Final 2015 Solar PV Forecast Details

Outline

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- ICF’s PV Economic Drivers Study
- Discount Factors & Seasonal Claimed Capability
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- Classification of PV Forecast by Market Participation Type
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BACKGROUND & OVERVIEW

Background

- The 2014 PV forecast represented the first multistate forecast
  - The forecast was primarily based on state policy goals
- 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)
    - Changes to federal Investment Tax Credit (ITC), post-2016;
  - 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 draft 2015 PV forecast methodology is similar to that of the 2014 forecast

Background, cont'd

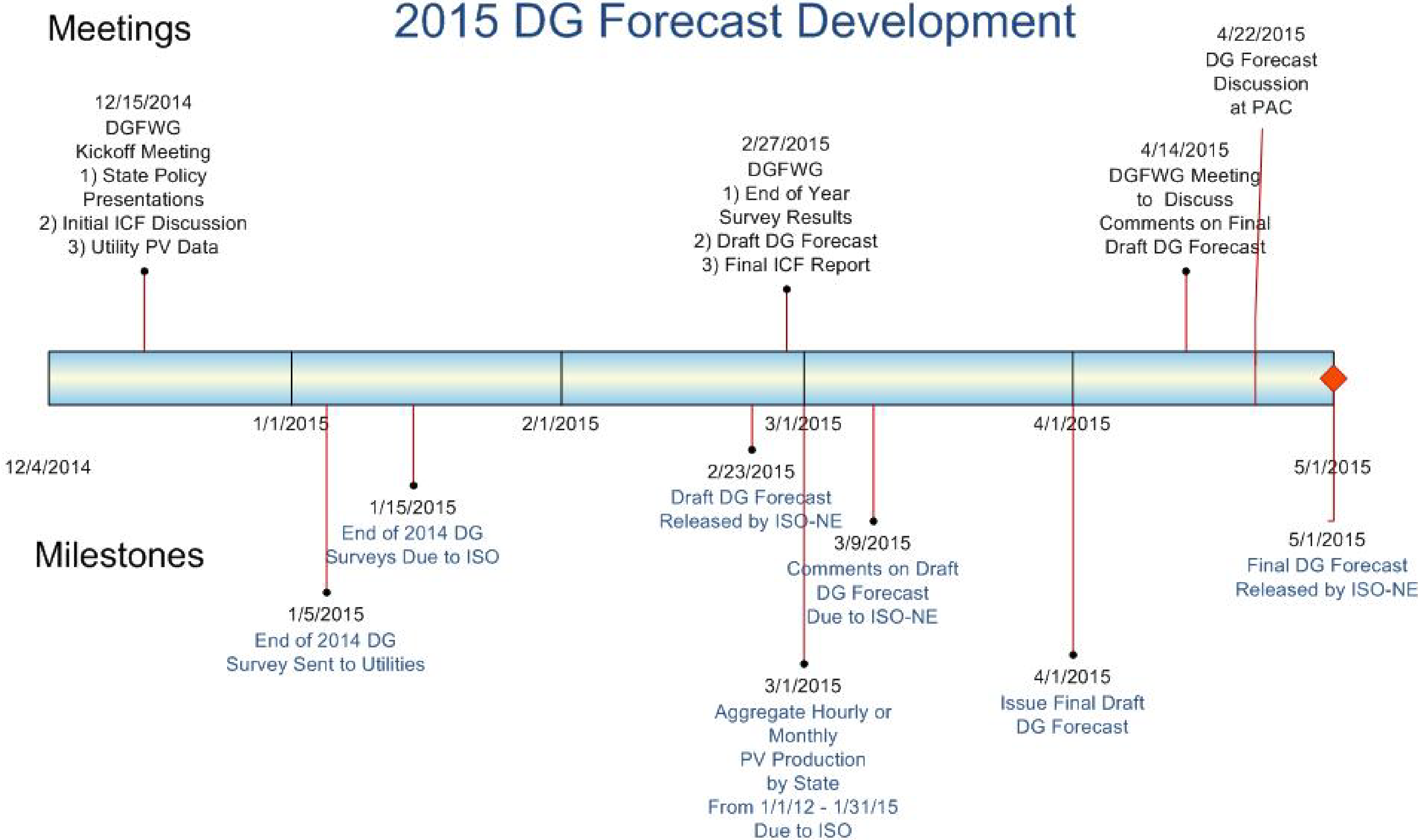
- PV development is happening more rapidly than projected in 2014
  - Based on discussions with stakeholders and data exchange with the New England states and Distribution Owners
  - The 2015 PV forecast is higher than the 2014 PV forecast
- The interrelated factors influencing the potential future development of PV resources are complex
  - The 2015 PV forecast reflects a qualitative approach, but with better information than was available to the ISO last year

What's New in the 2015 PV Forecast?

- Greater availability of historical data
  - Distribution owner survey of installations
  - Energy production information from the states (to be provided by March 2)
- Consideration of the anticipated economic drivers of PV over the forecast horizon
- Updates on state policies and programs influencing PV deployment in New England
- Classification of PV resources by market type
  - FCM resources with capacity supply obligations
  - Settlement only resources that are not FCM resources
  - Behind the meter resources that are already accounted for as part of the ISO load forecast*
  - Other behind the meter resources not accounted for as part of the ISO load forecast

**Existing PV decreases the historical loads seen by the ISO, which are an input to the load forecast*

2015 DG Forecast Development



DISTRIBUTION OWNER SURVEY RESULTS

Solar PV Installed Through December 31, 2014

PV Installed Through 2014

- The ISO thanks the distribution owners that responding to the survey of DG installations
  - The survey is a critical input to the PV forecast
- Distribution Owners provided PV nameplate installation data (in MW_{ac}) within their respective service territories as of 12/31/14
- Distribution Owners serving approximately 95% of the New England load responded: (check list below)
  - **CT**: CL&P, CMEEC, UI
  - **ME**: CMP, Emera, MEPUC
  - **MA**: Ashburnham, Braintree, Chicopee, National Grid, Norwood, NSTAR, Shrewsbury, Unitil, West Boylston, WMECo
  - **NH**: Liberty, NHEC, PSNH, Unitil
  - **RI**: National Grid
  - **VT**: BED, GMP, VEC, VPPSA, WEC
- Based on respondent submittals, year-end 2014 installed nameplate PV by Distribution Owner and state are listed on the next slides

2014 Year-End Installed PV by Distribution Owner

State & Utility	Installed Capacity (MW_{ac})
Connecticut	**118.80**
Connecticut Light & Power	99.80
Connecticut Municipal Electric Energy Co-op	0.45
United Illuminating	18.55
Maine	**10.38**
Central Maine Power	8.86
Emera	1.52
Massachusetts	**666.83**
Ashburnham Municipal Light Plant	3.44
Braintree Electric Light Dept	0.48
Chicopee Electric Light	7.82
National Grid	310.44
Norwood Municipal Light Dept	0.08
NSTAR	231.15
Reading Municipal Light District	0.79
Shrewsbury Electric & Cable Operations	2.59
Unitil	7.69
West Boylston Municipal Lighting Plant	0.32
Western Massachusetts Electric Company	46.12
Other Municipals, aggregated by ISO per MA SREC data	56.00

2014 Year-End Installed PV by Distribution Owner

State & Utility	Installed Capacity (MW_{ac})
New Hampshire	**12.71**
Liberty	0.45
New Hampshire Electric Co-op	2.61
Public Service of New Hampshire	8.33
Unitil	1.32
Rhode Island	**18.21**
National Grid	18.21
Vermont	**81.85**
Burlington Electric Department	1.19
Green Mountain Power	67.62
Vermont Electric Co-op	9.48
Vermont Public Power Supply Authority	1.89
Stowe Electric Department	0.24
Washington Electric Co-op	1.42
New England Total	**908.8**

