MEMORANDUM

TO:	National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Rate Design
FROM:	Technical Staff, Massachusetts Department of Public Utilities
RE:	Comments on the draft NARUC Distributed Energy Resources Compensation Manual
DATE:	September 2, 2016

SUMMARY: The technical staff of the Massachusetts Department of Public Utilities ("MA DPU") offers feedback on the draft of the NARUC Distributed Energy Resources Compensation Manual ("Manual") that was released to the public for comment on July 21, 2016. We provide our feedback in the form of comments and redlines on specific sections in the Manual. Please note that some of the feedback provided is specific to the Massachusetts experience and, therefore, may not be applicable to all jurisdictions. Comments provided in this document reflect the personal views of certain technical staff available to review the Manual, and do not represent an official position of the MA DPU, its Commissioners, or the Administration. The feedback provided in response to this call for comments is not intended to serve as a formal position of the MA DPU.

I. <u>GENERAL COMMENTS</u>

- The Manual is quite comprehensive and should be a useful regulatory resource.
- State regulators benefit from learning from other states' experience. A few call out boxes with mini-case studies of an alternative rate design or compensation methodology that a utility or jurisdiction is implementing/has implemented and, to the extent possible, its struggles with the process, would be helpful. The reader would have enough info to dig deeper and contact the staff person in that state for a more thorough discussion.
- As mentioned by other stakeholders, there is significant content repetition between *Section III* and *Section IV* regarding costs and benefits, cost shifting, technology and physical issues, cross subsidies, the increasing importance of DER and the issues presented by DER.
- We suggest additional clarification regarding whether the Manual is intended for residential or for C&I customers, or for both. This should be made clear in the Introduction (or Executive Summary, if one is included) and for each compensation methodology, especially if one applies to a particular customer class vs. another.

II. SPECIFIC COMMENTS

A. <u>I: Table of Contents/ Introduction/ Appendix</u>

- Table of Contents Add subheadings in TOC to make a bit more granular.
- Executive Summary Consider adding one that might include key takeaways:
 - Changing landscape DERs are being adopted at ever-increasing rates.
 - The LBNL graphic on DER Adoption Levels (page 61). Increased DER integration can cause significant issues for traditional ratemaking models and delivery of electricity.
 - One key variable in considering DER ratemaking: the level of adoption of the resources. Consider adding:
 - A list of sample questions a state regulator may want to ask itself in order to determine which rate design/ compensation methodology to explore/ pursue.
 - A non-exhaustive list of telltale signs that indicate where a state falls within a certain DER Adoption level.
 - Some of the biggest issues/ barriers facing PUCs today regarding DER compensation (e.g., cost shifting, valuing benefits to and from the grid).
 - More customer benefits are being identified at individual and grid level.
 - Some compensation methodologies require advanced technologies for implementation.
- Appendix Although the Manual is written to apply to all jurisdictions, consider adding a reference index or matrix of the 50 states, indicating which states:
 - o Are restructured vs. vertically-integrated
 - o Are decoupled
 - Are affiliated with a wholesale market (indicate name)
 - Offer a retail competitive supply program (indicate level of penetration for residential and C&I customers in each state)
 - Have implemented advanced metering, since many advanced rate designs require it (indicate % of ratepayers in the state with advanced meters)

This matrix could be a useful reference, as PUC staff might first look for jurisdictions that have similar characteristics before researching the compensation methodology that utilities in that state have implemented.

B. <u>II: What is the Rate Design Process</u>

• Time-Variant Rates - (page 9-10) consider adding a table of all utilities (IOUs and

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municipal utilities) that have implemented dynamic pricing, TOU, CPP, PTR, and whether the programs are opt-in or opt-out.

C. <u>III: What is DER</u>

- DER Adoption/ Penetration Levels (page 21-22) consider adding a chart or table identifying the ten states with the greatest DER adoption levels and the approximate percentage.
 - Page 22 states: "one key variable in considering DER ratemaking: the level of adoption of the resources". Consider adding some ways a state regulator could determine the level of adoption in its state. Generally speaking, how this did the state measure this? What metrics did it employ?
 - What steps have states taken to measure their DER penetration levels? A call out box with an example of a state that has measured its level and how they did it would be helpful.

D. IV: Rate Design and Compensation Considerations, Questions, and Challenges

- Price Signals (page 30) Consider expanding this section. Perhaps cite to recommendations in the NY PSC *Staff White Paper on Ratemaking and Business Utility Models*' section on Approaches to Sending Pricing Signals (page 86-87).
- Grandfathering (page 36-38) It would be helpful to add a call out box and mini-case study of Nevada's recent changes to its net metering policy, and a counter example of a state that grandfathered aspects of its program.
- DER as a Separate Rate Class (page 29) Consider expanding this section. Which states have implemented this? It is a viable solution to address cost shifting? Consider adding links to published results or studies on this topic.

E. <u>V:</u> Compensation Methodologies

- Consider adding a matrix that identifies each compensation methodology, the states that have implemented the methodology (if known), the DER adoption level in the state (if known), and the technology requirements necessary to adopt that compensation methodology.
- Pilot Programs/ Studies Consider adding a call out box with a mini-case study for each of the different the compensation methodologies including: (1) a brief description of the objective, geographic location, and timeframe of the pilot program/study that the utility has undertaken; (2) the technologies being considered/implemented; (3) the benefits that are being evaluated; and (4) the costs, barriers, issues raised by stakeholders, and results to date, if available.

