2014 Interim Forecast of Solar Photovoltaic (PV) Resources

BACKGROUND

Background (1 of 2)

- Many factors influence the future commercialization potential of PV resources
- Some of the most critical drivers to the future commercialization of PV:
  - 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; investment potential could be affected if the federal ITC is reduced from 30% to 10%
  - 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

Background (2 of 2)

- Given the complex and interrelated factors influencing the commercialization of solar PV resources, a data-driven approach analogous to the ISO's Energy-Efficiency forecast methodology was not pursued for RSP14
- The 2014 Interim PV forecast reflects a more qualitative approach based on:
  1. State policy goals, funding, and recent performance
  2. Recent trends in PV development in each state based on data obtained from Distribution Owners and state program administrators
- Based on discussions with stakeholders and data exchange with the New England states and Distribution Owners, existing PV-related programs have thus far demonstrated success in achieving policy goals in the region, and there is no evidence to suggest likelihood of a significant departure from the current path towards implementing the policy goals

DISTRIBUTION OWNER SURVEY RESULTS

Solar PV Installed Through December 31, 2013

Determining Total PV Installed Through 2013

- To obtain a baseline of PV that is already installed and operational, ISO requested Distribution Owners to provide the total nameplate PV (in MW_{ac}) installed within their respective service territories as of 12/31/13
- Distribution Owners serving approximately 95% of the New England load responded:
  - **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 2013 installed PV data by Distribution Owner and state are listed on the next slides

2013 Year-End Installed PV by Distribution Owner

State & Utility	Installed Capacity (MW_{ac})
Connecticut	**73.75**
Connecticut Light & Power	61.55
Connecticut Municipal Electric Energy Co-op	0.45
United Illuminating	11.75
Maine	**8.12**
Central Maine Power	6.52
Emera	1.60
Massachusetts	**361.55**
Ashburnham Municipal Light Plant	3.18
Braintree Electric Light Dept	0.35
Chicopee Electric Light	3.46
National Grid	190.00
Norwood Municipal Light Dept	0.08
NSTAR	104.19
Shrewsbury Electric & Cable Operations	2.56
Unitil	3.10
West Boylston Municipal Lighting Plant	0.32
Western Massachusetts Electric Company	30.68
35 MA Munis, aggregated by ISO per MA SREC data	22.70

2013 Year-End Installed PV by Distribution Owner

State & Utility	Installed Capacity (MW_{ac})
New Hampshire	**8.22**
Liberty	0.23
New Hampshire Electric Co-op	1.32
Public Service of New Hampshire	5.87
Unitil	0.80
Rhode Island	**10.90**
National Grid	10.90
Vermont	**36.13**
Burlington Electric Department	1.10
Green Mountain Power	26.00
Vermont Electric Co-op	4.31
Vermont Public Power Supply Authority	1.23
Washington Electric Co-op	3.49
New England Total	**498.7**

2013 Year-End 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 AC nameplate as of 12/31/13.

State	Installed Capacity (MW_{ac})
Connecticut	73.75
Maine	8.12
Massachusetts	361.55*
New Hampshire	8.22
Rhode Island	10.90
Vermont	36.13**
New England Total	**498.7**

Notes:
*Includes values based on MA SREC data associated with 35 of the 41 MA munis
**ISO did not receive data from Stowe Electric Dept.

FORECAST ASSUMPTIONS AND INPUTS

Introduction

- The interim 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
  - All forecast assumptions and inputs were discussed with the DGFWG on 12/16/13 (slides 31-41), 1/27/14, and 4/2/14 (hyperlinks to materials provided)
  - All submitted stakeholder comments on ISO's PV forecast are publicly-available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2014mtrls/jan272014/index.html
  - ISO's responses to all stakeholder comments can be found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2014mtrls/jan272014/dg_frcst_comment_response_pres.pdf

Forecast Methodology (1 of 6)
MA Assumptions/Inputs

- MA DPU's 9/30/13 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 (2 of 6)
MA Assumptions/Inputs

- MA SREC I/II programs successfully achieve 2020 state goal
- Existing PV by end-of-2013 is based on Distribution Owner survey results, and the remainder of policy-based MWs are applied from 2014-2020 according to the following anticipated factors:
  - There is a ramp-up of large-scale projects attempting to garner SREC-I eligibility prior to transition to SREC-II mid-2014, resulting in increased PV commercialization through 2014
  - Potential expiration of federal ITC in 2016 will promote increased development through 2016, with residual impact continuing through 2017
  - Program stabilizes from 2018-2020 until goal is achieved
- Post-SREC (after 2020) values remain consistent with 2020 value, but are more significantly discounted (refer to slide 19)

