Review of State Net Energy Metering and Successor Rate Designs

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Any remaining errors or omissions are my own doing. As always, I invite readers to notify me if they notice anything that needs correcting, and I welcome ideas about future research projects.

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List of Acronyms Used

DER – Distributed Energy Resources

DG – Distributed Generation

IRP – Integrated Resource Plan

kW, kWh – kilowatt, kilowatt-hour

MW, MWh – megawatt, megawatt-hour

LCOE – Life-cycle Cost of Energy

NEB – Net Energy Billing

NEG – Net Excess Generation

NEM – Net Energy Metering

PPA – Power Purchase Agreement

PSC – Public Service Commission

PUC – Public Utility Commission

PV – Photovoltaic

REC – Renewable Energy Certificate

T&D – Transmission and Distribution

TOU – Time-of-Use

VDER – Value of Distributed Energy Resources

VOS – Value of Solar

Review of State Net Energy Metering and Successor Rate Designs

Executive Summary

The objective of this paper is to summarize actions now being taken in many states to change rate designs for distributed energy resources (DER) on the customer side of the meter. Net energy metering (NEM) has been the most common rate design used for customers with small-scale generators that provide what is sometimes known as self-service power. Recently, there has been considerable interest in finding alternatives to net metering by legislatures and public utility commissions (PUCs), with some related deliberations underway or recently concluded in at least 48 states and the District of Columbia. These actions sometimes arise from preexisting legislative or regulatory requirements that trigger reviews when the total installed NEM system capacity or energy production, either for individual utilities or statewide, reaches a predetermined threshold. In other cases, regulatory reviews have been requested by utility companies through proposals to replace net-metering with other alternatives.

Alternative proposals to supplant net metering include rate designs with various combinations of: (a) compensating for energy delivered to the grid at a price other than the retail service rate; (b) increasing fixed charges and sometimes also minimum bills; (c) time-varying rates; and (d) adding demand-charges to bills for customers who did not previously have them. Several states have considered creating a separate rate class for customers with distributed generation (DG), whereas others have made provisions for utility ownership of DG under specific circumstances. Another important factor included in this review is the treatment of customers who entered into NEM arrangements under previous rate designs. There is often some provision for grandfathering, allowing customers to continue operating under a previous rate design for some period after the new rate becomes effective.

In some jurisdictions, the proposed or adopted changes affect all residential and small commercial customers, whereas in others the changes apply only to NEM customers. In some jurisdictions, NEM or successor rate designs also apply to customers participating in variations of aggregated, neighborhood, or virtual net metering, which often also includes participants in community-solar projects. The rates for community solar participants are often somewhat different from customers with on-site DG, but they are sometimes considered part of the same overall tariff.

This NRRI briefing paper includes reviews of changes to NEM or DG program rate designs. The changes resulted from either new legislation that directs state commissions to make changes, or changes that state public utility regulatory commission have already adopted, or both.

The review encompasses legislative changes that have occurred since 2014 and regulatory changes that took effect by mid-2018 or earlier. It draws from and expands upon information provided in the North Carolina Clean Energy Technology Center's *50 States of Solar* series; particularly, the *4th Quarter Report and Annual Summary for 2017* (2018a) and *Q1 and Q2 2018 Update Reports* (2018b and 2018c).

Table 1 provides a summary of recent changes to NEM rate designs that are already effective for one or more utility companies in those states listed.

Table E-1: Policy Types Already Adopted by States

Policy Types	Vertically Integrated States	Restructured States
NEM 2.0 or NEM Successor Tariff[1]	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT	CT, DC, MA, ME, NY
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI	ME, NY, OH, TX
Increasing (decreasing) customer fixed-charges[2]	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV	(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX
Assigning demand-charges or stand-by charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT	MA, NH
Creating a separate customer class for DG	IA, ID, KS, MT, NV	TX
Providing for third-party or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT	DC, NY, RI, TX
Adding provisions for community solar[3]	CA, CO, HI, MN, NC, OR, VA, VT, WA	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, RI

Source: NCSU CETC *50 States of Solar* report series, 2015 through 2018.

1 See Figure 2, p. 12.

2 In these instances, the decisions result from specific regulatory commission orders and affect individual utility companies.

3 See Figure 4, p. 37. Several states have provisions for community solar programs that treat participants as virtual or remote net metering customers. Listed here are those states where legislation provides for community solar programs. Many more states have one or more active community solar projects, but as yet have no statewide law or rules: Most often, those projects were proposed by individual utility companies and approved by state regulatory commissions (or, for those utilities that are not state regulated, were approved by their municipal or cooperative regulatory bodies). See Stanton and Kline 2016.

Organization of Paper

Part I introduces the subject matter of this report and includes four sections.

The first section briefly describes the major drivers that are causing policy makers and utilities to focus attention on this topic and the second section provides observations about the implications of those drivers for possible changes in rate design. The third section reviews one of the major decisions regarding rate designs for DER, which is whether rates should be based primarily on estimates of the value that the resources produce and provide to the utility system or to society at large, or if it is better to base rates on the costs of the DER systems.

The last section of Part I introduces the eight major types of state actions that are included in this review:

- Net metering replacement or successor tariffs, sometimes called "NEM 2.0";
- Comprehensive reviews of different rate designs for customers with DG;
- Changing the rates for net excess generation (NEG) or for all energy delivered to the utility grid;
- Increasing monthly fixed charges for residential and small commercial customers;
- Adding demand charges or standby charges to rates that previously had none;
- Treating customers with DG as a new customer class;
- Providing for third-party and/or utility ownership of DG; and
- Enabling community solar projects.

Part II summarizes the changes taking place in the nineteen states that are actively updating or replacing NEM tariffs and rules. This part of the paper focuses on the period from 2015 through the first half of 2018. In addition, summaries of actions are presented for two states where NEM was never fully implemented, but similar policy changes are being considered.

Part III reviews additional related actions that are ongoing in many states. Those include:

- Comprehensive reviews of rate designs for customers both with and without self-service power, underway in 14 states;
- Commission decisions in 34 states, affecting about 125 utility companies, changing fixed charges for small customers (mostly increases, but recently a few decreases, too);
- Eleven states have added system-capacity based demand charges, as-used demand charges, flat grid-access fees, or standby charges for customers with DG;
- Six states have taken actions toward treating customers with distributed generation as a separate class for ratemaking purposes;
- Third-party ownership of customer-sited DG, as approved in 34 states, and utility ownership approved in seven states, with decisions pending in four more; and
- Legislative or regulatory actions in 20 states, enabling community solar projects, and many additional states approving specific utility-run community solar projects.