1. Net Energy Metering (NEM) (p. 41-44)

- Consider adding a table or graphic of states that have net energy metering in place, and which technologies (solar, small hydro, etc.) the NEM policy applies to.
- The NEM section varies between referring to (1) any customer generating system, and (2) PV specifically. In practice most NEM is PV, but it is worth being consistent or noting upfront that while NEM could be a variety of technologies PV is most prevalent and therefore used consistently as the example.
- NEM is incorrectly equated to storage. The electric grid is not a storage device or "bank". Rather, NEM is a transactional arrangement between customers and utilities in which the customer may both sell excess generation back to the utility and purchase power from the utility when the self-generation is not sufficient to meet the customer's load. The increase of DER on a system, in part incentivized by NEM, can impact local reliability precisely because the power must flow on the system, and with DER power is flowing bidirectionally on a system originally designed to deliver power to customers (<u>i.e.</u>, one way flow).
 - A key benefit of NEM is that it allows customers to reduce their utility bill by self-generating while remaining connected to the electric grid as a source of power for those times when the output of self-generation is not sufficient to meet their load.
- NEM is referred to several times as a method for interconnection. We recommend changing this language. In Massachusetts, we refer to NEM as a method of <u>compensation</u> for DER. Systems may interconnect without NEM.
- The tone of the NEM section does not appear to be consistently objective or observational. There are instances in which the authors state that NEM has great advantages and/or shortcomings. The language should be changed to be objective (<u>i.e.</u>, "Proponents of NEM claim that it has advantages..."). To the extent possible, we have highlighted such instances in the redline.
- The section appears imbalanced in terms of pros and cons. One pro that would be helpful to add is that NEM is a way to support and/or incent the uptake of clean, renewable generation such as solar. It also allows customers a way to support clean energy by installing solar panels or other clean generation technology ("going green" and cost savings are often the two major reasons customers cite in their decision to NEM).
- There are some NEM considerations that aren't discussed in the Manual that frequently come up in our work in Massachusetts:

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- A discussion of virtual net metering. This would be especially useful in the discussion of a customer's negative net consumption. (In Massachusetts, there is currently no requirement to size one's DER system to load).
- NEM is often a capped incentive. A discussion of how caps are set and who is responsible for determining those caps would be useful.
- 2. Valuation Methodologies (p. 44-48)
- Value of Resources
 - Consider adding a table or chart that lists all the states and/or utilities that have completed a value of solar study and the date it was completed.
 - Name the states that have implemented a value of solar tariff provide a mini-case study on one of them.
 - Consider adding a call out box that list the benefits and limitations of conducting VOS studies that have been articulated by different parties.
 - Benefits Valuing hard to quantify benefits of DER to the grid list the states that have experience with this. Consider adding an example (perhaps a mini-case study) of a state that is doing this, the process and whether and how they are getting buy-in from utilities.
- Transactive Energy
 - Consider adding more content about distribution Locational Marginal Pricing (DLMPs).
 - Consider adding a case study about the Pacific Northwest Smart Grid Demonstration project or NY REV's approach to calculate the full value of DER to the distribution system. See page 90-94 of the NY PSC's Staff White Paper on Ratemaking and Business Utility Models, which includes Section E. Determining the System Value of DER and Section F. Potential Compensation Mechanism Reforms.
- 3. Demand Charges (p. 48-50)
- Residential Demand Charges Consider adding a list of all utilities (IOUs and municipal utilities) that have implemented a residential demand charge and indicate whether they are optional/ mandatory.
- 4. SMART Inverters (p. 65-66)
- The main functionality of smart inverters is communications, both with the

distribution company and potentially with other inverters.

- IEEE 1547 is under current revision to address these types of inverters and UL 1741 is also being review accordingly to allow for the testing and certification of such inverters.
- The Massachusetts Technical Standards Review Group continues to track and discuss this topic in their quarterly meetings.
- 5. Hosting Capacity (p. 66)
- This topic has been discussed in Massachusetts Technical Standards Review Group meetings.
- There are some security concerns centered on the type of information that maps like these contain/make available (confidential electric infrastructure information).
- There are concerns about who pays for the initial analysis, ongoing maintenance, data storage, etc.
- In Massachusetts, there remains a question as to whether DG developers need this information.

III. <u>REDLINES</u>

Time Variant Rates (p 9-10)

Time variant rates are designed to-recognize differences in a utility's cost to provide of service service over a defined period of time (e.g., hour, day, season)and marginal costs at varying times during the day. Generally, a time variant rate design charges customers a higher price during peak hours than off peak hours. Unlike flat rates, customers need to be aware of usage throughout the day and the month to respond to the price signals in a time variant rate design. Under a time variant rate, Aa customer may achieve increase savings under a time variant rate design. Under a time variant rate, Aa customer alignsuses their its energy use in response to the time variant price signals appropriately during specific peak and off-peak hours. A regulator can consider a variety of time variant rateprice options-can be considered by a regulator; each option provides the regulator with the ability to reflect in pursuit of a variety of goals. Additionally, with the advent of advanced metering infrastructure <u>enables regulators to</u>, the metering technology is capable of implementing these rate design options on a wider scale.

A time of use (TOU) rate <u>is a time variant rate structure that</u> charges customers different prices according to a pre-determined schedule of peak and off-peak hours and rates. For many utilities, TOU rates have been a voluntary option for residential customers for decades, but, generally, few customers participate. Lack of cost-effective metering technology hindered the wider development of TOU, but <u>utility roll-out of</u> advanced metering technology-<u>is being rolled</u>

Comment [A2]: The author may want to cite to something to back up this statement. We cannot verify whether "many" utilities have voluntary TOU rates, and whether "few" customers participate.

Comment [A1]: We edited this introductory paragraph to try to make it generic to time variant

rates rather than just TOU (peak and off-peak hours).

out across many jurisdictions, which can facilitate roll-out of <u>residential</u> TOU. Many commercial and industrial (C&I) electric customers already take service under TOU rate designs.⁶¹

Under a real-time <u>rate structurepricing plan for electricity rates</u>, the customer <u>paysis charged</u> for generation at the <u>hourly</u> price set in the wholesale market (for deregulated utilities) or the short-run marginal generation costs (for vertically integrated utilities) by the hour. Large electric customers may already be indexed to the hourly generation price through a competitive supplier or utility rate design, but <u>utilities typically will need to deploy</u> advanced metering infrastructure-<u>is needed</u> to implement real-time pricing for residential and smaller C&I customers.⁸² Real-time pricing is available to residential customers in the Illinois service territories for Commonwealth Edison and Ameren. The real-time rates for these programs are based on the day-head hourly wholesale price for the given utility zones.

