Draft 2016 PV Forecast

Distributed Generation Forecast Working Group

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Revised March 7, 2016 (slide 27 added)

Outline

- Introduction and Background Information
- 2015 PV Growth: Forecast vs. Reported
- Forecast Assumptions and Inputs
- Draft 2016 PV Forecast - Nameplate
- PV’s Reduction of Future Summer Peak Loads
- Next Steps for CELT 2016

INTRODUCTION AND BACKGROUND INFORMATION

Summary: Draft CELT 2016 PV Forecast

- More PV development is expected in the region than projected in 2015
- Factors influencing future development of PV resources are complex
- The 2016 PV forecast reflects a qualitative approach, but with better information than was available to the ISO last year
- The 2016 forecast reflects discussions with stakeholders and data exchange with the New England states and Distribution Owners
- The 2016 draft forecast is approximately 30% higher than the final 2015 forecast

What's New in the 2016 PV Forecast?

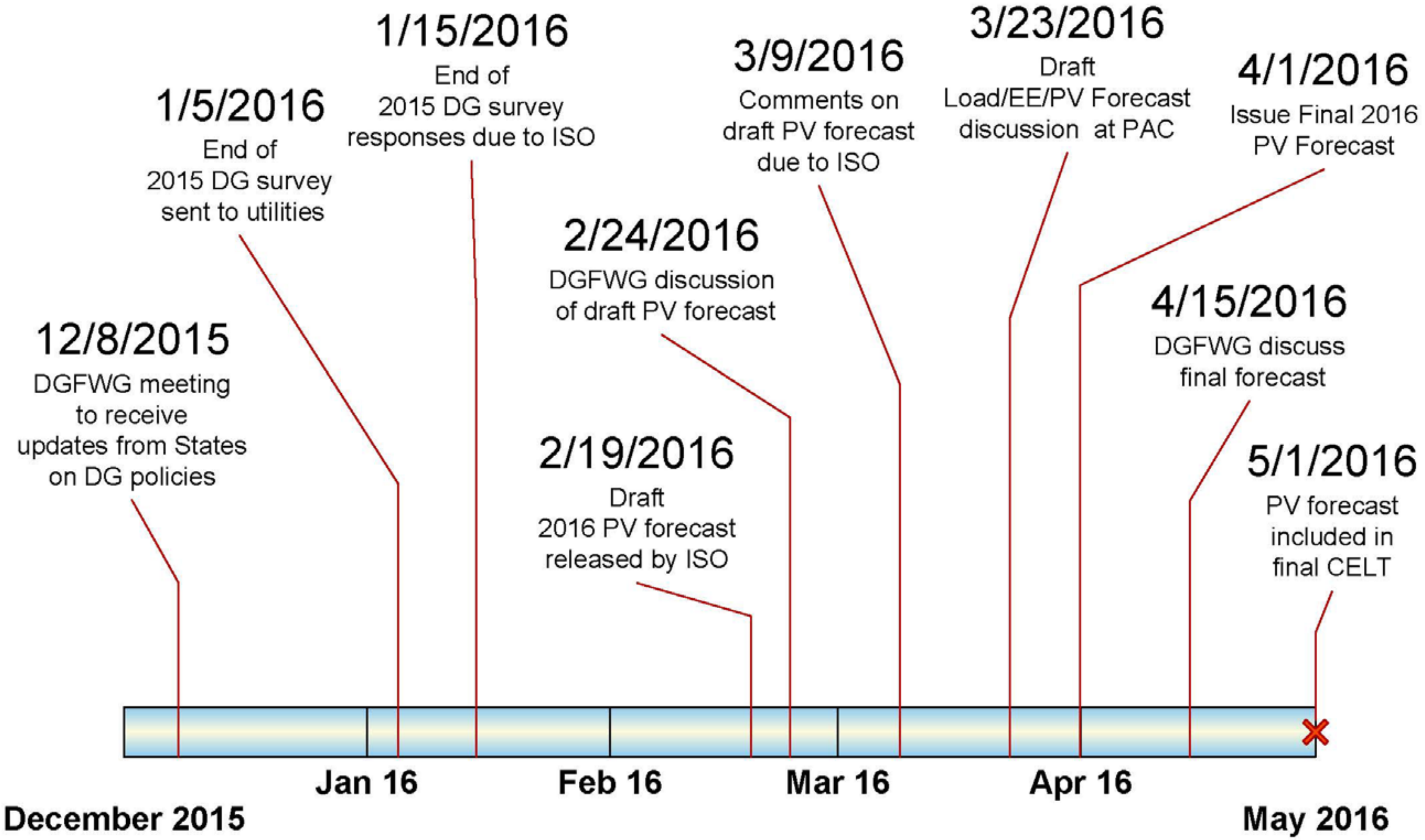
- Longer set of historical data
  - Reflects recent PV growth through the end of 2015 as reported by Distribution Owners
- Consideration of recent federal and state policy changes
- PV forecast will be categorized differently this year
  - Final category breakdown will be discussed at the April 15, 2016 DGFWG meeting

Similar to EE, behind-the-meter PV will be reconstituted into historical loads*

The 2016 gross load forecast will reflect loads without PV load reductions

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

KEY DATES: 2016 DG Forecast Development



Many Factors Influence the Future Commercialization Potential of PV

- Policy Drivers:
  - Feed-in-tariffs (FITs)/Long-term procurement
  - State Renewable Portfolio Standards (RPS) programs
  - Net energy metering (NEM)
  - Investment Tax Credit (ITC)
- Other Drivers:
  - Role of private investment in PV development
  - Future equipment and installation costs
  - Future wholesale and retail electricity costs

- The draft 2016 PV forecast methodology is similar to that of the 2014 and 2015 forecasts, with consideration to recent federal and state policy changes and recent trends in PV development in the region
  - December 2015 DGFWG materials available at: http://www.iso-ne.com/committees/planning/distributed-generation/?eventId=125762

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

2015 PV GROWTH: FORECAST VS. REPORTED

Based on 2015 PV Forecast and January 2016 Utility Data

2015 PV Nameplate Growth

- Reported growth in region was roughly 90 MW higher than forecast
- Table below compares the forecasted (2015 PV forecast) annual PV growth (MW_{AC}) and the reported growth for 2015

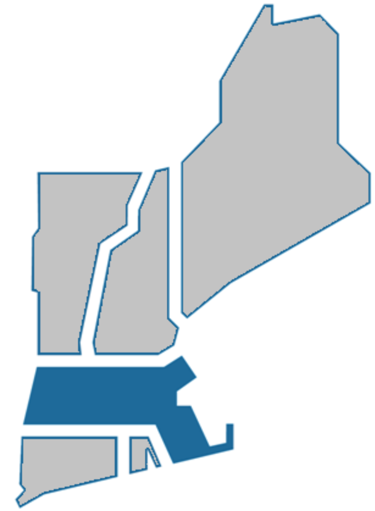
State	2015 Forecasted Growth	2015 Reported Growth	Difference
CT	70.9	69.2	-1.7
MA	197.0	280.3	83.3
ME	2.2	4.9	2.7
NH	4.3	13.7	9.4
RI	9.7	5.4	-4.3
VT	40.4	42.8	2.4
Region	324.5	416.3	91.8

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

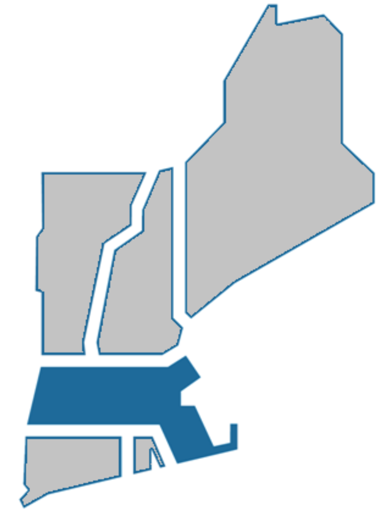
Massachusetts Forecast Methodology and Assumptions



- 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
- Remaining MWs needed to reach state goal are applied from 2016-2020 and are front-loaded in early years
- Post-SREC (after 2020) forecast values are kept at 2020 growth level, but are more significantly discounted

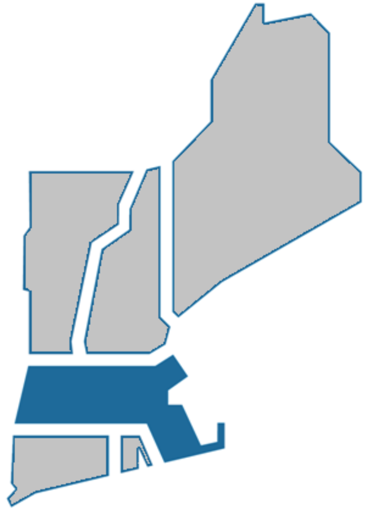
****Source**: J. Fiorelli and M.Z. Martinson, *How Oversizing Your Array-to-Inverter Ratio Can Improve Solar-Power System Performance*, Solar Power World, July 2013, available at: http://www.solren.com/articles/Solectria_Oversizing_Your_Array_July2013.pdf

Massachusetts Forecast Methodology and Assumptions *continued*



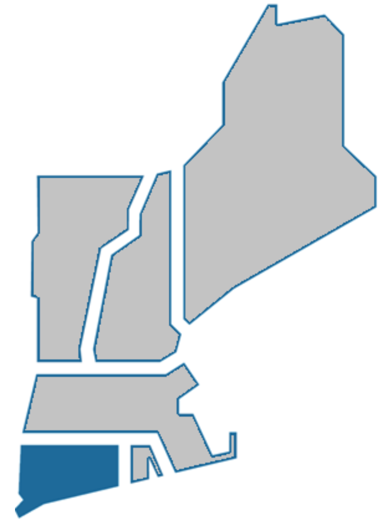
- SREC I/II data shows that 978.1MW$_{DC}$ were in operation at the end of 2015 (SREC I: 647.9 MW$_{DC}$; SREC II: 330.2 MW$_{DC}$)
  - Leaves 621.9 MW$_{DC}$ to satisfy 2020 goal (~516 MW$_{AC}$)
- SREC II Cap for Projects >25 kW$_{DC}$ was reached by February 1, 2016
- SREC data does not align with assumed DC-to-AC conversion given the 947.1 MW$_{AC}$ reported by utilities at end of 2015
  - At the assumed 83% derate, this would be equivalent to 1,141 MW$_{DC}$
  - A derate of >93% would align reported capacity with SREC data, but is unrealistic

