# Docket No. 2016-00222 – Maine Public Utilities Commission Proposed Rule on Customer Net Energy Billing

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## Background and Qualifications

I am the Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including but not necessarily limited to pricing, market rules, and regulation, as well as environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so this paper represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated. My biography is attached as Appendix A.

## Introduction

The State of Maine Public Utilities Commission has issued a Notice of Rulemaking relative to proposed amendments to Maine's Net Energy Billing Rule. The proposed amendments increase the number of systems potentially eligible for Net Energy Billing (NEB), but also provide for the very gradual reduction of the subsidy provided by NEB, bringing NEB closer to reflecting the true costs of service provision to NEB customers by gradually eliminating credits associated with the transmission and distribution (T&D) portions of customer bills, focusing the net energy credit on the energy value actually produced by NEB customers.

The Commission deserves commendation for joining with many other Commissions across the U.S. in taking up reform of a pricing regime that is not only outdated, but imposes unfair burdens on many consumers, particularly those at the low end of the income spectrum, distorts efficient price signals, supports inflated prices for rooftop solar, and is harmful to the long term sustainability of solar energy. Although the proposed reform is more incremental than ideal, it still represents a significant step forward in redressing the adverse effects of Retail Net

Metering (or, following the Maine language, Net Energy Billing)[1]. As I explain below, the proposed revised rate would bring Maine's tariff for distributed generation much closer to fulfilling the classic pricing principle of "cost causer pays" and would make significant strides towards reducing the cross-subsidy from non-solar to solar customers that necessarily results from the current NEB tariff. In what follows I discuss the following topics:

- Traditional utility ratemaking principles and the origins of retail net metering for rooftop solar;
- How retail net metering suffers from problems associated with cross-subsidies, inefficiency, and unfairness to competing resources;
- The problems with "value of solar" claims, and why value of solar analysis generally, and the Maine "Distributed Solar Valuation Study" in particular, do not provide any justification for continuing the burdensome and unfair cross subsidies intrinsic to retail net metering;
- How current efforts nationwide to reform retail net metering, and Maine's proposed Net Energy Billing reform, can help to address current inequities and inefficiencies.

[1] In the discussion that follows, I will use the term "retail net metering" in writing generally about rates that allow rooftop solar customers to receive credit for all per kWh retail charges on their bill (including both energy charges and charges such as transmission and distribution). I will use "Net Energy Billing" when referring specifically to Maine, keeping in mind that the proposed revised Net Energy Billing tariff would no longer qualify as Retail Net Metering, since it would gradually transition to giving credit to customers only for the energy value of their distributed generation production.

## Cost-based Utility ratemaking principles

In his seminal 1961 book on utility ratemaking, the economist James Bonbright,[2] whose writings on the subject are widely regarded as authoritative, argued for the importance of a "cost of service" standard in setting rates.[3] Writes Bonbright:

> *[O]ne standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—the standard of cost of service, often qualified by the stipulation that the relevant cost is* necessary *cost or cost reasonably or prudently incurred.*[4]

In implementing "cost of service" ratemaking, ratemaking bodies typically follow a two-step process: 1) determining the utility's total costs—including a fair rate of return on capital investments, and 2) setting rates by allocating a share of those costs to different classes of customers and then selecting rate structures to recover sufficient revenue from each class of customer.

The three most important types of costs for electric utilities are 1) variable energy costs: the total number of kilowatt hours (kWh) used; 2) demand costs: the total capacity (kilowatts, or KW) the utility must build and maintain in order to meet peak demand—generation, transmission, and distribution adequate to supply all the power needed at the moment of the very highest demand (keeping in mind that the obligation to serve is unlimited); and 3) fixed costs: costs that must be incurred regardless of kWh or KW, and which do not vary with demand.

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[2] Bonbright, who died in 1993, was a long time member of the Business School Faculty at Columbia University and served for some time as Chairman of the New York Power Authority. He is widely regarded as one of the nation's most distinguished writers and commentators on regulations and a most important thought leader on the subject.

[3] This view is generally held by others as well. *See, e.g.*, https://mitei.mit.edu/system/files/Electric_Grid_8_Utility_Regulation.pdf.

[4] Bonbright, op cit, p. 67.

Fixed costs are typically thought of as costs that are unaffected by individual customers' changes in energy consumption. Examples include the costs of customer service and billing.

For residential customers, those three separate kinds of costs have traditionally been bundled together into two-part rates, consisting of a monthly fixed charge[5] and an energy charge (based on total kilowatt hours used). Commercial and industrial (C&I) utility customers, in contrast, have long been subject to three part rates, corresponding with the three types of utility costs. Thus, rates for a commercial or industrial customer typically include a fixed charge and two variable charges—an energy charge, based on total kilowatt hours used, and a demand charge, based on how much capacity the utility needs to maintain to meet the customer's peak demand (measured in kilowatts).[6] Accordingly, C&I customers are not only positioned to reduce both system costs and their own costs by getting a discrete demand price signal, but by providing that signal, new market entrants with the capability of managing demand costs could enter the market and provide such services.

## Residential utility rates and Retail Net Metering

The initial connection of rooftop solar systems to the grid posed an issue for utilities and regulators. If customers supply power to the grid, how should they be compensated? When rooftop solar systems were first connected to the grid in the 1980s and 1990s, most households had a single meter capable only of running forwards, backwards, and standing still, and utilities and regulators had limited options. Given the very limited amount of rooftop solar market penetration anticipated at the time, and the high cost of rooftop solar, large scale investment in

[5] Traditionally, the fixed charge on the bill of a residential customer represented only a tiny fraction of the totality of the fixed costs. The bulk of the fixed costs and all of the demand costs were recovered through volumetric based rates (i.e. on a per kwh basis).

[6] It is interesting that when talking about the forces that likely would prompt a utility to adopt a demand charge for industrial customers, Bonbright calls out distorting effects caused by industrial customers who provide some of their own generation. (Bonbright, pp. 309-311)

new technology or overall tariff reform was not a priority.[7] Many utilities adopted retail net metering (or, as it is referred to in Maine, "Net Energy Billing"). Under a retail net metering tariff, a single meter for these customers runs forward when solar PV DG customers are purchasing energy from the grid. When those customers produce energy and consume it on premises, the meter simply stops, and when the customer produces more energy than is consumed on premises, the meter runs backwards as the excess energy is exported to the grid. Thus, the solar PV DG customer pays full retail price for all energy taken off the grid, pays nothing for energy (or such fixed costs as distribution, transmission, generating capacity, or demand costs) when energy is being produced on premises, and is credited the fully delivered retail price (for all energy plus all fixed costs, despite the fact that solar customers incur no such fixed or demand costs) exported into the system. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due or the utility credits the customer for excess energy delivered.

