**STATE OF MAINE**
**PUBLIC UTILITIES COMMISSION**

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| **MAINE PUBLIC UTILITIES COMMISSION**<br><br>**RE: Notice of Inquiry into the Determination of the Value of Distributed Solar Energy Generation in the State of Maine.**<br><br>**Docket No. 2014-00171** | **COMMENTS OF THE OFFICE OF THE PUBLIC ADVOCATE ON DRAFT VALUATION METHODOLOGY**<br><br>**November 14, 2014** |

The Office of Public Advocate (OPA) offers the following comments on the detailed draft value of solar methodology issued on October 30, 2014 in this docket.[1] The Comments below generally follow the order in which these issues are addressed in the draft methodology.

## I. General Comments

One of the clear takeaways from the November 30th workshop is that the methodology involves substantial uncertainty, both in the input variables and assumptions, and how it may affect future action by state policymakers regarding solar PV. To maximize the value of the methodology, we propose the following general recommendations.

First, we encourage the Commission to adopt a valuation model that readily allows stakeholders to investigate and incorporate changes to key input variables and assumptions. Where applicable, we encourage the Commission to take note of variations that may occur from year to year and strive to update these inputs on a frequent basis. We also recommend

[1] These comments were prepared with the assistance of Synapse Energy Economics and Next-Phase Energy.

that the model include an option for computing valuation based upon the alternative DG paradigm of behind-the-meter as described below.

Second, if the valuation model excludes benefits and costs that could not be quantified for the purposes of this study but may have values in the future, it should include placeholders in the valuation model for these inputs. This may also be appropriate when a coordinated approach is taken for a specific project (such as the Boothbay pilot project), where more location-specific information may be substituted for general assumptions and values.

Finally, we suggest that the methodology identify the key inputs within each valuation category that have significant impact on the final result (*e.g* fuel escalation rate, discount rate, projected $CO_2$ costs) and provide sensitivities for each of these categories. These additional sensitivity analyses would account for uncertainties in these key variables. We also suggest that the methodology provide a sensitivity analysis for the valuation at 20 and 30 year timeframes, to correspond to available commodity price forecasts and common contract terms.[2]

**Behind-the Meter versus Separate Metering**

The draft methodology takes the perspective that all energy produced from distributed solar is ultimately "delivered to the grid through its own meter."[3] While the OPA does not necessarily disagree with this approach, certain inputs and outputs might be valued differently were these same resources assumed to be behind-the-meter. Key outputs of the valuation that would change under this scenario could include renewable energy credit impacts, avoided fuel price uncertainty, avoided distribution capacity costs, and the opportunity to calculate non-levelized fuel avoidance. For instance, for a behind-the-meter solar PV system, the solar PV adopter would realize the majority of the benefits from fuel

[2] The US Energy Information Administration's *Annual Energy Outlook* forecast window is 25-30 years, for example. http://www.eia.gov/forecasts/aeo/ Many third party residential rooftop PV contracts are 20 years in nature, and forecasts for commodity prices are more likely to be available for 30 years than 35.

[3] 10/30/2014. Tr. at 14, lines 5-10.

price certainty, by shielding them from future increases. Therefore, there is no need to layer on a benefit already being internalized by the customer. In addition, with a behind-the-meter paradigm, policymakers can view energy costs in terms of the actual avoided costs realized by the customer year-to-year, instead of a forecasted figure that is then levelized. As an initial step, this optionality could be incorporated in a general manner without specific rate class granularity.

## II. Assumptions

### Fuel Price Escalation

Since future fuel prices are inherently uncertain, we recommend providing, for informational purposes, a range of fuel price escalation rates when estimating future year avoided fuel cost. The escalation rate in the Draft Methodology relies upon a natural gas price forecast for electric power from the EIA's 2014 Annual Energy Outlook (AEO).[4] In addition to a Reference Case, the AEO provides multiple gas resource scenarios that could provide a basis for developing a range of price escalation rates.