Massachusetts Forecast Methodology and Assumptions *continued*



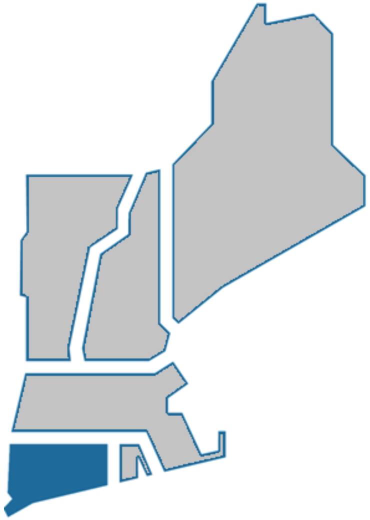
- Some uncertainty regarding the interplay between meeting the SREC goal and reaching the existing net metering caps
  - Based on November 2015 EIA Form 826 data, 775.3 MW_{AC} of the current 999 MW_{AC} net metering cap has been reached
  - Some Class I net metered facilities are exempt from cap
    - Less than or equal to 10 kW nameplate on single-phase circuit
    - Less than or equal to 25 kW nameplate on three-phase circuit
- No consensus reached yet on new net metering policy
  - On February 6th, DOER released a Request for Quote for *Post-1,600 Megawatt Solar Policy Development Technical Support*
    - See: http://www.mass.gov/eea/docs/doer/rps-aps/rfq-ene-2016-010-post-1600mw-techical-support.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

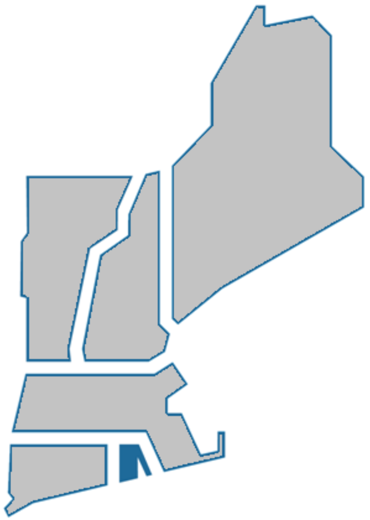
Vermont Forecast Methodology and Assumptions *continued*

- 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

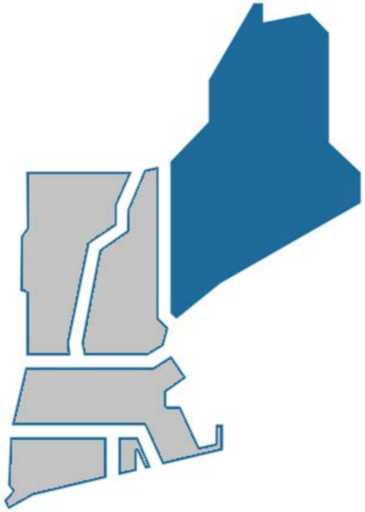
- NH PUC's 12/8/15 DGFWG presentation serves as primary source for NH policy information
- Based on distribution owner survey results, net metering and other state rebate/grants resulted in 13.7 MW of PV growth in 2015
- Post-2020, annual forecast values are kept constant, but are more significantly 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**

Discount Factors, *continued*

- Annual discount factors for policy-based solar PV are tabulated on the right
  - Draft 2016 vs. final 2015 shown
- Policy-based discount factors are lower starting in 2017 when compared to those developed for the 2015 PV forecast which reflects federal ITC extension
- All post-policy MWs are discounted at 50%, consistent with last year's forecast approach

Forecast	Final 2015	Draft 2016
Thru 2015	0%	0%
2016	5%	5%
2017	15%	5%
2018	20%	10%
2019	25%	10%
2020	25%	10%
2021	25%	15%
2022	25%	20%
2023	25%	20%
2024	25%	20%
2025	- -	20%

Summary of State-by-State 2016 Draft 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	129.1	129.1	86.1	86.1	86.1	86.1	86.1	86.1	86.1	86.1	**1,894.0**
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	31.8	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	**388.1**
Pre-Discount Annual Policy-Based MWs	**1325.0**	**292.5**	**324.5**	**246.0**	**246.0**	**234.7**	**71.7**	**64.9**	**33.9**	**33.9**	**33.9**	**2,907.2**
Pre-Discount Annual Post-Policy MWs	**0.0**	**0.0**	**0.0**	**8.0**	**8.0**	**8.0**	**153.1**	**159.8**	**190.8**	**190.8**	**190.8**	**909.4**
Pre-Discount Annual Total (MW)	**1325.0**	**292.5**	**324.5**	**254.0**	**254.0**	**242.7**	**224.7**	**224.7**	**224.7**	**224.7**	**224.7**	**3,816.6**
Pre-Discount Cumulative Total (MW)	**1325.0**	**1,617.6**	**1,942.1**	**2,196.1**	**2,450.1**	**2,692.8**	**2,917.6**	**3,142.3**	**3,367.1**	**3,591.8**	**3,816.6**	**3,816.6**

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

DRAFT 2016 SOLAR PV FORECAST

Nameplate MW

Final 2015 PV Forecast

Nameplate Capacity, 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 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

Draft 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	122.7	122.7	77.5	77.5	77.5	43.0	43.0	43.0	43.0	43.0	**1,640.0**
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	30.2	22.5	22.5	22.5	21.3	20.0	20.0	20.0	20.0	**353.7**
Regional - Annual (MW)	**1325.0**	**277.9**	**308.3**	**225.4**	**225.4**	**215.3**	**137.5**	**131.8**	**122.5**	**122.5**	**122.5**	**3,214.3**
Regional - Cumulative (MW)	**1325.0**	**1602.9**	**1911.2**	**2136.6**	**2362.0**	**2577.3**	**2714.8**	**2846.6**	**2969.2**	**3091.7**	**3214.3**	**3,214.3**

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
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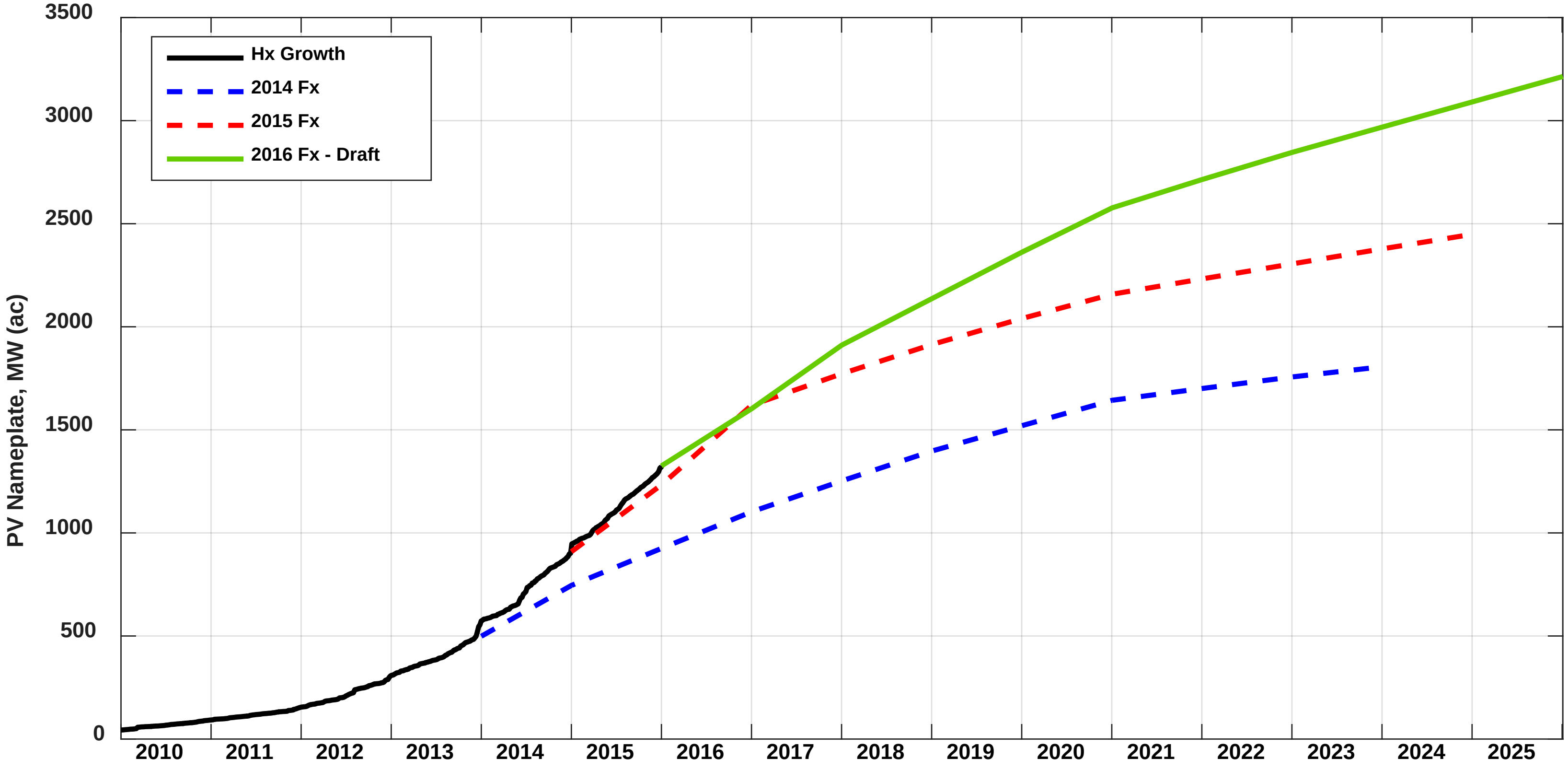
PV Growth: Reported vs. Forecast



2016 Draft PV Forecast Summary

- Draft 2016 forecast is roughly 30% higher than 2015 forecast
  - Federal ITC extension
  - State policy expansions in CT and VT
  - Added another forecast year (2025)
  - More realized MWs in 2015 → now undiscounted
- Significantly front-loaded, similar to last year
- Includes >400-MW of post-policy PV, mostly during the later years of the forecast

PV’S REDUCTION OF FUTURE SUMMER PEAK LOADS

Magnitude and Timing

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
- Slides 38-58 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

