New England Ratepayers Association

Written Testimony of Marc Brown, President of the New England Ratepayers Association, provided to the Energy, Utilities and Technology Committee in opposition to LD 1373 on May 4th, 2017.

Chairman Woodsome, Chairman Berry, members of the Energy, utilities and Technology Committee Representatives of the Maine Legislature, my name is Marc Brown. I am the President of the New England Ratepayers Association and we are submitting this testimony in opposition to LD 1373.

The proposed net metering structure in LD 1373 in Maine represents an ill-conceived and irresponsible cost shift from non-solar customers to those who can afford to install solar generation. Instead of the current tariff which was established in part due to the simple form of metering at the premises, or the tariff as proposed in this bill, the Legislature should institute a tariff that properly reflects the value of the electricity generated, when it is generated and where it is generated. This pricing structure will provide benefits to the solar generators when they are producing power when the regional grid needs it most, while sending price signals to those same generators if they are producing electricity when the grid is not short of power. Any other form of tariff, especially the tariff outlined in LD 1373, will only be a distortion of pricing, create a cost shift burden on some portion of the ratepayer base, and will create the wrong types of incentives to participants.

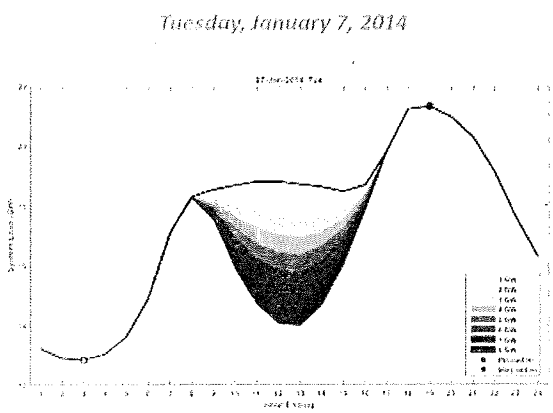
My testimony here covers a variety of the critical issues that must be considered as you discuss and debate a net metering tariff. We consider these topics from the point of view of the ratepayers – the families and businesses which bear the burdens of your decisions on this matter – and we hope you seriously consider these issues as you deliberate over this legislation.

Solar and Peak Coincidence and the Duck Curve

A key assumption in identifying the value that solar generation provides to the overall grid and electricity end users is that solar generates at the time of peak power demand and peak power prices. In fact though, this is not the case, and in New England it is far from the truth. ISO-NE has provided presentations (see Figure 1) noting that the expected generation of solar in the region will not coincide to the periods of peak demand in the region, but will in fact exacerbate the steepness of the ramp in generation required to maintain stability in the electricity grid.

This has several important implications to our grid and the cost of electricity. First, since solar is not peak coincident its ability to provide power at the most expensive times of the year is limited (more on this below) thus minimizing solar's ability to lower peak electricity costs. Just as important, with more and more solar installations creating an ever steeper "duck curve" (so called due to the shape of the curve as more solar is added), the region will require more short term, fast ramping peaking power to back-up the solar capacity. This type of generation is typically some of the most expensive generation in the region which means when solar isn't sustained on a particular afternoon ISO will need to dispatch very expensive power, vitiating any cost benefits solar may have provided earlier in the day.

Winter Season Net Load Profile



- PV does not reduce winter peak
- Load reductions from PV can be significant during midday hours on sunny winter days
- High PV penetrations will increase the need for ramping capability throughout sunlight hours

Figure 1: ISO-NE Presentation Material on the incremental impact of solar on a winter load profile

The issues created by solar generation's lack of coincidence with peak power and the duck curve problem are typically ignored by solar advocates. Yet decision makers and legislators should recognize and identify the potential long term costs of additional subsidization and growth of solar power in Maine and the region.