Part IV presents conclusions and recommendations, which are shaped by four primary observations:

(1) There is no consensus about which rate designs are most suitable for updating or replacing retail NEM;

(2) Differences in the existing markets and rates of growth for NEM and DER technologies, and differences in electric utility industry structure, should help inform policy makers about the kinds of rate design changes that are most appropriate for each jurisdiction;

(3) In the near term, at least some related actions are underway in almost every state, as shown in Table E-1, so it is important for all interested parties to observe how those actions are affecting markets for NEM and more generally for DER; and,

(4) Many important questions remain, for continuing research and analysis of the changes presently underway, including:

- How do NEM rate changes affect the rate of adoption of DG or even broader DER technologies? Are the markets for DG and DER still in the earliest stages of consumer adoption, or are some technologies already starting into emerge into uninhibited market growth?
- How big are the potential markets for community solar? What kind of offerings work best for low- and middle-income participants?
- In states that create a separate rate class for DG customers, what can we learn about the class usage patterns? How similar they are to non-DG customers? And, how do the class usage patterns affect utility costs of service?
- Are studies of the value of solar, the value of DER, and utility costs of service measuring the right benefits and costs? Are they measuring all of them? Finally, are the measuring methods valid and reliable?
- Are there marked differences in DG markets between jurisdictions allowing versus prohibiting third-party ownership? If yes, what are those differences?
- In jurisdictions with utility-led programs, utility ownership, or both, what happens to market growth rates? And, what happens to competition?
- If the policy approaches are different in vertically integrated and restructured states, how are they different?

An Appendix provides additional descriptions of related actions in ten representative states, five with vertically integrated and five with restructured electric utility industry structures. The states reviewed in this appendix have each engaged in more than one of the actions included in the review completed for this project. The five vertically integrated states are Arizona, Georgia, Hawaii, Minnesota, and Vermont. The five restructured states/ jurisdictions are the District of Columbia, Illinois, New Hampshire, New York, and Texas. The appendix is available for downloading from the NRRI website, at http://nrri.org/download/appendix-nem-policies.

I. Introduction

The purpose for this report is to summarize recent changes in rate designs applied to net energy metering (NEM) and other tariffs that apply to distributed generation (DG). It is based on reviews of state legislation, recent decisions by state public utility commissions (PUCs), and to a lesser extent, on open dockets and utility company tariffs complying with commission decisions.[1,2,3] This updates an earlier NRRI report addressing similar topics (Stanton, 2015).

The eight major types of rate design approaches and policy changes included in this review are listed in Table 1. It provides information for states with vertically integrated industry structures (listed in rows without shading) and restructured utilities (listed in rows with blue-shading) that have already taken actions to enact those changes by mid-2018 or earlier.[4] Almost every state listed in Table 1 has engaged in one or more actions related to these kinds of changes.

The vast majority of utility regulatory jurisdictions have either statewide programs or individual utilities that offer some version of what is variously called NEM or similar programs typically referred to as net energy billing. The federal Energy Policy Act of 2005 (EPAct 2005) amended the Public Utility Regulatory Policies Act (PURPA), to include the following standard that states are required to consider, but not required to adopt:

> Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period (16 U.S.C. 2621(d)(11)). State PUCs and non-state-regulated utilities were directed to consider the adoption of this net metering standard by August 2008 (Flores-Espino 2015, p. 4).

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1 This report is based on a snapshot at one point in time. Many of the actions discussed in this report remain under review and changes are taking place rapidly. The intent is to provide a broad view, characterize the types of changes that are being considered, and summarize decisions that have been made to date. Readers aware of any needed corrections, additions, or deletions are invited to contact Mr. Stanton, at NRRI. Please email tstanton at nrri dot org.

2 This review includes information about nearly all of the 50 states, plus the District of Columbia. Throughout the report, the word "state" is used to refer to any of the 51 jurisdictions.

3 This review does not include tariffs for merchant power plants, meaning facilities that are in the business of generating and selling electricity. Rather, it focuses on DG used by a customer, primarily to offset their own use of electricity that would otherwise be purchased from a regulated utility or competitive electricity supply company.

4 For a map showing restructured states, see U.S. Energy Information Administration, *Electricity retail choice states, 2010*, at https://www.eia.gov/todayinenergy/detail.php?id=6250. However, note that this source includes among restructured states both Oregon and Michigan, though electricity retail choice is restricted in those two states: In Oregon only large non-residential customers are eligible for "direct access" service (OARD Chapter 860-038: Direct Access Regulation) and Michigan restricts what it calls "Electricity Choice" to not more than 10 percent of each utility's annual sales (MCL 460.10a). Because the competitive offerings in those states are so limited, in this document Oregon and Michigan are listed as vertically integrated.

Table 1: DER Policy Types Recently Adopted by States

Policy Types	Vertically Integrated States	Restructured States
NEM 2.0 or NEM Successor Tariff[1]	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT	CT, DC, MA, ME, NY
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI	ME, NY, OH, TX
Increasing (decreasing) customer fixed-charges[2]	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV	(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX
Assigning demand-charges or stand-by charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT	MA, NH
Creating a separate customer class for DG	IA, ID, KS, MT, NV	TX
Providing for third-party or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT	DC, NY, RI, TX
Adding provisions for community solar[3]	CA, CO, HI, MN, NC, OR, VA, VT, WA	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, RI

Source: NCSU CETC *50 States of Solar* report series, 2015 through 2018.

1 See Figure 2, p. 12.

2 In these instances, the decisions result from specific regulatory commission orders and affect individual utility companies.

3 See Figure 4, p. 37. Several states have provisions for community solar programs that treat participants as virtual or remote net metering customers. Listed here are those states where legislation provides for community solar programs. Many more states have one or more active community solar projects, but as yet have no statewide law or rules: Most often, those projects were proposed by individual utility companies and approved by state regulatory commissions (or, for those utilities that are not state regulated, were approved by their municipal or cooperative regulatory bodies). See Stanton and Kline 2016.

By 2015, 43 states and the District of Columbia had NEM programs for at least some of their regulated utility companies.[5] NEM was "arguably the most widespread state distributed solar policy in the country" (NCSU-CETC 2016, p. 13).

The major impetus for actions to replace NEM is the concern that NEM customers could drive their utility bills so low that they would not be making their fair contribution to utility fixed cost recovery. A 2013 report from the Edison Electric Institute raised concerns about "disruptive challenges" and "game changers" for the electric industry, from a combination of factors including the rapid and increasing growth of distributed generation, especially solar photovoltaic systems, as well as the flat or slow-growth of energy sales, and rate designs where most fixed costs are recovered through volumetric charges (Kind 2013). That report proposed several changes in policy, including:

- Ending subsidies for distributed solar;
- Instituting higher fixed charges;
- Increasing charges for interconnection, for utilities managing increasing variability in supply and demand, and for backup supply;

5 Some state laws and rules apply to all electric utilities, but others apply only to state-regulated utilities and sometimes to additional, specifically identified non-state-regulated utilities. Non-state-regulated utilities often offer NEM or NEB programs as directed by their own boards of directors.