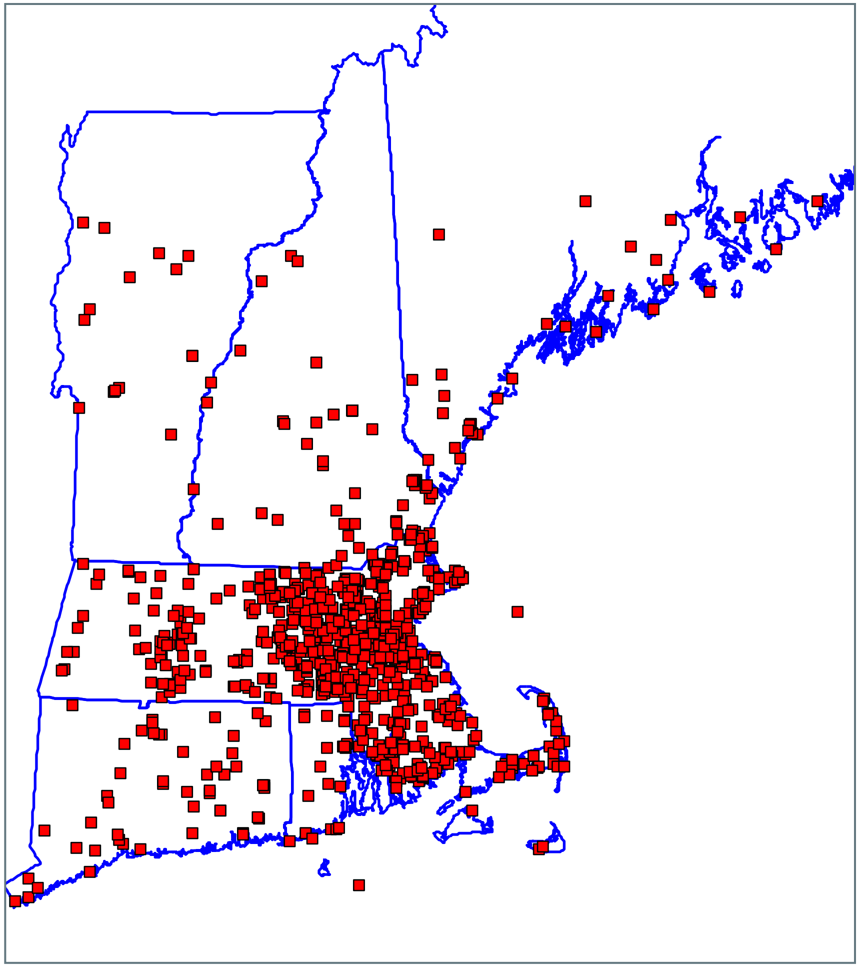
TOPIC ADDRESSED IN FOLLOWING SLIDES

- 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

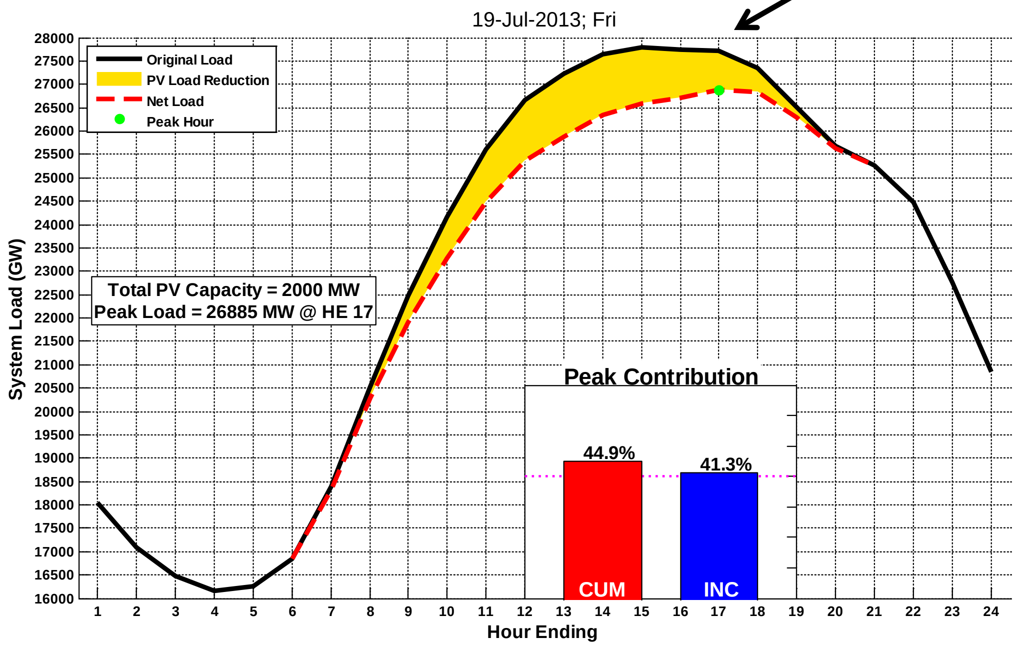


*Accessed via http://www.solrenview.com/

Net Load Simulation Method *continued*

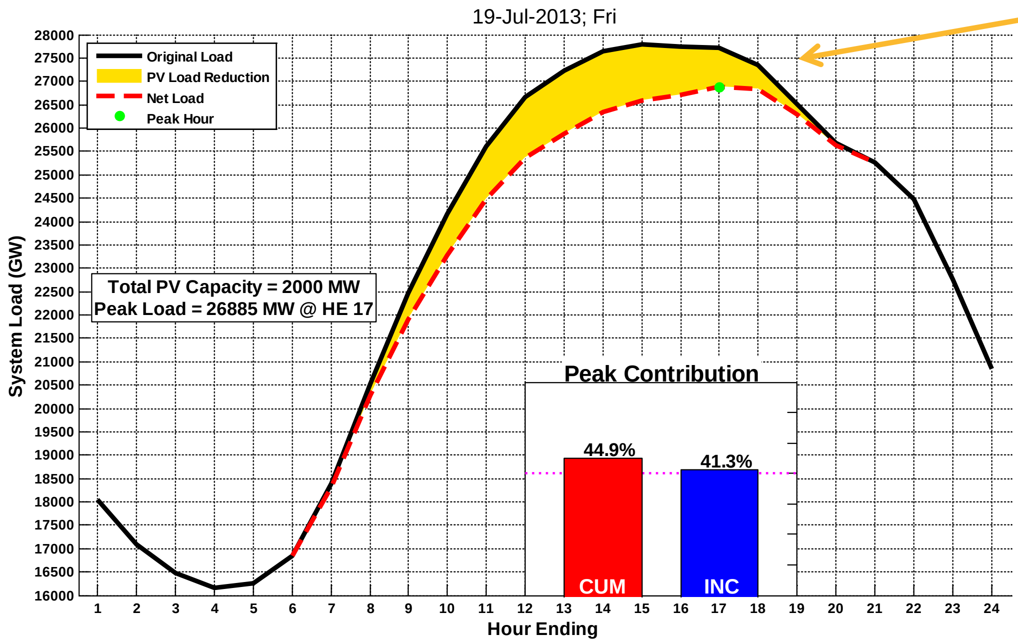
- Existing PV system design and technology trends are not anticipated to change *significantly* over the next decade.
- It is assumed that upscaling of these profiles yields a reasonable estimate of future profiles associated with larger PV fleets that is adequate for simulation purposes
- Hourly load 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



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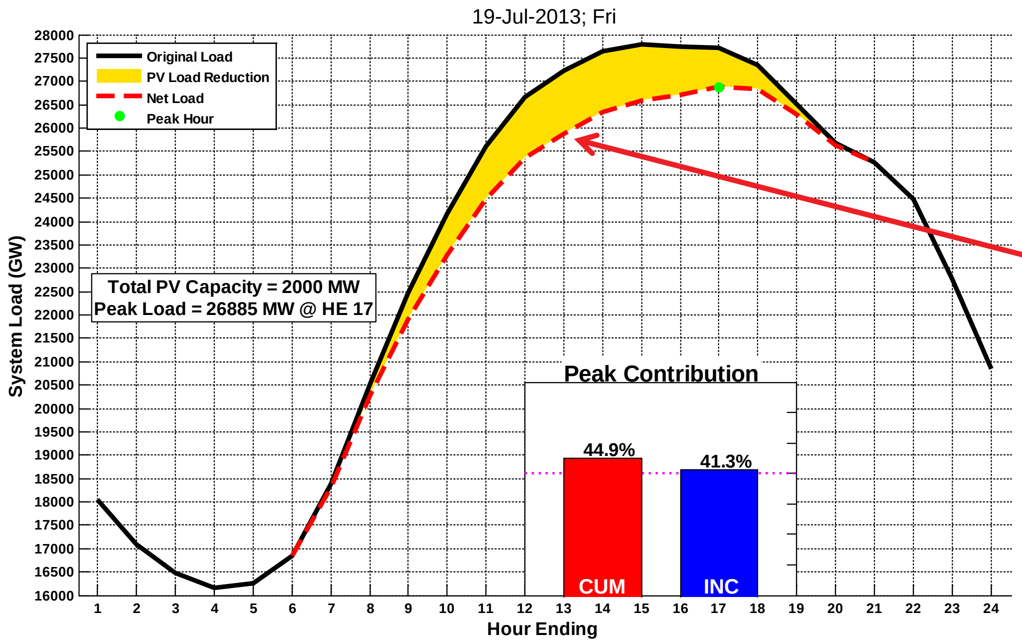

