Maine Public Utilities Commission

Maine Distributed Solar Valuation Study: Addendum

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Presented to:

The Joint Standing Committee on Energy, Utilities and Technology

127th Maine Legislature

Maine Public Utilities Commission

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Purpose

This addendum supplements and adds further clarification to the report “Maine Distributed Solar Valuation Study,” dated March 1, 2015, presented to The Joint Standing Committee on Energy, Utilities and Technology, 127th Maine Legislature. The material includes additional analysis performed since the publication of the report. The following sections are meant to be additive to the existing report narrative and not a standalone document. Reference is made where each section will be added to the report in a subsequent revision to be posted on the Commission’s website.

Long Term Value (insert at Page 7 beneath first paragraph)[1]

It is important to note that Figure ES-2 of the report does not identify who the benefits and costs accrue to. For example, avoided energy cost is calculated based on avoided wholesale energy purchases, but this value may involve a series of transactions between the solar customer, the distribution utility, and the energy market participants.

The value shown in Table ES-2 represents a longer term projection of the levelized value of a solar PV system over a 25 year horizon. It is meant to be illustrative and not as a standalone value apart from First Year Value descriptions.

ELCC (insert as new Appendix 6 to Volume II: Valuation Results)

Importance of Solar Rating Convention

The ELCC for the Base Case was calculated as 54.4%. It is important to understand that this result reflects the solar capacity rating convention used in the report, namely, AC capacity with losses. While the solar industry has standard rating conventions for modules and inverters, it does not for as-built systems. Among the ratings used for system capacity are:

- DC (the DC module rating at standard test conditions)
- PTC (the DC module rating at “PVUSA Test Conditions”)

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[1] All page numbers refer to the hard copy of the “Maine Distributed Solar Valuation Study,” dated March 1, 2015, presented to The Joint Standing Committee on Energy, Utilities and Technology, 127th Maine Legislature.

- California Energy Commission, or CEC (the PTC rating times the load-weighted inverter efficiency)
- AC nameplate (the maximum power output of the inverter
- AC with losses (the CEC rating, less system losses)

The selection of rating convention is arbitrary, but must be used consistently. As shown in Table A-1, the same Base Case Time Series (AC electrical energy delivered by the fleet to the grid) is used to show how two different rating conventions yield the same end result, but that intermediate results may differ.

For example, the 1 kW AC rating (with losses) is equivalent to a 1.30 kW DC rating. The fleet time series is identical, and yields the same effective capacity of 0.544 kW. However, when expressing ELCC as a percentage of rating, the result is an ELCC of 54.4% and 41.9% for the AC method and DC method, respectively. Similarly, the capacity factor (annual energy as compared to a constant output of full rated capacity) yields 18.6% and 14.3%, despite the fact that the annual energy production is the same. Finally, the table shows an illustration of how first capacity year capacity value yields the same value. These values were not included in the study results and are provided only as an illustration of how rating convention is an arbitrary selection.

Table A-1. AC versus DC Rating Conventions

	AC Rating Convention	**DC Rating Convention**
Marginal PV Production Profile	Base Case Time Series	Base Case Time Series
Resource Rating	1 kW AC	1 /0.77 = 1.30 kW DC
ELCC	0.544 kW / 1 kW = 54.4%	0.544 kW / 1.30 kW = 41.9%
Annual Energy	1628 kWh / 1 kW = 1628 kWh/kW (18.6% capacity factor)	1628 kWh / 1.30 kW = 1252 kWh/kW (14.3% capacity factor)
First Year Capacity Value (Illustrative)	\$10/kW-mo x 12 mo/yr x 1 kW (dispatchable) x 54.4% (effective) ÷ 1628 kWh/kW = \$0.040 per kWh	\$10/kW-mo x 12 mo/yr x 1 kW (dispatchable) x 41.9% (effective) ÷ 1252 kWh/kW = \$0.040 per kWh

Differences with Seasonal Claimed Capacity

As described in the methodology section, the calculation of ELCC was based on the median fleet output over the top 100 hours in each of the three years of the Load Analysis Period. This method was selected instead of basing it on the ISO New England rules for Seasonal Claimed Capacity in order to perform the anticipated High Penetration scenario.

Specifically, the Seasonal Claimed Capacity is based on the defined intermittent reliability hours:

- Summer: Median output HE 14:00 to 18:00 (June to Sept)
- Winter: Median output HE 18:00 to 19:00 (Oct to May)

Therefore, the SCC is independent of penetration level. It is well understood that the effective capacity of solar will decline with penetration as load shifts to non-solar hours, yet this effect would not be indicated had these defined periods been the basis of the ELCC calculations.

The time series for the Base Case fleet results in the following:

- Summer median output is 18.4%
- Winter median output is 0%
- Annual weighted SCC is (18.4% x 4 months + 0% x 8 months) / 12 months = 6.1%

Thus, the SCC method would have yielded a result of 6.1% versus the 54.4% used in the study. This result would have been applied to the capacity-related economic benefits, significantly reducing their value.