DG and Capacity Value to the Grid

Solar advocates have argued that distributed solar generators are providing substantial benefits to the grid. One of the major elements of compensation that the solar companies attempt to justify above market price net metering tariffs is a large "capacity" benefit. Depending on the distributed generation study, this benefit request can be as large as \$50/MWh (\$0.05/kWh)[i]

Given the form of intermittent power produced from solar, and the fact that the capacity market payments are made to those generators who can produce electricity at the times when the grid needs it most (and not necessarily the times when those producers can/will produce electricity), it makes little sense to provide a capacity benefit to solar generators. Many studies have shown that in fact, solar generators are not peak producing coincident with peak load. Typical peak loads in New England and Maine occur in the late afternoon hours in the winter and in the summer, coinciding with a ramp up of residential power demands for greater heating and cooling. Unfortunately, solar power tends to peak a little after noon, when the ISO-NE grid does not typically face capacity constraints. In addition, maximum solar generation occurs in the May/June timeframe which typically are low demand months in New England. On this basis alone, a capacity benefit in the net metering tariff makes little sense to consider.

While much of the claimed benefit of solar is based on the idea that there is substantial cost savings from solar generation during periods of high congestion and/or real time pricing for electricity. A review of the actual data for 2015 and 2016 indicates this benefit is marginal. In 2016 there were 273 hours during the year when the real time LMP (Locational Marginal Price) in Maine was greater than $75/MWh. If we exclude the hours between sunset and sunrise when solar generation is impossible, and excluding the months of December, January and February when solar generation is extremely limited due to the low angle of incidence (98% of annual solar generation occurs between March and November in northern New England), solar generation only occurred for 28% of those hours (77 out of 273 hours). In 2015, there were 1142 hours of generation with LMP above $75/MWh. Solar generation could have only taken place in 201 of those hours, or in less than 18% of the time. The data indicates that there is very little value that solar provides during the most periods of highest cost electricity.

Solar advocates will argue that even if solar is not peak coincident (or materially coincident with high prices), the ability of solar generators to lower demand during the day provides some benefit to the grid. But that argument doesn't provide a substantial case to justify inclusion of overpriced compensation through net metering. Capacity payments are made to ensure the stability of the grid at times of stress. It is a system of compensation that flows to generators (from the users through their electric bills) that can ensure that electricity will be available in times of high demand. In fact, the ISO-NE has included a future "pay for performance" mechanism to ensure that those generators who receive capacity compensation deliver at times of need or face financial penalties. If solar generation is providing a capacity benefit, then solar generators, either directly or through an aggregator, can and should bid into the capacity market directly and receive the appropriate market-derived compensation. The intermittency of solar makes this difficult since any and every solar generator has no ability to ensure that they will be able to generate electricity at the most critical times when the system needs power.

When it comes to the capacity market, the most recent trend in New England's Forward Capacity Market is very instructive as to the net benefit/cost of intermittent resources. Over the past decade, New England has been incorporating more and more renewable resources into the regional grid. Due to external policies driven for political reasons, solar resources receive numerous subsidies and benefits through mandates, renewable energy credits (RECs) and production/investment tax credits. The result of this out-of-market support for these generators has allowed them to bid into the wholesale energy market at "below market" rates – rates at which when added to their "out of market" support results in marginal profits. Those large generators who don't benefit from these "out-of-market" programs are faced with declining revenues in the wholesale market for their power. Recently, the ISO-NE has started to allow negative prices to be bid into the wholesale market, which results in only subsidized generators being able to economically produce power at those times of negative prices. The consequence of this type of wholesale power structure is that the New England region is now seeing many large, energy market dependent generators who could participate in the capacity market shut down. The economics of the wholesale market, driven by in large part by the intermittent generators like solar which are supported by non-market compensation, is removing the generators who could bid into the capacity markets and likely lower overall capacity costs to ratepayers. Many generators who have left the market have indicated that the artificial decline in wholesale energy pricing is a major factor in their decision. If this is in fact the case, then intermittent DG suppliers are likely costing ratepayers through the distortions they are causing to the energy and capacity markets. Quantification of this shift in cost is difficult to calculate, but it is clear from the recent increases in annual capacity payments from approximately $1 billion a year (for New England) to $3-4 billion a year, this distortion by subsidized power like solar is creating a net capacity <u>cost</u> to non-solar ratepayers. At the same time, the costs for wholesale energy markets have gone from an average of $6.63 billion per year over 2009-2011, to only an average of $6.36 billion per year over 2014-2016. We face billions of additional costs a year in capacity while only saving a few hundred million a year in energy – but that few hundred million is sufficient to drive important generators out of the market.