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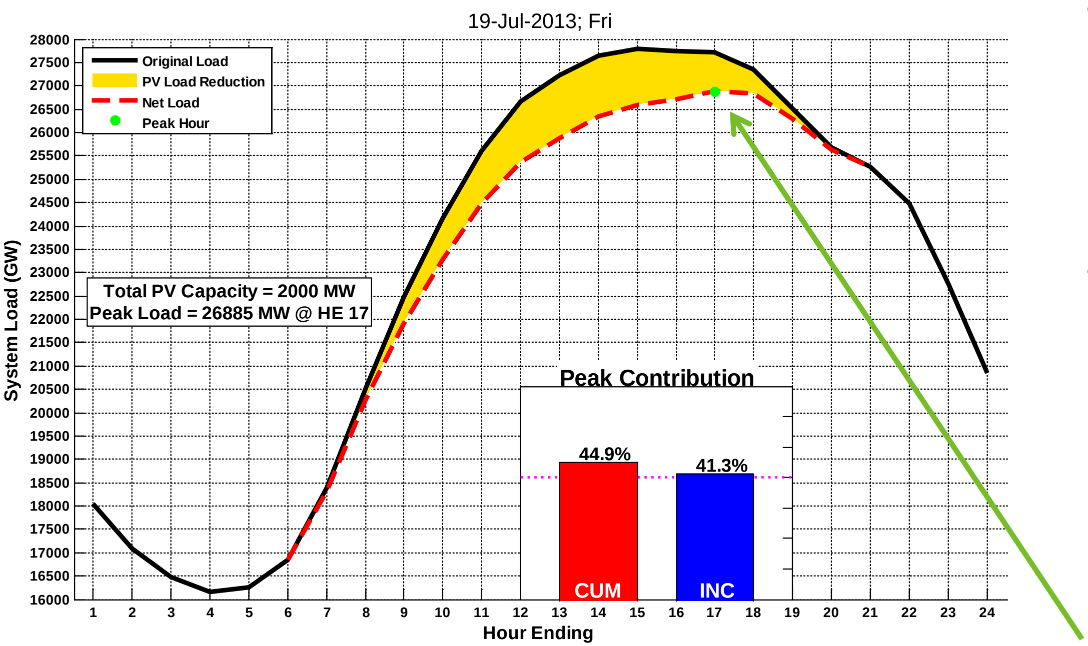
Terms Defined



- 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*

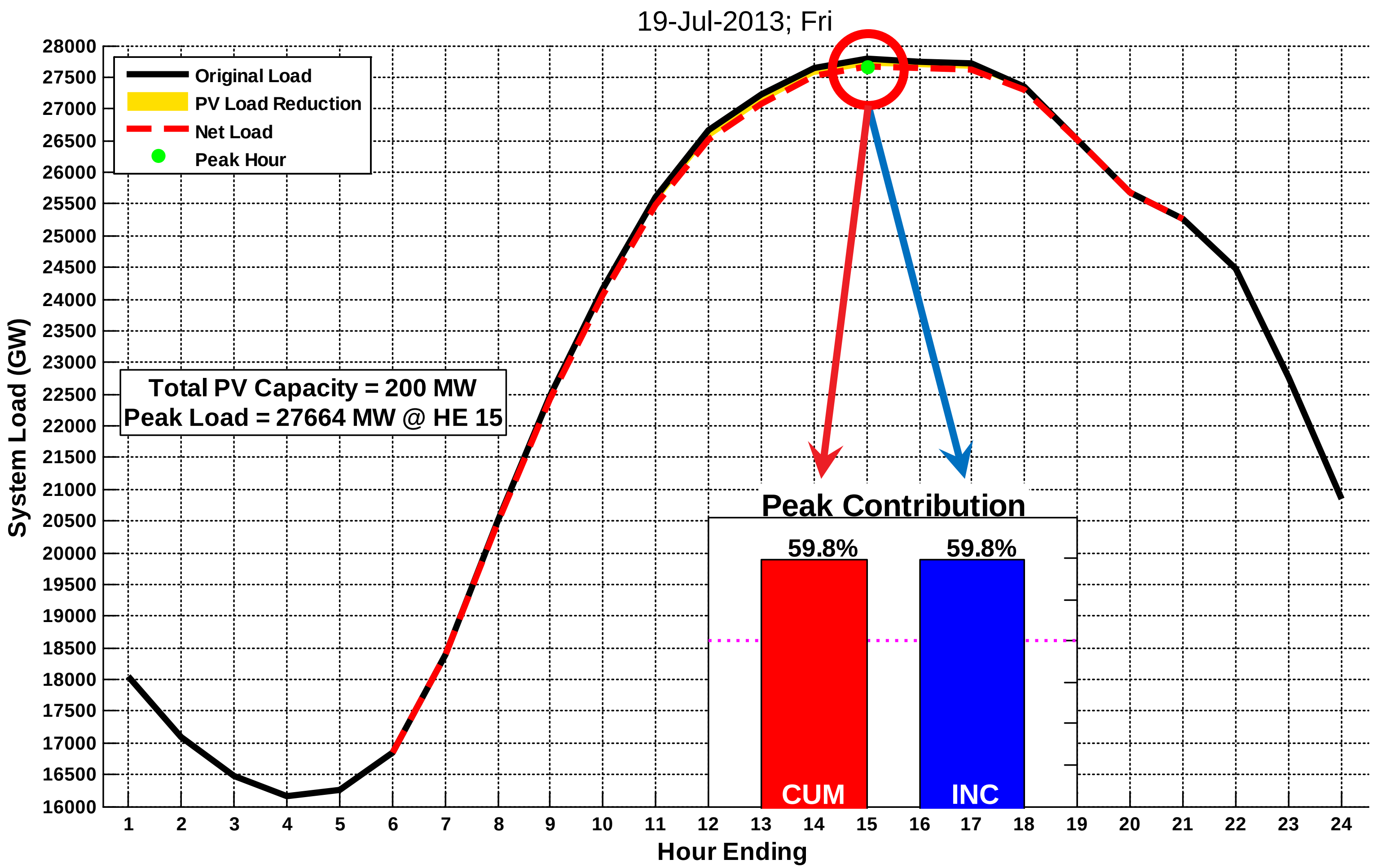
- **INC** represents the incremental reduction of the new daily peak load, including associated time shifts, from adding the next MW of PV
- **CUM** represents the total reduction of the original daily peak load (i.e., without PV) as a percentage of the total installed nameplate capacity of PV