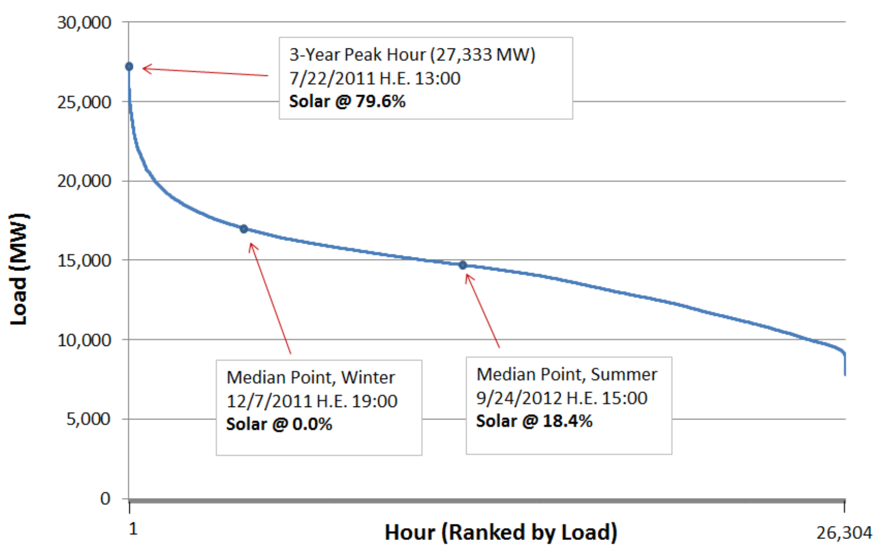
To determine why the discrepancy is so large, an additional analysis was performed, considering only the 10 highest peak load hours over the three year period. The results are shown in Table A-2. The top 10 hours are found in two days: July 22, 2011 and July 19, 2013. The average output during these 10 hours is 73.5% of AC rating. This is significantly higher than the analysis based on the top 100 hours, and it is of interest to note that the fleet output during the highest, most critical hour of the three year period was 79.6% of rated output.

Table A-2. Base Fleet production during highest 10 hours, 2011-2013.

Hour Ending	Load (MW)	Base Fleet
7/22/2011 13:00	27,333	79.6%
7/22/2011 12:00	27,283	85.0%
7/22/2011 14:00	27,262	69.3%
7/22/2011 11:00	27,181	85.0%
7/22/2011 15:00	27,082	55.0%
7/19/2013 15:00	26,919	54.8%
7/19/2013 14:00	26,913	68.9%
7/19/2013 13:00	26,910	77.2%
7/19/2013 12:00	26,886	79.3%
7/22/2011 10:00	26,880	80.5%

A further investigation indicates that the median output over the summer season intermittent reliability hours occurs on September 24, 2012, in the hour ending 15:00. The fleet output was 18.4% as indicated previously. However, as shown in Figure A-1, the ISO-NE load during that hour was only 14,733 MW, when the control area load was only about half of its maximum of 27,333 MW. Median output during the winter hours occurs at 12/7/2011 at hour ending 19:00, when load was 16,974 MW. These two points define the effective capacity using the SCC method, despite the fact that they do not represent peak load hours.

Figure A-1. Selected Base Case fleet output on ISO-NE load duration curve.



Another way to view these results is that the “capacity value” could have been broken into two separate components: a “market value” showing the value of solar that would result from participation in the forward capacity market, and a "ratepayer avoided cost" value representing the remaining reduction in installed capacity requirement (ICR) that results from the reduction in peak load in New England.

Displaced Pollutants (insert below paragraph 3 on Page 83)

The SO2 and NOx emissions rates calculated by AVERT are larger than marginal emission rates reported by ISO-NE in its 2013 Electric Generator Air Emissions Report.[2] For example, using the Locational Marginal Unit (LMU) method, which is based on production from the units that set the hourly LMP, the 2013 ISO-NE marginal rates for emitting units for SO2 and NOx are 0.69 lb per MWh and 0.42 lb per MWh, respectively. This compares to the AVERT results of 1.059 and 0.824, respectively.

The discrepancy has not been investigated, except to note that the Northeast data file used as an input to AVERT includes New York, which is not part of the ISO-NE control area. A different fuel mix in New York (e.g., higher coal usage) may skew the result. The discrepancy may also be due to the fact that the hourly weightings in the AVERT analysis are solar-weighted, while the ISO-NE are not, and even include non-solar hours.

An additional comparison may be made using the Fuel Type Assumed (FTA) method based on units fueled with oil and natural gas (i.e., without coal). The ISO-NE reports 2013 FTA emissions rates for SO2 and NOx of just 0.11 and 0.16 lb per MWh, respectively, significantly lower than the AVERT results. These lower rates may be more indicative of emissions going forward, rather than historical rates. If the FTA rates were used rather than the AVERT methodology for this study, the displaced emissions and the net social costs calculated below could be significantly reduced. Although ISO-NE's marginal rate is somewhat illustrative, since that rate is an annual average marginal emission rate across all hours of the year, it is not ideal because it includes hours when solar does not generate (at night).

Going forward it would preferable to use the data set utilized by ISO-NE in the 2013 Electric Generator Air Emissions Report with an hourly analysis of PV output like the methodology used in the AVERT tool. Assumptions as to long-term emission rate declines should be included in the levelized analysis.

Errata

Errata 1: Figure 2: Overview of value calculation (Page 15)

[2] The report is found at http://www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf. See Table 1-3 for LMU marginal rates and 1-2 for FTA marginal emission rates.

The first sentence under “Methodology Overview” should be replaced with the following sentence: “Figure 2 shows the calculations for the value of distributed solar in Maine, denominated in dollars per kWh.” In addition, the phrase “25 Year Levelized Value” should be deleted from Figure 2. The figure is meant to represent all of the permutations of the Methodology not simple the Long Term Value calculation.

Errata 2: Avoided Generation Capacity Cost (insert at paragraph 2 on Page 79)

The sentence beginning “For years beyond 2018…” should be replaced with the following sentence: “For years beyond 2018, the pricing forecast was used as described in the methodology. “