Under Retail Net Metering, therefore, customers produce generation, but are compensated at rates that reflect the full cost of generation and of transmission and distribution. This generous arrangement seemed to make sense originally, at a time when market penetration of rooftop solar was negligible, when rooftop solar systems were far more expensive than they are today, when metering technology was relatively primitive, when wholesale energy and capacity markets did not generate the very sophisticated and unbundled signals they do today, and when the amount of fixed and demand costs that would be bypassed by widespread deployment of rooftop solar were unknown. To the extent that any policy considerations contributed to its adoption, it was that RNM would provide a short-term stimulus to the

[7] Indeed, some utilities, trying to avoid the issue altogether, simply refused to interconnect rooftop solar units to the grid at all.

development of distributed solar technology, not that it was sustainable as a long term pricing methodology.[8]

Today, the technological limitations that were a primary driver of current residential retail rate design have largely disappeared. "Smart meters," as well as internet-based technology, are capable of measuring not only how much electricity consumers use in a month, but when and even how they use it.

At the same time that smart meters have become widely deployed, the costs of solar systems have declined dramatically, with the costs of the solar panels themselves showing particularly dramatic declines. As I argue below, the full benefits of the declining costs are not being passed on fully to customers (solar and non-solar alike)—however, even so, the price of a rooftop solar system is significantly lower than it was when regulators initially settled on generous retail net metering schemes as a way of providing a short term boost to enable rooftop solar to attain full commercial viability. Now that the costs of rooftop solar have declined that rationale for tolerating the flaws of net metering no longer applies. Stated succinctly, the underpinnings of net metering: dumb meters, poor energy price signals in the wholesale market, miniscule market penetration by distributed resources, and out of market costs, are all historical relics that decidedly not characteristic of 21st century electricity markets

## What's wrong with retail net metering?

Through RNM, solar customers have until recently had the same residential tariffs applicable to them as were applied to non-solar residential customers (adapted, of course, to give credit for solar production). However, by the standards of cost-based ratemaking, traditional residential tariffs (i.e., volumetric rates based on kWh, and encompassing charges related to

[8] While the full effects of retail net metering were unknown at the time of their adoptions, many jurisdictions, just to be cautious about the unknown, actually hedged against severe distortions by capping the amount of rooftop solar that would be on an RNM tariff.

generation, transmission, and distribution), when applied to customers with solar generation, do a markedly worse job of reflecting actual customer costs than they do when applied to other customers.

This breakdown of the relationship between costs and rates has three main consequences:

- Cross subsidies. Distributed generation customers are undercharged for their usage, and end up subsidized by customers without distributed generation;
- Inefficiency. Distributed generation customers do not receive price signals that would encourage them to maximize the value of the solar energy they produce; at the same time, the distributed solar industry, shielded from market pressures, fails to maximize efficiencies and savings to customers.
- Unfairness to competing technologies.

### Cross subsidies

As discussed above, traditional rate plans, including Maine's existing Net Energy Billing plan, use volumetric rates to recover both fixed and demand (transmission and distribution) costs. Customers who generate their own electricity use less electricity, but the fixed costs of service still exist, and the demand costs are largely unabated. The result of linking RNM with a purely volumetric rate structure that makes no distinction between generation costs and distribution and transmission costs is a subsidy to rooftop solar customers. The costs of that subsidy are borne by the rest of the utility's rate base.

This subsidy does not exist for most residential customer classes. This is because most customers' peak demand (measured in KW) and overall kWh usage typically vary together. (This is true for customers who invest in energy efficiency, as well as other customers). For solar DG customers, however, the traditional relationship between peak demand (KW) and overall kWh

usage breaks down. Solar customers can reduce their kWh usage by a lot (especially if they get credit for excess kWh produced) while only slightly reducing their peak demand (or even, in some cases, increasing it).

The fact that customers with rooftop solar may produce energy when the sun is shining does nothing to reduce the utility's fixed per-customer costs and, at least in the short run, has not been reliably shown to reduce the capacity costs the utility must incur in order to make sure that it is prepared to meet all of the electric requirements of the solar customers. Thus, when solar DG customers are producing energy and not buying it, the utility cannot fully offset the revenue loss by simply buying or producing less energy. Thus the utility has a revenue shortfall, which must be made up by collecting more money from other customers.