### Heat Rate

The draft methodology proposes that natural gas be assumed to be the marginal fuel for all hours that PV produces energy.[5] However, the document does not specify the heat rate of the marginal unit, an essential factor when considering both avoided energy costs and avoided emissions. Given the precision and sophistication associated with other components of the methodology and the heat rate variation amongst gas-fired generation, we suggest that the heat rate of the gas-fired unit on the margin for each hour be used for that hour's calculation.

[4] Maine Public Utilities Commission, Maine Distributed Solar Valuation Methodology (DRAFT), Oct 23, 2014. Page 22.

[5] *Id.,* page 10.

## III. Technical Analysis

### A. PV Energy Production

#### 1. Use of Historical Data in ELCC and PLR Calculations

For informational purposes, the OPA suggests including example Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) calculations utilizing multiple years of historical data. Undoubtedly the ELCC and PLR calculations will need to be updated on a periodic basis as system conditions in ISO-NE change, and as PV penetration increases. As such, we suggest providing some examples that demonstrate how a range of these values would affect the calculations. The methodology could also include a discussion of the potential effects that year-to-year differences in ELCC and PLR might have on valuation.

Precise PLR calculations are based on the single maximum hourly load level over the load analysis period. Because the hour of peak load could reasonably occur at 3pm one year and 6pm the next year, we are concerned that the PLR calculation results may be extremely sensitive to the typical randomness associated with historic weather conditions. The specific hour (and associated load) of the year's peak in a given year could occur in any one of a number of months, on any number of hours within that month. Naturally, the PV production for the associated hour of peak load will also vary substantially across the range of months and hours wherein peak load may occur in Maine. Whereas ELCC calculations are insensitive to the annual manifestation of typical weather patterns in the region, PLR may be extremely sensitive to natural historic weather variations. As a result, value of solar calculations relying on PLR are likely to vary significantly from year to year.

Embedding this randomness in a valuation methodology is problematic, and is precisely the reason why statistical valuation methods like ELCC were created. We recommend the following:

1. The PLR be calculated for a series of one year load analysis periods, for at least the past ten years;

2. To the extent that the PLR calculation does vary substantially from year to year, a revised PLR calculation with less year-to-year variation should be proposed. This modified PLR would then yield a more stable value from one VoS study to the next. One way to modify the PLR is to simply average the values calculated in (1), thereby dramatically reducing the variation of reported PLR from one years' VoS calculation to the next.

If, in fact, the concern that the PLR varies significantly from year-to-year doesn't manifest in the calculations of (1) above, modifying the PLR methodology may not be necessary.

### 2. Load Match Factor

It is unclear why the ELCC load match factor is proposed to be used for all avoided capacity costs (including avoided transmission capacity) with the exception of avoided distribution capacity, for which the PLR load match factor is proposed.

In addition, load matching on the distribution system may not be uniform for all customer classes. For example, this valuation component could be considerably different when comparing between commercial PV installations versus residential. If the data is available, the methodology should provide load match statistics generalized for typical circuits of different customer classes (e.g. commercial, residential).

### 3. PV Rating System Convention

While we understand the need to convert from nameplate DC to delivered AC, we have two concerns regarding the proposed PV Rating System Convention. First, both the CEC module and CEC inverter ratings include the disclaimer that the "Information presented … does not demonstrate equipment quality, performance over time, reliability, or durability,"[6] suggesting that it may not be appropriate to use the ratings for this purpose. Second, the

[6] California Public Utilities Commission, "Incentive Eligible Photovoltaic Modules in Compliance with SB1 Guidelines," http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php . Accessed November 5, 2014; California Public Utilities Commission, "List of Eligible Inverters per SB1 Guidelines

http://www.gosolarcalifornia.ca.gov/equipment/inverters.php . Accessed November 5, 2014.

right hand side of the equation includes a "loss factor" valued at 85%.[7] The source or methodology associated with that 85% value is not identified, but contributes to an overall derate value of 0.727% when converting DC wattage to AC wattage. A commonly used industry tool, NREL's PV Watts tool, calculates the overall derate as 0.770%.[8] Absent further information as to why the draft methodology value of 0.727% is more accurate, the OPA recommends the use of the national standard of 0.770%.