Most importantly, the lower wholesale prices are not materially impacting the prices end users are paying for energy. Wholesale prices are making up less and less of the cost of energy in New England because of the rapidly rising cost for capacity and the impact of the state policies (RECs, ACPs, RGGI . . . .) raising prices. Solar's distortion of wholesale prices are having an impact, but it is mostly in the form of raising electricity prices for businesses and families.

DG and Grid Reliability

Beyond the pricing concerns that our organization has, we have overall concerns about solar's longer term impact on grid reliability.

The greater integration of solar DG negatively impacts grid stability on a much broader scale than the enhancements it theoretically makes on a local level (i.e through avoided costs on distribution system upgrades). The very real implications of a more extreme duck curve means that the region as a whole, and ISO-NE in particular, must manage a much more volatile and less predictable load environment throughout a particular day. Instead of a steady and regular ramp in the morning hours, a peak in the late afternoon and a steady ramp down at night, renewables in general and solar DG in particular creates a morning demand peak, a deep afternoon valley, and then an even steeper late afternoon peak. This requires far more grid management activity and a much larger coordination with fast start units, which makes the risk of grid destabilization greater, not less.

Beyond this macro concern for grid stability, the fact that an unforecasted overcast condition can occur means that large quantities of solar generation/users can flip from being electricity suppliers to an immediate and large electricity demand. Depending on the time of day, if this were to occur at a peak coincident time in a high demand zone of New England, there could be serious problems trying to identify, start and then shut down large amounts of generation to compensate for the intermittency and vulnerability of solar DG generation.

Voltage Support, Reactive Power and DRIPE

While there may be times when solar provides benefits to the distribution system by contributing voltage support that benefit may change to a detriment quite quickly. Each incremental unit of electricity added to the distribution system has a different impact on voltage support/reactive power and could result in a benefit or detriment. Moreover, compensation for this type of service should not be imbedded in any solar tariff, but solar generators should apply for this benefit as any other generator can already. If an individual DG customer provides benefits to the distribution system in the form of voltage support/reactive power the DG host can apply for "Capacity Cost" Compensation through the Independent System Operator of New England's Open Access Transmission Tariff[ii]. It should not be assumed that ALL DG customers provide this type of benefit to the distribution system; and it is more likely that the more DG penetrates the distribution system the more the need for voltage support/reactive power. Other non-solar electricity users should not be paying for this assumed benefit through a net metering tariff.

DRIPE is essentially savings that consumers may see from a reduction in electricity demand, both capacity and energy. However, it is extremely difficult to quantify any purported benefits that DG, especially rooftop solar which is not peak coincident, may have. DRIPE is often cited as a result of increased energy efficiency investments, but retail net energy metering actually distorts energy efficiency in that full compensation for "banked" generating credits fails to incent the DG homeowner from investing or partaking in energy efficiency measures. Any DRIPE "benefits" MUST not only be quantifiable, but if included in a net metering tariff should also be proven to be the 'least-cost" method for achieving demand reduction savings. Compensation that directly or indirectly assumes DRIPE in a net metering tariff is akin to providing additional compensation (beyond the electricity savings) to a homeowner that makes the personal financial decision to unplug his/her refrigerator. The legislature will be going down a dangerous and very expensive road for ratepayers if it chooses to subsidize this type of activity through a formal compensation structure. This is especially problematic as the demand reduction from solar DG in not necessarily coincident with peak load and therefore is likely to be providing marginal benefits at best. In addition, demand response and energy efficiency compensation are currently available through existing ISO market mechanism. If the solar advocates believe they should be compensated for this type of benefit, then they should work through the existing structures and not hide this compensation in a net metering tariff.

DG Impact on Utilities and New England ISO

ISO grid management

Related to the localized load forecasting costs, ISO-NE has frequently indicated that they are being challenged more and more by the incorporation of intermittent generation as it is added to the New England grid. While the ISO-NE has indicated some of the specific changes they have had to make to their practices, the exact cost of this grid management process is ultimately borne by the ratepayers of the region. These costs could include increased weather forecasting services, more personnel devoted to real time or near real time wind and solar projections, greater oversight of the substantial drops/surges in intermittent generation by wind and solar, and ultimately the increased costs associated with immediate dispatch to ensure grid stability in times of the substantial drops/surges of electrical generation from wind and solar. ISO-NE has not publicly provided any data on these incremental costs, but they are solely due to intermittent power supplies.