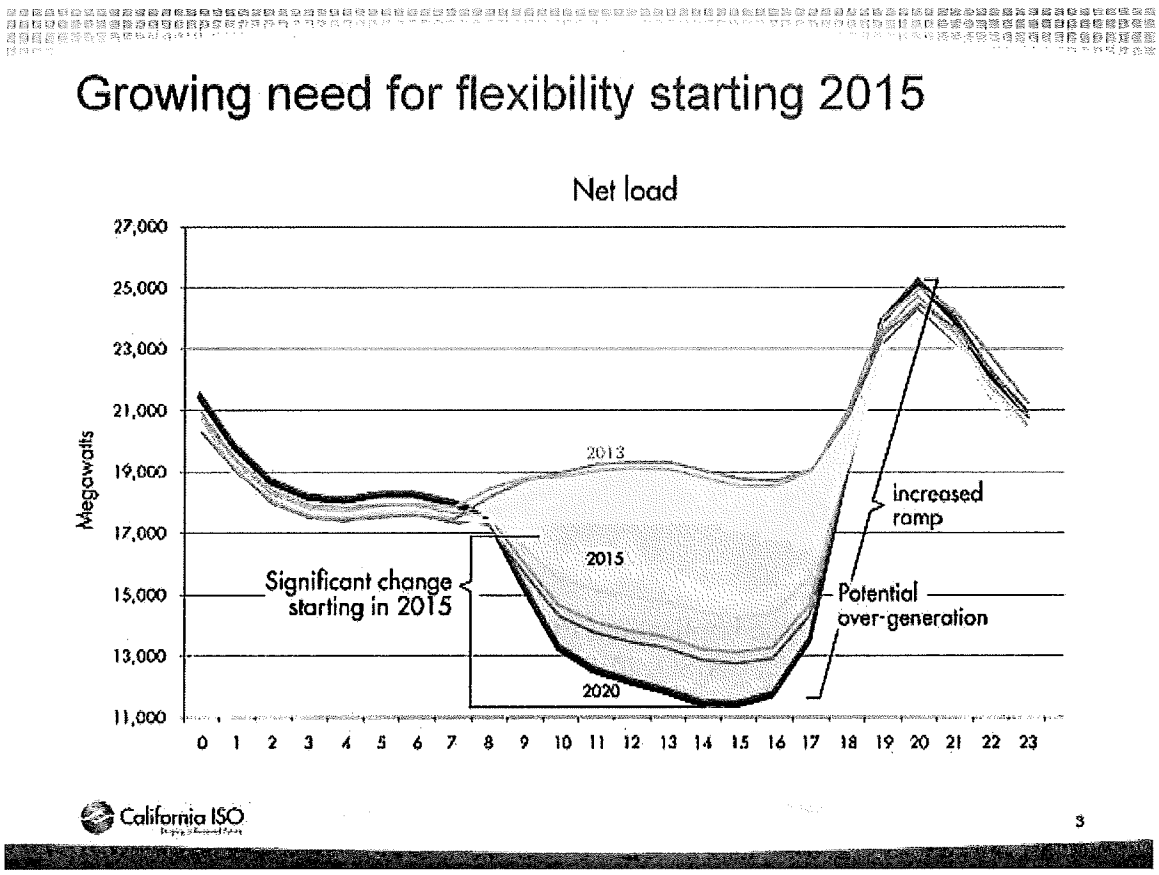
Rooftop solar generation does not significantly offset a utility's capacity costs for two reasons. The first is that solar production is, with some minor exceptions, not coincident with system-wide peak demand.[9] The second reason is that even if solar production generally matched the time when demand was projected to be at its peak, solar production is intermittent, unpredictably so,[10] and thus not dispatchable by the grid operator (i.e., the grid operator cannot call upon it to produce to meet peak demand, or stop producing when there is cheaper, excess capacity on the system). For a utility that is required to meet all of the electricity demand of customers in their service territory, the existence of rooftop solar therefore does little to avoid the

[9] As can be seen below, in the charts from ISONE on "Seasonal variation in load profiles," there is zero overlap between solar production in spring and winter. Summer shows a limited amount of overlap, which diminishes with greater levels of solar penetration. In New England, wholesale electricity prices are higher during the winter, so this means solar is not offsetting peak energy costs during the most expensive time of year. (See ISONE, 2016 Regional Electricity Outlook, p. 23, at https://www.iso-ne.com/static-assets/documents/2016/03/2016_reo.pdf)

[10] It is important to note that rooftop solar is doubly intermittent. It not only depends on the presence of the sun, but also on how much of the energy being produced is being consumed on premises by the solar host. That is in contrast with utility scale solar, which is a single contingency intermittent resource.

need to incur the costs of meeting all demand and, in effect, providing free back up "battery" service to solar customers.

In fact, rooftop solar production generally creates a new and challenging daily variation in the net load that must be served by the utility, a pattern that has come to be known as the "duck curve." Briefly stated, the "duck curve" refers to the phenomenon by which rooftop solar generates large amounts of power in the middle of the day, but as solar production declines throughout the afternoon, the corresponding increase in demand must be met by other generation supplied or procured by the utility.[11] The "duck curve" phenomenon is illustrated in the chart below, in which the belly of the duck shows the increasingly steep drop off and ramp up of net load that is occurring and expected to increase with greater adoption of solar generation:




[11] **http://instituteforenergyresearch.org/solar-energys-duck-curve/;** https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

As is dramatically illustrated in the graph, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in the Golden State has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the drop off in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g. directing solar panels to the west, or linking solar production with storage) is simply something that can no longer be tolerated.[12] While Maine's situation is certainly not identical to California's, it would be pure folly for the state not to learn the lesson of what has gone wrong in other jurisdictions, and adopt a remedy before finding itself in a similar dilemma.

Intermittent sources of generation add additional complexity and cost to maintaining the high degree of reliability expected from the system. This is particularly true because the grid was originally designed to accommodate one-way delivery of electricity, not the two-way exchange associated with rooftop solar generation.[13] Thus, when rooftop solar penetration increases beyond minimal levels, new investments to the grid are required.[14]

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[12] For further discussion of the implications of the duck curve, see *What the duck curve tells us about managing a green grid*, CAISO, 2013 (http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.)

[13] The two way flow, particularly since the energy inputs to the distribution system are from diverse and unpredictable places, can fundamentally alter grid dynamics by impacting on such critical elements as voltage support and reactive power. Since location of solar units can be a critical element in how these grid phenomena play out, the inability to plan locations for solar dg, almost inevitably drives up utility costs in accommodating distributed solar.

[14] **https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf** at xviii.

Maintaining reliability on a distribution system, particularly where market penetration of rooftop solar has increased significantly, is far more than an engineering challenge. It requires a substantial investment in more modern control and monitoring technology, as well as a substantial rethinking of pricing and the incentives produced from the economic signal produced, in order to move the entire system in directions that will best accommodate all of the changes in the power sector, particularly those related to the increasing deployment of intermittent generating facilities.[15]

In the face of concerns about additional ramping and other system management costs required to respond to the new demand patterns created by the adoption of more solar energy, and of cross-subsidies between customer classes resulting from retail net metering rates, some advocates of retail net metering call for "value of solar" analyses, in order to claim that additional non-energy attributes of distributed solar generation add substantially to the value provided by solar DG to the utility and other customers. As a result, they argue, concerns about cross-subsidies to solar customers are misplaced. These arguments are discussed in more detail below. However, in order to believe that such cross subsidies among customers are cancelled out by the "value of solar", one would need to believe that the "value of solar" supplied is, ascertainably and quantitatively, worth an amount well in excess of the price of energy in the wholesale market at the time the energy is produced, and, in the case of the Maine Value of Solar study, more than double the delivered price of electricity. I discuss in more detail below why this is simply not credible.