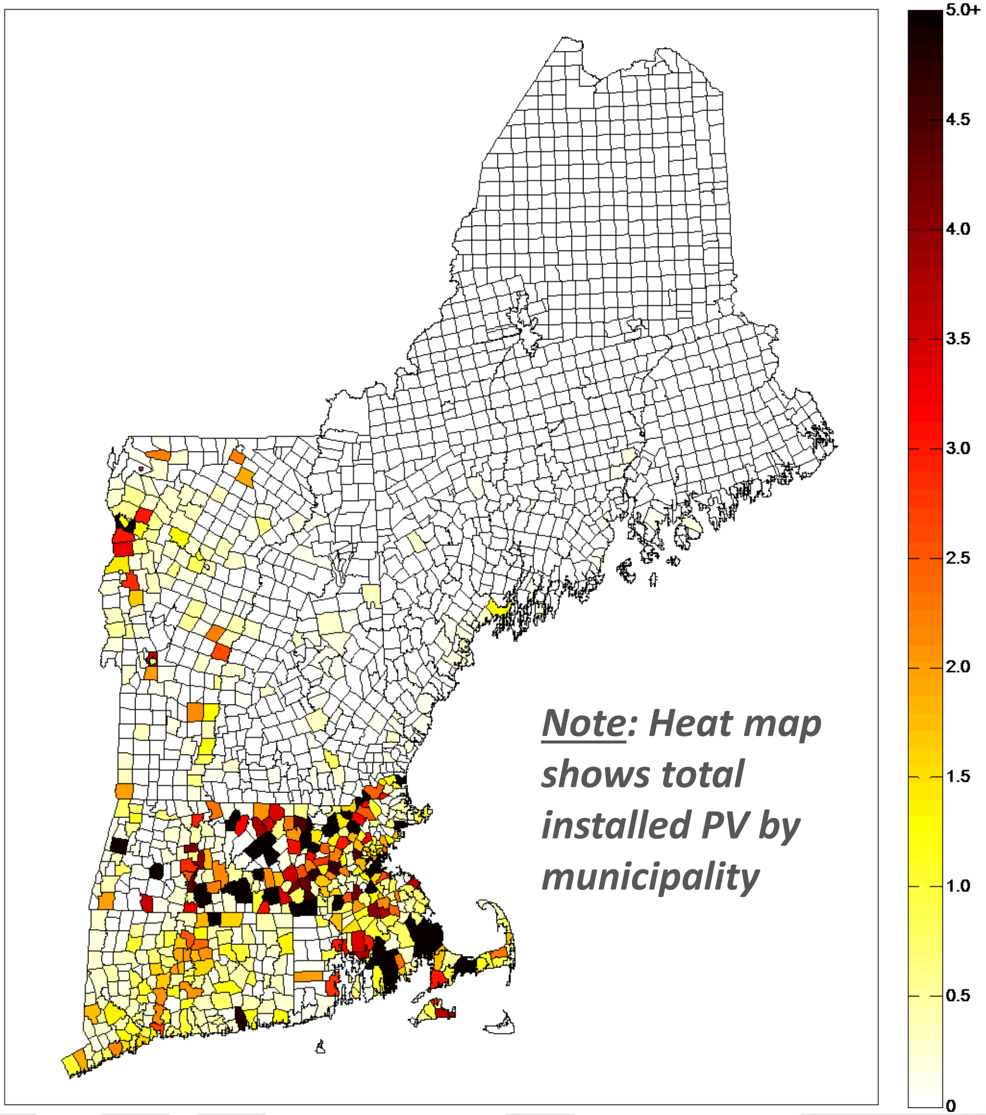
2014 Year-End PV Installed Capacity (MW_{AC})

State-by-State

Total installed nameplate PV (in MW_{AC}, as of 12/31/14) according to data provided to ISO by regional Distribution Owners.

State	Installed Capacity (MW_{AC})	% of Total
Connecticut	118.80	13%
Maine	10.38	1%
Massachusetts	666.83*	73%
New Hampshire	12.71	1%
Rhode Island	18.21	2%
Vermont	81.85	9%
New England Total	**908.78**	100%

<ins>Notes</ins>:
*Includes values based on MA SREC data associated with 35 of the 41 MA munis



STATE 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 state-by-state assumptions and inputs to the PV forecast are listed on the following slides

Forecast Methodology
MA Assumptions

- MA DPU's 12/15/14 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**
  - DC nameplate capacity is determined by the sum of the DC ratings of all the panels that make up the solar array, and AC nameplate capacity is determined by the (sum of the) inverter(s) rating(s).
    - E.g., a 120 kW_{DC} solar panel array is connected to 100 kW_{AC} inverter
  - This factor is called any of the following:
    - Array-to-inverter ratio, oversizing ratio, overloading ratio, DC-to-AC ratio
  - 1/1.2 = **83%**
  - Converted MA 2020 goals: 1,600 MW_{DC} = **1,358 MW_{AC}**

**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

Forecast Methodology
MA Assumptions, cont'd

- MA SREC I/II programs successfully achieve 2020 state goal
- Remaining MWs needed to reach state goal are applied from 2015-2020 according to the following anticipated factors:
  - Planned reduction of federal ITC in 2016 will promote increased development through 2016
  - Program stabilizes from 2017-2020 until goal is achieved
- Post-SREC (after 2020) forecast values are kept at 2020 growth level, but are more significantly discounted (refer to slide 30)

Forecast Methodology
CT Assumptions

- CT DEEP's 9/30/13 DGFWG presentation serves as primary source for CT policy information
  - Policy updates were provided verbally during the 12/15/14 DGFWG meeting
- ZREC program will be satisfied entirely with PV
  - 288 MW CL&P + 72 MW UI = 360 MW total
  - Year 4 competitive solicitation scheduled for April 2015
  - Assumed 37 MW of ZREC projects in service by 12/31/14
    - Remaining 323 MW go into service from 2015-2020
      - Project commissioning within approximately 2 years from procurement
  - Program review in year four will find technology costs have decreased and extend program for its last two years (refer to PA 11-80, Section 107(c)(2))

Preliminary Forecast Methodology
CT Assumptions, cont'd

- CT Green Bank's Residential Solar Investment Program
  - 20.75 MW_{AC}/year (25 MW_{DC}) for 2015, based on recent project approvals and those anticipated this year
- Discrete utility-scale project
  - 20 MW project in Sprague/Lisbon assumed to be commissioned in 2016
- Existing PV by end-of-2014 is based on Distribution Owner survey results
  - Includes approximately 30 MW of "legacy" PV that pre-existed aforementioned programs
- Post-ZREC (after 2019) forecast values are kept at 2018 growth level, but are more significantly discounted (refer to slide 30)

Forecast Methodology
VT Assumptions

- VT DPS' 12/15/14 DGFWG presentation serves as primary source for CT policy information
- PV comprises 110 MW of Standard Offer Program goal of 127.5 MW goal is reached by 2022
  - Assume 34 MW of SOP projects in-service by end of 2014, remaining MWs applied evenly over years 2015-2023
- Assume net metering projects will promote 135 MW of PV until 15% cap is reached
  - Planned reduction of federal ITC in 2016 will promote increased development through 2016, with residual impact continuing through 2017
- Assume 75% of existing PPA projects reported by DPS go into service
  - 2014: 3.7 MW, 2015: 2.95 MW, 2016: 2.95 MW
- Overall timing and total capacity of annual installed PV are generally consistent with VT DPS's 9/30/13 presentation to DGFWG
- Annual forecast value from 2023 kept constant for 2024 (post-policy), but is more significantly discounted (refer to slide 30)

Forecast Methodology
RI Assumptions

- RI OER's 12/15/14 DGFWG presentation serves as primary source for RI policy information
- Consistent with DG Standard Contract program data to date
  - A total of 30 MW of DG Standards Contract projects will be PV
- Renewable Energy Growth Program, 2016-2021
  - Total of 144 MW PV (90% of goal) anticipated, applied from 2016-2021 in proportion to phased-in timeline with one year commissioning for 50% of procured capacity, and two year commissioning for the remaining 50% of procured capacity
- Renewable Energy Fund & Net Metering
  - Combined influence results in 2.7 MW/year over the forecast horizon
- Post-2021 (after REGP ends), annual forecast values are kept constant, but are more significantly discounted (refer to slide 30)

Forecast Methodology
NH & ME Assumptions/Inputs

- NH
  - NH PUC's 12/15/14 DGFWG presentation serves as primary source for NH policy information
  - Based on Distribution Owner survey results, net metering and other state grants/incentives resulted in 4.5 MW of PV growth in 2014
    - Growth carried forward at constant rate throughout forecast period
  - Assume 50 MW net metering cap reached by 2020
  - Post-2020, annual forecast values are kept constant, but are more significantly discounted (refer to slide 30)
- ME
  - ME PUC's 9/30/13 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 2.7 MW of PV growth in 2014
    - Growth carried forward at constant rate throughout forecast period