Grid Destabilization Costs

The incorporation of distributed generation creates a new set of challenges for the operation of the grid. The transmission and distribution infrastructure were initially designed and maintained for "uni-directional" power flow. Power was generated at central locations and moved across the transmission and distribution lines to the end users. For the most part, all the electricity "ran downhill". In an environment with distributed generation at the local loop, the need for bi-directional electricity flow becomes greater. In certain circumstances, a local loop with a large amount of solar power generation located on it will need to "export" any additional electricity that cannot be consumed on the local loop. Ratepayers eventually have to cover the cost of this incremental investment in the distribution system to manage this type of problem. In addition to requiring a change in the equipment at the local substation that allows bi-directional flow, it also creates a more dynamic electrical flow that requires a higher level of management to prevent events that can destabilize the local or regional grid. This problem is not theoretical, and in fact has become a primary reason for the State of Hawaii to impose higher tariffs/fees on solar generation.

In addition to this type of local loop problem, the daily production curve of solar generation creates greater challenges to maintaining the stability of the grid. Typically solar generation slowly ramps up in the morning, peaks shortly after noon, and then quickly drops in the late afternoon or early evening. Of course, this pattern is effected by the time of year and the local weather conditions, but even considering the average pattern, it creates the potential to cause problems managing the transmission and distribution network. For a given region (in this case New England) increasing penetration of solar generation requires other forms of generation to ramp down as solar ramps up in the morning. This pattern then must be reversed in the late afternoon as solar pares down. But since peak demand in New England typically occurs in late afternoon hours both in winter and in summer (the two peak demand periods of the year) and is not coincident with peak solar generation, solar starts to ramp down just as demand is also ramping up. Many states and regional grid managers increasingly face the problems associated with distributed generation. This creates a far steeper ramp than if distributed solar generation did not exist and requires the ISO to more adeptly manage the transition from solar to other generation over a short period of time. Since most traditional baseload generation does not ramp that quickly, smaller and more expensive peaker units would be dispatched to manage this rapid increase in net demand (net demand in this case defined as the loss of solar generation PLUS the increase in typical demand from non-solar users PLUS the increase in demand from solar users as they no longer have their distributed generation systems producing electricity). The result is a greater risk of a local or regional disruption in power as the ISO attempts to manage these large swings in generation and demand.

This incremental cost to manage a less stable grid is what can be referred to as a grid destabilization cost (GDC). It includes the costs to manage a local loop problem when large amounts of distributed generation are installed on a particular local loop, requiring both additional equipment and better management practices by the grid managers. In addition, it is the costs incurred by ISO to manage the regional grid in an environment with larger and more rapid ramp up/down due to the installation of distributed generation with its daily fluctuations.

Elements of the Grid Destabilization Cost are quantifiable, but require substantial input from ISO-NE as to the specific values. What can be irrefutable is that these costs are greater than zero and are not theoretical.

DG and Economic Impacts

Any study claiming economic benefits of solar would need to not simply look at the number of jobs in the industry; but would also need to thoroughly account for the impact when money is removed from the economy due by distributed generation policies, ratepayer subsidies, avoided property taxes and job losses imposed on other participants in the energy sector due to public policies that favors renewable energy. For example, the negative economic impact of the Vermont Yankee nuclear plant closure—which was closed for, among other reasons, artificially depressed wholesale energy market prices as a result of out of market programs like RPS and retail net energy metering – was substantial for southern Vermont and Southeast New Hampshire. The loss of 600 jobs in a rural region will have a large impact on the overall income, economic activity and housing prices in that part of New England.

Most models used by solar DG advocates fail to account for the probability that more efficient allocation of capital within a net metering structure (i.e. a wholesale reimbursement rate instead of a retail rate) would generate more jobs and economic growth. This would also include funds taken from the private and public sectors through tax subsidies.