- Revising NEM programs to treat credits as utility "purchases at a market-derived price"; and
- Considering exit fees for partial requirements and "fully departing" customers, "to recognize the portion of investment deemed stranded as customers depart."

Many utilities and some other interested parties subsequently described NEM as a program that was inherently causing cross-subsidies to be paid by non-participating customers to participating customers. Because the vast majority of NEM customers use solar photovoltaic systems, and markets for those systems were growing rapidly in some jurisdictions, such factors led to widespread perceptions that NEM programs, originally intended to support nascent markets for marginally cost-effective solar PV, have served their purpose and the time has come to replace them with cost-based or value-based tariffs.

The logic supporting alternatives to retail compensation for NEM is that those customers who are supplying some of their own power by self-generating are still making extensive use of the existing utility grid in two very important ways: (1) as a sink for excess generation whenever their usage of electricity is less than the output of their on-site generator; and (2) for receiving supplemental energy whenever their local usage is greater than the production of their on-site generator. A reverse argument, however, is that exports from NEM customers are a service that the customer provides to the utility system, and the regulatory treatment should appropriately compensate NEM customers for the services they are producing and delivering.

Advanced metering can account for those times when excess power is being delivered, either in small intervals by meters capable of recording the outflow of electricity from the generator into the grid (or from the generator in excess of the customer's usage during the same time interval), or by netting outflow in excess of inflow over the course of a billing period.

In a traditional NEM tariff, the credit for excess generation delivered to the grid is equal to the full retail price that the same customer pays for energy purchases from the grid. Whether NEM results in a subsidy for distributed solar is a complex question, which cannot be answered without detailed analysis, utility by utility. To this end, many states have engaged in studies of the long-term benefits and costs of distributed solar. A majority of these studies find that NEM results in a net benefit, at least at the levels of participation in the present time and near future. (Muro and Saha 2016; RMI 2013; Darghouth, Barbose, et al. 2014).

In any case, increasing numbers of state public utility regulators have adopted multi-tier rate structures for self-generators, where the rate for excess energy delivered to the grid is different from the rate charged for the energy the same customer receives from the grid. These new rates for exported energy differ by jurisdiction, based on variations of (a) a calculation of the value of the energy delivered to the grid, particularly for solar energy (referred to as a VOS rate), or (b) a commission-approved "avoided cost" to the utility, which is most often derived from the wholesale price of energy that the utility would otherwise have to generate itself or purchase in a wholesale market.

In states with open markets that reveal wholesale power prices, a supply rate can be used as the credit proxy. That can help simplify calculating the credit amount, although even then it can be difficult to reach any consensus on exactly how to do so. For example, should the credit rates include both capacity and energy costs bundled into an average rate at all hours, or should the credit be differentiated by the prices at the specific times energy is delivered? And, how should transmission charges and line-losses be included in such calculations, if at all?

A. Implications for rate design

The time pressure associated with such changes depends, in large part, on how fast DER options are spreading and how much those changes affect utility revenues. Table 2 presents a high-level summary of a range of different conditions of existing DER markets. It is intended to present a preliminary picture of how the depicted differences might relate to different parties' perceptions of the time pressure for making policy changes.

Table 2 names three market types, based on their general market conditions as described in the second row and as characterized by the general benefit/cost comparisons shown in the third row. Readers can think of markets for solar PV, especially, as gradually having moved from left to right as equipment has improved in conversion efficiency, reliability, and durability while also declining in cost (Woodhouse, Jones-Albertus, et al. 2016). The same general trends in learning-curve improvements hold true for most manufactured products (Rogers 2003).

In the earliest stages, the market for solar PV could be termed "uneconomic," because systems were high-priced, such that participating customers would receive only modest returns on investment and payback periods were lengthy. By and large, that meant that the early customers were either true believers or innovators—the few who might not care so much about financial returns, but might be motivated by their interest in solar power and self-reliance, or their status among their peers as innovators. Eventually, however, the performance of solar PV equipment improved and costs declined, partly as a consequence of its policy driven adoption, which often included the impacts of multiple government support policies promoting solar, such as grants, loans, and tax incentives. In concert with those changes, some jurisdictions moved into the pre-economic and eventually grid-competitive positions shown in the final column of the table.

Table 2: Preliminary Model of Different DER Market Conditions

Market Model Name	Price Support	Transitional	Price-competitive
General market condition	Uneconomic	Pre-economic	Grid-competitive
B/C ratio[1]	B < C, slow if ever ROI	B ≈ C, modest ROI or payback under optimistic scenarios	B > C, patient ROI, reasonable payback under many scenarios
LCOE to VDER comparison	LCOE > VDER	LCOE= VDER	LCOE < VDER
Other relevant support policy impacts	Low	Medium	High
Types of adopters[2]	True believers, Innovators	Early adopters	Early majority
Market share for DER[3]	~1% or fewer customers	~1 to 2.5%	>2.5%
DG, NEM growth rates[4] (customers or capacity)	< 1/3 per year	1/3–2/3 per year	Annual doubling or more
Trend in total utility sales levels	Growing or flat	Growing, flat, or declining	Flat or declining
Time pressure for regulatory actions	Low	Medium	High

Source: Author's construct based on Taylor, McLaren, et al. 2015 (NREL/TP-6A20-62361) and adapted from Rogers 2003, *Diffusion of Innovations, Fifth Edition*.

1 The benefit/cost (B/C) ratio takes into account utility rates and includes as benefits available support policies, like financial incentives, plus any other costs DER can avoid.

2 Adopter types from Rogers 2003.

3 Market share characterizations shown are the author's construct based on Rogers 2003 and observations of NEM growth reported by U.S. Energy Information Administration.

4 DG, NEM growth rates depicted here are the author's construct, based on personal observations and published solar market data. Depending on the purpose for analysis, growth rates might be measured in terms of cumulative capacity or numbers of customers.