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

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

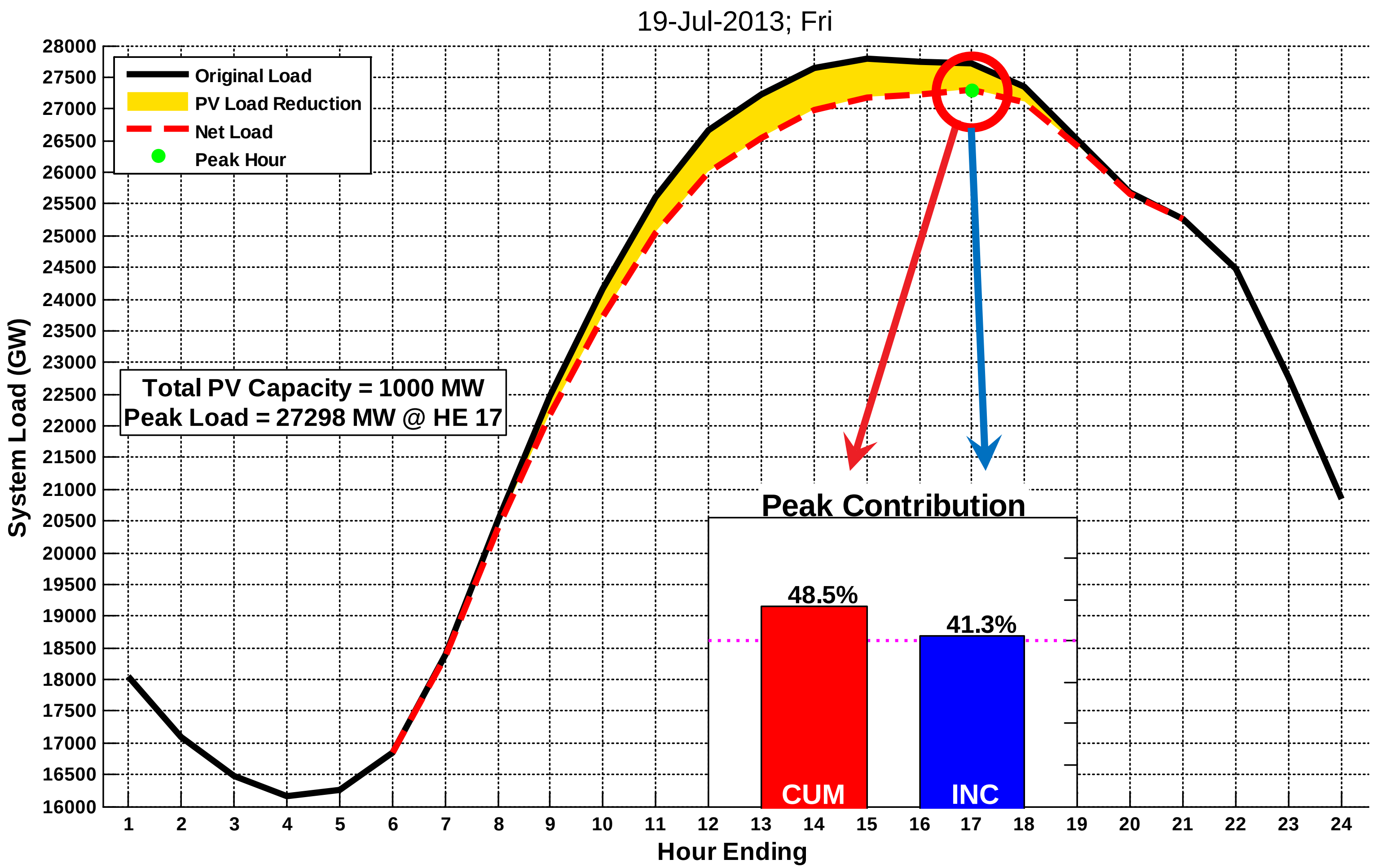
July 19, 2013 Net Load Profile

200 MW PV



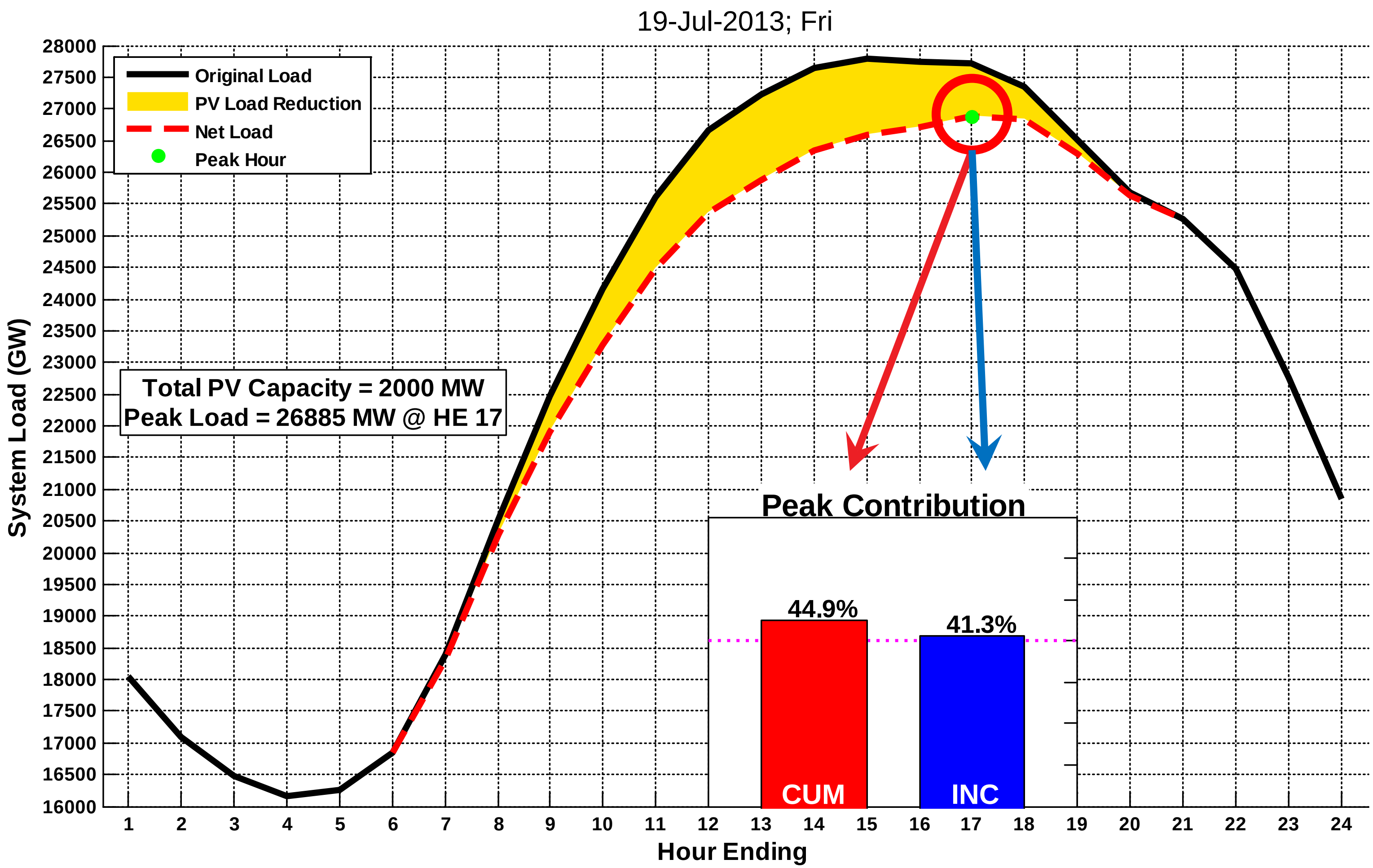
July 19, 2013 Net Load Profile

1000 MW PV



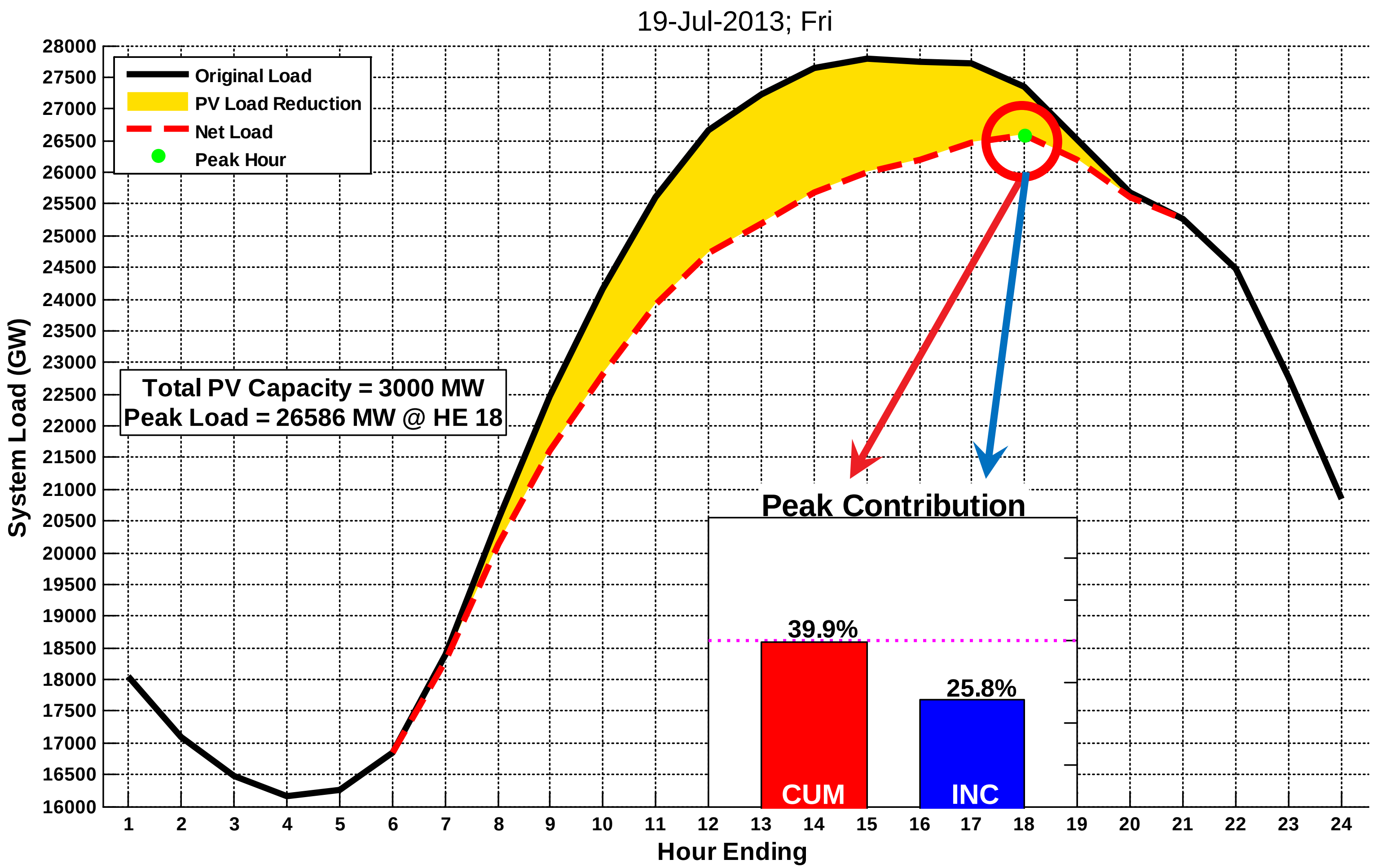
July 19, 2013 Net Load Profile

2000 MW PV