ICF’S PV ECONOMIC DRIVERS STUDY

What the ICF Study Is

- ICF was contracted by ISO-NE to deconstruct PV economics into individual drivers to help inform ISO-NE's 2015 PV forecast process in response to stakeholder feedback that PV economics need to be considered as part of the forecast process
- The study helps illustrate the complex interplay of public and private investment and business models commonly involved in PV commercialization
- It characterizes the relative importance of economic drivers under standardized assumptions across states & customer types
- The study assesses how economic drivers may change over time due to changes in technology cost and performance, electricity rates, federal & state incentives, etc.
- Links to the ICF study materials
  - Report: http://www.iso-ne.com/static-assets/documents/2015/02/icf_economic_drivers_of_pv_report_for_iso_ne_2_27_15.pdf
  - Presentation: http://www.iso-ne.com/static-assets/documents/2015/02/icf_economic_drivers_of_pv_summary_presentation_for_iso_ne_2_27_15.pdf
  - Stakeholder Comments and ISO/ICF Responses: http://www.iso-ne.com/static-assets/documents/2015/02/icf_study_comments.pdf

What the ICF Study Is Not

- The study does NOT analyze the cost-effectiveness of federal, state, or utility PV policies nor make value judgments about the need for, or appropriateness of, such policies.
- Not a review of the “value of solar” nor the grid integration of renewable energy
- Not a forecast of PV capacity deployment, electricity production, nor incentive levels in the region
- Does not suggest how the ISO should use the results

Interpretation of ICF Results

- The results of the ICF study are useful in the determination of suitable discount factors applied over the forecast horizon
- To this end, values for the “Fully Supported PV Economics” summary measure were compared across all project start years and customer types in each state to aid in understanding the ICF results
  - Fully Supported PV Economics represent the “best-case” scenario for PV projects, in which the benefits of all federal and state incentives are captured
- Given that the overall PV economics in 2015 are similar to 2014, normalizing the results to the 2015 base year helps to compare the PV economics over time to the recent PV economics within which recent PV growth trends occurred in each state
  - This comparison is based on the numerous assumptions and inputs, as well as the financial modeling methodology used by ICF

ISO's Main Takeaways From ICF Study

- There are a number of interrelated federal and state policies, financing options, and ownership models that should be considered when evaluating the viability of current and future PV investments
  - Evaluating existing and future PV economics is a complex task!
  - Frequently, there are a dozen individual drivers that increase or decrease PV economics by $.01/kWh or more on a levelized basis for PV projects
- The largest economic drivers of PV tend to be:
  1. System installed cost (i.e., first cost)
  2. Physical power revenue (wholesale, offsetting on-site electricity loads, net metering)
  3. Renewable energy credit (REC) revenue
  4. Federal investment tax credit
  5. Federal depreciation

  (The order of importance (1-5) of these largest economic drivers can vary between state, customer type, and project start year)
- Future trends with respect to all of these drivers are uncertain
- Physical power revenues become increasingly important over time, while REC revenues and total federal support tend to decline over time

ISO’s Main Takeaways From ICF Study, cont’d

- PV projects should continue to offer strong investment returns in the next couple of years if all incentives can be monetized
  - Recent trends in PV deployment should continue through 2016, and may accelerate near the planned decline of the federal Investment Tax Credit (ITC)
  - ISO suggests that the following trends will likely result:
    - Policy drivers that do not significantly constrain the timing of PV development (SRECs, net metered project growth below caps) will likely facilitate accelerated deployment until the slated ITC reduction
    - Policies that involve periodic procurement or solicitation (CT ZREC, RI Renewable Energy Growth, VT Standard Offer) will likely facilitate more consistent, incremental growth
- The planned decline of the federal ITC beginning in 2017, together with the planned reduction of some state PV policy support, creates more challenging overall PV economics in 2019 and 2024, as compared to 2015
  - Much more uncertainty regarding PV deployment in the region from 2017 onward
- By the 2024 timeframe, the overall economics of PV investment does not entirely recover from the ITC reduction, despite the following assumptions:
  - Modest reductions in installed costs (in real dollars)
  - Improvements in system performance
  - Increases in wholesale/retail electricity rates
  - Existing net metering policies remain intact, and existing net metering caps would not be constraints on future PV investment

DISCOUNT FACTORS & SEASONAL CLAIMED CAPABILITY (SCC)

Discount Factors

- Notwithstanding the recent success of state programs, discount factors were developed and incorporated into the forecast, and are meant to reflect a degree of uncertainty in future PV commercialization
- The results of the ICF study have been considered as part of developing the discount factors
- Discount factors were developed for two types of future PV inputs to the forecast:
  1. Policy-based – PV that results from state policy
     - Discounted by values that increase annually up to a maximum value of 25%
  2. Post-policy – PV that may be installed after existing state policies end
     - Discounted by 50% due to the higher 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
- All discount factors are applied equally in all states

Discount Factors, cont'd

- Annual discount factors for policy-based solar PV are tabulated below

Anticipated federal ITC reduction

Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
0%	5%	5%	15%	20%	25%	25%	25%	25%	25%	25%

- All post-policy MWs are discounted at 50%

PV's Seasonal Claimed Capability

- 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)
- 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:
  1. PV performance often differs from its summer SCC during the variety of peak load conditions that occur
  2. As PV penetrations grow across the region, PV will shift peak net loads later in the afternoon, when PV output is diminishing due to the lowering solar altitude angle as the sun begins to set, thereby decreasing PV's incremental contribution to serving peak loads
- 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

FINAL 2015 PV FORECAST

Final Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	118.8	74.6	94.6	53.8	53.8	53.8	53.8	53.8	53.8	53.8	53.8	**718.6**
MA	666.8	207.4	241.9	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	**1,599.9**
ME	10.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	**33.4**
NH	12.7	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	**57.7**
RI	18.2	10.2	21.5	32.0	38.7	38.7	27.5	9.5	9.5	9.5	9.5	**224.5**
VT	81.9	42.5	42.5	26.2	17.3	8.5	8.5	8.5	8.5	8.5	8.5	**261.1**
Pre-Discount Annual Policy-Based MWs	**908.8**	**341.4**	**407.2**	**179.3**	**177.1**	**168.3**	**157.0**	**20.2**	**13.5**	**13.5**	**5.0**	**2,391.2**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**118.8**	**125.6**	**125.6**	**134.0**	**503.9**
Pre-Discount Annual Total (MW)	**908.8**	**341.4**	**407.2**	**179.3**	**177.1**	**168.3**	**157.0**	**139.0**	**139.0**	**139.0**	**139.0**	**2,895.2**
Pre-Discount Cumulative Total (MW)	**908.8**	**1,250.2**	**1,657.4**	**1,836.7**	**2,013.8**	**2,182.1**	**2,339.1**	**2,478.1**	**2,617.2**	**2,756.2**	**2,895.2**	**2,895.2**

Notes:

(1) The above values **are not the forecast**, but rather pre-discounted inputs to the forecast (see slides 11-17 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 load reducing PV resources
(4) All values represent end-of-year nameplate capacities

Final 2015 PV Forecast

Annual Nameplate (MW_{ac})

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	118.8	70.9	89.9	45.8	43.1	40.4	40.4	26.9	26.9	26.9	26.9	**556.8**
MA	666.8	197.0	229.8	51.4	48.4	45.4	45.4	30.2	30.2	30.2	30.2	**1,405.1**
ME	10.4	2.2	2.2	2.0	1.8	1.7	1.7	1.7	1.7	1.7	1.7	**28.9**
NH	12.7	4.3	4.3	3.8	3.6	3.4	3.4	2.3	2.3	2.3	2.3	**44.4**
RI	18.2	9.7	20.4	27.2	31.0	29.0	20.6	7.1	5.4	5.4	5.4	**179.3**
VT	81.9	40.4	40.4	22.3	13.9	6.3	6.3	6.3	6.3	6.3	4.2	**234.7**
Regional - Annual (MW)	**908.8**	**324.3**	**386.9**	**152.4**	**141.7**	**126.2**	**117.8**	**74.6**	**72.9**	**72.9**	**70.8**	**2,449.1**
Regional - Cumulative (MW)	**908.8**	**1233.1**	**1620.0**	**1772.4**	**1914.1**	**2040.3**	**2158.1**	**2232.6**	**2305.5**	**2378.4**	**2449.1**	**2,449.1**

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 4
(3) All values represent end-of-year installed capacities
(4) ISO is working with stakeholders to determine the appropriate use of the forecast

Final 2015 PV Forecast

Cumulative Nameplate (MW_{ac})