Table 2 also describes market conditions in general terms of the relationship between the lifecycle cost of energy (LCOE) and the value of DER (VDER). The LCOE from any new DER measure represents an estimate of the productivity of the measure, compared to the cost to implement and maintain the measure over its useful lifetime. Analysis can also be used to compare VDER to the embedded costs for the pre-existing utility infrastructure. The benefit/cost information can be quite similar, depending on what benefits and costs are included in analysis. LCOE/VDER analysis can be used to explore two different perspectives: (1) the investor perspective comparing cost to value; and (2) the utility or social perspective, which looks at LCOE in terms of the embedded costs in the pre-existing utility system that are reflected in current and predicted future rates. In considering VDER, it is important to recognize that VDER will often decline over time as the cumulative production from those resources increases: The DER resources supplant marginal utility supplies, but as DER supplies increase, the marginal benefits gradually approach the average cost (Darghouth, Barbose, et al. 2014). Generally, this means that the value of the early, small numbers of DER measures is greater, perhaps equal to or possibly even exceeding current retail prices, but as the deployment numbers expand, the VDER will eventually converge toward the average wholesale prices.

There would presumably be strong causal links among the market conditions shown in Table 2, including: (a) each general market condition, including the financial viability of self-generation and the relationship between LCOE and VDER, based in part on the effects of "other relevant support policies"; (b) the types of adopters attracted; (c) the achievable market share, and, (d) annual growth rates as measured by either cumulative capacity or numbers of customers.

The trend in total utility sales can be thought of as an independent variable. Sales lost to self-generators represent only one of many relevant factors in rate-setting and revenue recovery. In the early market stages those losses have a relatively small influence on total utility sales. Similarly, various parties' perceptions of the time pressure for regulatory actions can be affected by many factors, and those perceptions could diverge widely among different interested parties and policy makers.

In addition to measures of DER equipment cost and performance, there can be other features of state policy and regulatory landscapes that support or hinder DER adoption (Stanton 2015, pp. 21, 23). Hledik and Lazar conclude that multiple influences shape "the role for policymakers and state regulators." Important among those influences would be the existing: (a) state policy guidance about utility regulatory support of DERs; (b) the scope of non-regulatory state support programs; (c) industry structure and determinations about regulated utility responsibility for power supply, including utility ownership; and, (d) rates of DER deployment. Hledik and Lazar state:

> In jurisdictions with rapid deployment and vertically integrated utilities, there is likely a need for more rapid movement toward some sort of discrete pricing for the distribution services needed by and provided by DERs. Regions with slow deployment may be able to learn from experiences in fast-deploying jurisdictions… before adopting policies and pricing frameworks (Hledik and Lazar 2016, p. 8).

Hledik and Lazar assume a future with widespread adoption of DER, and review four different approaches towards packaging and pricing grid services, both for the services that the utility provides to its customers and for the services that DER might provide to the utility. The four approaches include:

(1) granular retail rates, where each service is "discretely priced… [and] [e]ach price is calculated so that expected sales will generate the overall revenue requirement determined by the regulator;"

(2) retail buy/sell arrangements, where "[c]ustomers pay retail prices for all services delivered by the utility system [and] they are paid separately for any discrete services they supply to the grid;"

(3) procurement model, where "[t]hird-party aggregators maintain the direct business relationship with DER customers, pricing services on a competitive basis;" and,

(4) DER-specific retail rates, where, "[c]ustomers with DERs pay separate tariffs for service, based on the unique service characteristics of their requirements [and] [s]tandardized credits are calculated for services provided by DER customers… ."

Hledik and Lazar review rate design options based on five major criteria: (1) economic efficiency; (2) equity/fairness; (3) customer satisfaction; (4) utility revenue stability; and (5) customer price/bill stability. They compare the alternatives from the utility perspective, and from the perspectives of both participating and non-participating consumers (Hledik and Lazar 2016, pp. 32-34).

As the NARUC *Manual on Distributed Energy Resources Rate Design and Compensation* explains, it is important for jurisdictions to determine the level and pace of adoption of DERs before deciding what, if any, policy reforms are needed. There are different impacts on each utility system that result from increases in the numbers and types of interoperated DERs. Before taking any reform actions, policymakers should request and review data, analyses, and studies for their own jurisdictions. Policy reforms that are rushed and not well thought out can have unintended consequences, including creating volatile business conditions of boom and bust cycles for DER businesses. It is necessary to understand how current policies and their associated growth rates in DER adoption are affecting: (a) utility system costs and revenues; (b) DER business models; and, (c) the costs and benefits that accrue to different DER technologies and services. Once those factors are well understood, policy makers can consider changes in rate designs, along with any changes in other support policies (*Manual* 2016, p. 59).

B. Value-based or cost-based rates for distributed resources?

Changes to NEM tariffs are often premised on whether rates for self-generation are more appropriately based on estimates of value or cost. Initially, NEM was largely understood to be an administratively simple, rough-justice approach that was acceptable at a time when markets for solar PV and other DG were uneconomic. In many of the initial decisions about NEM, policy makers assumed that the retail rate was a close-enough proxy for the value of solar or value of DG, and the total numbers of participating customers and kilowatt hours being credited at the retail price were relatively small: The product of the close-proxy rate, representing a rough approximation of the avoided cost of utility generation or purchases that would otherwise be needed if NEM generators did not export some energy to the grid. When NEM was just getting started, the small number of participating customers multiplied by the small quantity of energy each would deliver to the grid, meant that any error associated with under- or over-estimating the true value would be small. Barbose (2017) explores "the potential effects of distributed solar on retail electricity prices," and on utility revenues. That study models the effects on both the utility cost of service and retail electricity prices, at both the relatively low participation levels in most jurisdictions today, and at much higher projected future participation levels, when as many as 5, 10, 15, or 20 percent of all eligible customers might participate.

Now that some markets are shifting into the new status of transitional or price competitive, and larger numbers of customers are demonstrating their interest in obtaining and using DG and other DER, policy makers are demonstrating much greater interest in alternative rate structures and in establishing credit rates that accurately reflect benefits and costs.

At the heart of decisions about DER rate design are fundamental determinations about the expected value of distributed resources and decisions about whether to design rates based on value, cost, or some mix of the two. This has led many states to engage in studies to determine the VOS or VDER through studies. There are already roughly two dozen completed studies in over one dozen states (RMI 2013; Taylor, McLaren et al. 2015). Interestingly, there is little consistency in the findings from those studies to date. The studies have not all included the same list of potential benefits or costs, nor have they all used the same measurement methods. Thus, the resulting values range widely, from as little as 4¢/kWh to as much as 30¢/kWh, with a mean value of 16¢/kWh (RMI 2013).