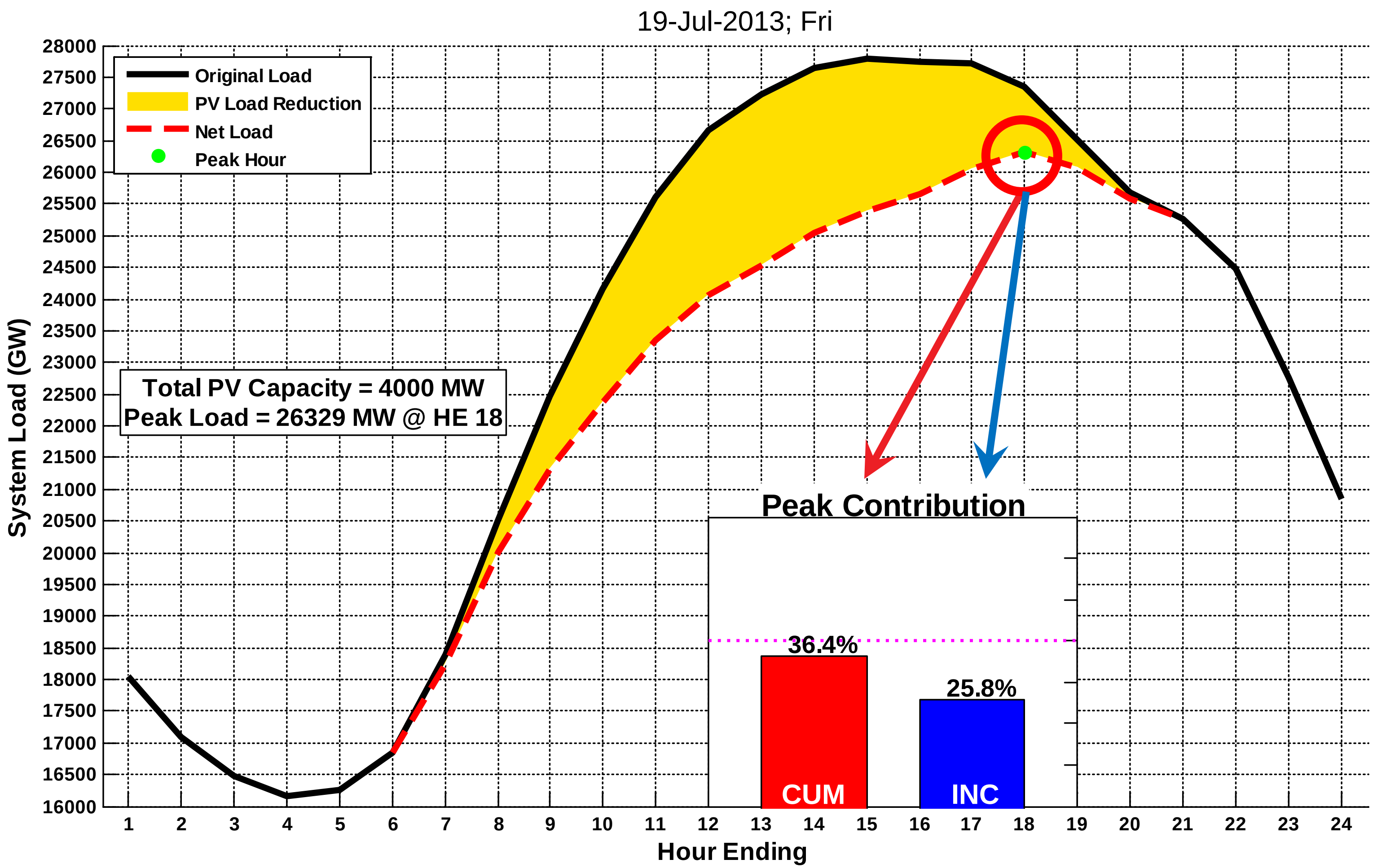
July 19, 2013 Net Load Profile

3000 MW PV



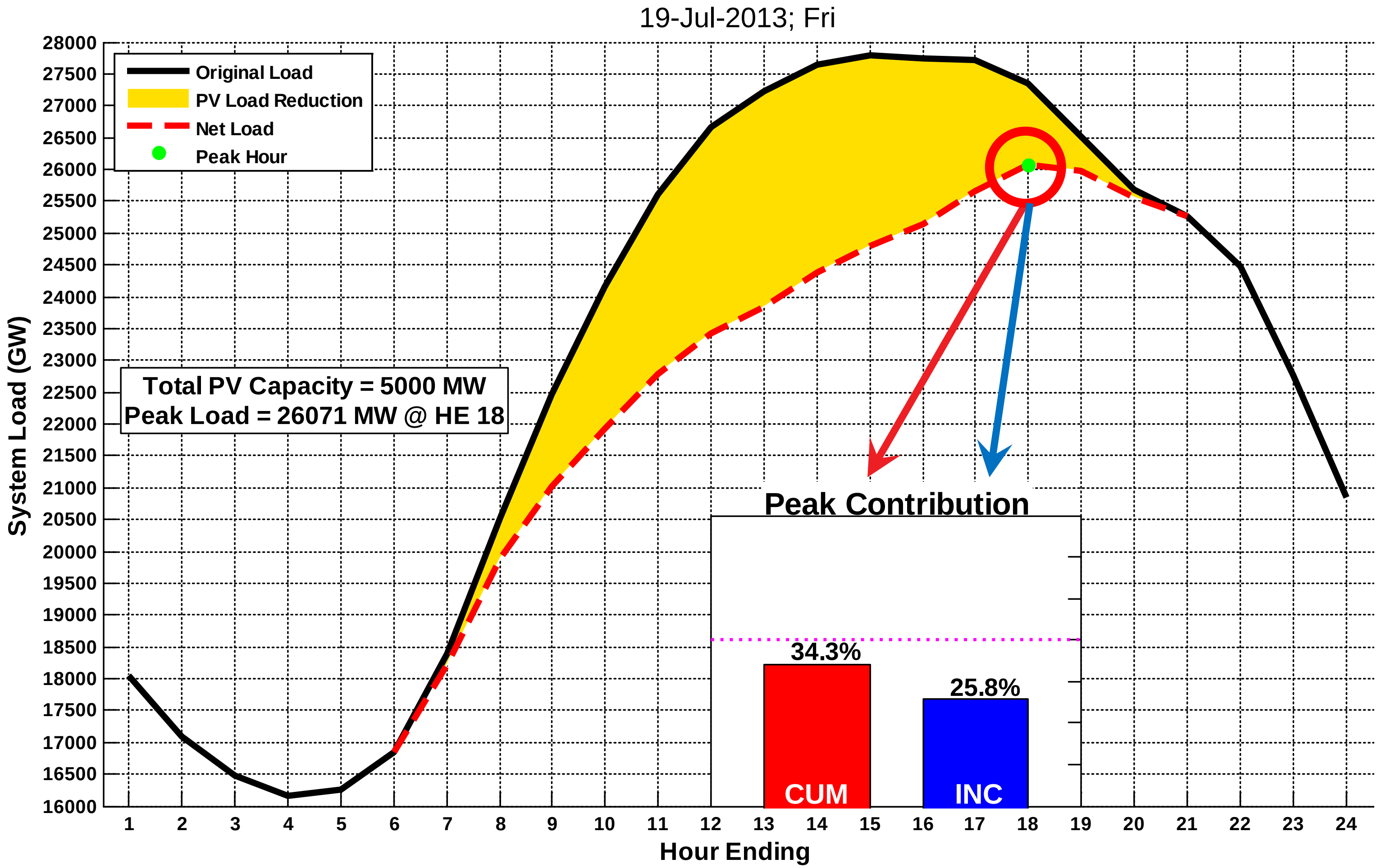
July 19, 2013 Net Load Profile

4000 MW PV

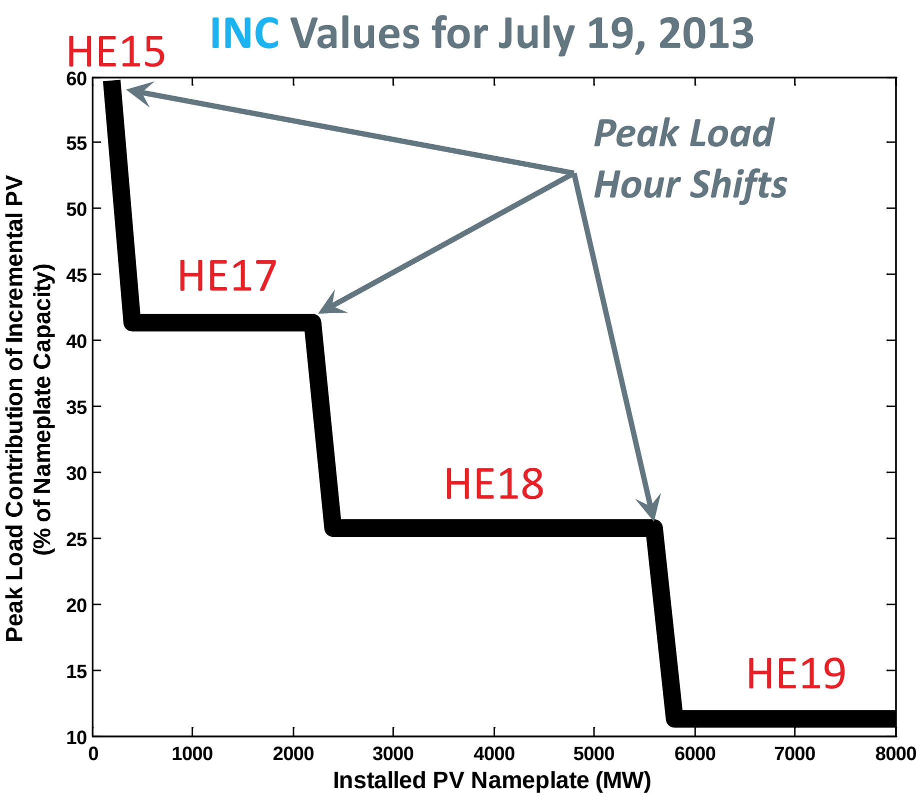


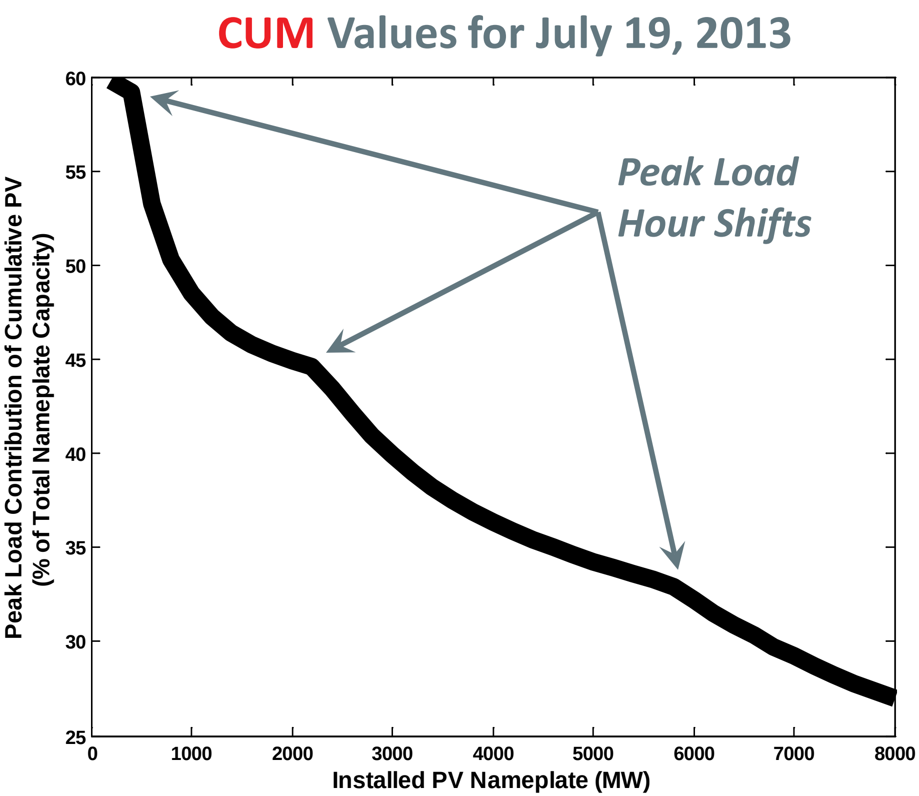
July 19, 2013 Net Load Profile

5000 MW PV



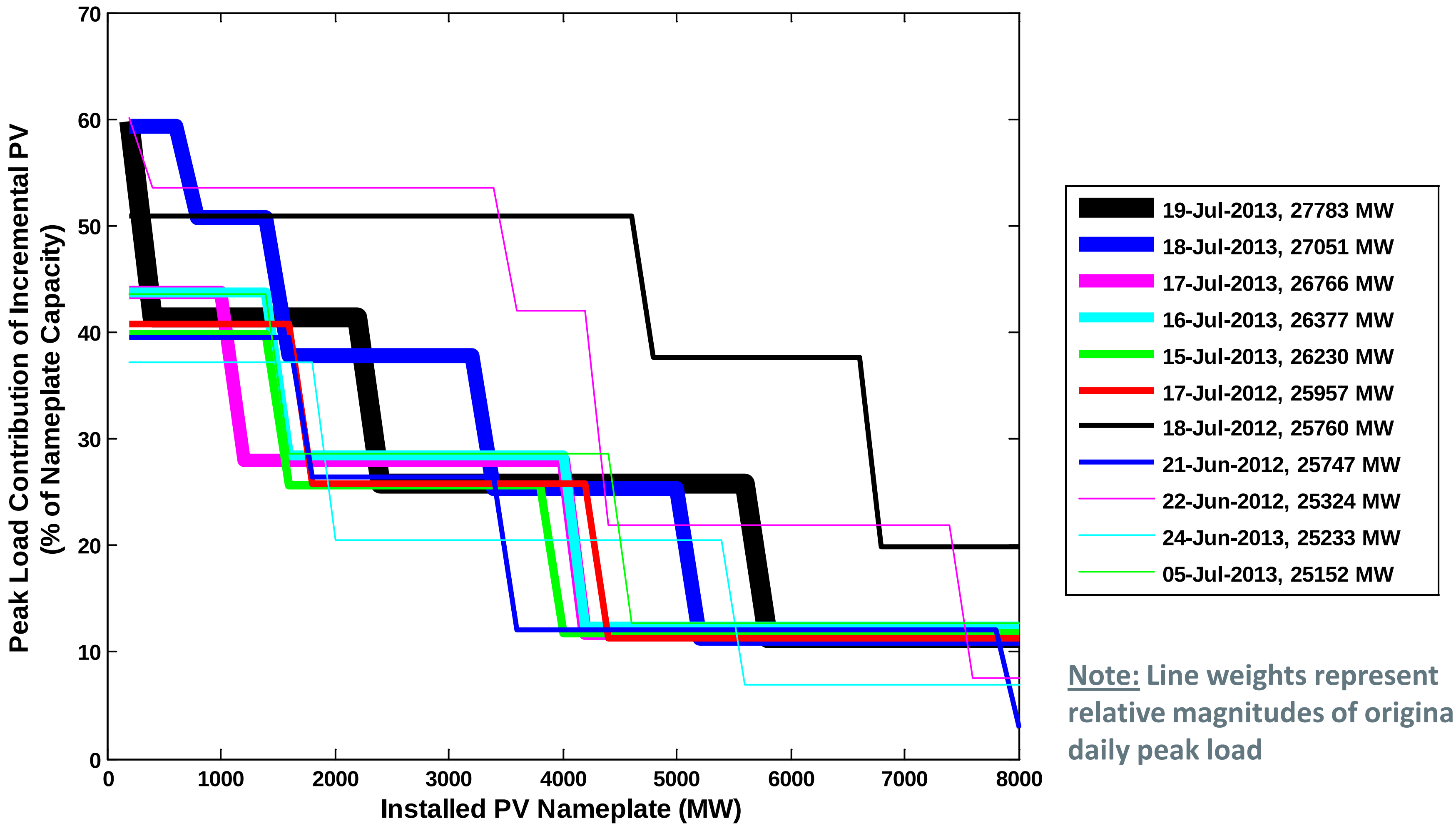
July 19, 2013
Resulting INC and CUM





