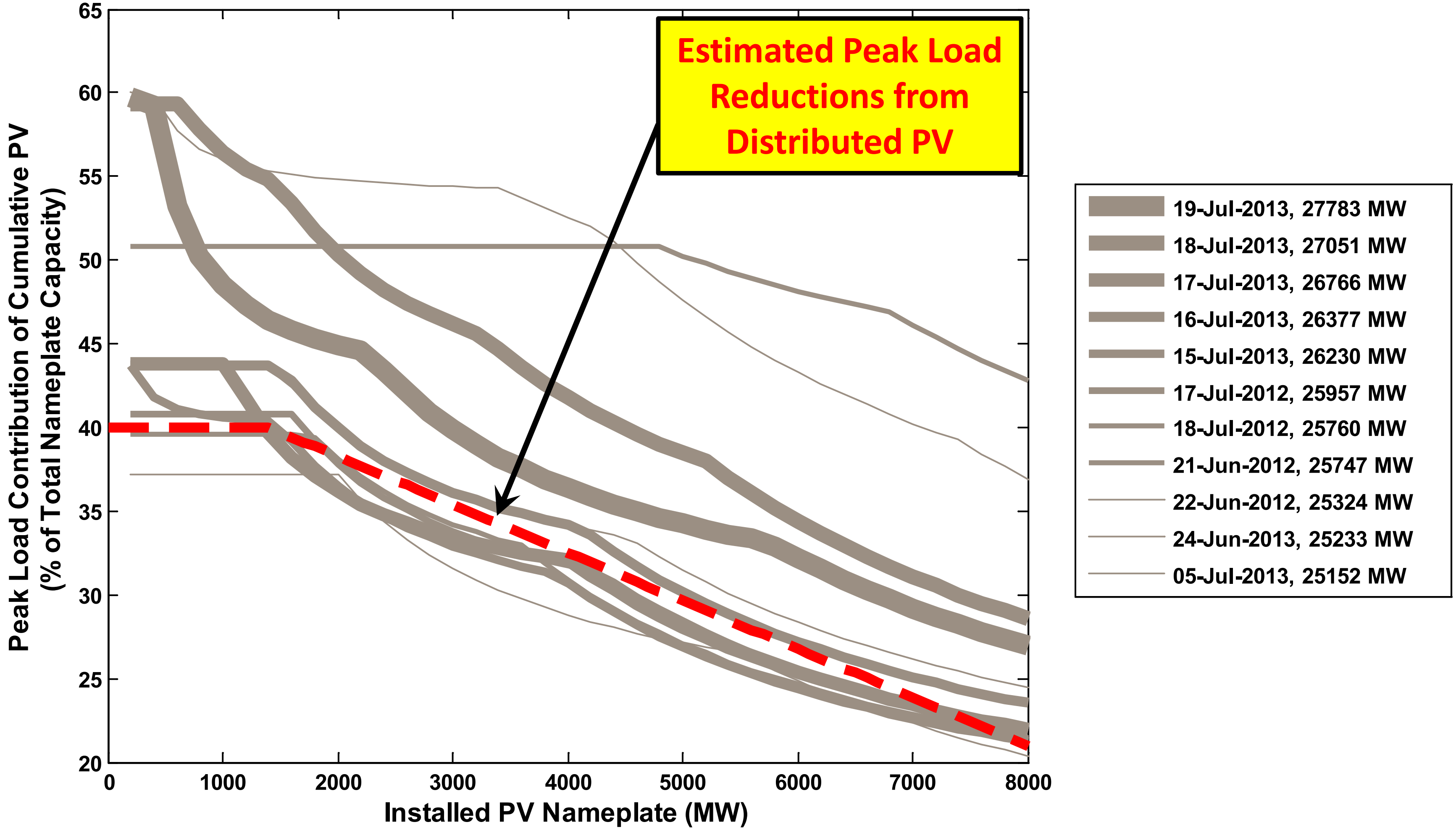


Estimating PV's Future Peak Load Reductions

- The seasonal summer peak load may look like any of the eleven load shapes illustrated on the previous slides
- ISO needs to plan the system to serve any of these summer peak load shapes
- In consideration of the variety of peak load shapes analyzed, the dotted red line on the following slide is the proposed estimated summer peak load reduction due to PV as the amount of installed PV increases

Distributed PV's Estimated Peak Load Reductions

Assumed Load Reduction Considers a Variety of Peak Load Shapes



Distributed PV's Estimated Peak Load Reductions

Total Installed PV** (MW$_{ac}$ Nameplate)	Estimated Peak Load Reduction (% of AC nameplate)	Estimated Peak Load Reduction (MW)
0-1,400	40.0%	560 (@1400 MW$_{ac}$ Nameplate)
1,500	39.7%	596
2,000	38.3%	766
3,000	35.4%	1,062
4,000	32.5%	1,300
5,000	29.6%	1,480
6,000	26.8%	1,608
7,000	23.9%	1,673
8,000	21.0%	1,680

Note: Nameplate values include an 8% gross up reflecting avoided transmission and distribution losses estimated for summer peak load conditions.