A dynamic pricing rate design <u>structure</u> contains pre-established blocks of hours reflecting the characteristics of costs that occur during those blocks. Compared to a TOU rate design that predetermines a schedule of peak and off-peak hours and rates, <u>a utility may revise</u> the dynamic pricing schedule and rates <u>may be revised</u> based on market conditions.

A utility may implement a critical peak pricing (CPP) rate <u>structure to reflect in retail rates the</u> <u>high wholesale price of electricity or the existence of delivery constraints</u> during times of <u>anticipated energy expected</u> shortages or anticipated high <u>energy</u> usage (i.e., <u>CPP events</u>)-days to mimic peak time price increases. <u>Typically</u>, utility tariffs limit <u>CPP events</u> to a maximum <u>number of hours per year</u>, and <u>Tt</u>he utility will announces the hours that the CPP rate will be in effect prior to the CPP event. <u>The CPP rate reflects the higher generation price of electricity</u> during those <u>CPP hours or the existence of scarcity during the event hours</u>. Generally, the CPP rate is <u>set</u> significantly higher than the non-CPP rate <u>andas a means of</u> incent<u>sing</u> customers to reduce consumption <u>during CPP events</u>. A <u>utility can incorporate a</u> <u>CPP rate structure</u> can be <u>included</u> within a TOU rate <u>structure</u>; in both cases, the rate is determined by the regulator, but a <u>CPP event is usually limited to certain peak hours over a year</u>.

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Comment [A3]: See above comment.

¹_One alternative to a TOU rate is a peak time rebate (PTR), which operates concurrent with traditional rate design. <u>Under PTR, a customer pays a traditional flat rate, but the A-utility establishes a</u> pre-established customer baseline of <u>the customer's</u> energy consumption-is established prior to implementation, and <u>awards</u> the PTR-is awarded if <u>thea</u> customer reduces their consumption below the baseline during those peak-time hours. Customers will still pay the traditional rate during the peak time, but are also rewarded for any reduction in consumption during those peak hours. Since a PTR does not change the traditional rate design, it may be easier for residential customers to understand.

Compensation Methodologies (p 41)

The growth of DER across the country and its impacts on the utility is increasing every day. Regulators are often tasked with two, potentially competing goals: ensuring the financial health and viability of the regulated electric utility and developing policies, rates, and compensation methodologies for DER. This section outlines several options that a regulator may consider in determining how to compensate DER. It is possible that a regulator may choose to implement one or more of them at a timesimultaneously. Additionally, it is important to note that a regulator should maintain flexibility in determining the compensation policy, as changes in the market, policy, law, and technology continue to evolve over time;-_understanding Understanding this is an evolutionthese changes will assist the regulator in recognizing that the appropriate compensation methodology may change over time.

Net Energy Metering (p 41-44)

Net Energy Metering (NEM) is the simplest and least costly method to implement a compensation methodology for DER. NEM adapts the traditional monthly billing practices to the introduction of generation facilities located on the customer side. In traditional, non-time-differentiated billing, the meter is read once a month. The difference between two consecutive readings defines the quantity of electric service provided by the electric utility and received by the customer. If, for example, a meter displayed 10,000 kWh (cumulative) on March 30, and subsequently displayed 10,200 kWh on April 30, the difference between the two readings, 200 kWh, signifies the movement of 200 kWh across the meter from the electric service provider to the customer. That 200 kWh is then calculated against the rate to determine the cost, plus additional billing determinants, such as a fixed customer charge, taxes, or other charges as approved by the differences between the periodic readings of the meter. This is the method of calculating electric energy consumption used by most U.S. utility systems for residential service.

NEM works in the same way: the kWh charge is based on the difference between two periodic readings of the meter. The new ingredient in NEM is that there is not only energy consumption behind the meter, but also energy generation. Neither the amount of generation nor the amount of energy consumption can be determined from the meter reading alone. Using the same example, the 200 kWh difference between the two subsequent meter readings signifies the net movement of the meter and the net quantity of service provided by the utility for the benefit of the customer. It is possible that the customer produced some amount of kWh greater than zero while consuming some amount of kWh greater than 200 between the two readings. Neither the amount of production nor the amount of consumption can be determined from the two readings of the meter, only the net movement of the meter can be measured by this method. Once again, the key point is that the measure of service is determined for billing purposes by the difference between the two periodic readings.

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Page 8

Comment [A4]: The identification of the competing goals does not seem correct. The task is to "develop policies, rates, and compensation methods for DERs." – so that can't be one of the competing goals.

NEM developed as a straightforward method for interconnection compensation of very small distributed energy systems at a time when residential electric meters were analog systems designed to be read manually. While the high capital cost and operating expenses associated with multiple specialized interval recording meters could be justified – and were required – for large industrial and commercial electric service customers, such costs would have been prohibitive for residential properties and would have overwhelmed any savings from selfgeneration. As long as only a very small fraction of households were connecting PV or other self-generation systems, and as long as the quantities of energy moving from customers to the grid were very small, it seemed reasonable to allow customers to hook up their behind-themeter solar panel systems without mandating additional costs for more precise metering systems. So, in the age of analog meters and manual reading of those meters, NEM was the onlya practical way to introduce PV and other home-based generation systems. At the time when residential PV systems were new and costly, adoption of NEM provided a strong incentive to install home systems. Much has changed since then; solar PV costs continue to decline and the cost of advanced meters are much less expensive, are more precise than the interval meters of the last century, and can be read electronically at very short intervals (five minutes or even shorter).