All 11 Days: Incremental (INC) Peak Reduction

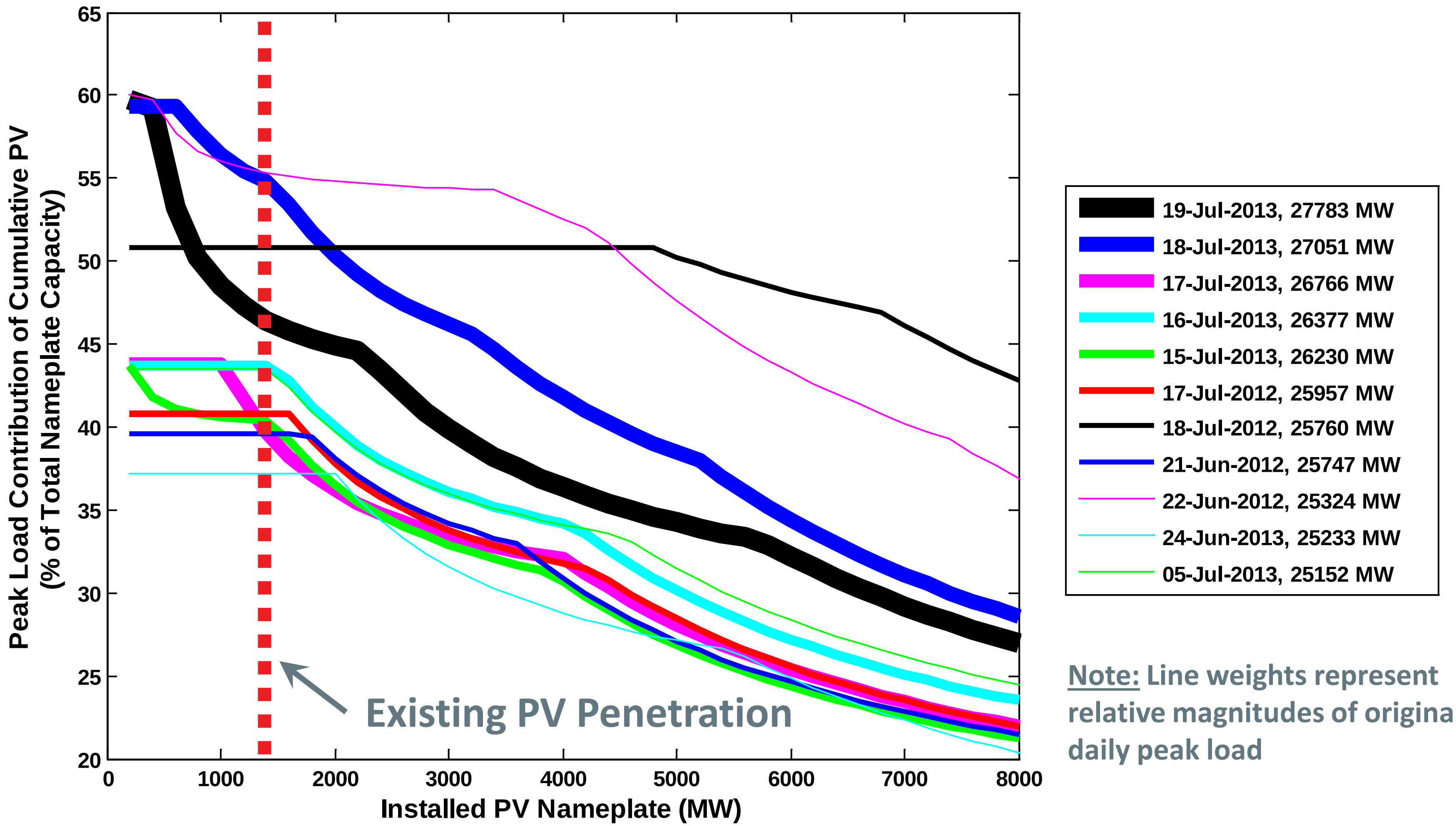
% of Incremental Nameplate Capacity



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

All 11 Days: Cumulative (CUM) Peak Reduction

% of Total Nameplate Capacity

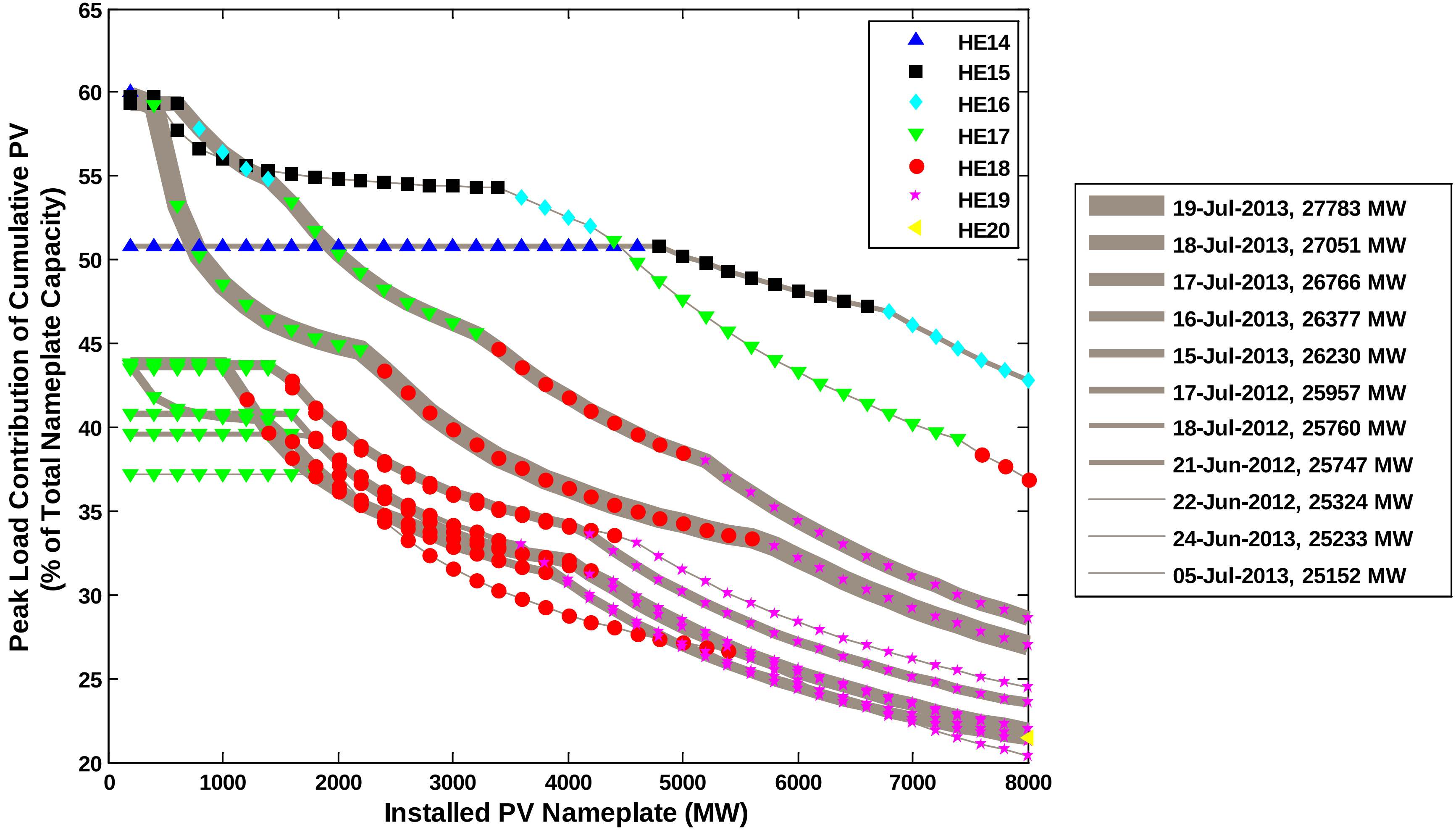


<u>Note:</u> Line weights represent relative magnitudes of original daily peak load