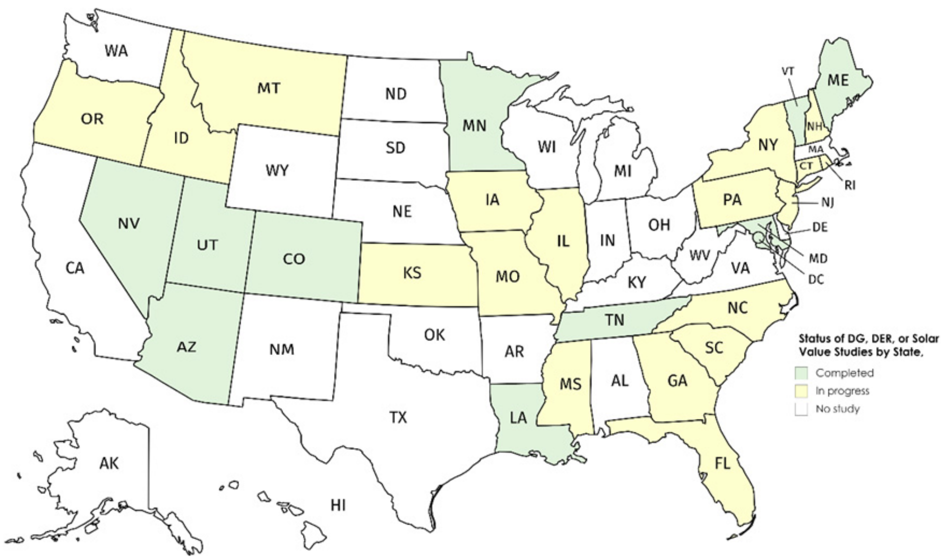
Figure 1 shows the 11 states that have recently completed value-based studies, along with 18 other states that have proceedings in progress for completing value-based studies. States are included in Figure 1 if they have studies recently directed by state legislatures or regulators. The map does not include several other states where individual utility companies or other interested parties completed studies; many such studies have been completed by academic researchers, hired consultants, and utility companies. Several states are forming stakeholder groups to provide input and decision-making about study parameters and methods. In Figure 1, states are marked as pending even if one or more value-based studies has been completed for that state, as long as a study requested by state regulators is not yet completed.

At present, there is no "one size fits all" system for completing these studies. Fundamental differences of opinions remain among different interested parties about both the identification of benefit and cost categories to be included, and the appropriate methods and time horizons to use for estimating what those benefits and costs might be. Different states even use different names for some of the same benefit and cost categories (NCSU-CETC 2018b, p. 27).

Another important parameter is the time-period of study, as many benefit and cost values are different in the short term as opposed to long term, and uncertainty increases the farther into the future studies try to predict. In addition, different cost and benefit components change over time, in response to different causes. Similar to other utility future modeling exercises, value studies can model a variety of scenarios and sensitivities. Examples include variations in fossil fuel supply costs; future global climate change policies; and the rate of DER market adoption (Bradford and Hoskins 2013; RMI 2013; Taylor, McLaren et al. 2015; Whited et al. 2017).

Several states are beginning to investigate benefits and costs in more detail, looking at seasonal and daily variations in the price of grid electricity, at locational value, and studying combinations of multiple DER technologies, most notably combining on-site generation with energy storage.

Figure 1: Map of States with Completed and In-Progress Value-Based Studies (2014–3rd Quarter 2018)



Source: NCSU-CETC, 2016-2018e, *50 States of Solar* report series.

These value-studies can serve multiple purposes, not just rate setting. VOS or VDER can be calculated and used as a point of reference to see how current estimates relate to wholesale avoided costs or retail prices, and to understand how current and near-term future DER costs compare to the calculated values, with and without various financial incentives and other policy supports. One consistency that does emerge from several of these studies to date is a recognition that distributed resources are generally more valuable than bulk power in the wholesale market, due mainly to cost savings because of reduced transmission and distribution system losses, and often adding some estimated value for environmental benefits. But, several studies have also concluded that distributed resources are less valuable than the full retail rate.

Another purpose for VOS or VDER studies is to apply prices derived from them to some, but not all, participants in DER programs. For example, New York is applying VDER prices to large DG generators, and Minnesota is applying them to community solar participants, but neither state is applying VDER prices to customers participating in other aspects of NEM or DG programs.

A few states have decided that studies should focus on embedded costs rather than value. The Kansas Corporation Commission has directed that compensation rates should be cost-based and not include any unquantifiable values, an approach also being considered in North Carolina and Louisiana. The 2017 North Carolina law, HB 589, G.S. 62-126.7, states specifically that both costs and benefits have to be considered. State commissions in South Carolina and Utah have also directed utilities to complete cost-of-service studies for DG customers prior to making any further changes to the existing NEM programs.

C. Types of policy decisions in this review

This review covers eight major kinds of proposals or decisions adopted by either state legislatures, public utility commissions, or both. Most of these actions took place between 2015 through the third quarter of 2018, although a few predated 2015. In addition, this report includes some discussion about activities slated for completion in late 2018 or after.

The actions reviewed here include state legislation and state regulatory commission orders addressing:

- Net metering replacement or successor tariffs, sometimes called "NEM 2.0";
- Comprehensive reviews of rate designs for customers with or without distributed generation;
- Changing the rates for net excess generation (NEG) or for all energy delivered to the utility grid;
- Increasing monthly fixed charges for residential and small commercial customers;
- Adding demand charges or standby charges to rates that previously had none;
- Treating customers with distributed generation as a new customer class;
- Providing for third-party and/or utility ownership of distributed generation; and
- Enabling community solar projects.

Several states are also considering or have adopted) time-varying or time-of-use (TOU) rates. The same TOU rates can be applied in both directions, to charges and credits, or different TOU rates can apply to retail sales versus customer export to the grid. That policy is related to and can be combined with several of the eight policies reviewed for this report.

II. Early Actions on Net Energy Metering Successor Tariffs

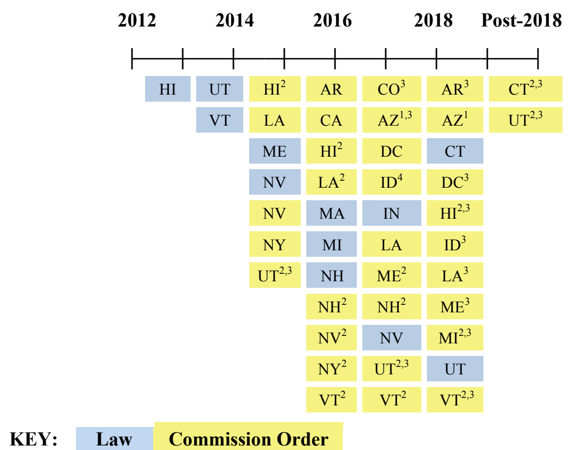
In several states, one or more of these actions has been adopted in response to a legislative or regulatory directive to review NEM, sometimes with the explicit intention of establishing a new approach to billing and crediting customers with on-site generation. Those successor tariffs are sometimes called "NEM 2.0," but they often change the rate structure in ways that differ from the definition of NEM, as that term is typically defined:

> Net metering "compensates a customer for excess generation [with] credits for exported energy deducted" from the amount charged for electricity purchased from the utility during a billing period, and compensation "at the retail rate" at least as long as the credit for excess generation is not greater than the bill for the customer's usage during the billing period. If excess generation exceeds the customer's usage during the billing period, some credit amount other than the retail rate can apply, but the compensation mechanism would still be called net metering (NCSU CETC 2017, p. 16).