Forecast Methodology (3 of 6)
CT Assumptions/Inputs

- CT DEEP's 9/30/13 DGFWG presentation serves as primary source for CT policy information
- ZREC program will be satisfied entirely with PV
  - 210 MW CL&P + 42 MW UI = 252 MW total
    - ZREC totals were divided and applied during 6-year program roll-out duration, from 2013-2018
      - Corroborated with CT state and Distribution Owner data through 2013
    - 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))
    - ZREC projects are completed and operational within approximately 12-months from procurement date
  - CEFIA 30 MW residential program divided into ten 3 MW allocations for period between 2013-2022
  - Discrete utility-scale projects
    - A 5 MW project (in East Lyme, CT) becomes operational in 2014 (5 MW Somers project became operational in November 2013)
    - A 20 MW project in Sprague/Lisbon becomes operational in 2016
  - Existing PV by end-of-2013 is based on Distribution Owner survey results, and the remainder of policy-based MWs are applied from 2014-2018, consistent with anticipated policy procurement
    - Includes approximately 30 MW of "legacy" PV that pre-existed aforementioned programs
  - Post-ZREC (after 2018) values remain consistent with 2018 value, but are more significantly discounted (refer to slide 19)

Forecast Methodology (4 of 6)
VT Assumptions/Inputs

- VT DPS' 9/30/13 DGFWG presentation serves as primary source for CT policy information
- PV comprises 75% of Standard Offer Program MWs until 127.5 MW goal is reached → 95 MWs total
  - No PV projects are determined to yield "sufficient benefits" and all are therefore counted towards the program goal**
- Assume 80% of net metered projects will be PV
  - Total of 40 MW
- Overall timing and total capacity of annual installed PV are generally consistent with VT DPS's 9/30/13 presentation to DGFWG
- Annual value from 2022 kept constant for 2023 (post-policy), but is more significantly discounted (refer to slide 19)

**For a description of "sufficient benefits" refer to VT's 30 V.S.A. § 8005a. SPEED; standard offer program, available at: http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=089&Section=08005a

Forecast Methodology (5 of 6)
RI Assumptions/Inputs

- RI OER's 9/30/13 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
    - Pre-2014: 84% of projects are PV
    - Post-2013: 63% of projects are PV
    - Total: 75% of 40MW DG Standard Contract goal is PV (30MW)
- Existing PV by end-of-2013 is based on Distribution Owner survey results, and the remainder of policy-based MWs are applied from 2014-2016, consistent with anticipated DG Standard Contract procurement
- Post-2016 (after DG contract installations end), annual forecast values are kept constant, but are more significantly discounted (refer to slide 19)

Forecast Methodology (6 of 6)
NH & ME Assumptions/Inputs

- NH
  - NH PUC's 9/30/13 DGFWG presentation serves as primary source for NH policy information
  - Class II RPS program and net metering will result in the development of 30 MW of PV through 2021
  - Existing PV by end-of-2013 is based on Distribution Owner survey results, and the remainder of policy-based MWs are evenly distributed from 2014-2021
  - Post-2021 annual forecast values are kept constant with 2021, but are more significantly discounted (refer to slide 19)
- ME
  - ME PUC's 9/30/13 DGFWG presentation serves as primary source for ME policy information
  - Net metering and other state grants/incentives will result in the development of 30 MW of PV by 2023, applied evenly throughout the forecast horizon
  - Existing PV by end-of-2013 is based on Distribution Owner survey results, and the remainder of policy-based MWs are evenly distributed from 2014-2023

Discount Factors (1 of 2)

- 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
- In general, 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 75% due to the much 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 (2 of 2)

- Annual discount factors for policy-based and post-policy solar PV are tabulated below
- All PV existing at the end of 2013 (“through-2013”) was verified by Distribution Owner and/or state data and was therefore not discounted

Policy-based MWs											Post-policy MWs
Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
0%	10%	15%	20%	25%	25%	25%	25%	25%	25%	25%	75%

PV's Summer Seasonal Claimed Capability

- In accordance with Market Rule 1, Section III.1.7.11, 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)

- In order to illustrate PV's intermittent nature and how it complicates efforts to determine how best to use the PV forecast in planning studies, ISO developed an estimated summer SCC for PV:
  - Estimate was based on analysis of different sources of PV production data
    - Discussion of analysis was shared with DGFWG on December 16, 2013: http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2013mtrls/dec162013/dg_forecast.pdf (slides 11-29)
    - The results of a similar previous analysis was shared with PAC on June 19, 2013: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jun192013/a7_solar_dg_update.pdf (slides 20-30)
  - Results suggest PV's summer SCC is approximately 35% of its AC nameplate (PV's winter SCC is zero)

- **It should be cautioned that**:
  1. PV performance often differs from its summer SCC during the variety of peak load conditions that occur, and in general, PV performance:
     - Can be higher than its summer SCC during earlier Reliability Hours (HE14-HE16)
     - Is typically lower than the summer SCC during later Reliability Hours, especially HE18
  2. PV's summer SCC will tend to vary from year-to-year, due to variations in the weather influencing its power output
  3. As PV penetrations grow across the region, PV will tend to shift peak net loads to 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 35% 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