[15] The complexities associated with solar dg are further compounded by two additional factors. The first is that the locating of solar units is unplanned, and from a planning perspective, random. That being the case, it is impossible to optimally locate panels to capture system benefits. As long as solar panels are sold or leased on a geographically unplanned basis, there is almost no likelihood that system costs will be systematically reduced by distributed solar. Secondly, distributed solar generation is unseen by ISO New England and is, therefore, not dispatchable. That effectively eliminates the possibility that solar DG makes any contribution to the efficiency of dispatch or of the overall energy market in New England.

The result of the re-allocation of the responsibility for costs is that net metering results in a subsidy from customers without rooftop solar systems to those with solar. These subsidies associated with retail net metering are particularly hard to defend because, in the aggregate, they benefit wealthier customers at the expense of less affluent customers. Less affluent customers lack the means to invest in solar and often do not own their residences, so they are unable to install solar, even if they could afford to do. This gap is exacerbated by the practices of rooftop solar providers like SolarCity, which offer a lease mode for customers without the cash to buy a whole system up front—but the lease product is only available to customers who meet stringent credit requirements.[16]

In addition, as Solar City's internal documents state, RNM encourages rooftop solar providers to "cherrypick" high-income, high-energy usage customers. A 2013 study by E3 Consulting clearly shows the socially regressive impact of net metering. The study found that the median income of rooftop solar customers under RNM was 168% of the median California household income.[17] A similar analysis of rooftop solar customers in California by Severin Borenstein also found installations, despite some decline in social regressivity recently, "heavily skewed towards the wealthy".[18] The Massachusetts DPU only recently made an explicit finding that net metering disadvantaged the poor and gave the state's low income customers explicit relief from having to subsidize solar dg customers in Massachusetts: "...low-income

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[16] The idea of lowering credit requirements was raised by SolarCity, but there are no immediate plans for doing so: http://www.reuters.com/article/us-solarcity-fico-idUSKCN0T82ZO20151119.

[17] *California Net Energy Metering Ratepayer Impacts Evaluation.* Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 8, 2013).

[18] Borenstein, Severin. "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives and Rebates." Energy Institute at Haas working Paper. 2015: 26. Paper available online at http://ei.haas.berkeley.edu/research/papers/WP259.pdf.

customers have experienced an increase in bills as a result of the growth of on-site generation."[19]

### Inefficiency

RNM encourages inefficient behavior, both on the part of individual customers and the rooftop solar industry as a whole. For individual customers, RNM (especially in conjunction with a flat rate that does not vary with time of day or peak energy demand) fails to provide any incentive to maximize the value (as opposed to the output) of their rooftop solar systems. RNM customers with distributed solar are motivated to produce as many kWh as possible, but not necessarily to target production or manage demand to offset peak consumption.

One example of this problem has to do with the orientation of rooftop solar panels. The monetary value of energy provided to the grid by rooftop solar panels varies depending on the time of day. Generally speaking, energy provided at the time of peak usage is the most valuable. That is because the generating fleet is dispatched on the basis that the least expensive plants are generally dispatched first. As demand increases, more and more expensive plants are dispatched until all demand is met.[20] However, RNM (in conjunction with flat, time-invariant rates, which are common in Maine) provides one signal to customers with solar DG systems—the more you produce, the more you are paid, regardless of the energy market prices at the time of production.[21] For this reason, as a *New York Times* article explains, flat RNM pricing has

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[19] See Order 9-30-16 of the DPU, case # 15-155, p. 470: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-155%2f15155_Order_93016.pdf.

[20] It is worth noting that, in general, the economic order to dispatch power plants also has a salutary environmental effect. That is because, in general, the least expensive plants are either non-emitting of pollutants (e.g. renewables), or low emitting, more efficient plants.

[21] Energy prices in the electricity market, as one might expect when supply and demand have to be instantaneously matched, vary widely over the course of every day. Thus the time at which energy is produced is a critical determinant of the price suppliers are paid. RNM ignores

contributed to solar panels generally being installed facing south, to generate the largest total quantity of solar energy over the course of the day (and the greatest savings and/or revenue for homeowners under RNM). If solar rates instead reflected the cost to the grid of the customer's period of highest demand, these panels would be adjusted to capture the most sun during peak hours—for many customers, this would mean aligning panels to face west, generating less total energy, but capturing the late afternoon power of the setting sun.[22] Thus, a customer who works outside the home and uses air conditioning in the evening during the hot summer months might well offset many (if not all) of his or her kWh of usage through robust rooftop generation—but still might impose a significant peak demand load on the grid when he or she arrives home at 6 or 7pm, when solar production is at or near zero, by turning on air conditioning and other electric appliances. In fact, the savings from solar electricity might even encourage such a user to use more peak electricity than he or she otherwise would—keeping the house a little cooler, or otherwise being more free with his or her energy use. Indeed, major solar installation company Solar City's own marketing materials, taking advantage of the lack of explicit and transparent demand cost price signals, promote this type of expensive, highly inefficient use of energy.[23] Thus, RNM incentivizes production in ways that are optimized for the dg solar industry and its customers, not to the system and non-solar customers.

Similarly, RNM discourages the adoption of batteries or other forms of storage in conjunction with rooftop solar production. This is because, under an RNM tariff, the utility operates essentially as a giant free battery available for use by DG solar customers—any excess

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that market place reality and, under RNM, fetches an above market price for solar dg output that is exported onto the grid.

[22] Matthew L. Wald. "How Grid Efficiency Went South" *New York Times*. October 7, 2014.

[23] A SolarCity advertisement encourages just this behavior: "Go ahead," it reads. "Sleep with the lights on. Solar energy is limitless." **https://mobile.twitter.com/solarcity/status/731167148882690048.** This advertisement is particularly irresponsible because solar power is not generated at night.