A well-known example of a robust economic evaluation of solar is a comprehensive impact of solar generation policies on job creation and destruction in Spain. That study found that for every new job solar developed, it cost the rest of the economy two jobs in the private sector. While a few may benefit from the generous amount of funding thrown at the solar industry (via ITC, grants, net metering, property tax abatement, etc.) the overall impact is a net drain on the economy as a whole, requiring vast numbers of ratepayers and taxpayers to support an inefficient allocation of capital.

In addition to the one sided look at the impact on employment, studies typically highlighted by solar advocates have a very large flaw. Most of these studies are based on IMPLAN economic analysis. The flaws in IMPLAN analysis is well known and documented, but a cursory look at the IMPLAN "multiplier" used in a particular study is usually the best indicator as to how exaggerated the outputs are. An IMPLAN multiplier of anything over 1.2x is considered far too generous in projecting economic benefits. Despite this economic reality, many renewable and energy efficiency studies continue to abuse the models by assuming multipliers of 2, 3, 10 or even 72x the economic benefit for each dollar spent. It is our opinion that any study with a multiplier effect above 1.2x should be dismissed and ignored outright.

Compliance benefits from distributed generators

RGGI, which currently costs Maine ratepayers for every kWh they use is already accounted for in the LMP (Locational Marginal Pricing) so there are no additional avoided compliance costs with solar generation. Additionally, further penetration of solar and renewables on the grid will likely have a counter-intuitive effect on regional carbon dioxide emissions, which increased by 7% from 2014 to 2015[iii] in New England despite an increase of renewables on the grid. This counterintuitive result was largely due to the closing of the emissions free Vermont Yankee nuclear plant. It is well-documented that the more we integrate renewables into the grid the more the grid needs additional fast-start units cycling on spinning reserve potentially increasing emissions. Claims that supporting a retail net energy metering policy will result in lower emissions is unfounded. In addition, baseload power generators like nuclear and large scale hydro do not receive additional compensation for carbon dioxide free electricity and just as importantly they don't require fossil-fueled combustion turbines to be on spinning reserves and available should the sun stop shining or the wind stop blowing. Unless we want to expand the inequality of how we treat generation options in the state and in the region, including avoided compliance benefits in the net metering tariff would not be justified. The potential downside of losing other baseload generators like Plymouth (announced closure), Millstone (advocating for state subsidies or Seabrook nuclear facilities may end up being a very expensive outcome from the continued subsides thrown at solar.

Externality Compensation

Many advocates for solar generation argue that any net metering tariff should include compensation for the other "externalities" where solar provides a benefit. The bulk of the external benefits argued for include the presumed benefit of generation from a carbon dioxide free source and the economic impacts that solar installation provides for the state.

"Externality" compensation for the presumed benefits of carbon dioxide free generation already takes place in abundance here in Maine. The Maine Renewable Portfolio Standard already includes Renewable Energy Credits for every kWh of electricity generated by solar in the state. The current requirement is for 10.0% of power generated in the state to be from Class I generators with additional benefits for Class II compliant generators. According the Maine PUC report for 2015, RPS compliance cost Maine ratepayers over $12,000,000.

In addition to this direct benefit to solar, the Regional Greenhouse Gas Initiative provides an indirect benefit to solar generation by imposing a higher cost of generation on more traditional forms like coal or natural gas. By making these forms of large scale base load power more expensive, it artificially makes solar power more cost competitive and an incrementally more economical source of electricity.

It is clear that solar DG is already being heavily compensated for the value of the "externalities". It is extremely unnecessary and unwarranted to impose even more "externality" charges on ratepayers through a net metering tariff. If the solar DG advocates feel that the current externality compensation is not enough, they should seek additional compensation through legislative channels and not attempt to hide it through net metering cost shifting via electricity bills.

Locational Benefits from DG

Advocates for solar DG continually argue that there are significant locational benefits that are provided to the local loop when solar is installed. For example, in the Acacia study looking at net metering benefits in Maine, the paper indicates that there is $0.04/kWh of benefits provided by solar on the distribution system. Unfortunately, for ratepayers, the exact nature and the quantification of how they arrived at that number is typically lacking in most analysis of the localized benefits of DG.