A few states have already moved far down the path toward finalizing decisions about replacements for NEM, including Arizona, California, Hawaii, Massachusetts, and Vermont. Several additional states have made decisions about ending previous NEM programs, although decisions about replacement tariffs are still pending. These include Connecticut, Idaho, Indiana, Louisiana, Maine, Michigan, New Hampshire, New York, and Utah. The process for investigating and deciding on an NEM alternative is also underway in Arkansas, although there has not yet been a decision about whether or when to end the previous NEM program.

Figure 2 provides a timeline of both legislative and regulatory actions geared towards developing NEM successor tariffs. As Figure 2 illustrates, the process of developing NEM successor tariffs is typically sequential, with the legislature triggering actions in most states, followed by one or more Commission actions. In two states, Nevada and Utah, the legislature made two rounds of changes during the time frame depicted. From Figure 2 and from the state descriptions that follow, it is clear that these procedures are tending to be time consuming and often contentious. It often takes as long as a few years to complete these actions; indeed, almost every state that has been engaged in these efforts still has commission decisions pending regarding particular implementation details.

Figure 2: Timeline of States Adopting NEM Successor Tariffs



Notes: [1] Indicates a decision affecting only one or more individual utility companies.
[2] Indicates additional state legislative or regulatory actions, subsequent to the enabling laws or rules.
[3] Indicates pending regulatory decisions.
[4] Idaho does not have statewide NEM legislation. The Idaho PUC has directed individual regulated utility companies to file NEM tariffs.

Source: Author's construct.

SIDEBAR 1: DEFINITIONS

Most jurisdictions refer to these programs as NEM, but there are many subtle differences in program designs that can result in at least some blurring of distinctions.[a] Therefore, some researchers are proposing standard definitions for these kinds of tariffs. North Carolina State University Clean Energy Technology Center researchers (2017, p. 16; box 2) propose definitions for net metering and net billing. In addition, several states have considered or adopted a "buy all, sell all" rate, and one state, Michigan, is considering a variation called an "inflow/outflow" rate. Those basic rate designs can be described as follows:

- **Net metering** "compensates a customer for excess generation [with] credits for exported energy deducted" from the amount charged for electricity purchased from the utility during a billing period, and compensation "at the retail rate" at least as long as the credit for excess generation is not greater than the bill for the customer's usage during the billing period. If excess generation exceeds the customer's usage during the billing period, some credit amount other than the retail rate can apply, but the compensation mechanism would still be called net metering (NCSU CETC 2017, p. 16).

- **Net billing** compensates a customer for excess generation using a rate other than the retail rate for consumption, after netting production and consumption over intervals shorter than the billing period (e.g., 15-minute or 1-hour intervals). "The rate for compensation varies by state and utility. It is usually lower than the retail rate, but is often higher than the monthly average rates paid in the wholesale electricity market." And, similar to net metering, the customers can use their on-site generation to meet their own on-site needs, which effectively reduces grid-supplied electricity that would otherwise be purchased at the full retail rate (NCSU CETC 2017, p. 16).

- **Buy-all, sell-al**l rates have participating customers purchase all of their service from their utility company, usually at the same retail rate that would apply if the customer did not have on-site generation; however, some specific charges might apply only to customers with on-site generation. Then, all of the energy generated by a participating customer is separately metered during each billing period, and that output is credited at a commission-approved price. Buy-all, sell-all rates treat all on-site production the same, regardless whether the energy is consumed on-site or exported to the grid. Some programs require all of the output to be delivered to the grid, not behind the customer's meter, but that is a policy decision, rather than an essential factor.

- **Inflow/outflow** rates are a variation of net billing. This approach was proposed in Michigan by Public Service Commission (PSC) Staff and was then adopted in principle by the Michigan PSC (April 18, 2018 Order in Case No. 18383). Michigan legislation in 2016 called for developing a new, "cost-based" tariff for distributed generation, to replace Michigan's preexisting NEM program.[b] Similar to a buy-all, sell-all or net billing rate options, in the inflow/outflow tariff framework, customers pays the standard retail price for all energy delivered through their meter, called inflow, just as other customers who have no on-site generation. When a customer's generator produces electricity that is consumed on-site, the customer avoids purchasing that energy at the regular retail rate. Then, all exported energy during a billing period, called outflow, is metered and a commission-approved rate other than retail will be applied to that energy. The preliminary Michigan PSC staff proposal was to credit outflow at the Commission-approved PURPA avoided-cost rate established for each utility. With the inflow/outflow method, on-site usage of on-site generation is treated as a simple reduction in use, equivalent to other reductions in usage due to energy conservation or efficiency improvements.

a For example, North Carolina Clean Energy Technology Center researchers note: "Maine calls its system 'Net Energy Billing' though it fits the standard definition of net metering, and Mississippi calls its new system 'Net Metering' even though it more closely resembles net billing" (January 2017, p. 43).

b See https://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html.

A. State actions to change existing NEM tariffs and program rules

To date, major actions to make changes to NEM tariffs and program rules have been undertaken in 19 states and the District of Columbia. Those actions include:

ARIZONA[6] – In a January 2017 Order in Docket No. E-00000J-14-0023, the Arizona Corporation Commission decided to end retail rate net metering and begin crediting customers at an avoided cost rate for solar energy injected into the grid. Customers will be credited at the retail rate for energy generated and used onsite. For power above their own needs, customers will be paid an avoided cost rate, based on the 5-year running average price of utility-scale solar, including both power purchase agreements (PPAs) and utility self-built solar systems, plus an additional amount to represent avoided transmission and distribution (T&D) capacity and line-losses. The credit rates are to be determined in rate cases for each of the state's three investor-owned utility companies. In addition, the Commission has determined that rooftop solar customers shall be treated as a separate class for ratemaking.

Arizona's existing net metering rules are codified in A.A.C. R-14-2-2301 through 2308. In a November 2017 Order in Docket No. E-00000J-14-0023 (p. 4) the Commission directs staff "to gather comments and hold workshops as necessary to develop a proposed Net Metering and Export Rate [and] develop draft rules for Commission consideration." Revisions are currently being considered in Docket No. RE-00000A-17-0260.