States	Cumulative Total MW (AC nameplate rating)										
	Thru 2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CT	118.8	189.7	279.5	325.3	368.3	408.7	449.1	476.0	502.9	529.8	556.8
MA	666.8	863.8	1093.6	1145.0	1193.4	1238.8	1284.1	1314.4	1344.6	1374.8	1405.1
ME	10.4	12.6	14.8	16.7	18.5	20.3	22.0	23.7	25.4	27.2	28.9
NH	12.7	17.0	21.3	25.1	28.7	32.1	35.4	37.7	39.9	42.2	44.4
RI	18.2	27.9	48.3	75.4	106.4	135.4	156.0	163.1	168.5	173.9	179.3
VT	81.9	122.2	162.6	184.9	198.7	205.1	211.4	217.7	224.1	230.4	234.7
Regional - Cumulative (MW)	**908.8**	**1233.1**	**1620.0**	**1772.4**	**1914.1**	**2040.3**	**2158.1**	**2232.6**	**2305.5**	**2378.4**	**2449.1**

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 4
(3) All values represent end-of-year installed capacities
(4) ISO is working with stakeholders to determine the appropriate use of the forecast

Final 2015 PV Forecast

Annual Estimated Summer Seasonal Claimed Capability

Based on 40% of Forecasted AC Nameplate Capacity

States	Estimated Summer SCC (MW)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	47.5	28.3	35.9	18.3	17.2	16.2	16.2	10.8	10.8	10.8	10.8	**222.7**
MA	266.7	78.8	91.9	20.6	19.4	18.1	18.1	12.1	12.1	12.1	12.1	**562.0**
ME	4.2	0.9	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	**11.6**
NH	5.1	1.7	1.7	1.5	1.4	1.4	1.4	0.9	0.9	0.9	0.9	**17.8**
RI	7.3	3.9	8.2	10.9	12.4	11.6	8.2	2.8	2.2	2.2	2.2	**71.7**
VT	32.7	16.1	16.1	8.9	5.5	2.5	2.5	2.5	2.5	2.5	1.7	**93.9**
Regional - Annual Summer SCC (MW)	**363.5**	**129.7**	**154.7**	**61.0**	**56.7**	**50.5**	**47.1**	**29.8**	**29.1**	**29.1**	**28.3**	**979.6**
Regional - Cumulative Summer SCC (MW)	**363.5**	**493.3**	**648.0**	**709.0**	**765.6**	**816.1**	**863.2**	**893.0**	**922.2**	**951.3**	**979.6**	**979.6**

Notes:

(1) ISO's methodology for determining SCC for Intermittent Resources is defined in Market Rule 1, Section III.13.1.2.2.2.1(c)
(2) Estimated SCC values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(3) Summer SCC values are based on the assumption that all end-of-year resources are in operation during the summer period
(4) PV's winter SCC is assumed to be zero
(5) Different planning studies may use values different from the estimated SCC based on the intent of the study

Final 2015 PV Forecast

Cumulative Estimated Summer Seasonal Claimed Capability

Based on 40% of Forecasted AC Nameplate Capacity

States	Cumulative Estimated Summer SCC (MW)										
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CT	47.5	75.9	111.8	130.1	147.3	163.5	179.6	190.4	201.2	211.9	222.7
MA	266.7	345.5	437.5	458.0	477.4	495.5	513.7	525.7	537.8	549.9	562.0
ME	4.2	5.0	5.9	6.7	7.4	8.1	8.8	9.5	10.2	10.9	11.6
NH	5.1	6.8	8.5	10.0	11.5	12.8	14.2	15.1	16.0	16.9	17.8
RI	7.3	11.2	19.3	30.2	42.6	54.2	62.4	65.2	67.4	69.6	71.7
VT	32.7	48.9	65.0	73.9	79.5	82.0	84.6	87.1	89.6	92.2	93.9
Regional - Cumulative Summer SCC (MW)	**363.5**	**493.3**	**648.0**	**709.0**	**765.6**	**816.1**	**863.2**	**893.0**	**922.2**	**951.3**	**979.6**

Notes:

(1) ISO's methodology for determining SCC for Intermittent Resources is defined in [Market Rule 1, Section III.13.1.2.2.2.1(c)]
(2) Estimated SCC values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(3) Summer SCC values are based on the assumption that all end-of-year resources are in operation during the summer period
(4) PV's winter SCC is assumed to be zero
(5) Different planning studies may use values different from the estimated SCC based on the intent of the study

CLASSIFICATION OF PV FORECAST BY MARKET PARTICIPATION TYPE

PV Forecast Classification of Market Type By State

Background

- In order to properly account for existing and future PV in planning studies and avoid double counting, ISO must classify PV according to its market participation (or lack thereof)
  - The four market types are shown in **blue** and defined on the next slide
- These market distinctions will become important as the ISO looks to use the PV forecast in a wider range of studies
  - Further and more detailed discussions will take place in other stakeholder meetings
- The classification process required the estimation of hourly PV production that is behind-the-meter (BTM), i.e., PV that does not participate in ISO markets
  - E.g., determining the amount of PV which is already embedded in the long-term load forecast requires historical hourly BTM PV production data
- Further details on the ISO's classification of PV can be found at: http://www.iso-ne.com/static-assets/documents/2015/04/classification_of__2015_pv_forecast.pdf

Market Participation Types

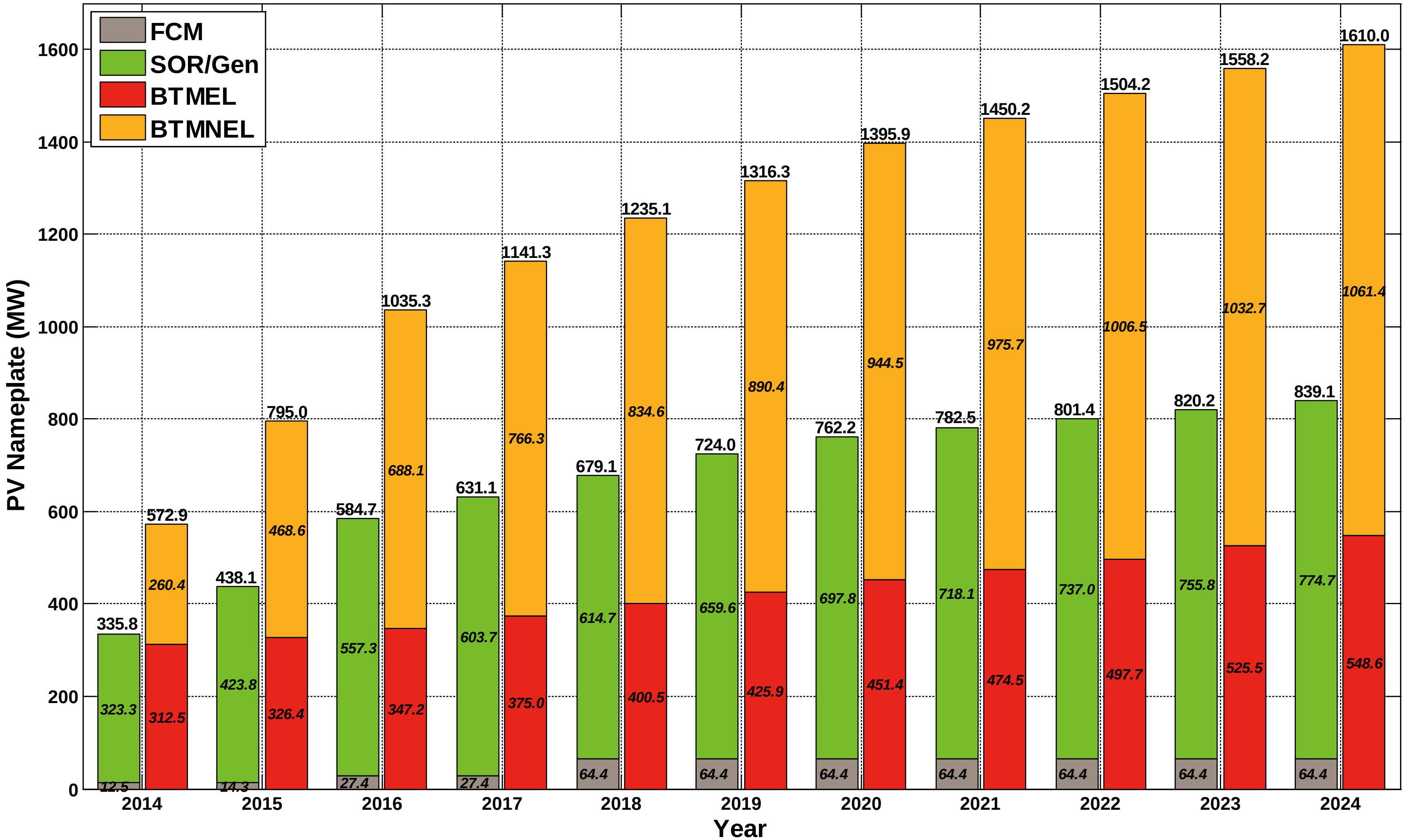
Mutually Exclusive to Prevent Double Counting PV