In fact, most assessments of this type do not consider the additional costs that are imposed on the local grid, especially in cases where a particular local loop has substantial amounts of solar installed. This should not be surprising as solar installations are typically biased towards higher income cities and towns and end up with areas of higher concentration of solar generation. In the case of Hawaii, this problem has forced additional fees/tariffs on solar DG to ensure that the local grids can be properly maintained.

In addition to quantifying the direct costs that overburdening local loops with solar may cause and should be factored into any calculation of locational benefits, it is incumbent for solar DG advocates to show that solar installations are the least cost option for the improvement of the local loop. Much like the way transmission upgrades are considered, it is the least cost option that is permitted to be charged to the ratepayers. Any solution over and above that least cost option must be borne by parties other than the ratepayers. For the case of solar, the same rules should apply. Unless solar DG can show that they are the least cost option to solve a problem on a local loop, they should not receive compensation (via any adder on a net metering tariff above the wholesale rate) that reflects an assumed benefit and not a real one.

Most importantly, it is incumbent that the solar generator bear the burden of proof regarding specific locational benefits of a DG installation. It is generally recognized and in practice is shown that incremental installations on a particular local loop provides smaller and smaller benefits to that local loop. While the first installation may provide some marginal operational benefit (typically via an assumed deferral of local loop upgrades) the 30th installation on that same local loop will likely not provide any benefit and may end up providing additional costs by requiring upgrades at the local substation in order to move electricity elsewhere in the grid at times of high solar generation.

Unless and until the solar DG customers can provide this type of value analysis that quantifies the actual benefit, and as stated above the burden of proof is on the DG customer/installer, then no consideration for locational benefits should considered as part of any net metering tariff.

New England Ratepayers Recommended NM Tariff for Solar

The New England Ratepayers Association believes the proper tariff structure should be:

Tariff = (LMP * kWh) + TD – IC - LFC

Where the tariff is comprised of:

LMP = Locational Marginal Pricing over a period of time

kWh = the amount of electricity generated over the LMP period

TD = the net quantified benefit (or cost) of having solar generation on that node

IC = a flat interconnection charge that represents the value of an interconnection to the grid

LFC = Load forecasting costs

This tariff structure properly compensates the generator for the value of the electricity when it is produced, plus any marginal benefit that integration of the distributed generation can provide to the local distribution/transmission systems, while charging the distributed generation site for the value of interconnecting to the grid and the incremental costs of load forecasting.

<u>(LMP * kWh)</u>

This element of the tariff is simply the locational marginal price at a particular time multiplied by the amount of electricity (in kWhs) that is generated over that period. While the ideal environment would make the increment of time as small as possible (i.e. 5 min LMP pricing at the node of the distributed generation), current metering practices by the utilities may make the ideal difficult to implement in the near term. The legislature should recognize the current limitations in metering and allow longer time increments to be used to meter ACTUAL generation by the distributed generators, presumably on an hourly or at worst daily period. At the same time the state should also implement a required phase in of better net metering practices that require distributed generators to incorporate better metering practices in order to receive compensation for their excess power. It is incumbent on all other non-solar generators to follow specific mandates when they interconnect to the grid to sell and move power to end users. Distributed generators have been given very loose criteria in comparison to traditional generation. Rules that require a better accounting of the actual generation that is pushed into the grid, the time of day that excess electricity is "sold" to the local utility and the real time LMP when that transfer takes place is required for proper price signals and compensation. The distributed generators must migrate towards this type of system in order to eliminate the current cost-shifting environment.

If the legislature determines that hourly LMP pricing is not a viable option, an alternative is to use a monthly "Solar LMP" pricing structure. This type of compensation would credit solar generators for the amount of excess electricity they sold into the grid on a monthly basis using an average LMP price for the hours in the month between sunrise and sunset – when solar could theoretically be generating. In months like January, August and December the value of a Solar LMP will likely be higher, compensating the generators for providing power when it is needed most. The value will be lower in months like May and October when the grid is rarely stressed and the value of the excess electricity is much lower. A calculation of the Solar LMP for a given month is easy to perform by the utilities and should be simple to implement as part of a net metering tariff.