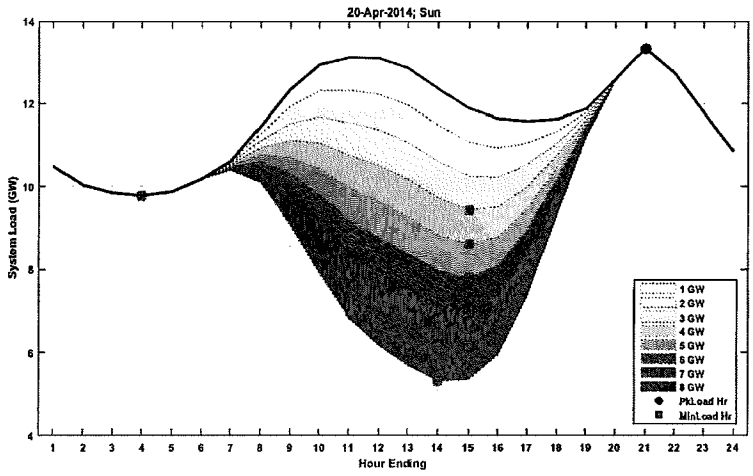
energy they produce is credited back to them at the full retail price, and they can use this credit to import an equivalent amount of energy back from the grid at any time at the full retail price. While at first blush that might seem reasonable, it is not sustainable. Solar production is largely off peak, while substantial imports are required at peak by solar customers. The following three charts show the relationship in New England during different seasons of the year, at a range of different levels of solar penetration. They are copied from the ISO New England's webpage titled "Solar Power in New England: Locations and Impact,"[24] and illustrate that facile assumptions made that solar benefits include near-term reductions in peak generation are precisely that.[25]

[24] Page can be found online at https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

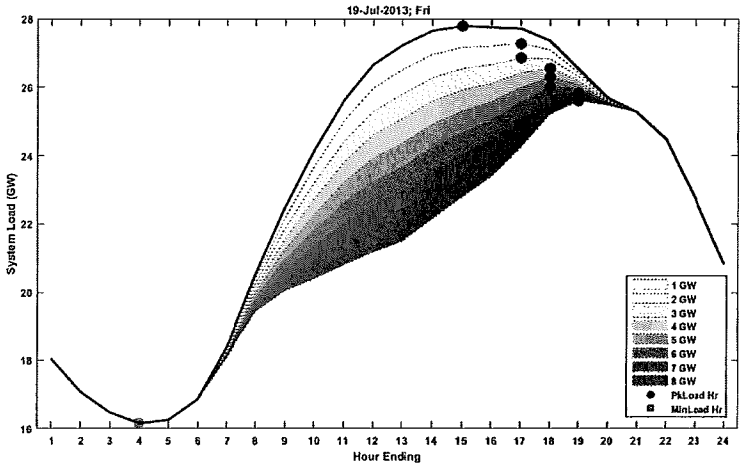
[25] Black, John. "Update on Solar PV and Other DG in New England." ISO New England (June 2013).

# Seasonal variation in load profiles, ISONE

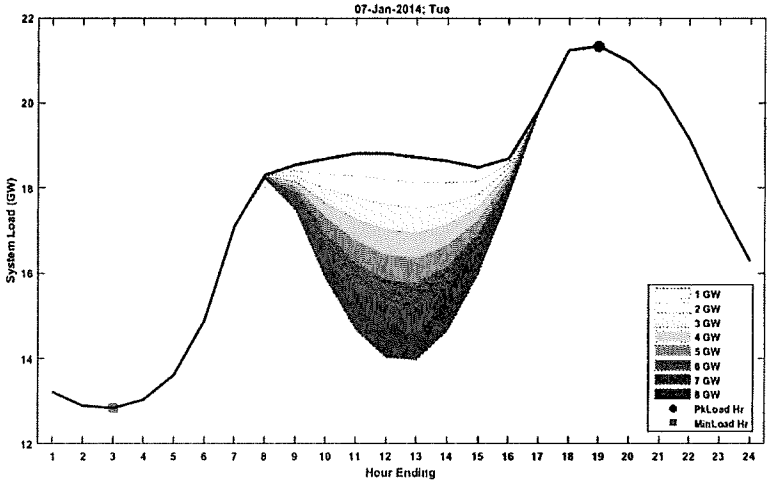
Spring




Summer




Winter



These two charts dramatically demonstrate that on the days chosen as representative of summer, winter, and spring in New England, solar PV peak and peak demand are not the same. Solar PV is completely absent during the winter peak and spring peak (however, it is interesting to note that winter solar production suggests the possibility of New England developing its own "duck curve.") During the summer, there is an overlap between solar production and peak demand, but as can be seen on the chart, and as ISO New England explains in the accompanying text, "Because greater amounts of PV will actually shift the timing of peak demand for grid electricity to later in the afternoon or evening, PV's ability to reduce peak demand will actually diminish over time." It should also be noted that on the days chosen, the sun was shining. The graph, of course, would look very different on cloudy days when solar production is virtually nil.

Technologies currently exist that could help customers with solar pv to manage their production and consumption so as to maximize the overlap between solar pv production and peak demand hours. Possible efficiency enhancers could include simply pointing pv panels to the west, rather than the south, but also using batteries to store off-peak energy, or smart thermostats to optimize energy usage patterns. However, under a flat RNM tariff, DG customers, who would seem to be a natural customer base for energy efficiency and/or capacity savings devices or storage batteries available on the market to better align their energy and capacity demand with system costs, have no incentives to invest in such products, therefore delaying the development of the integrated solar/battery home systems that may be a logical next step for distributed generation. That may be why, for example, Tesla—Solar City's own sister company, run by SolarCity's Chairman Elon Musk, which recently acquired Solar City—reportedly opposes

RNM.[26] As this conflict makes clear, RNM removes an incentive for residential customers to deploy batteries and other forms of energy storage.

A second issue of efficiency relates to the incentives that are or are not provided to the rooftop solar industry itself to maximize customer savings. It appears that the solar installation market is currently such that generous subsidies provided through programs like RNM do not get fully translated into reduced customer costs. The recent MIT study, *The Future of Solar Energy,* observes a "striking differential" between MIT's estimate of the cost of installing residential PV systems (even allowing for a profit margin) and the reported average prices for residential PV systems—actual prices for residential systems were approximately 150% of MIT's cost estimate—a difference between cost and price the MIT researchers did not observe for utility-scale installations.[27] Indeed, as documented in the MIT study, there is evidence now that the declining costs of solar panels, which have been quite dramatic in recent years, are not being passed through to consumers, enabling most of the benefits of declining panel costs to be retained by solar vendors, to the detriment of all consumers, solar and non-solar alike.

A recent study by Lawrence Berkeley National Labs found that out of four countries it compared to the U.S. (Germany, Japan, France, and Australia), the U.S. had the highest prices (per watt of capacity) for installed residential PV systems.[28] The reasons for these high U.S. prices are not fully understood—it is something more than market size, since the U.S. market is smaller than the solar pv market in some of the four other countries studied, but larger than others. A 2014 study aimed at better understanding variations in solar pv pricing, involving collaboration between researchers from Yale, Lawrence Berkeley National Laboratory, the

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[26] "Net Metering vs. Storage Creates Clash Between Some Allies." http://www.eenews.net/stories/1060025111

[27] MIT, *The Future of Solar*, p. 86.