- **PV as a capacity resource in the Forward Capacity Market (FCM)**
  - Qualified for the FCM
  - Have capacity supply obligations
  - Size and location identified and visible to the ISO
  - May be supply or demand-side resources
- **Non-FCM Settlement only Resources (SOR) and Generators (per OP-14)**
  - ISO collects energy output
  - Participate only in the energy market
- Behind-the-Meter (BTM) PV
  - 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
  - Can be further divided into two categories:
    - **Behind-the-Meter PV Embedded in Load (BTMEL)**
      - The portion of BTM that is captured in the historical load forecast
      - Can be estimated via reconstitution of hourly historical BTM PV production
    - **Behind-the-Meter PV Not Embedded in Load (BTMNEL)**
      - The portion of BTM that is not captured in the historical load forecast (i.e., not embedded)

Final 2015 PV Forecast

Cumulative Regional PV by Market Participation Type

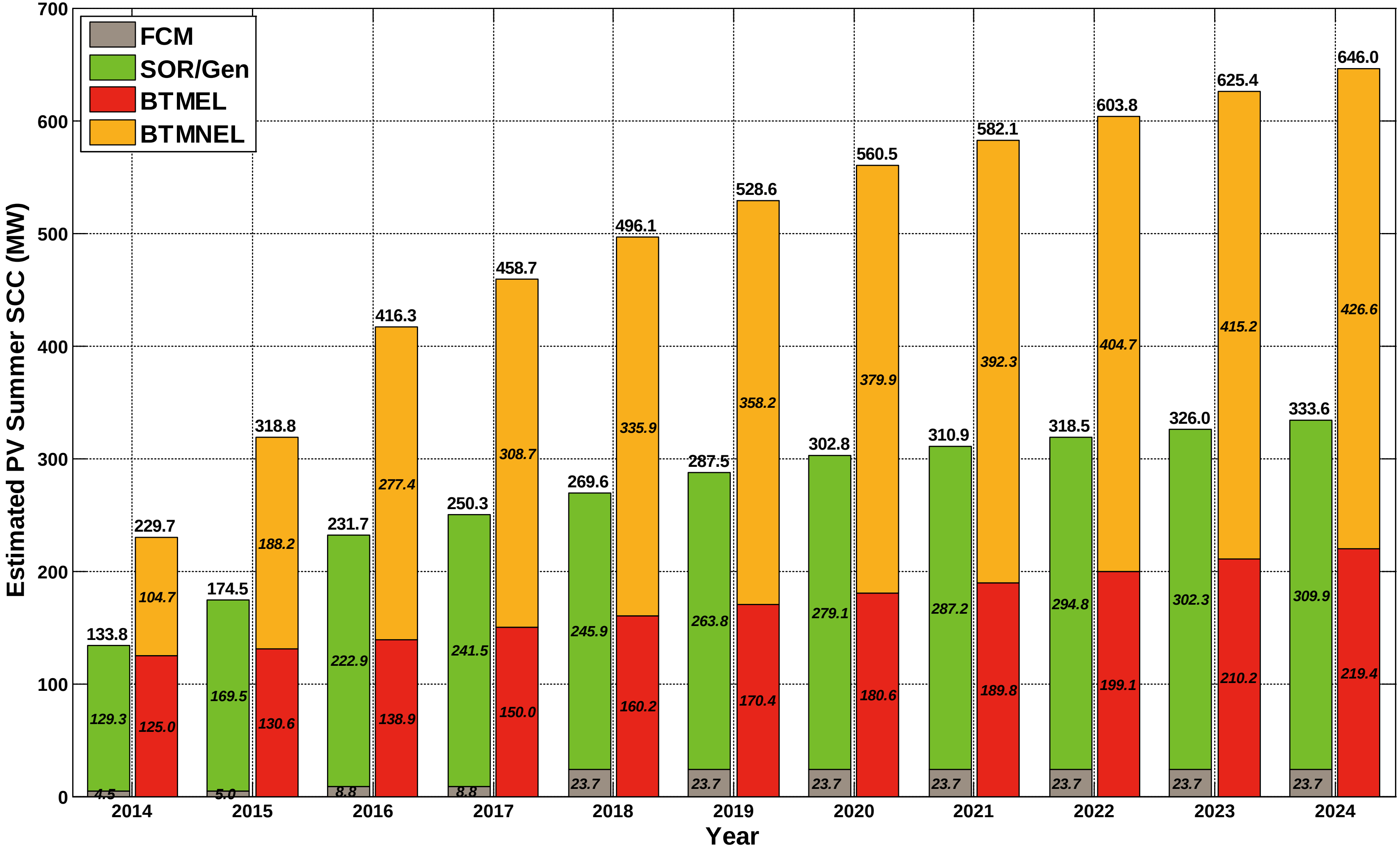
AC Nameplate



Final 2015 PV Forecast

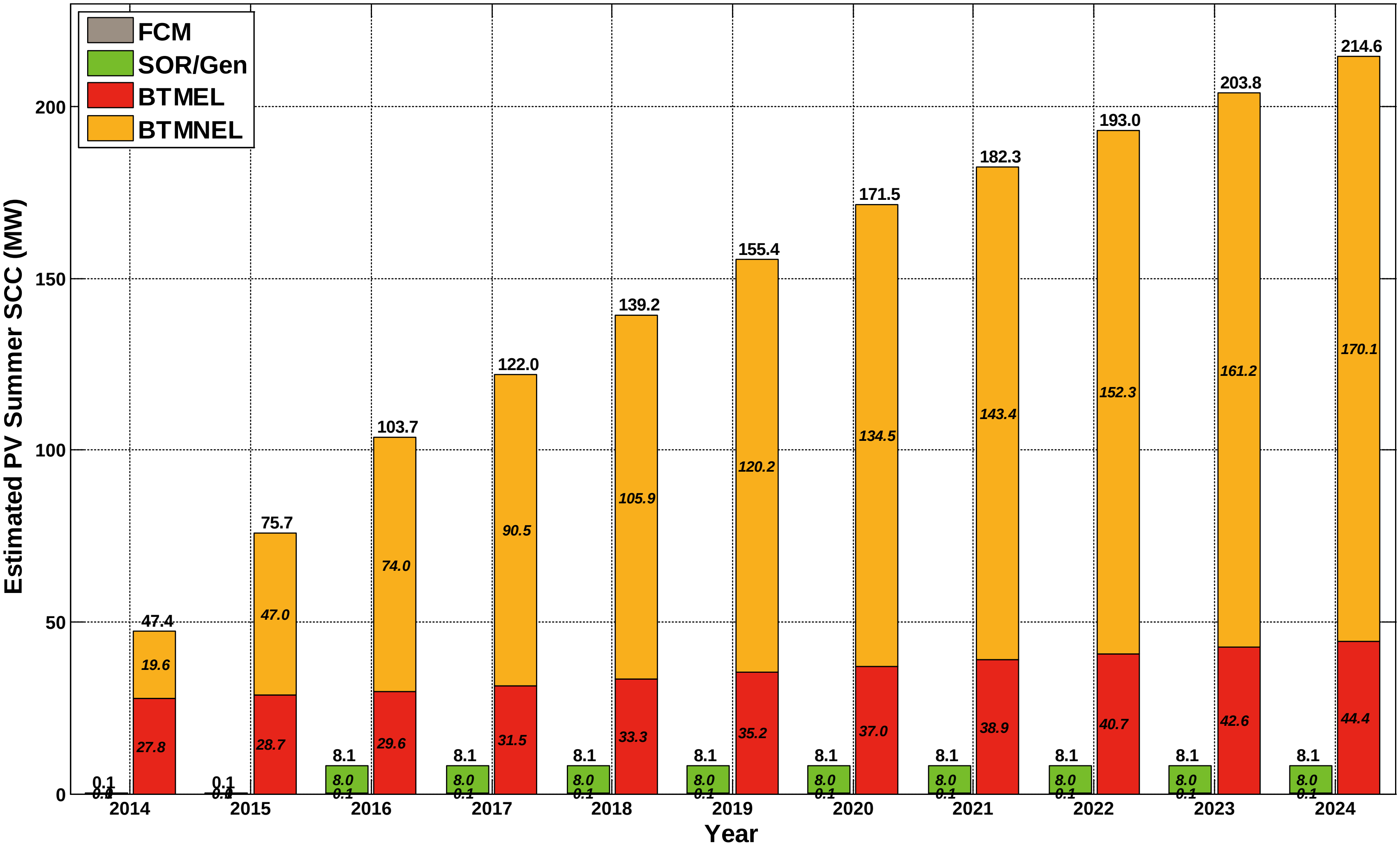
Cumulative Regional PV by Market Participation Type