NEM has great advantages for a homeowner or small system operator by allowing the customer to generate electric energy when the power is available and then consuming it at a time of convenience. For solar PV systems, solar panels are situated at an angle best identified to capture the greatest solar radiance, which typically covers noon to 4:00 PM in the afternoon.³ The customer can then "use" the electric energy at a time more convenient, such as in the late afternoon and evening. Essentially, the customer is able to use the utility as a bank for energy.

Proponents of NEM argue that the revenue reduction of utilities from NEM is justified and appropriate. First, utilitiesUtilities are not required to purchase or generate-the electric energy that the customers are generating and using themselves. Furthermore, it is argued that Ccustomer generation, it is argued, reduces utility generation even if a customer generates electric energy during a time when that customer is not consuming energy the generation occurs at times other than when the customers consume electric energy. Besides saving the system the cost of generating the electric energy that the customer generation offsets, customer generation also unloads the distribution system (and to some degree the transmission system), thereby reducing system losses and forestalling required expansion

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Comment [A5]: NEM is a method of compensation, not interconnection. You can interconnect a system without NEM.

Comment [A6]: Net metering is a transactional arrangement between customers and utilities in which the customer may both sell excess generation back to the utility and purchase power from the utility when the self-generation is not sufficient to meet the customer's load.

The electric grid is not a storage device or "bank". The increase of DER on a system, in part incentivized by NEM, can impact local reliability precisely because the power must flow on the system, and with DER power is flowing bidirectionally on a system originally designed to deliver power to customers (one way flow).

We believe the benefit that the authors are trying to capture is that NEM allows customers to reduce their utility bill by self-generating while remaining connected to the electric grid as a source of power for those times when the output of self-generation is not sufficient to meet their load.

³—______Typically, solar panels face southwest, which allows for the greatest amount of sunlight to power the panels. However, as identified by the Pecan Street Project, this may exacerbate afternoon ramping periods as the solar output declines rapidly as the angle of the sun goes down. Research from Pecan Street Project highlights the need for some panels to face west, even though solar radiance is less during late afternoon hours, as it may assist in alleviating afternoon ramping conditions due to the setting sun. (See

http://www.pecanstreet.org/2013/11/reportresidential-

solar systems reduce summer peak demand by over 50 in texas research trial/). This highlights one of the technical and economic challenges with NEM with policies supporting total production without location or timing attributes.

and/or upgrades. Proponents argue such savings to the system (and therefore to all system users), though difficult to calculate, justify granting customers the full benefit of reduced bills, including not only reduced energy costs but also any margin built into the kWh charge.

There are complications that arise from NEM. First, <u>NEM may result in consumption of a</u> <u>negative amount of electric service for a given billing month.</u> <u>il</u>t is possible – even likely – that during some hours between the two monthly readings, the amount of generation exceeded the amount of consumption. That is to say, at times the meter may run "backwards" in the sense that the flow of kWh was from the customer to the electric service provider. Then, during other hours, the meter will run "forward" recording consumption in excess of the amount of customer generation at that time. That one net measure is the billing determinant under NEM.

Returning once again to the example discussed previously, if the April 30 reading is 9,990 kWh, the net difference is -10 kWh, that is, consumption of a negative amount of electric service for the month. The result of NEM in this example is that the customer produced more kWh than was consumed, and it appears that the customer produced net electric service for the electric service provider. Under NEM in this example, the billing determinant of energy consumption is a negative number. Applying that negative number to the rate in the tariff may result in a negative invoice, which, depending on the rules in place in the jurisdiction, may be carried over into the next month as a credit.

The purpose of NEM is to allow customers to offset their load by self-generating electricity. However, negative net energy consumption overall, but it may occur during times of the year when both heating and cooling demands are low. At other times of the year, such as during the summer, when electric energy is used for air conditioning, and during the winter, when electric energy is used in heating systems, the net energy consumption over the month is likely to be greater than the amount of energy produced by the customer's generating equipment during that month, outweighing or at least matching the negative measurement for this April example. Over a longer period, such as a year, it is could be possible for a customer would to achieve a negative net balance for the whole period, thereby avoiding all charges associated with electricity service.

A second complication of NEM is that it does not account for any difference in value between the cost of service associated with the tariff rate for kWh and the value of the kWh itself. That energy may pass in either direction across the meter implies equivalence between the delivery of energy and the provision of electric service. Traditional electric rates carry a margin in excess of the direct costs of the measured kWh so that the total costs of the electric utility, including fixed costs and other variable operating costs, can be recovered through that charge. By measuring only net energy, and crediting excess against the total bill, NEM reduces not only the energy revenue of the utility but also the margin available for the coverage of other costs.

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Comment [A7]: This paragraph is not clear why this is a complication. We recommend adding a sentence clearly introducing this first complication (the NEM may result in negative consumption for a given billing month) that is then explained in the following 3 paragraphs.

Comment [A8]: This may not always be true. Virtual NEM allows for self-generation at sites with little to no on-site load as the credits are then transferred to other customers. It is also important to recognize the opportunity for customers to "game" the system by oversizing their systems to consistently achieve a negative net balance.

Comment [A9]: This is dependent upon the size of the net metering facility and the customer's consumption on a case by case basis.

A third complication is that NEM does not account for time or locational differences in costs or value of energy. Of course, the timing and location question is not attributable specifically to NEM, but is a feature of traditional monthly billing systems with or without customer generation. Still, the matter becomes more complex when both consumption and production are involved. The simplicity associated with a single monthly meter reading provides no information about a customer's pattern of generation or consumption, or the location of the customer. The advent of advanced meters has facilitated the ability to adopt of time-of-use (TOU) rates for traditional electric service and for NEM. Different rates for different TOU periods may reduce, but does not eliminate, the conceptual issue that neither the amount of generation nor the amount of consumption is measured under NEM, only the net.