All 11 Days: Cumulative (CUM) Peak Reduction

Peak Net Load Hour Timing

Timing of peak net load shown by marker type/colors

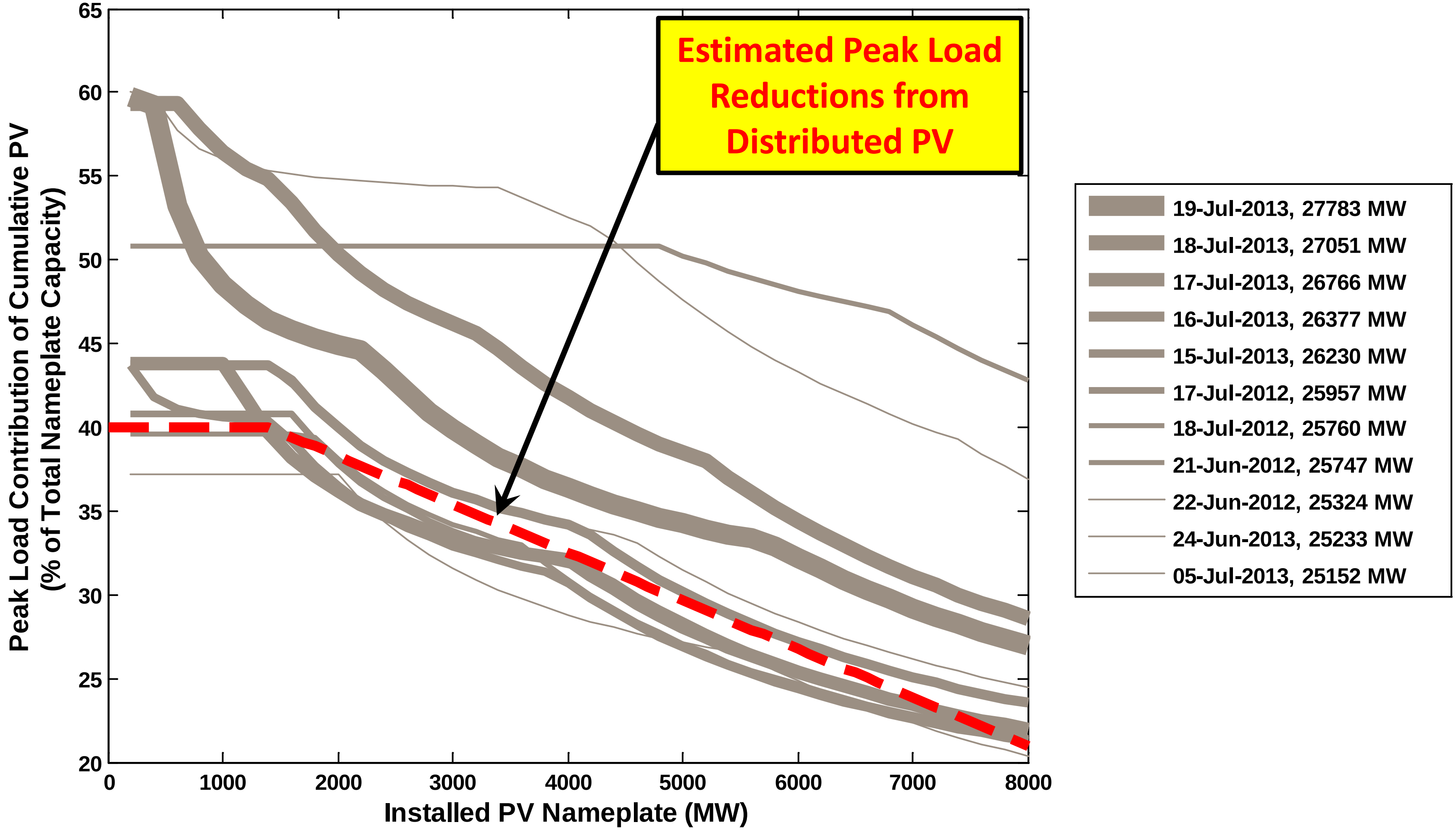


Estimating PV's Future Peak Load Reductions

- 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

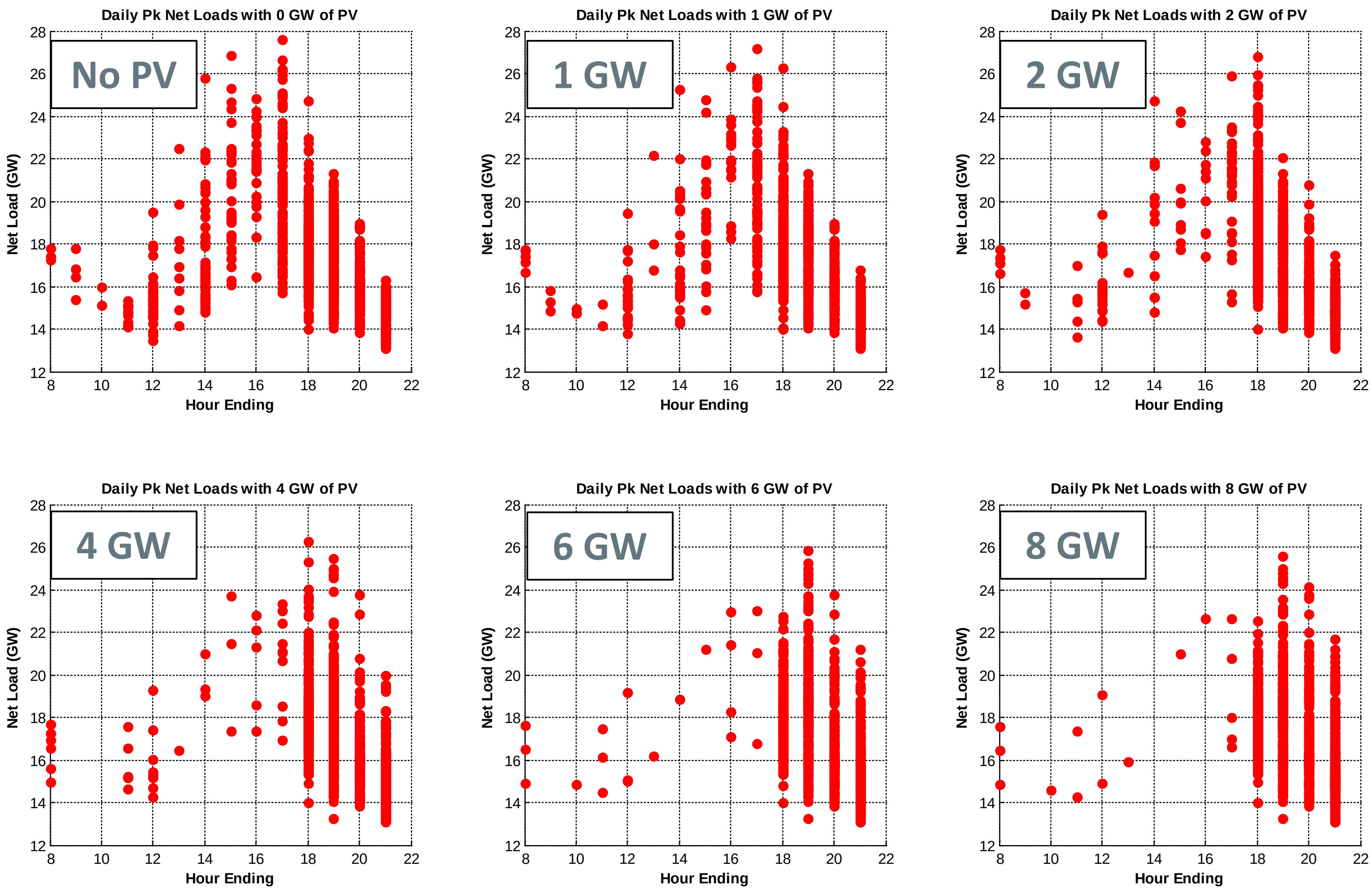


Distributed PV's Estimated Peak Load Reductions

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

Timing and Magnitude of Daily Summer Peaks

Six PV Scenarios Shown



Proposed Application of Peak Load Reductions

- PV will be fully reconstituted in gross load forecast
- Net load forecast will reflect the relevant peak load reductions given the amount of PV forecasted in a given year
  - An illustrative example is tabulated below using fictitious forecast
- Note that different studies may use values other than these to reflect the PV forecast

Illustrative Example of Proposed Application of PV's Peak Load Reductions

Forecast Year	2016	2020	2025
PV Forecast (MW, nameplate)	1,000	2,000	3,000
Peak Load Reduction (% of PV Nameplate)	40%	38.3%	35.4%
Peak Load Reduction (MW)	400	766	1,062

NEXT STEPS FOR FINAL CELT 2016

Next Steps for CELT 2016

- Once the 2016 nameplate PV forecast is finalized, ISO will:
  – Break down the forecast by market participation category
    - At the end of 2015, approximately 65% of PV was behind-the-meter
  – Create the PV energy forecast
- ISO will reconstitute PV into the historical loads used to develop the long-term gross load forecast
  – Overall accounting in the net load forecast will be the same, but behind-the-meter PV will no longer be separated into embedded vs. non-embedded
  – Three PV categories will be used for CELT 2016:
    1. PV as a capacity resource in the Forward Capacity Market (FCM)
    2. Non-FCM Settlement Only Resources (SOR) and Generators (per OP-14)
    3. Behind-the-meter PV
- ISO will use the same approach as last year for the geographic distribution of PV forecast
  – Assumes future development is in existing areas of PV development

We Want Your Feedback …

- Please share your comments today
- ISO requests written comments on draft 2016 PV forecast by March 9
- Please submit comments to DGFWGMatters@iso-ne.com

Questions