Estimated Summer Seasonal Claimed Capability



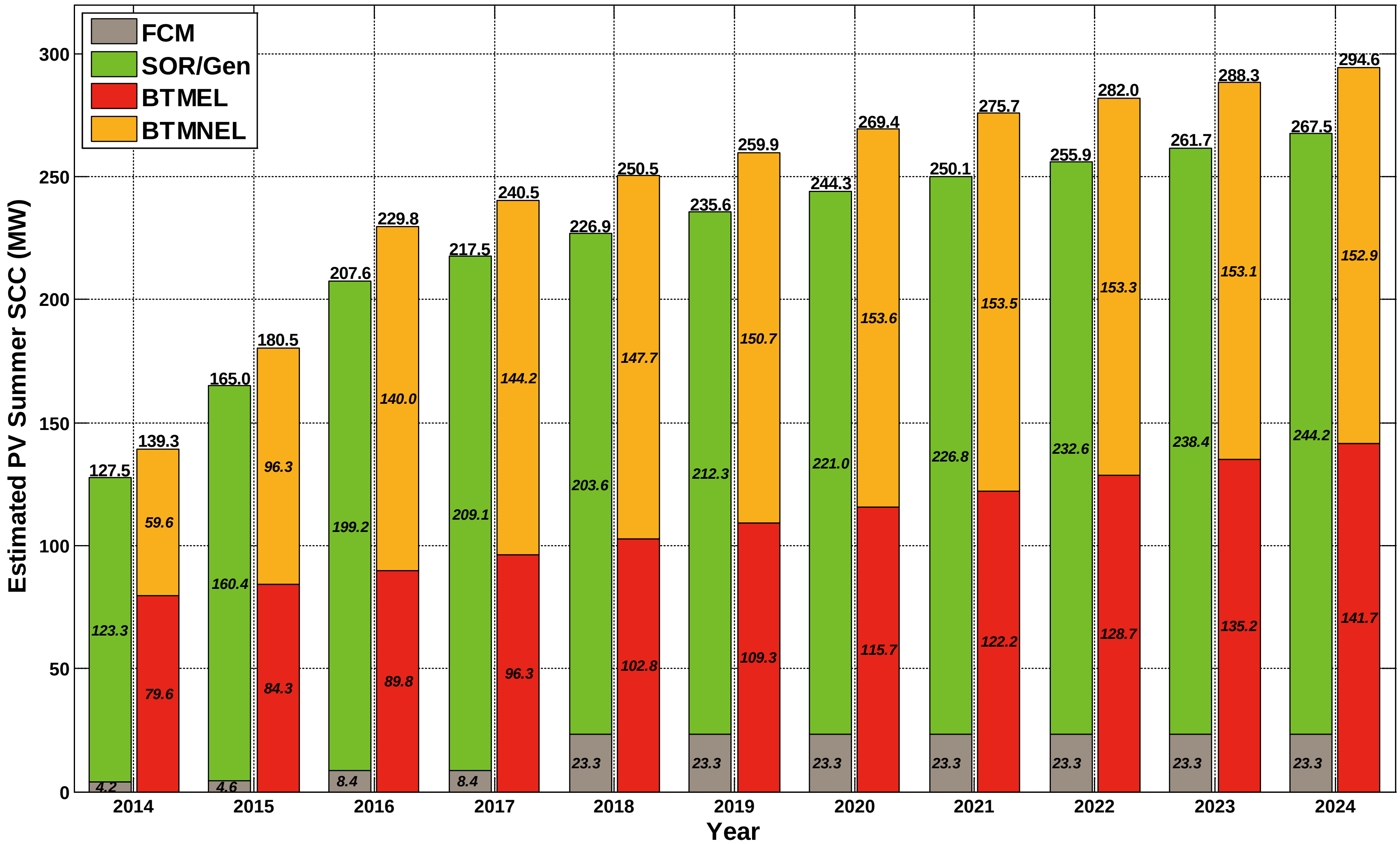
Cumulative SCC by Market Type

Connecticut



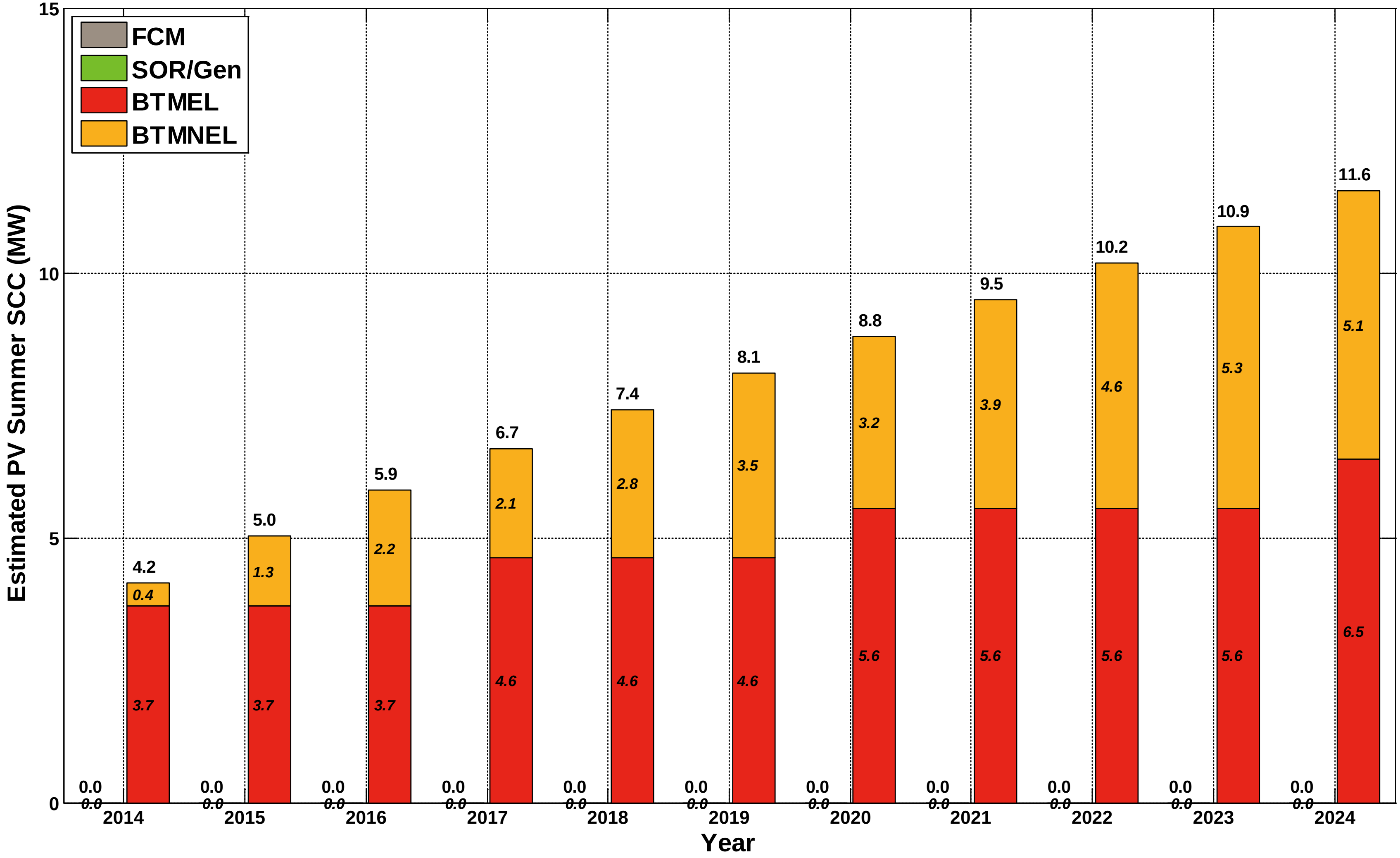
Cumulative SCC by Market Type

Massachusetts



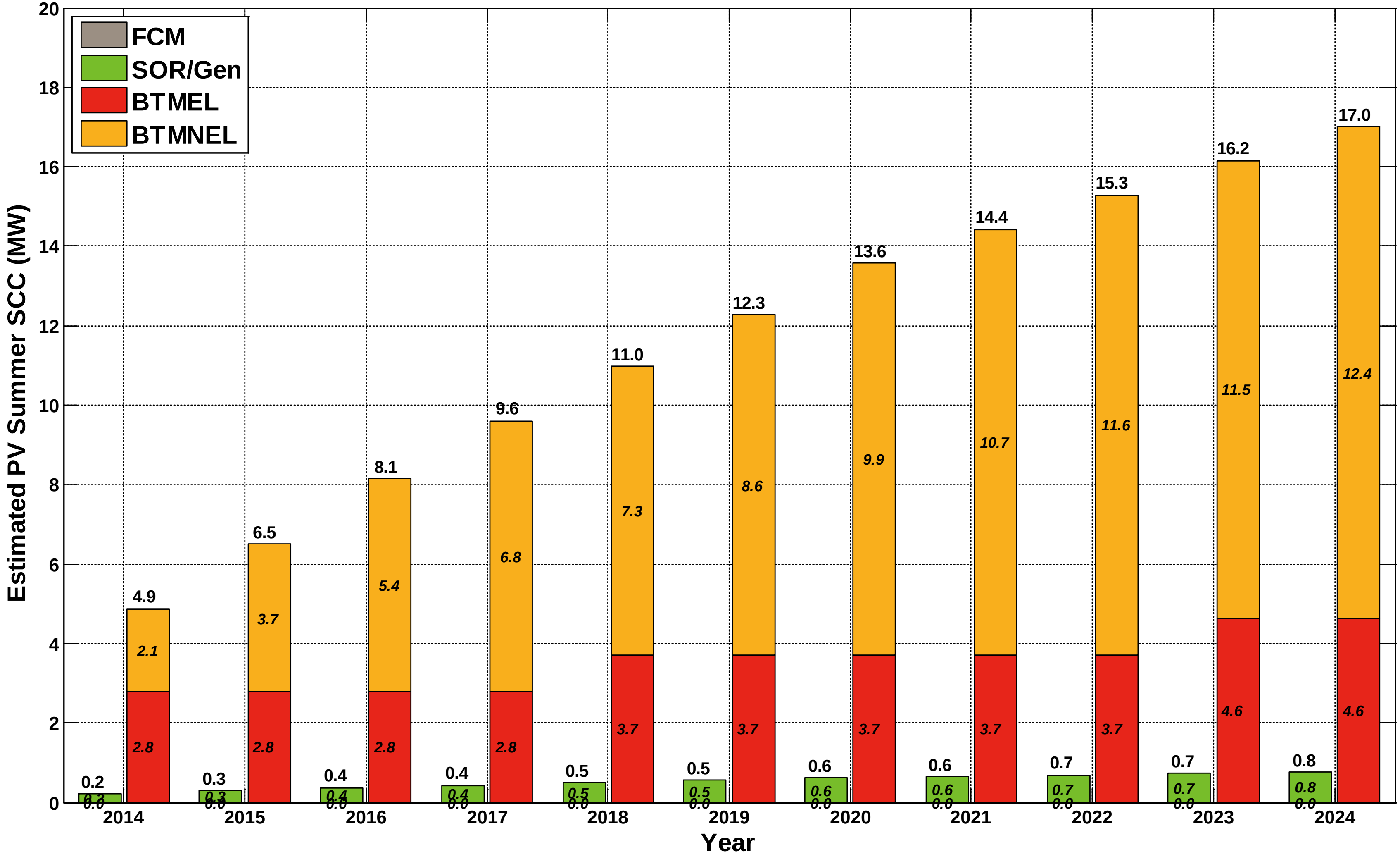
Cumulative SCC by Market Type

Maine



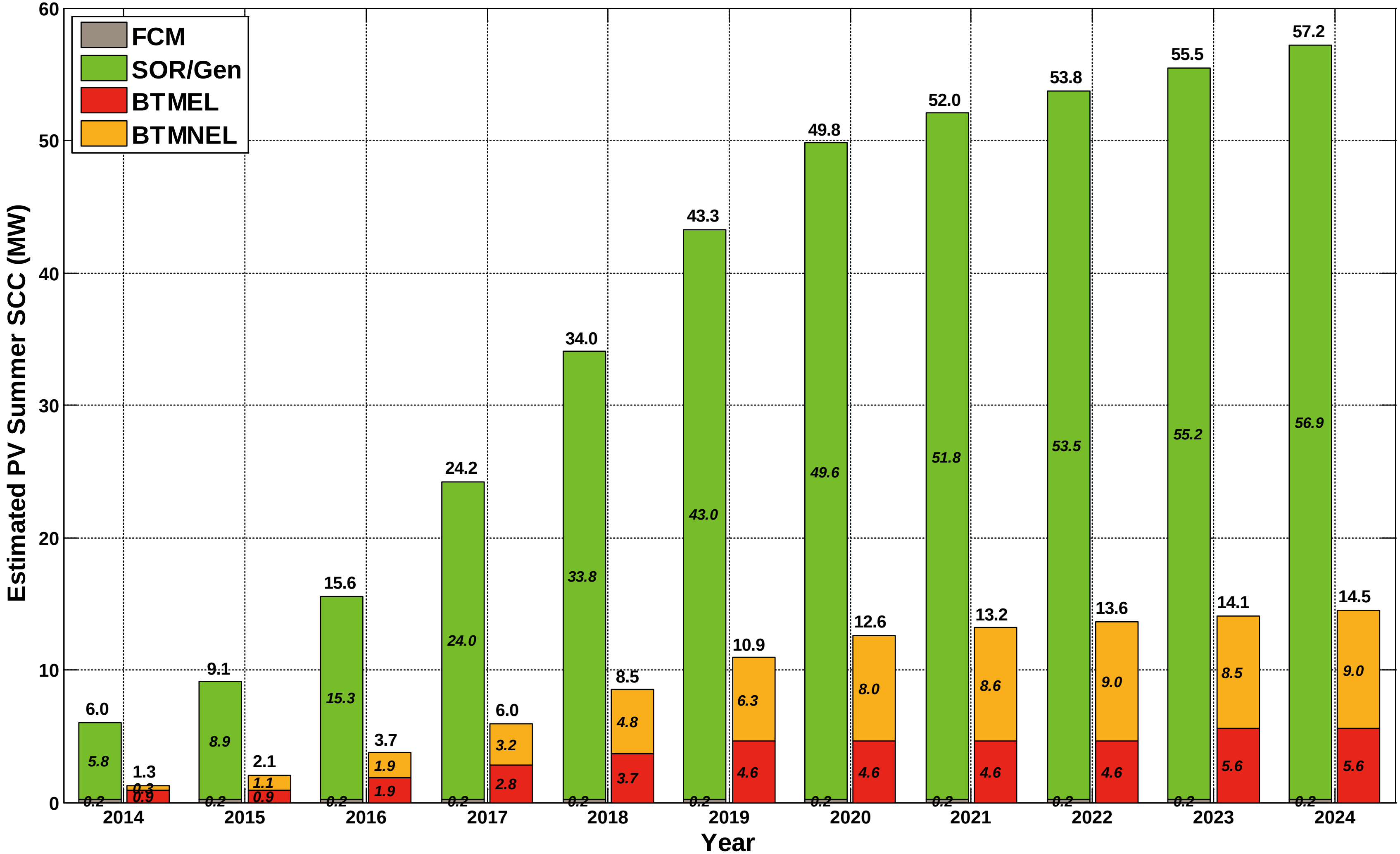
Cumulative SCC by Market Type

New Hampshire



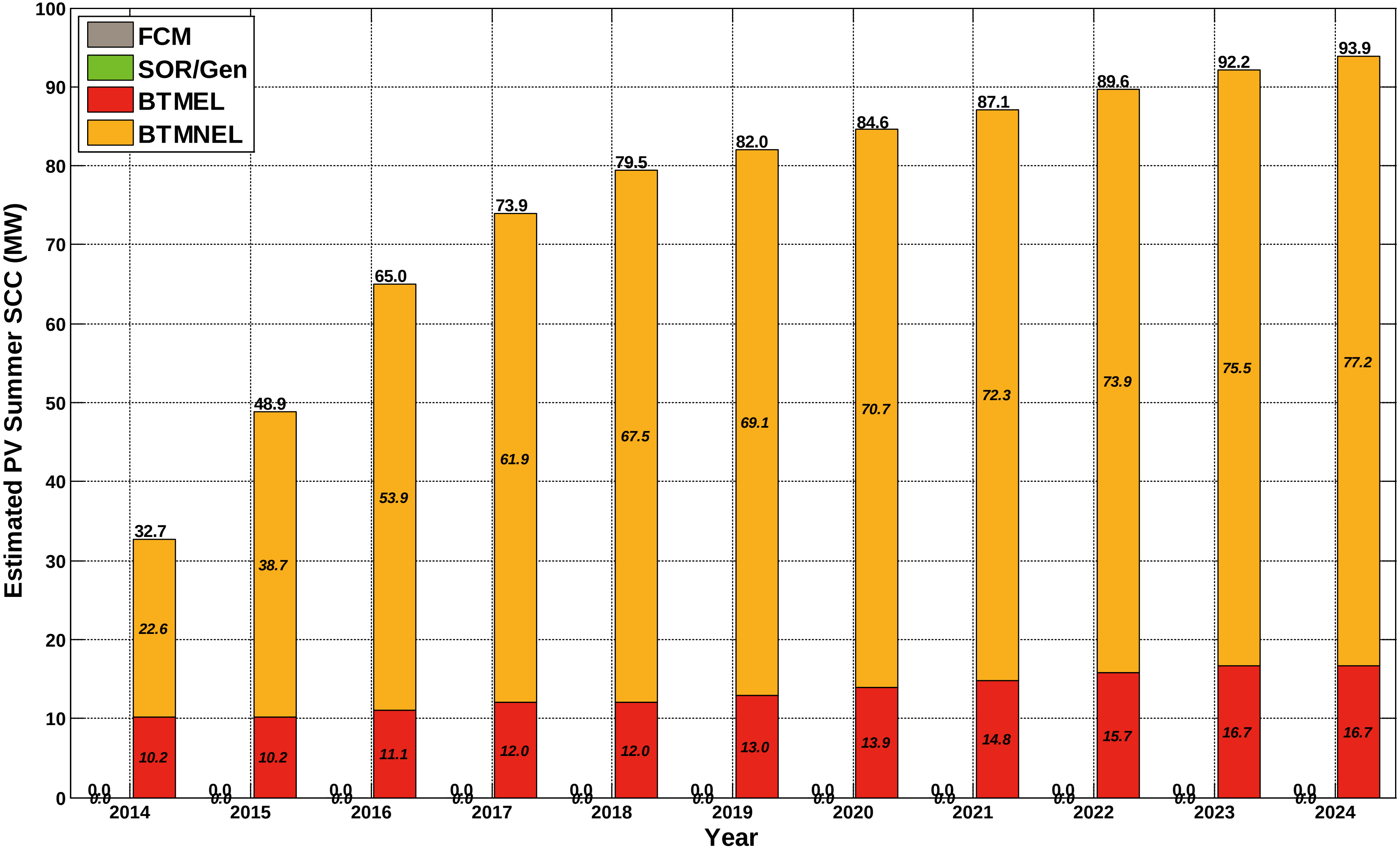
Cumulative SCC by Market Type

Rhode Island



Cumulative SCC by Market Type

Vermont



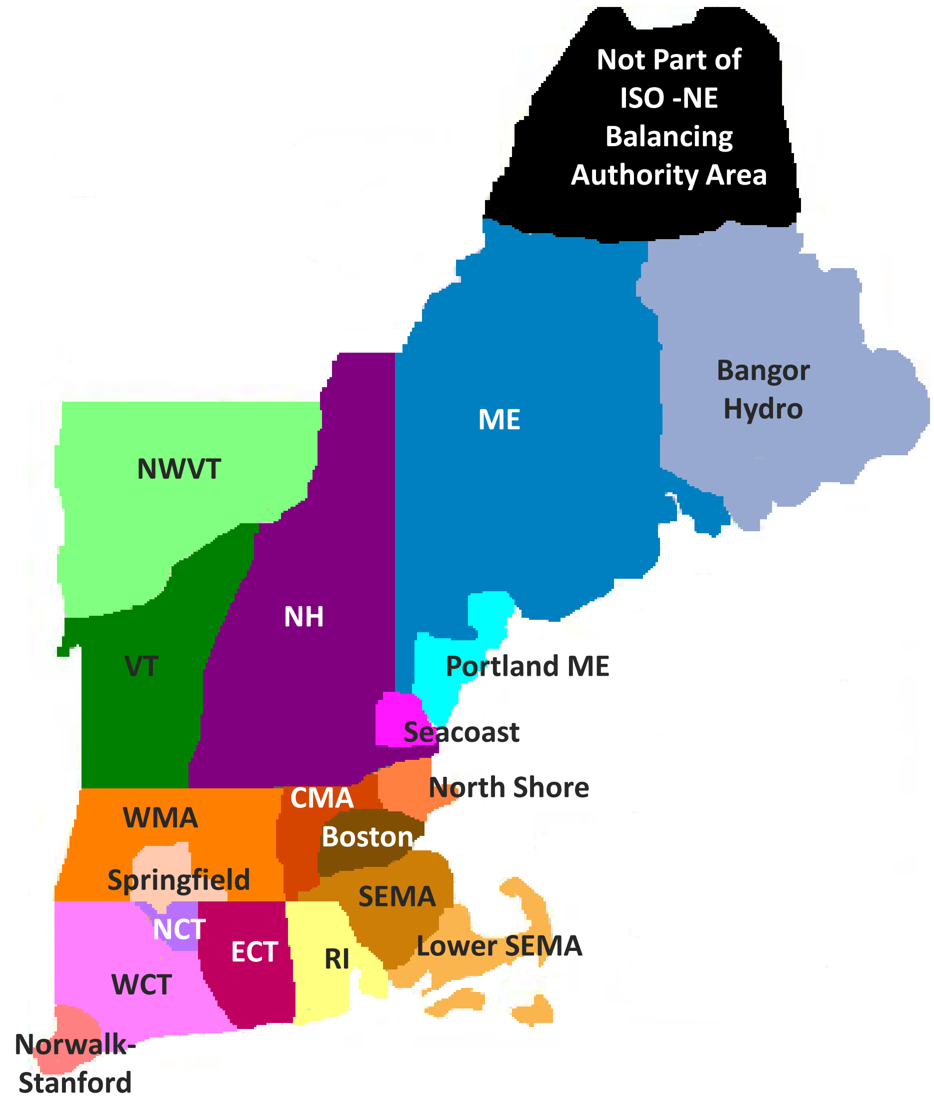