Additionally, many discussions of NEM discussions challenges frequently fall back onaddress the recovery of system costs. First, critics of net metering note that the operational issue: NEM customers do not compensate the system for the operational costs they impose on it. They force the system operator musted absorb their the excess generation from NEM customers during peak generating periods, and they force the system operator to then ramp generators and adjust the system to "repay" provide the customer generation with electric service at other hours/days/seasons. Critics argue that this This means the costs of the system are higher even though the NEM customers are not charged for those additional costs. Second, critics of NEM state that by overcompensating the NEM participants through their avoidance of kWh charges, NEM necessarily is imposing those avoided costs on the nonparticipants. In this view, the nonparticipants are subsidizing the NEM participants.

Though NEM is the simplest form of interconnection compensation for generating systems behind the meter, it fails to account for the complexity of grid operations. For grid stability to be maintained, there may be a need for the ability of the grid operator, such as the distribution utility, to curtail the operation of the generating system, essentially overriding the desire of the customer to generate as much as possible. The effects of any one customer's actions are often negligible and likely to make little difference to grid operations. However, NEM detractors argue that as greater amounts of customer generation are connected to the system, any savings to the system may be overwhelmed by greater costs. For example, Ccustomer-side PV generation peaks in the afternoon, and the grid operator accommodates the customer surplus flowing onto the grid by lowering the load service of dispatchable power plants down to minimum load, the lowest level of operation consistent with an ability to stay on line and be available to provide service. This action has a cost and, in the future, may strain the abilities of conventional plants. Then, later in the day, as customer generation falls off, customer loads begin to rise, and net customer loads, accounting for the reduction in customer-side generation, rise very rapidly. The dispatchable plants must rise quickly from their minimum loads up to their maximum to meet the increase in system load and keep the grid stable. This sudden ramp also has a cost. NEM detractors argue that NEM customers, far from saving costs to the system, may actually increase system costs. And because the system maximum loads do

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Comment [A10]: This reads as a strong critique. Adjust tone to be objective. This paragraph seems redundant with the one below.

Comment [A11]: NEM is a method of compensation, not interconnection. You can interconnect a system without NEM.

not occur at a time when the customer generation is high, there may be no savings from postponing system expansion or system upgrades. From the point of view of NEM detractors, NEM overcompensates customers with customer-side generation and adds system costs that must be paid by all customers.

Finally, while NEM may reduce the total amount of utility generation, it does little to encourage customers to use less electric service overall. In fact, under a situation of inclining-block rates, the charges that the NEM customers avoid are the in the highest blocks. NEM customers may move from a high block to a lower block, thereby decreasing the marginal cost of using more electric energy. If NEM customers use more than they otherwise would have, then any system savings – especially saving from reduced system generation – is reduced.

Demand Charges (p 48-50)

Demand charges have long been used in commercial and industrial customer class rates, but have not historically been applied to other customer classes. Some advocates are looking to use demand charges on a more widespread basis since all customer classes conceptually incur demand charges.

Demand charges are another line item cost included on a utility bill - in addition to fixed and energy costs, which make up a utility's revenue requirement. Demand is often calculated and charged in KW and used, at least in part, to "split up the pie" of the revenue requirement within each class. Demand charges endeavor to measure the "size of the pipe," or capacity needs of a customer. There are two historical ways to calculate a demand charge, either by taking the customers highest instantaneous demand a customer draws from the system, measured in KW, over a certain time period; or, alternatively, by using the customer's highest KW (peak) divided by the relevant timespan, during the period in question.

When proposed or used in a residential context, demand charges are often included as a percentage of the delivery portion of a bill and are measured on a more frequent basis, often monthly, presumably to increase bill stability and allow customers to more frequently react to price signals. If the rates are understood by customers and <u>theirits</u> loads can be shifted, then these demand charges can incent customers to "shave" their peaks or shift usage to another time, and with coincident rates, reduce the overall system peak. How, when, and how often this demand is calculated can vary in practice.

Lately, interest has been paid to use of demand charges on residential and small commercial customer classes in areas with the technology to do so, such as advanced metering technology.

Parties advocating for the use of demand charges on a more widespread basis state that the short-run costs of the distribution system are all fixed in nature and should be proportioned among customers in the same rate class based on their maximum demand regardless if it

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Page 12

Comment [A12]: We think it would be helpful to note that the high cost of demand meters and the homogeneous load of residential customers have resulted in the costs outweighing the benefits of purchasing the meters for this group of customers. contributes to a system peak. Other parties insist that to use demand charges they must be coincident and thus measure a customer's contribution to certain system peaks.

Advocates argue that demand charges can ensure greater revenue certainty and cost recovery for the utility – and costs are better more accurately recovered by the cost causers (unlike NEM, or other rates which offset distribution costs). Since the costs are recovered based on individual peaks rather than overall volume of usage, which can vary greatly from year to year, there is also more certainty that the utility will be able to fully recover its authorized return. In this way it reduces risk for the utility. Additionally, advocates argue that demand charges are a charge the industry is already familiar with demand charges, and therefore they should come with a smaller learning curve.

However, as opponents argue, there are many unknowns and uncertainty surrounding the use of demand charges on classes other than C&I – mainly regarding customer impacts. Empirical data on the impacts and customer acceptance and responses to residential and small commercial demand charges are insufficient. In a review of residential demand charge rate designs, RMI identified only 25 demand charge rates offered to residential customers.⁷⁵

While demand charge structures may encourage reduction in peak (depending on how peak is defined), it may not send an adequate conservation signal to reduce usage, if implemented with an associated reduction in kwh/volumetric costs, and subsequently the costs of generation (as compared to volume-based rates). Additionally, demand charges do not assist in customer understanding of the rate design as there is a small margin for customer error; higher bills can be earned-result through a shorter timeframe of a lapse of attention (*i.e.*, too many appliances on at once) and also can result in the possibility of higher bill volatility from month to month. Lower income customers (or those with low load factors) are especially hard hit as they can may have less control over their peak demand usage. Lastly, demand charges, if atoo large a portion of a customer's distribution bill, would over collect customer costs as demand costs.