### 4. Additional Sensitivities

#### a. Penetration Rates

The capacity value of PV is partially dependent upon the overall market penetration. Ideally an estimate of future PV penetration would be based on a modeled rate of PV adoption given trajectories in PV system pricing (including incentives), retail electric rates, and net metering policies. This type of modeling has recently been undertaken by WECC in Western states.[9] Absent this type of sophisticated modeling effort, the OPA recommends a sensitivity analysis for penetration rates of PV ranging from 2% to 3% of retail sales.[10]

#### b. Orientation

The capacity value of a fixed panel PV system depends significantly upon its orientation toward the sun. The valuation model should provide a sensitivity analysis of three different orientations: 1) the assumed fleet average orientation; 2) an orientation that maximizes energy production; and 3) an orientation that maximizes capacity value. We recommend that the difference between these configurations be depicted using a basic "de-rate chart."

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[7] Maine Public Utilities Commission, Maine Distributed Solar Valuation Methodology (DRAFT), Oct 30, 2014. Slide 26.

[8] NREL, How to Change Parameters in Legacy Calculators, http://www.nrel.gov/rredc/pvwatts/changing_parameters.html#dc2ac . Accessed November 7, 2014.

[9] E3. *Market-Driven Distributed Generation in the 2024 Common Case.* December 20, 2013.

[10] A penetration rate of 2-3% of retail sales over ten years is in line with what other states have achieved, or exceeded, in recent years (including CO, AZ, CA,NJ, and MA).

The methodology proposes to use rooftop properties "from an analysis of systems from the Northeast."[11] For reasons related to the size and age of the housing stock, as well as different meteorological conditions, the OPA is concerned that the rooftop properties typical in Maine may not be in perfect alignment with those of other Northeast states. To the extent that Maine-specific data regarding the orientation of rooftop PV in Maine becomes available, the OPA encourages the use of those more precise data.

As discussed in the Workshop, the OPA also recommends that any zip code-based PV modeling be weighed by the zip code's population, number of households, or similar quantity.

### 5. Collection of Installation Data

The draft methodology, by necessity, relies on various assumptions regarding the characteristics of Maine's solar PV fleet, in the absence of Maine-specific data. To address this lack of data and better inform future policy, solar installers and/or utilities should be required to provide data for every project installation and interconnection request. These data would include, but not be limited to, system size, location and type; the make, model, and quantity of the solar panels and inverters; and a precise description of the panel orientation, both array tilt and array azimuth. This information will be particularly useful for any future updates to the methodology. In Massachusetts, the Department of Public Utilities requires all net metered facilities above a certain size to file an "Application for Cap Allocation" which includes location, size, and other information. There is an exemption for small systems (below 10kW for single-phase connections; below 25kW for three-phase connections).[12] Arizona and California have similar requirements.

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[11] Maine Public Utilities Commission, Maine Distributed Solar Valuation Methodology (DRAFT), Oct 23, 2014. Page 16.

[12] Massachusetts Department of Public Utilities, *Factsheet: Rules on Net Metering (as of July 2013)*, http://www.mass.gov/eea/docs/dpu/electric/net-metering/2013-7-2-net-metering-fact-sheet.pdf . Accessed November 6, 2014.

# IV. Economic Analysis

## A. Avoided Generation Capacity Cost

### 1. Use of Historical FCM Prices vs. net CONE

The draft methodology proposes to use Forward Capacity Market (FCM) auction results to determine the value of avoided generation capacity. Historical and near-term FCM auction prices are unlikely to represent longer term trends in capacity prices, because they will often reflect both unusually high and unusually low prices. Historical data will be skewed by the over-supply conditions prevalent in the first seven auctions (FCA1 through FCA-7). Most recently, FCA-8 clearing prices were unusually high due to a combination of inadequate supply and insufficient competition. Clearing prices for FCA-9 and FCA-10 are likely to be anomalous due to substantial changes in the FCM construct related to a demand curve and new performance payments and penalties. In PJM, where a demand curve has been used for a dozen auctions, clearing prices vary by over 100% year to year.