ARKANSAS – Act 827 of 2015 directs the state's PSC "to ensure net metering rates, terms, and conditions are appropriate to recover the full utility costs of serving net metering customers, net of any quantifiable benefits." A Commissioner Order is pending in Docket No. 16-027-R. Briefs and Reply Briefs have been filed.

Companion Docket No. 16-028-U was expanded in December 2017 to investigate and address broadly defined DER issues, and a recent Order No. 10 directs the participating parties to file comments on procedural issues, including how multiple substantive issues and sub-issues involving grid modernization and power sector transformation should be organized and addressed by stakeholders and the Commission. The Commission expects to engage a facilitator by the end of 2018 to assist the Commission and the parties with organizing, hosting, and addressing issues in workshops, working groups, and technical conferences over the next two years or more.

CALIFORNIA – The generic rulemaking proceeding for developing net energy metering successor tariffs in California is Docket No. R1407002. One successor tariff was adopted in Decision 16-01-044 January 28, 2016.

In California, net metering was initiated by 1995 legislation, and subsequently amended multiple times. A Commission order in 2008 added virtual net metering for multi-family affordable solar housing and it was further expanded in 2011. Aggregated net metering was authorized by 2012 legislation. In 2013 a new law, AB327, directs the Commission to develop a successor tariff "based on the costs and benefits of the renewable electrical generation facility [and ensuring] that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" (see Decision 16-01-044, pp. 12-16).

The NEM successor tariff, among other details, provides for: minimum bills; non-residential NEM customers paying fixed charges applicable to their customer class; NEM customers paying non-bypassable charges on all kWh of inflow during each metered time interval; residential customers taking service under any TOU rate available to them; and the successor tariff calls for maintaining and updating both virtual net metering and net metering aggregation (Decision 16-01-044, pp. 2-5).

6 See also Appendix, p. A-2.

A second phase of this docket has been established, for developing alternatives for "residential customers in disadvantaged communities, and… consumer protection and evaluation measures for the NEM successor tariff (Decision 16-01-044, p. 5). Decision 17-12-005 in December 2017 modified virtual net metering to facilitate pairing eligible generation with energy storage. Tariff alternatives for disadvantaged communities were issued in a June 2018 Decision 18-06-027.

COLORADO – The Commission opened Docket No. 17M-0694E in 2018 to review its rules regarding electric resource planning (ERP), Colorado's Renewable Energy Standard (RES), and Enabling New Technology Integration. A March 2018 Colorado law, SB 18-009 (CRS 40-2-130), states:

> Colorado's consumers of electricity have a right to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees (CRS 40-2-130(1)(b)(II)).

Docket No. 17-M-0694E is considering proposals for amending: (a) existing rules to accommodate energy storage, to include non-wire alternatives and to take into account any and all demand-side resources in ERP; (b) distribution system planning; (c) interconnection rules; (d) PURPA implementation; (e) net energy metering; and (f) provisions for including low-income customers in community solar gardens.

CONNECTICUT – Public Act No. 18-50, passed in May 2018, broadly addresses Connecticut's Energy Future. It includes provisions for updating the Connecticut renewable portfolio standard, which is now set to grow annually from 21 percent after January 1, 2018, until reaching 44 percent on January 1, 2030. In addition, the law directs the Public Utilities Regulatory Authority (PURA) to develop program requirements and tariff proposals for shared clean energy facilities.

The new law initiates the process of replacing net metering with either buy-all sell-all or net billing options, and directs PURA to establish the new rates. Existing net metering customers are grandfathered until year-end 2039.

DISTRICT OF COLUMBIA[7] – In Formal Case 1130 (FC1130), the PSC proposes amendments to the District's net metering rules, renewable energy portfolio standard, electricity quality of service standards, small generator interconnection rules, and more. Amendments to the District's net metering rule include new definitions for customer generator; backup generation; energy storage and microgrids; and revised definitions for cogeneration facilities, combined heat and power facilities, demand response, and distributed energy resource.

An RM-9 Working Group is being assembled to consider NEM and interconnection rules, including rules affecting community renewable energy facilities (CREFs).

HAWAII[8] – Net metering successor tariffs were first approved by the Hawaii PUC in October 2015, and were revised in an October 2017 Order in Docket No. 2014-0192. Participating customers can choose a customer-self-supply option with no credits for grid export, or one of two additional tariff options: (1) "smart export" for solar plus storage systems; or, (2) "controllable grid-supply" with advanced inverter functions enabled and subject to utility control. Compensation for energy exports under both options is set below the retail rate. In a June 2018 Order No. 35563 in Docket No. 2014-0192, the PUC approved Hawaiian Electric Companies' smart export tariff and invited comments on the Companies' proposed controllable grid supply tariffs.

7 See also Appendix, p. A-14.

8 See also Appendix, p. A-2.

IDAHO – In a May 2018 Order No. 34046 in Case No. IPC-E-17-13, the Idaho PUC discontinued Idaho Power Company's previous net energy metering rate, and started the process of introducing a successor tariff. The Commission determined that "use [of] the grid to both import and export energy" should be treated as a separate class for assigning both costs and benefits. This Order starts the process of creating a separate rate class, but "does not change rates, rate design, or the current compensation credit structure for on-site generation customers."

The Commission directed the Company to file tariff advice regarding advanced inverter capabilities under IEEE Standards 1547-2018, and to initiate a new docket "to study the costs and benefits of net metering on Idaho Power's system, proper rates and rate design, … [and] compensation for net excess energy… ." The Commission also directed the Company "to undertake a comprehensive customer fixed-cost analysis to determine the proper methodology and 'spread' of fixed costs… ." The Company is also directed to "file a study… exploring fixed-cost recovery in basic charges and other rate design options prior to its next general rate case."

In a September 2018 Final Reconsideration Order No. 34147, the Commission states that it is "open to the possibility" that non-exporting customers might be removed from the Company's net metering schedules. The Commission directs, "a non-export option should be studied for feasibility and vetted for safety and operational concerns by the Company and interested stakeholders in the forthcoming docket." The Order does, however, direct that "for now," non-exporting DG customers would be considered in the same separate customer class as exporting DG customers (Order, p. 16).

ILLINOIS – Illinois started updating NEM rules in 2015, in Illinois Commerce Commission (ICC or Commission) Docket No. 15-0273. The Commission's November 12, 2015, Order in Docket No. 15-0273 outlines the changes in NEM rules. Some of the changes respond to updated legislative directives and others result from workshops conducted with electricity providers (see April 26, 2016, Order in Docket No. 15-0273, p. 1).