Importantly, many parties on all sides of the issue seem to recognize the potential for using demand charges sparingly (*i.e.*, to represent a dollar or two on an average bill) and when measuring demand coincident with system peaks,⁷⁶ but the number of opponents quickly grow as the utilities begin to depend more and more on these rates for recovering their distribution system costs.

Some utilities have proposed using demand charges in conjunction with NEM rates. Since the NEM rates usually provide a credit against consumption on a volumetric basis, charging a residential customer their distribution costs through KW-based rates eliminates the possibility that NEM compensation is shifting costs. This practice, however, would not compensate or charge DER customers for any benefits, or additional costs, they represent to the grid.

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Page 13

Comment [A13]: We would say "customers' individual peak demands typically do not vary as significantly as their overall volume of usage from year to year."

As discussed below, the demand charge success will be largely driven by the fine details of the structure imposed – ultimately who pays what portion of the charge and the parity of that allocation.

Fixed Charges and Minimum Bills (p 54-55)

Fixed charges (also called customer charges, facilities charges, etc.) are rates that do not vary by any measure of use of the system. Fixed charges have a long history of use across the United States, and are a fixture of many bills. Fixed charges have been used by utilities to recover a base amount of revenue from customers for connection to the grid. Some argue that, as the majority of a utility's costs are fixed (at least in the short run), fixed charges should reflect this reality and collect more (if not all) of such fixed costs. Others argue that higher fixed charges dilute the conservation incentive, fail to reflect the appropriate costs as fixed (long-term rather than short term), or should only be set to recover the direct costs of attaching to the utility's system.

Higher fixed charges accomplish the goal of revenue stability for the utility, and, depending on the degree to which one agrees that utility costs are fixed, match costs to causation. However, the interplay between collecting more costs through a fixed charge and the volumetric rate may result in uneconomic or inefficient price signals. Indeed, an increase in fixed charges should come with an associated reduction in the volumetric rate. Lowering the volumetric charge changes the price signal sent to a customer, and may result in more usage than is efficient. This increased usage can lead to additional investments by the utility, compounding the issue. This potentiality also highlights the disconnect between costs and their causation that a higher fixed charge may have. If higher usage leads to increased investment, then it may be appropriate for the volumetric rate to reflect the costs that will be necessary to serve it, which would point towards the appropriateness of a lower fixed charge. In other words, it may be more reasonable to lower the fixed costs and increase the volumetric rate, which would send a more efficient price signal.

A related movement is the adoption of a minimum bill component. California, which does not have a fixed charge component for residential customer bills, adopted a minimum bill component to offset concerns raised by its regulated utilities regarding under-collection of revenue due to customers avoiding the costs of their entire electric bill. In other words, some NEM customers in California were able to zero out the entirety of their bill, and avoid paying the distribution utility any costs. In a decision revamping its rate design, the California PUC adopted a minimum bill component, which ensures that all customers pay some amount to the utility for service. The California PUC set a minimum bill amount at \$10, which is collected from customers who have bills under \$10. Massachusetts passed the Solar Energy Act ("MA Solar Act"), Chapter 75 of the Acts of 2016 in April 2016. The MA Solar Act allows distribution companies to submit to the DPU proposals for a monthly minimum reliability contribution to be included on electric bills for distribution utility accounts that receive net metering credits.

Proposals shall be filed in a base rate case or a revenue neutral rate design filing and supported by cost of service data. On the other hand, minimum bills eliminate a conservation signal by encouraging consumption up to the minimum bill amount.

In either event, distribution utilities often dispute which components are fixed and should be recovered from customers. As discussed previously, there is a great deal of disagreement as to what constitutes a fixed cost. Are overhead costs fixed? What portion of the distribution system is fixed? Understanding and identifying what are "fixed costs" is a key component to determining compensation to DER, revenue recovery for the utility, and how to best balance utility financial health and the growth of DER.

Standby and Backup Charges (p 55-58)

Standby service is service available to a full- or partial-self-generating utility customers to protect the customer from loss of service in the event of an unanticipated outage of its own self-generating equipment. Standby service is provided through a permanent connection in lieu of, or as a supplement to, the usual internal source of supply. It is power generally not taken, but available on an almost instantaneous basis to ensure that load is not affected. Of course, any and all generation sources are subject to failure from time to time. Therefore control areas and utility systems maintain reserves, including reserves that are operating and ready to pick up load. When utilities operated almost all of the power plants on the system, standby power was supplied by all generators to all generators, and it was an implicit part of the system of operating reserves supported through charges for retail service. Only large non-utility generators, such as combined heat and power systems, faced fees for standby service. Now, with the advent of ever larger portions of non-utility generation, the subject of the cost of providing standby service comes up anew.

Standby charges are charges assessed by utilities to customers with DER systems that do not generate enough electricity to meet <u>all</u> its needs or may experience a planned or unplanned outage and therefore must receive power from the grid. These customers are commonly referred to as "partial requirements" customers. The standby charge is assessed by the utility to assist in the payment of grid services and standby generation and is usually comprised of a demand charge\$/kW and an energy charge based on a \$/kWh basis. These charges recover both the cost of the energy used to serve the customer as well as the costs of the utility for providing the capacity that has the ability to meet the peak demand of the customer receiving the standby service.

These charges are generally approved by state regulators primarily due to system reliability concerns of utilities. With the increase of DER systems on the grid, some parties fear that utilities are assessing these charges to discourage customers from investing in DER systems because projects become uneconomic with standby fees even though <u>these parties claim that</u> the DER project is providing benefits to the grid.

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Comment [A14]: In my view distribution rates should be designed to recover embedded costs based on the long-run marginal costs.

Comment [A15]: Also, for a planned outage.