The value of net-cost of new entry (net-CONE) is a better proxy for the avoided cost of generation capacity than actual clearing prices. The net-CONE value, developed by ISO New England prior to each auction is intended to quantify the incremental capacity cost for a new gas combustion turbine (peaking unit). The net-CONE value is established through a set methodology and escalated up each year to reflect increased construction costs, based on the Handy-Whitman index for new power plant costs. Over time, the individual annual clearing prices are assumed to average out to net-CONE.

### 2. Use of ICR vs. Net ICR:

To the extent that PV solar would avoid the purchase of capacity, the value of that reduction should be applied as an incremental value to the net installed capacity requirement (ICR) value developed by the ISO for a specific auction year, rather than the ICR.

ISO New England develops an ICR for each annual auction, as well as subsequent reconfiguration auctions, for each delivery year (June 1 through May 31). The ICR value represents the total quantity of capacity that is needed to meet anticipated peak load levels of energy and reserves for the delivery year (occurring on summer peak days). The ICR will vary for each delivery year (year to year) due to changes in forecasted loads and other variables. The methodology that the ISO uses to calculate the ICR for an individual year is generally consistent year to year, but there are occasions when changes, usually with small impacts, are made to the methodology.

Once an ICR value for a specific delivery year is developed, the ISO reduces that value to reflect the capacity value of the Hydro-Quebec (HQ) transmission line that was built by a consortium of New England transmission owners. The reduction in ICR is justified because the New England customers, as of the owners of the HQ transmission line, paid for the line. The capacity value of the line, therefore, is used to reduce the overall quantity of capacity to be purchased; if the overall capacity purchased was not reduced, then customers would double pay for capacity (once as part of the line cost and once as part of the auction cost). The reduction is expressed as the Hydro-Quebec Interconnection Capacity Credits (HQICCs) and will vary a bit year by year. Recent HQICCs have been calculated as 1042 MW for the 2015-2016 delivery year; 1055 MW for the 2016-2017 delivery year; and 1068 MW for the 2017-2018 delivery year.[13]

After the reduction of ICR to reflect the HQICC value, the new value is designated as the net-ICR for that delivery year. In the auction, the net-ICR value is used as a parameter for the Demand Curve that will be used for that auction. Since net-ICR is used to actually determine the capacity requirement in the forward capacity auctions, it is appropriate to use this value and not ICR in the methodology.

### 3. Capacity Factor Confidence Adjustment

The draft methodology requests comments on a capacity factor confidence adjustment recently published by Charles Frank. The OPA does not recommend including this adjustment in the final valuation methodology at this time. The concept is an unconventional

[13] ISO-NE, PSPC meeting #308, agenda item 2.2, slide 8, September 25, 2014. http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2013/sep262013/icr_values_2014ara3_2015ara2_2016ara1_pspc.pdf

adjustment to the capacity factor that is not necessary when state specific production and load data is known.

### B. Avoided Natural Gas Pipeline Cost

The OPA agrees that, to the extent that solar installations in Maine could help to alleviate natural gas delivery constraints that would otherwise require an investment in pipeline infrastructure, the value of PV solar include a share of the avoided cost of a new pipeline in the region. However, the ability of Maine's solar generation to reduce winter peak loads requires careful consideration. The coincidence between electric and gas peak usage on cold days in winter occurs around 6 pm, when solar panels are no longer producing electricity. Solar PV's contribution to reducing the state's peak gas usage would occur at a time several hours earlier than the electric peak. The methodology should reflect the likely marginal generation units in the mid to late afternoon on cold winter days, together with the expected impact of load reduction in these "shoulder" hours on gas constraints and gas prices.

In addition, to the extent the methodology reflects price, emissions or other assumptions that reflect existing gas pipeline capacity constraints, these assumptions should be changed to reflect the likely contribution of any additional pipeline capacity.

Finally, the methodology should use more precision than a winter-average heat rate. The variation in heat rate as a function of system electric load (and perhaps the inability for some gas-fired generators to obtain sufficient gas resources) should be included.