[28] Barbose, Galen and Naim Darghouth. *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States.* Lawrence Berkeley National Laboratory (August 2016):22-23.

University of Wisconsin at Madison, and the University of Texas at Austin, found a revealing association:

> "...regions with a higher consumer value of solar, considering retail electricity prices, solar insolation levels, and incentives, tend to face higher prices. This phenomenon may be the result of a shift in consumer demand caused by the presence of rich incentives, enabling entry by higher-cost installers and allowing for higher-cost systems. Alternatively, the results may be a symptom of high information search costs or otherwise imperfect competitions, whereby installers in these markets are able to "value price" their systems, effectively retaining some portion of the incentive offered...In the short-run at least, policies that stimulate demand for PV may have the exact opposite of their intended effect, by causing prices to go up rather than down."[29]

That is, RNM, by effectively shielding rooftop solar suppliers, from both robust competition and from cost-based regulation, may be removing a key incentive for rooftop solar installation companies to pass on declining costs to customers.[30]

In fact, emphasizing this very point, in a recent 10K filing, SolarCity, the nation's largest solar dg company, clearly describes this as its business model:

> We compete mainly with the retail electricity rate charged by the utilities in the markets we serve, and our strategy is to price the energy and/or services we provide and payments under MyPower below that rate. As a result, the price our customers pay varies depending on the state where the customer is located and the local utility. The price we charge also depends on customer price sensitivity, the need to offer a compelling financial benefit and the price other solar energy companies charge in the region. Our commercial rates in a given region are also typically lower than our residential rates in that region because utilities' commercial retail rates are generally lower than their residential retail rates.[31]

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[29] Gillingham, Kenneth, Hao Deng, Ryan Wiser, Naim Darghouth, Gregory Nemet, Galen Barbose, Varun Rai, and C.G. Dong. *Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy.* (December 2014): 20-21. Available online at: http://www.seia.org/sites/default/files/LBNL_PV_Pricing_Final_Dec%202014.pdf

[30] The failure to pass on declining input costs to customers is pricing behavior often considered to be characteristic of monopoly pricing.

[31] SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, p. 38 (available at http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf)

From Solar City's perspective, of course, the issue is not whether rooftop solar can be competitive, but whether it can remain so without suppliers like Solar City having to pass on to consumers some of the cost reductions in their supply chain, something that might reduce their profit on a per transaction basis, but make solar more attractive to more customers enabling more sales. In short, Solar City's, the leading solar dg provider in the country, has a business model premised on keeping prices high in a declining cost industry, and relying on subsidies and cross-subsidies in lieu of the classic economic formulation that lower prices (in this case enabled from lower costs) stimulate demand. Stated succinctly, the business model articulated by Solar City in its 10K filing, and shared by those solar dg vendors who demand retail net metering is to chase subsidies and cross-subsidies rather than to compete in the marketplace.

### Unfairness to competing technologies

The failure to provide incentives to invest in efficiency-enhancing technologies points to another problem with retail net metering, which is that retail net metering distorts the competitive market for other resources. In seeking cost-effective means of reducing their electricity bills and environmental impact, consumers have a variety of options. Rooftop solar is one possibility, but there are a variety of competing alternatives; many of them provide greater value to the grid, and, absent rooftop solar subsidies, to the customer himself/herself, most notably various energy efficiency programs and means of flattening out their load profile.[32] The subsidies associated with RNM, however, substantially bias decisions in favor of rooftop solar over these other options, which would be more efficient, and, in the absence of subsidies, would be the most economic for the customer.

[32] Load profile is the configuration of how much energy a customer consumes (kilowatts hour, (kWh)) and precisely when it is consumed. The time when the demand hits its maximum defines the amount of capacity (kilowatt (KW)) a utility must have available to serve that customer.

Rooftop solar is the most expensive form of commonly deployed renewable generation in the U.S. today. The latest annual update of Lazard's *Levelized Cost of Energy Analysis* continues to show this, with a levelized cost for rooftop solar ranging from $184-$300 per MWh, higher than all other energy sources analyzed, including fuel cell, solar thermal, utility-scale solar, geothermal, biomass, wind, and energy efficiency.[33] The Lazard analysis goes on to compare the cost of carbon abatement per ton for different alternative energy resources. As one would expect based on its levelized cost, rooftop solar power had the highest cost per ton of carbon emissions avoided ($335 per ton, assuming gas is the comparison generation). In contrast, Lazard's calculations found that utility-scale solar PV could abate the same ton of carbon emissions at a cost of only $15 per ton. The difference here is staggering. [34]

A recent study by the Brattle Group comparing generation costs of utility-scale and residential-scale PV in Colorado confirms that most of the environmental and social benefits provided by PV systems can be achieved at a much lower cost at utility-scale than at residential-scale."[35] RNM, however, operates to make rooftop solar more attractive than other forms of renewable generation via subsidies from non-solar ratepayers, diverting resources away from competing (and, arguably, superior, technologies).

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[33] *Lazard's Levelized Cost of Energy Analysis-Version 9.0.* November 2015. Data cited is from p. 2 table, "Unsubsidized Levelized Cost of Energy Comparison." Full report available online at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

[34] *Lazard's Levelized Cost of Energy Analysis-Version 9.0.* November 2015. Data cited is from p. 6 table, "Cost of Carbon Abatement Comparison." Full report available online at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

[35] Bruce Tsuchida, Sanem Sergici, Bob Mudge, Will Gorman, Peter Fox-Penner, and Jens Schoene, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area." The Brattle Group, July 2015, p. 3.

## Value of Solar Claims: Does additional "value" provided by rooftop solar change the calculus in establishing rates for distributed generation/partial requirements customer?

In the face of arguments like those above against retail net metering, advocates of RNM have tried to develop theories as to why the obvious cross-subsidization does not occur in RNM. Their line of line of argument is based what has been described as "value of solar" theory, and it is particularly salient in Maine, where a recent study found distributed generation to have an astonishing (unbelievable, in fact) levelized value of 33.7 cents per kWh (in a state in which a typical residential customer rate might be around 13 cents per kWh). As I argue below, "value of solar" numbers, in general, should be treated with extreme caution. Value of solar calculations, far from being definitive, are part of an ongoing debate, in which there is no consensus. In the case of Maine specifically, as I will go on to explain in more detail, there are a number of significant problems with the analysis presented in the *Value of Distributed Generation* report that result in grossly inflated claims of "value" provided by distributed solar energy.