<u>TD compensation</u>

Most debates and discussions on net metering and in the net metering analysis put forward by solar advocates, it is suggested that solar power provides a benefit to the transmission and distribution system. Most of this benefit is presumed to be in the deferral of capital expenses to upgrade and maintain these elements of the grid. Providing a formal quantification of this "benefit" (not a hypothetical quantification which most solar advocates use) is incumbent on the advocates for distributed generation. Most of this benefit is derived by gross assumptions about future expenditures to maintain local distribution grids. The burden of proof in determining this value is upon the distributed generators and should not be assumed to be positive by the legislature. In addition, it is incumbent on the solar advocates to show that the installation of distributed generation on a local loop is the least cost option to provide that benefit. If there are other options that can defer that capital expenditure, then the solar generator is actually providing an incremental COST relative to other options and should have its compensation lowered accordingly.

But any evaluation of this "benefit" must also consider the potential direct costs of additional integration of distributed generation. Concentration of solar generation in a particular local distribution loop may require upgrading of either the local loop itself, or the substation infrastructure to allow for large amounts of electricity to be moved beyond the local loop. In these cases, where maximum output of the distributed generation exceeds the maximum load there may be an increase in distribution costs. This potential cost increases the more distributed generation is integrated into the electrical grid. Thus any TD compensation included in the net metering tariff should both quantify the actual benefits, but also decrease over time as incrementally more distributed generation resources are added to local loops.

Interconnection Charge

A critical component of DG generation is the interconnection with the grid. This interconnection has two aspects to it. The primary one is the ability of the customer to pull electricity from the grid when there is no power being generated on the premises, and the second one is to allow excess generation to be exported from the premises to the local distribution network.

Since net metering has been a somewhat new electricity resource, early on the utilities typically only used a single bi-directional meter to "net meter". The meter would not provide any information as to when the DG electricity was produced, how much was consumed on site and when, or how much was exported to the grid. Instead, the utilities would just make accounting adjustments for the net power produced over the course of the month and calculate how much to charge or credit the customer.

Unfortunately, the utilities and the net metering customers did not fully appreciate the full impact of the cost-shifting that would take place as net metering policies, along with other non-market policies, subsidized adoption of solar generation. The result of the single bi-directional metering was that fully understanding the time of day and amount of electricity generated and consumed on sight was lost. Now that the utilities, other ratepayers and the Maine Public Utilities Commission recognize the need for a better understanding of the value of the electricity generated by net metering, it is incumbent on the legislature to require the proper metering equipment be installed at DG premises as part of any net metering tariff. This would either be a single meter which can properly track, record and send data on time of day generation/consumption, or two meters installed on site, one for tracking outgoing excess generation into the local grid (time, day and amount) and one for tracking consumption by the end user. It is only through the tracking of this information can the correct value of the electricity that is generated by the solar facility be determined and properly compensated. This will also ensure the end of the cost shifting that has been occurring due to the basic form of net metering that is mis-allocating the costs of net metering onto non-solar customers.

Of course, with a mandate to install the necessary equipment, the question arises as to who should bear the cost of the equipment and its installation. To answer this, we should look to which party bears the costs for interconnection of any traditional generator. For every other generator who exports power into the grid and receives compensation for that power, it is the generator who must pay for and install directly or indirectly. In the case of DG, there is no rational argument that would justify the utility (and the non-DG ratepayers) to pay for this equipment and installation. It should be incumbent on the DG providers, who are making a choice to interconnect for the purpose of exporting power, to pay for the second meter which must be able to track when power is exported to the grid and in what quantity.

Advocates for DG often argue that there are substantial benefits provided to the grid via the fact that DG can provide electricity to the local distribution loop. Much of this discussion and counter argument is included above. But what the advocates of DG fail to consider is the tremendous value that interconnection to the grid provides to DG. The interconnection to the grid is the ONLY way for a solar generator to receive any compensation for their excess power. It is that connection that actually enables the DG to export power at all, and it is the interconnections to the local loop, other end users and the local substation which provide the true value, not the DG itself. Without the local distribution system, the excess electricity generated by a solar customer would remain stranded and valueless.