### C. Avoided Transmission Capacity Cost

#### 1. Option 2

The proposed valuation puts forth two suggestions for valuing the avoided cost of transmission. Option 2 states that, because Maine is an export-constrained region, "additional load in Maine is not necessarily going to cause a need for additional PTF RNS transmission facilities, and avoidance of that load by solar PV installations will not necessarily create the benefit of avoiding or deferring investments."[14] While the OPA appreciates the scrutiny of the relationship between load growth and PTF construction reflected in Option 2, its premise appears to no longer be accurate. A recent filing by ISO New England states that Maine will not be an export constrained zone for purposes of determining ISO New England's installed capacity requirement for the February 2015 Forward Capacity Auction (2018/19 Capacity Commitment Period).[15] Our comments therefore focus on possible revisions to Option 1.

### 2. Option 1

Option 1 calculates avoided transmission capacity cost using the historical ISO-NE transmission tariff as a proxy for the cost of future transmission that is avoidable or deferrable through the use of distributed solar PV.[16] The methodology includes both the charges covering the cost of Pool Transmission Facilities providing Regional Network Service (RNS) and the cost of local transmission facilities that provide Local Network Service (LNS). CMP and Emera Maine/Bangor Hydro Division recover their transmission revenue requirements through a combination of these LNS and RNS rates. For Emera Maine/Maine Public Service Division, the amount used is the historical cost under Section 6 of the NMISA tariff.

For purposes of the valuation we agree that any avoided costs for transmission attributable to solar PV will be realized through reductions in the RNS and LNS rates. However, as described in greater detail below, these rates are calculated based upon different factors and assumptions and combining them as proposed in Option 1 does not account for

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[14] Maine Public Utilities Commission, Maine Distributed Solar Valuation Methodology (DRAFT), Oct 23, 2014 at 28-29.

[15] See November 4, *2014 ISO New England Inc. Docket No. ER15- 325-000, Filing of Installed Capacity Requirements, Hydro Quebec Interconnection Capability Credits and Related Values for the 2018/2019 Capacity Commitment Period.*

[16] Option 1 calculates the value of avoided transmission by using the five year average cost of both RNS and LNS costs to arrive at an annual cost of transmission in dollars per kW-year. For each future year the cost is escalated by the general escalation rate. The avoided transmission cost for each year is calculated by multiplying the cost of transmission for that year by the ELCC for that year. The NPV is calculated and the result is levelized over the study period.

these differences. They should be considered, and accounted for, in a manner that reflects these differences.

**LNS Rate**

We generally agree with the premise of the draft methodology, that reductions in load (through the contribution of distributed solar PV) can reduce transmission capacity costs, either by delaying the in-service date for planned transmission upgrades or obviating the need for such upgrades altogether. This is consistent with the NTA analysis required by statute under 35-A M.R.S. § 3132-A. The Boothbay Pilot provides a concrete example of how such reductions might be achieved through a mix of load reduction measures, including solar PV.

However, actually calculating a value for the reduction to the LNS rate is complex because the needs identified in local system planning are particularly site and time specific, and the resources deployed and their corresponding costs are extremely variable. Some system upgrades may be deferred by load reduction or site specific generation that address the corresponding reliability needs at a given site, but some may not, further complicating any attempt at calculating this benefit.

It may be possible to develop this value based on the data from the non-transmission alternative studies completed to date.[17] These studies are representative of the impacts of installing generation which provides specific locational and time sensitive benefits, and the potential for savings that could be attributed to solar PV (if such savings exists). This value could be refined as more such studies are completed.

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[17] See *Central Maine Power Company, Request for Approval of Non-Transmission Alternative (NTA) Pilot Projects for the Mid-Coast and Portland Areas*, Docket No. 2011-138, Order Approving Stipulation, (April 30, 2012) and *Emera Maine, Request for Approval of Certificate of Finding of Public Convenience & Necessity for Construction of Transmission Line in Northern Maine Pertaining to Emera Maine,* Docket No. 2014-00048.