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of future PV resources are ultimately unknown, but mitigation of some of this uncertainty (especially for near-term development) is likely possible via analysis of available data
- Distribution Owner queue data through 12/31/14 has been collected by regional utilities and was used to estimate the geographic distribution of the 2015 PV forecast

ISO-NE Dispatch Zones

- ISO developed the Dispatch Zones for the active Demand Response program
- Dispatch Zones were created in consideration of electrical interfaces
- Quantifying existing and forecasted PV resources by Dispatch Zone will aid in the modeling of PV resources for planning and operations purposes



Dispatch Zone Distribution of PV

State	Dispatch Zone	% of State Based on 12/31/14 Survey Data
MA	SEMA	20.3%
	Boston	10.2%
	Lower SEMA	17.6%
	Central MA	17.2%
	Springfield MA	5.9%
	North Shore	5.3%
	Western MA	23.5%
CT	Eastern CT	20.0%
	Western CT	50.0%
	Northern CT	22.0%
	Norwalk-Stamford	8.0%
NH	New Hampshire	89.0%
	Seacoast	11.0%
VT	Northwest Vermont	65.0%
	Vermont	35.0%
RI	Rhode Island	100.0%
ME	Bangor Hydro	21.0%
	Maine	53.0%
	Portland Maine	26.0%

Note: The tabulated distribution of PV by Dispatch Zone as of December 31, 2014 is based on Distribution Owner survey data