Summary of State-by-State Forecast Inputs

Pre-Discounted Nameplate Values

States	Pre-Discount Annual Total MW (AC nameplate rating)											Totals
	Thru 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
CT	73.8	51.3	46.2	66.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	**561.2**
MA	361.6	187.2	138.1	138.1	138.1	131.6	131.6	131.6	131.6	131.6	131.6	**1,752.8**
ME	8.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	**30.0**
NH	8.2	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	**35.4**
RI	10.9	8.1	6.3	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	**62.8**
VT	36.1	22.3	15.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	6.8	**141.8**
Pre-Discount Annual Policy-Based MWs	**498.7**	**273.9**	**211.3**	**222.6**	**198.0**	**191.4**	**148.2**	**148.2**	**16.6**	**13.9**	**2.2**	**1,925.0**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**0.0**	**4.7**	**4.7**	**47.9**	**47.9**	**179.5**	**182.2**	**192.0**	**659.0**
Pre-Discount Annual Total (MW)	**498.7**	**273.9**	**211.3**	**222.6**	**202.6**	**196.1**	**196.1**	**196.1**	**196.1**	**196.1**	**194.2**	**2,584.0**
Pre-Discount Cumulative Total (MW)	**498.7**	**772.6**	**983.9**	**1,206.5**	**1,409.1**	**1,605.3**	**1,801.4**	**1,997.5**	**2,193.6**	**2,389.8**	**2,584.0**	**2,584.0**

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 installed capacities

FINAL INTERIM PV FORECAST

Final Interim PV Forecast

States	Annual Total MW (AC nameplate rating)											Totals
	Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
CT	73.8	46.2	39.3	53.0	34.7	34.7	13.1	13.1	13.1	13.1	11.6	**345.4**
MA	361.6	168.5	117.4	110.5	103.6	98.7	98.7	98.7	32.9	32.9	32.9	**1,256.4**
ME	8.1	2.0	1.9	1.8	1.6	1.6	1.6	1.6	1.6	1.6	1.6	**25.2**
NH	8.2	2.5	2.3	2.2	2.0	2.0	2.0	2.0	2.0	0.7	0.7	**26.7**
RI	10.9	7.3	5.4	3.7	1.2	1.2	1.2	1.2	1.2	1.2	1.2	**35.5**
VT	36.1	20.1	13.4	7.0	6.5	6.5	6.5	6.5	6.5	6.5	1.7	**117.3**
Regional - Annual (MW)	**498.7**	**246.5**	**179.6**	**178.1**	**149.6**	**144.8**	**123.1**	**123.1**	**57.3**	**56.0**	**49.7**	**1,806.5**
Regional - Cumulative (MW)	**498.7**	**745.2**	**924.8**	**1102.9**	**1252.5**	**1397.3**	**1520.4**	**1643.6**	**1700.9**	**1756.9**	**1806.5**	**1,806.5**

Notes:

(1) Forecast values include FCM Resources, non-FCM Settlement Only Generators, and load reducing PV resources
(2) The forecast reflects discount factors described on slides 18-19
(3) All values represent end-of-year installed capacities
(4) ISO is working with stakeholders to determine the appropriate use of the forecast

Estimated Summer Seasonal Claimed Capability of PV Forecast

Based on 35% of Forecasted AC Nameplate Capacity

States	Estimated Summer SCC (MW)											Totals
	Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
CT	25.8	16.2	13.8	18.5	12.1	12.1	4.6	4.6	4.6	4.6	4.0	**120.9**
MA	126.6	59.0	41.1	38.7	36.3	34.5	34.5	34.5	11.5	11.5	11.5	**439.7**
ME	2.8	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	**8.8**
NH	2.9	0.9	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.2	0.2	**9.4**
RI	3.8	2.6	1.9	1.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	**12.4**
VT	12.6	7.0	4.7	2.4	2.3	2.3	2.3	2.3	2.3	2.3	0.6	**41.1**
Regional - Annual Summer SCC (MW)	**174.5**	**86.3**	**62.9**	**62.3**	**52.4**	**50.7**	**43.1**	**43.1**	**20.1**	**19.6**	**17.4**	**632.3**
Regional - Cumulative Summer SCC (MW)	**174.5**	**260.8**	**323.7**	**386.0**	**438.4**	**489.0**	**532.1**	**575.2**	**595.3**	**614.9**	**632.3**	**632.3**

Notes:

(1) ISO’s methodology for determining SCC for Intermittent Resources is defined in Market Rule 1, Section III.1.7.11
(2) Estimated SCC values include FCM Resources, non-FCM Settlement Only Generators, and load reducing 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