**RNS Rate**

We have similar concerns regarding developing the value of avoided transmission values for the RNS. However the impact of a load reduction attributable to PV on Maine's share of RNS costs could be calculated.

RNS costs are allocated by ISO New England to each of the region's utilities to pay for all of the upgrades to the region's bulk power system. Each utility in the region is allocated its share of the costs of the region based upon its monthly peak load.[18] Therefore, for purposes of calculating a value for avoided cost in the RNS rate, we suggest that a value be determined based upon the reduction in peak load brought about by PV installation. Because RNS costs are allocated based upon each utility's share of monthly peak load within Maine, a reduction in monthly peak load can reduce Maine's allocation of RNS charged to each state by ISO NE.

This calculation can be made by comparing Maine's RNS obligation with and without the contribution of the solar PV fleet. The first step would be to obtain an annual RNS figure escalated by the general escalation rate, and project those costs going forward as contemplated under Option 1. This amount would then be reduced to reflect the applicable reduction value. The reduction value would be obtained by first calculating Maine's projected peak load as a percentage of the projected regional peak load including the expected solar fleet installation and a calculation of that amount multiplied by the ELCC for that year. The difference in these values would be the reduction in the allocation of the RNS rate charge to Maine. This NPV would then be calculated and the result levelized over the study period.

[18] LNS costs are driven by the utilities' local needs and are excluded from regional treatment and are recovered from the individual utility's load.

### D. Avoided Environmental Cost

#### 1. Avoided RPS Compliance

To the extent that the electricity generated by rooftop PV in Maine is able to reduce the RPS obligation of the associated utility that avoided cost to utilities should be included in the methodology's base case. However, the formula proposed at the Workshop may not handle levelized cost correctly.[19]

Because both the REC price and the utility RPS obligation vary across years, the avoided cost for each future year should be calculated separately. Only then should the stream of benefits be levelized.

#### 2. Avoided Carbon Emissions

The OPA agrees that the value of solar includes avoided environmental costs including the avoided cost of carbon allowances, and that a RGGI allowance price forecast represents this future cost. However, the introduction of the U.S. Environmental Protection Agency's Clean Power Plan (Section 111(d) of the Clean Air Act as applied to the electric generation industry) may reasonably be expected to change future RGGI allowance prices from their current forecasts. RGGI is a likely mechanism for Maine's compliance with the Clean Power Plan, and the use of RGGI for compliance may require a tightening of the emission cap that would result in higher allowance prices. As new RGGI forecasts that take Clean Power Plan compliance into account are developed, the Commission should incorporate this information into any updated value of solar.

In addition, the Maine statute requires a consideration of the societal value of reduced environmental impacts of the energy. The federal social cost of carbon is an estimate of this social cost that is used in evaluating the expected impact of federal regulations and is used in estimation of the value of solar in Minnesota.[20] Another value used to represent the social

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[19] Maine Public Utilities Commission, Maine Distributed Solar Valuation Methodology (DRAFT), Oct 30, 2014. Slide 51.

[20] U.S. EPA(2013b), Technical Support Documents: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 – Interagency Working Group on Social Cost of Carbon, May 2013.

cost of carbon emissions in New England is the $100 per ton "non-embedded" cost of carbon developed in the 2013 Avoided Energy Supply Costs report in which Efficiency Maine was a stakeholder.[21]

Rather than using an average emissions rate for estimating avoided $CO_2$ and criteria pollutants, the methodology should reflect New England's actual generation fleet. The EPA's *Avoided Emissions and Generation* Tool (AVERT) allows users to estimate the reduced emissions in a specific region, for a specific generation profile. [22] We suggest that the methodology use AVERT to estimate the emissions reductions associated with additional rooftop PV in Maine.

Respectfully submitted,

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[21] Hornby et al (July 2013) Avoided Energy Supply Costs in New England: 2013 Report. Prepared for the Avoided-Energy –Supply-Component (AESC) Study Group.

[22] US EPA. "Avoided Emissions and generation Tool (AVERT)" http://epa.gov/avert/ . Accessed November 7, 2014.