Comment [A16]: Or the Nameplate rating of the generator which is the maximum output of the generator, whichever is lower

Electric system operators must be able to maintain satisfactory system conditions in the presence of changes in conditions, both on the production side and on the consumption side. They must be prepared for the largest contingencies that can befall their systems. Sometimes this kind of preparation is referred to as "n-1" or "n-minus-one" preparation. This relates to the planning for large system events, such as the loss of a transmission line or a commercial generating unit. In the traditional case of nearly all generation being supplied by utility-operated plants, standby is provided by all for all. However, with the advent of significant amounts of generation being supplied by non-utility generators, including DER, not explicitly accounting for the cost of standby power may provide a cost advantage to the non-utility generators and may be a cost burden upon traditional non-generating customers. It would never be the case that any single DER would rise to merit attention in a list of important contingencies for an electric system.

Backup service is similar to standby service except that it is a planned service and is usually not available on an instantaneous basis. When commercial generators plan maintenance, they provide long notice to the system operators and generally make contract arrangements for reliable backup service to maintain local area load, as well as system load. There may be regulated tariffs for backup service for commercial generators, but they are not common for DER, such as behind-the-meter systems of small commercial and residential customers. Still the term "Backup service" may, in some cases be used in the same way as "standby service."

Both backup charges and standby charges have been associated with large commercial and industrial systems, both load and generation.86 Historically, they are most associated with nonutility generating systems, such as large self-generation systems at industrial plants and with combined heat and power cogeneration systems. They exist so that utilities and system operators are not saddled with costs of maintaining large reserves beyond mere prudence. They have not generally been associated with intermittent generating sources except for large commercial-sized projects whose output (or lack of output) could alter system operations and requirements.

The relevance of standby service to DER is that if a distributed source of power fails, the utility or other load-serving entity must be prepared to meet the load. Generally there is no direct purchase of standby service for DER, particularly at the residential or small commercial level. Power plants, including large commercial renewable energy resources, may make standby arrangements and may pay specific standby charges.

Even though most DER are small and operate independently, a large number of small DER in aggregate, if they all do the same things at the same time, whether planned or not, could rise to the level of an important contingency. For example, a large number of household PV systems, just a few kilowatts each, spread throughout a service territory, and all responsive to the same sun and the same clouds, could, and should, be considered an important planning contingency. Since PV generation is concentrated in the early afternoon, and their production drops off in a

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Comment [A17]: is out of service

very predictable manner as the afternoon wears on, it may be difficult for the system operator to manage the system. The resulting net load, the load that the electric system must dispatch, can be counted on to vary up and down each day in response to the pattern of the PV systems. Sudden system changes, such as a change in cloud conditions, could make for a combined reduction in output that would be worthy of system operators' attention. However, there does not seem to be a call for specific standby charges for small distributed energy resources, particularly for behind-the-meter resources, at this time.

If there is a reason for standby and backup service for DER systems, there will be a cost of providing it, of course. And if it were not charged to the DER system owners, that cost would still exist. Only it would have to be absorbed by the system overall and by the non-participating customers in the form of higher costs or in the form of lower reliability. If it is determined that system reliability will suffer without greater reserves than could be justified for a system without DER resources, then by all means, the DER customers should pay for the service. Instituting an explicit standby charge for DER would allow for the cost causer to pay for the costs associated with the standby service for which the utility provides. A study of the requirements of the utility by determining what customer demand may have to be met when the DER system goes down, either planned or unexpectedly, may produce evidence of considerable costs.

In considering whether to implement a standby charge or backup service charge, regulators should consider the policy impacts of requiring all DER to pay a small tariff to support standby power availability. When the concentration of PV and other DER generating systems becomes greater than it is now, that question should be considered again. Without a study of the actual costs of additional reserves required for system reliability, it is possible that a naïve calculation of the standby charge may overstate the actual costs to the system and the needs of the customers. Any charge would need to be justified directly and not be allowed to discourage the investment by customers.

Advanced Metering Infrastructure (p 63-64)

According to <u>the U.S.</u> Energy Information Administration, <u>utilities have installed</u> nearly 52 million advanced meters have been installed across the residential customer class throughout the United States as of 2014. These advanced meters are capable of measuring consumption in 15 minute to 1 hour increments. The meters are connected to a communications network and are then able to transmit the consumption information back to the utility's backoffice for billing. This stands in stark contrast to the historical mode of metering, which usually occurred once a month.⁴ Some modes of automated meter reading were capable of reading daily, in support of specific tariffs, but were not implemented widely. In other words, utilities have gone from having 12 data points a year about a customer to 8,760 data points, if measured hourly. If

⁴ Some modes of automated meter reading were capable of reading daily, in support of specific tariffs, but utilities did not implement this technology widely.

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Comment [A18]: and the benefits provided by DER

is also possible that This technology also can enable customers tocan now access that same amount of information; instead of waiting for the monthly bill, customers can log-on to their utility's webpage and access their hourly usage information, typically on a 24 hour lag. The uses offor this information is still in its infancy and is likely to evolve over time.

With the installation of advanced meters, implementing rate <u>variant</u> designs like TOU, CPP, and real-time pricing becomes possible at lower costs than in the past. An integral part of an advanced metering system is a <u>two-way</u> communications network. That network allows the meter to communicate <u>with the utility</u> and <u>can</u> send information, like consumption, <u>to the</u> <u>utility</u>, and<u>but</u> also <u>allows the utility to communicate and send information receive messages</u>, like prices or demand response signals, <u>to the customer</u>. This two-way flow of information means that the utility can <u>continuously</u> provide customers with usage, price, and cost information over the course of the month rather than only once, <u>via the monthly billat the end</u> of the month.

Advanced meters also often includes a second radio to support a Home Area Network (HAN). The HAN is capable of transmitting information, including usage, voltage, and generation data to a router or other in-home display in as often as eight second increments. This communication is supported by Zigbee (IEEE 2030.5), which is a low-power communication standard. In-home displays or routers can connect to the customer's Wi-Fi networks and any other devices inside the customer's home that support Wi-Fi, including thermostats.