### Problems with the "Value of Solar" from PURPA to today

Generally speaking, studies of the "VOS" are highly subjective and readily manipulated, because there is no established, commonly accepted methodology for assessing the value of solar, and, furthermore, given the complexity of the analyses needed to assess all the various "VOS" claims, no analysis can effectively avoid the need to make multiple subjective judgments. Indeed, the "calculation" requires so many inputs, assumptions, estimates, etc., all of which are highly contestable, that no consensus may be possible.

Value of Solar pricing is an attempt to quantify the costs a utility avoids because of the deployment of rooftop solar generation. So-called "avoided cost" pricing has a history in utility regulation, and it is not one that inspires any confidence in its use. In 1978, Congress enacted

PURPA (the Public Utilities Regulatory Practices Act). Among other things, PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from "qualifying facilities" (QFs) at their incremental or avoided costs. "Avoided costs" was defined as: "[T]he incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."[36]

Efforts to calculate "avoided costs" rapidly encountered difficulties. As one article describing avoided cost pricing under PURPA observed:

> Errors in the estimation of long-run avoided costs are inevitable. However, as PURPA was implemented by state regulators in the 1980s, a combination of questionable methods of setting avoided cost and/or poor application of these methods led to excessive avoided cost payments and forced utilities to buy QF capacity even when the utilities did not require more capacity. In addition, excessive, non-dispatchable QF output created operating problems for some utilities. Many complaints about PURPA's implementation were raised by electric utilities and others.[37]

As was clearly demonstrated by the PURPA experience, avoided cost analysis is subject to the biases and policy predispositions of the authors and/or sponsors of such studies.

This reality is well illustrated by the extraordinarily wide variance in the conclusions of VOS studies. The range is dramatic, with a VOS study in Louisiana finding a negative value (principally because it considered the cost of other government subsidies already supporting solar, which are usually excluded from such discussions), with Maine's own VOS having the distinction of being an extreme outlier on the high value side, with a calculated "value" in Maine

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[36] 18 CRF §292.101(b)(ii)(6) (Public Utility Regulatory Policies Act of 1978).

[37] Graves, Frank, Philip Hanser, Greg Basheda. "PURPA: Making the Sequel Better than the Original." Prepared for the Edison Electric Institute (December 2006). Available online at http://www.eei.org/issuesandpolicy/stateregulation/Documents/purpa.pdf

of 33.7 cents/kWh.[38,39,40] Additional disagreement exists over the individual components that make up VOS analysis.

Furthermore, analyzing the "value" of rooftop solar in isolation produces an essentially meaningless number, in the absence of similar "value" analysis for all other competing resources. VOS studies are technology-specific (almost always limited to rooftop solar) and almost always ignore market conditions and how the calculated value of rooftop solar compares with the value of competing resources to meet the same objectives.

In addition, VOS studies rarely, if ever, look at the opportunity costs associated with spending money on rooftop solar, as opposed to using that money on something that produces energy and/or reduce emissions more efficiently (many other major renewable technologies, as discussed above, beat rooftop solar by these measures). This kind of one-dimensional, out-of-context analysis of an extraordinarily complex subject is almost useless as an evaluative tool, much less a rationale to justify administrative extractions of higher rents from consumers.

Even a cursory analysis of the various individual elements generally offered up to calculate the value of solar suggests that, with the exception of avoided short-term energy costs, and perhaps, on a time and location specific basis, some savings on transmission congestion,

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[38] Dismukes, David E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. Prepared on behalf of the Louisiana Public Service Commission.* Prepared on Behalf of Louisiana Public Service Commission Draft, February 27, 2015. *Please see:* **http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5.**

[39] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* **http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.**

[40] To put the 33.7 cents /kWh valuation in perspective, that number is more than double the full retail rate of Maine's largest electric utility. In other words, the authors of that study calculated that the "value" of the energy produced by each rooftop solar installation is worth double the full delivered cost of electricity. That is the equivalent of saying that the value of a part of a product is worth double the value of the entire product.

there is little bankable value there. Few of the "values" attributed to rooftop solar in Maine's or other VOS studies stand up to scrutiny, and those that do are compensated under appropriate ratemaking, to the extent they are real[41].

*Avoided energy costs*

Rooftop solar generation, when produced, does reduce the amount of electricity the utility must provide. Almost every participant in the conversation about the "value" of solar agrees on this.[42] Caution should be exercised, however, when the suggestion is made that the value of the generation to be offset should be calculated on a "levelized" basis—projected for twenty years, and then averaged. This introduces unnecessary and unhelpful speculation about future gas prices and inflation, while doing little to illuminate how actual current cost savings should be considered. A "levelized" value number looks bigger, but caution must be used in understanding what this number means—comparing a larger "levelized" value of solar against current (non-levelized) costs of RNM, for example, is comparing apples and oranges.

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[41] An example of appropriate ratemaking compensating rooftop solar for benefits would be to apply the relevant locational marginal price (LMP) to the price paid for rooftop solar exported to the grid. That automatically captures not only the precise avoided energy cost at the same time that the energy is produced, but also captures the transmission congestion benefit (or cost, depending on the circumstances at a given location at a given time).

[42] Many value of solar analyses present the avoided energy cost as a "levelized" number, which factors in predictions of increasing energy costs in upcoming years to come up with a "levelized" avoided energy cost which is higher than the actual energy cost today. It is tempting here to focus on the fallibility of making reliable predictions about future energy costs (look at recent trends in natural gas prices. Most people did not foresee recent declines). But the whole issue of prediction is a red herring in this context, because RNM does not provide utilities with ownership of distributed solar resources, and therefore gives it no protection against future energy price increases. If an RNM system of compensation continues, reimbursement rates will always be tied to overall energy price increases. So costs of RNM to the utility will go up right along with savings. Trying to give solar resources credit ahead of time for rising energy costs needlessly complicates the analysis, which would then have to be balanced with appropriately rising net energy metering costs. It is simpler and less misleading to use current avoided energy costs, recognizing that these need to be updated regularly.