In order to quantify the value of the distribution system to solar generators, it is simple to consider the alternative cost to the DG end user without an interconnection to the grid. Consider a DG location which has a 4kw system and the end user consumes 600 kWh per month. Also, given there is no interconnection to the grid for this location, we can assume the need for five days of electricity storage on site (this assumes five days of cloud cover resulting in no power generation from the solar array for that time). This would result in 100kWh of storage required on site (600Kwh/30days = 20Kwh/day * 5 days = 100kWh capacity needed). Currently the Tesla Powerwall capacity is 6.4kWh, therefore 15 Powerwall units would be needed to ensure continuous electrical supply. The current cost of a Powerwall unit is approximately \$3000 per unit, which would equate to a \$45,000 "replacement cost" for the interconnection. Of course, the Powerwall units do have a limit in the number of cycles that they can operate, and while the Powerwall is somewhat new and the lifecycle limitations are subject to change, current data indicates a 1000-2000 cycle life for $LiNiMnCoO_2$ batteries. This means that a system like this is likely to require complete replacement over a 10-15 year period whereas an interconnection to the grid is more or less permanent and does not require any additional up-front capital expense from the customer. Even ignoring this substantial life cycle cost factor, if we simply associate the cost of the initial Powerwall as the replacement cost of the interconnection, we find that the value of that interconnection is on the order of \$75 per month over a 50-year period. While this value is based on gross assumptions, the legislature, the Maine PUC and the utilities should be able to better quantify this value. Given these economics, it is very difficult for the DG advocates to argue that the value of having the DG on the grid is worth more than having the grid interconnected with the end user.

<u>Load forecasting costs</u>

One element that DG supporters ignore is the incremental costs with load forecasting and real time electricity sales which are associated with DG. Most utilities must anticipate the forward demand of their customers and ensure through contractual agreements the electricity they need to serve that demand. In order to fill any incremental demand above the supply they have under contract, the utilities typically enter into the Day Ahead ("DA") market to secure the electricity they will need for the following day. In making their estimates for the DA load there is typically an assumption of the electricity which DG will generate. But due to the intermittency of the DG supply, both in terms of amount and time of day, the suppliers will have to enter the Real Time ("RT") market to balance their electrical supply with their load. If in fact, the solar DG are providing too little power than anticipated, the utility will have to purchase power on the RT market, likely paying a premium for that electricity as demand is exceeding supply at that point in time. If in fact, the solar DG is supplying more power than expected, the utility will have to sell a portion of the power they purchased in the DA market on the RT market, but likely at a loss as demand is now lower than anticipated supply. Management of this supply-demand matching process is likely costing the utilities, and thus non-solar ratepayers, as they would be either paying a premium for additional RT power purchases, or facing small losses on power they have during times of excess. It is beyond our abilities to quantify this real cost, and therefore we have not identified its specific value as part of a net metering tariff. The PUC and the utilities should be able to determine the correct calculation and value for this component of a net metering tariff.

Conclusion

The New England Ratepayers believe that the proposed net metering tariff in LD 1373 will exacerbate and already distorted energy market and accelerate the cost shift from non-solar customers (including most of the low and middle income families of Maine) to solar customers.

This testimony has helped identify for lawmakers the critical issues they need to consider as they debate and vote on this measure. From the lack of real benefits that solar provides, the real costs that expanded solar generation creates in energy markets, the increased distortions of the supply/demand curve with greater costs for managing that curve by ISO, the extensive subsidies through other state and federal energy policies and the real additional costs borne by ratepayers when the utilities are forced to pay above the alternative LMP pricing – solar generation has been given massive support and subsidies at the state and federal level. It is entirely unnecessary and unfair to impose this type of net metering tariff on the ratepayers of Maine. If legislators truly care about the cost of energy and the impacts of those high costs on families and businesses in the state, then they will vote against LD 1373. Thank you for your time and consideration and I am open for any questions you may have.

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[i] http://acadiacenter.org/wp-content/uploads/2015/10/AcadiaCenter_GridVOS_NewHampshire_FINAL_2015_0904.pdf

[ii] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[iii] https://www.bostonglobe.com/metro/2016/05/15/carbon-emissions-rising-new-england-power-plants/9WfbtQMJEMBszzxPzf2OLO/story.html