With this new data and new communication networks, regulators can have a better understanding of potential customer responses to rate designs by having access to more granular data sets and expanded phased roll-outs of new rate designs. Furthermore, with this information, customers can better understand the potential impacts of installing DER at their location or signing up for community DER programs. By being able to "do the math," customers can identify the financial impacts to themselves and understand whether it makes sense to invest in DER or not. With policies supporting the development of HAN and data access, it may be possible to identify additional services from the home itself that may be beneficial to the grid, either individually at the premise or aggregated across a specific geography.

Lastly, advanced meters are not only capable of collecting consumption information about a premise, but can also collect generation data related to an on-site DER (e.g., such as solar, and voltage), to name two. By being able to collect this information, advanced meters can be used to facilitate compensating DER for <u>energy</u>its generation <u>and any</u>, as well as a number of other services that a regulator chooses to allow. Such policy development presumes a large enough amount of DER is present across the distribution system as to impact delivery of electricity. Use of data generated by advanced meters can assist regulators to identify potential DER compensation methodologies, and have the data available to support the viability of the methodology as well as us it for settlement and compensation.

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Comment [A19]: We do not necessarily agree with the "large enough" qualifier here. It may be relevant for compensating DERs with respect to distribution system impacts, but even for a single DER with no measurable distribution grid impact there might still (at least theoretically) be energy supply/commodity impacts that may be relevant for DER compensation policy development? (see Cross Subsidies, NEM, and Valuation Methodology sections of this Manual)

Comment [A20]: We deleted this sentence because it seemed to repeat the point of the 2^{nd} sentence.

For many utilities, the amount of DER interconnected to its electrical system increases each year. The increased penetration of DERs poses additional challenges for electric utilities. In order to support the adoption levels of DER, utilities may seek additional infrastructure and technological support to assist in maintaining reliability and enhanceing resiliency of the electric systeme. Two options Two tools for meeting these challenges include an Advanced Distribution Management System (ADMS) or a Distribution Energy Resources Management System (DERMS). ADMS adds levels of communication, intelligence, and visibility into the distribution grid for the distribution utility to better understand real-time conditions across its distribution service territory. ADMS provides the utilities with several specific functions that automate system operations and optimize the grid performance, such as automated fault location, isolation, and service restoration (FLISR), conservation voltage reduction, and volt/VAR optimization. 99 Installing ADMS is not merely about better integrating DER; rather, ADMS will change how a utility operates and where a utility envisions itself and customers in the future. As customers continue to adopt technology and DER continues to grow, having the information about the grid that is possible from ADMS investments will help the utility meet customer demands while maintaining safety, reliability, resilience, and flexibility.

With higher levels of DER adoption, DERMS builds upon an ADMS network, and provides functionality that increases an operator's real-time visibility into its underlying distributed asset capabilities. DERMS can allow the utility to dispatch resources, both on the utility side and the customer side, forecast supply and demand conditions up to 24 to 48 hours in advance, better integrate AMI data with other utility systems, such as ADMS, outage management, and weather systems, and communicate with third party/aggregator systems. 100 DERMS can also be used to support islanding and microgrid features, which may provide additional value to both the customers and the utility in certain times of need.

Both DERMS and ADMS are suites of technology solutions that can enable the distribution utility to better understand, plan, operate, and optimize the increasing amount of DER<u>5</u> showing upintegrated across a service territory. Understanding the costs and benefits of these technologies, and how they can be use to better plan, price, and value the DER across a service territory can be very helpful in designing and implementing more advanced compensation methodologies. Indeed, by being able to make DER a dispatchable resource, technology can help mitigate and minimize risks to the reliability of the distribution grid. Utilizing technology to turn DER into a resource that can be counted on and dispatched may open up new value streams to the utility and the consumer.

Smart inverters (p 65-66)

As with the availability of technology on the utility side, there are technology options also available to customers. One specific technology is a Smart Inverter. For solar PV installations, an inverter is necessary to <u>switch-convert</u> electricity from Direct Current (DC) to <u>an</u> Alternating Current (AC). The grid, including the local distribution grid, uses AC power, so before electricity

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Comment [A21]: 99 "Voices of Experience: Insights into Advanced Distribution Management Systems," Department of Energy (February 2015) (https://www.smartgrid.gov/files/ADMS-Guide_2-11.2015.pdf).

Comment [A22]: 100 "Inside SDG&E's Plan to Optimize the Distributed Grid of the Future," Greentech Media (May 16, 2014) (http://www.greentechmedia.com/articles/read/sd ge-and-spirae-break-new-ground-on-the-grid-edge).

generated by a solar PV installation can be exported onto the grid, it must be changed converted into AC. More recently, this inverters can now be outfitted with additional software that can accomplish additional services. For example, a Smart Inverter is capable of actively regulating the voltage of the solar PV's output. As clouds pass over a solar PV unit, the voltage can drop on the electricity that is exported onto the grid causing drops in voltage at that location; in order to raise the voltage levels up, the transformer capacitors will step in and can be activated to provide voltage support. Having a Smart Inverter that can address voltage drops before exporting to the distribution grid is a value and service that can be provided by the customer, and deferring or avoiding additional distribution upgrades.

In many cases, the Smart Inverter is now included in new solar PV installations. Indeed, the recommendation of the California PUC Smart Inverter Working Group, subsequently adopted by the California PUC, is to require Smart Inverters for all new solar PV installations seeking to interconnect with the distribution grid upon completion of the safety standard currently pending before Underwriters Laboratory. Utilizing the capabilities of the Smart Inverter to allow for the generation or storage resource to autonomously manage and balance the flow of electricity, and other ancillary services, like voltage ride-through, can be enabled and valued through appropriate compensation methodologies, especially in areas of high solar PV adoption. Regulators should continue to monitor progress on adoption rates of Smart Inverters and the standards development process for this technology and capability.