*Avoided capacity costs (generation and transmission)*[43]

The idea that having a lot of distributed solar on the system means that the utility requires less capacity of various kinds is one of the commonly asserted claims made by retail net metering advocates. These claims are unfounded. Solar energy is intermittent and only available when the sun is shining, and, in the case of rooftop solar, only available for export to the grid if the sun is shining and the solar customer is not using the energy produced on his/her rooftop. It is not and cannot be relied upon to produce any energy when called upon to do so, nor to reduce demand reliably, because there is no way to be certain that the conditions necessary for rooftop solar energy to produce when asked to do so will be met.

Of course, in their planning, utilities do consider the potential impacts of rooftop solar generation on overall capacity needs, from a probabilistic point of view. However, as a former regulator, I believe there is an important distinction to be made in thinking about capacity from a ratemaking standpoint, as opposed to a planning standpoint. From a ratemaking standpoint, payments for capacity should depend on performance.

In the wholesale market in which, when a generator obtains a capacity payment, the generator agrees to either deliver the energy when called upon to do so, or assumes liability for supplying replacement energy. In contrast, rooftop solar providers under RNM make no such assurances. If the utility incorporates this "value" into rates, it potentially pays twice—first, in a lower rate for rooftop solar customers, and, second, if the rooftop solar producer fails to deliver, the utility must pay again, this time to an alternative supplier to provide what the solar provider did not. It is, quite simply, a "heads I win, tails you lose" proposition. From a consumer

[43] Capacity in electricity refers to the generating resources to deliver energy when called upon to do so. What is produced, of course, is energy, whereas capacity is the ability to produce when called upon to do so.

perspective, the capacity value claimed by VOS proponents is for phantom capacity, not something real.

*Potential savings related to power flow: Line loss reductions and ancillary services*

It is true that energy losses occur during transmission and distribution. However, whether or not solar PV systems reduce the amount of energy lost in long distance transmission and distribution is a fact-specific question, dependent on an array of variables (including the location and times of generating energy of rooftop solar systems), and the answers may be counterintuitive. Electricity flows on wires according to laws of physics, following the course of least impedance, a natural phenomenon impacting every interconnected wire, regardless of whether the wire is sized to withstand the current.[44] As a result, energy flow on the grid is highly dynamic in real time. Every injection or withdrawal of energy impacts the ability to access the grid throughout the system. Maintaining optimal grid functionality requires careful planning, vigilant and prudent dispatchers, and the ability to call upon resources to provide what are called ancillary services, such as voltage support, reactive power, black start, and other very location specific service that are essential to grid operations, many of which also affect line losses.

Thus, with respect to the distribution grid, the production or non-production of energy affects line losses on a very location- and time-specific basis. While it is true that DG can have a salutary effect on line losses, it is equally correct to say that it could have an adverse effect of line losses. As a matter of physics, there is simply no generic "value" associated with rooftop solar reducing line losses on the distribution grid. Indeed, as noted above, given the random,

[44] The flows of the high voltage transmission system and the low voltage distribution system are separate and distinct from one another, so the flows according to least impedance are system specific. While demand shifts at any given interconnection point where high voltage is stepped down to low voltage can influence flows on the high voltage system, the actual flows between the two systems are separated by transformers, so the flows between systems are controlled.

uplanned siting of solar dg units, the likelihood that solar panels will be optimally located and in appropriate configurations to add system value is almost non-existent. VOS claims of such value are little more than claiming that solar producers are entitled to compensation for system benfits that, perhaps, in theory they could provide, even though they simply cannot be rfelied upon to deliver.

With respect to the transmission grid, the issue is a bit different, because rooftop solar is not directly interconnected to the high voltage system. Nonetheless, rooftop solar, simply as a matter of scale, probably has very little impact on transmission line losses. Further, (here the counterintuitive interconnected properties of electricity grids come into play) there is no simple and reliable relationship whereby less power delivered to a certain location guarantees less congestion on the grid, and correspondingly fewer transmission losses. Electricity on an interconnected grid impacts the whole grid according to Kirchoff's law. Inputs into the grid need to be carefully balanced with withdrawals to avoid overloading any specific wire and to allow for access to the cheapest possible generation. The impact of lessening demand from a particular node on the grid depends on the specific constraints affecting dispatch at a given point in time. Just as in the case of distribution, to the extent that rooftop solar impacts transmission line losses at all, it is very location and time specific, so generic conclusions are simply not reliable.[45]

If utilities got to select exactly where distributed generation was installed, it might be possible to leverage DERs to provide more reliable transmission and distribution benefits. But this not currently how distributed generation installations work.

For this reason, there is no basis to claim that solar PV systems, *ipso facto*, reduce losses. Furthermore, additional costs can also be the result of efforts to incorporate new DERs. On

[45] For a technical discussion, see M. Rivier, "Electricity Transmission," in Perez-Arriaga, ed. *Regulation of the Power Sector* (p. 276, footnote 8), which acknowledges that in some cases, increased demand at a node (a distribution node) can decrease system costs overall.

distribution systems, this point is being debated among experts, and it appears to be that DERs could well, in some circumstances, increase losses or cause additional costs to be incurred to cope with the newly bi-directional energy flow on the distribution grid, which was designed and built to accommodate one directional flows. With regard to transmission losses, it is certainly true that distributed solar PV does not rely on high voltage transmission. That, however, is no assurance of value. Rooftop solar can also adversely impact the transmission system because of its intermittent and unpredictable nature, which requires utilities to incur expenses to assure that backup power is available in order to be able to instantaneously call upon other resources. Similarly, even when solar units are producing energy, those flows have the potential to cause changes in the flows on the high voltage transmission in ways that add congestion to the system. Should either such circumstance occur, it is likely that losses would be increased, not decreased.

Ancillary services, similarly, can be impacted in both positive and negative ways by distributed solar generation. Certainly, there is the potential for distributed solar installations to include "smart inverters," which have the potential to provide frequency regulation and reactive power even when the sun is not shining—but these are potential capabilities, which RNM does nothing to incentivize, and which should be thought of as a separate product from rooftop solar. To realize the potential benefit here, some form of separate compensation would be needed—and, in my opinion, such compensation should, like compensation for other forms of ancillary services, be provided as a result of services actually provided, not in the hope of services that could potentially be provided at some future date.

*Environmental benefits (emission mitigation costs)*

Even the emissions mitigation benefits associated with rooftop solar are not unquestionable. As discussed above, rooftop solar may have no emissions when producing