Effective in June 2017, new legislation titled the *Future Energy Jobs Act* (S.B. 2814), directed Illinois utilities to allow meter aggregation "for properties owned or leased by multiple customers, individual units within single buildings that are owned or leased by multiple customers (e.g., apartments or offices), and community renewables projects." The law established community renewable energy programs, and created a "Solar for All" program promoting community solar options for low-income customers. The same law also created a solar set-aside within the state's renewable portfolio standard (RPS), setting quotas for RECs from different kinds of projects including: new wind; PV projects, with separate quotas for distributed, utility scale, and brownfield redevelopment projects. The Illinois community renewable generation program created by the Act in §1-10, is not only for solar PV systems but can also support "community projects powered by wind, solar thermal, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams."

In March 2017, the ICC opened a broad, grid modernization proceeding known as NextGrid. NextGrid working groups are focused in part on DER topics, including VDER, DER grid integration, environmental impacts of DER, ratemaking, which includes both time-varying rates and VDER, and distribution system planning.

INDIANA – Indiana Act No. 309 of 2017 triggers a transition to a net billing arrangement to replace net metering. "Indiana will close net metering to new customers by July 2022 or when the state's 1.5% aggregate cap is reached; new customers entering net metering arrangements before this date are grandfathered until July 2032 only." "Indiana will begin to credit customers at 1.25 times the avoided cost rate in July 2022 or once the 1.5% aggregate cap is reached, whichever occurs first." The legislation defines avoided cost as "the average marginal price of electricity paid by the electricity supplier during the most recent calendar year." Indiana utilities are directed to file proposed avoided cost rates, not later than March 1, 2021, and "may request… recovery of energy delivery costs attributable to serving customers that produce distributed generation."

LOUISIANA – In December 2015, the Louisiana PSC opened Docket No. R-33929, to modify net metering rules and consider changes to solar policies. The Commission's General Order No. 12-8-2016 adopted revised rules. Utilities were directed to file updated tariffs within 30 days from the effective date of the new rules. The new net metering tariff provides for net excess generation to be compensated at the utility's Commission-approved avoided cost rate; however, the Commission indicates it may also approve, on a utility-specific basis, "alternative avoided cost rates such as seasonally differentiated avoided cost rates or average avoided cost rates that reflect upward adjustments for avoided line losses and daytime, on peak generation."

In Phase II of this proceeding, the PSC "is reviewing additional changes to its NEM Rules intended to address on-going concerns and have general applicability to all small-scale DG technologies." The Commission issued its *Phase II Notice of Proposed Modified Rules and Request for Comments* in November 2017, and directed parties to file comments by December 29, 2017. A decision is pending.

MAINE – In 2015, the Maine legislature adopted a Resolve, which states in part, "[I]t is in the public interest to develop an alternative to net energy billing that fairly and transparently allocates the costs and benefits of distributed generation to all customers, allows participation by all customers and creates a sustainable platform for future growth of distributed generation to the benefit of all ratepayers." The legislature overrode Governor Paul LePage's veto, to pass this resolution, which directs the Maine Public Utilities Commission to convene a stakeholder group to develop an alternative to net metering. This action was in response to a 2015 report prepared by Strategen Consulting for the Maine Office of the Public Advocate (OPA), titled *A Ratepayer Focused Strategy for Distributed Solar in Maine*.

The Maine PUC opened Docket No. 2015-00218, for this stakeholder process, which culminated in a January 30, 2016 *Report to the Legislature*. As stated in that *Report* (p. 7), "The stakeholders reached substantial agreement on a large number of important aspects of a market-based solar development policy and on some aspects of an alternative to [net energy billing] [but,] there was no stakeholder consensus on an overall solar program."

In September 2016, the PUC opened rulemaking Docket No. 2016-00222. In its Notice of Rulemaking, the Commission stated its intention to gradually reduce the percentage of kilowatt hours that customers could net against transmission and distribution charges, reducing the number by 10 percent per year starting with customers who begin net energy billing in 2017, until "after the year 2025, there would be no netting of the T&D bill" (September 14, 2016 Notice of Proposed Rulemaking, p. 5). The Rule would also increase the eligible facility size from 660 kW to 1MW, and allow for and include provisions governing community-based net energy billing.

In a March 2017 Order, the Commission adopted amendments to the rule, which moves to a buy-all, sell-all framework including a gradual phase-down of the credit rate. The Commission subsequently issued a December 2017 Order in Docket No. 2017-00308, temporarily waiving the revised rule's implementation schedule "to provide stakeholders further opportunity to resolve all outstanding technical issues." Central Maine Power and Emera Maine filed revised net energy billing tariffs in Dockets Nos. 2018-00037 and 2018-00038, respectively. In a March 2018 Order in both Dockets, the Commission rejected the Companies' proposed terms and conditions, and directed the companies to refile, reflecting the Commission's decisions in that Order. The Companies' revised tariffs were then filed and approved, in March and April 2018.

In the Commission's most recent action on the NEB program, an August 2018 Order in Docket No. 2018-0037 directs the Commission Staff to establish a "Rapid Response Process (RRP) to settle disputes over NEB metering costs" and to work with the utilities and solar installers "to explore the feasibility of utilizing inverters that include revenue grade meters and other relevant emerging technologies to reduce the costs to install a meter to measure the gross output of an NEB facility" (Order, pp. 1, 5).

MASSACHUSETTS – The Massachusetts legislature passed a new law in 2016, "to provide… for the continued support of solar power generation and a transition to a stable and equitable solar market at a reasonable cost to ratepayers." That law provided that once the installed capacity of solar net metering in Massachusetts reached 1,600 MW_{dc} (direct current), credits for excess energy would decline to a value known as "market net metering credits" (Acts 2016, Chapter 75, §4b). Those credits would be reduced for residential and commercial customers, compared to credits accruing to municipalities or other government agencies. In general, the credits would be based on the distribution company's default service charge, plus distribution, transmission, and transition charges, all per kWh (Chapter 75, §3). Residential and commercial customer credits would be set at 60 percent of that product, whereas municipalities and government agencies would be entitled to the full amount. Massachusetts calls this net metering replacement its "Solar Massachusetts Renewable Target (SMART) Program." Details about the program are found in the Code of Massachusetts Regulations, 225 CMR 20.[9]

The legislation, in Chapter 75, §11, directs the Commission to promulgate rules for the SMART Program that will, among other things: (a) promote the orderly transition to a stable and self-sustaining solar market at a reasonable cost to ratepayers; (b) rely on market-based mechanisms or price signals as much as possible to set incentive levels; (c) minimize direct and indirect program costs and barriers; (d) encourage solar generation where it can provide benefits to the distribution system; and (e) promote investor confidence through long-term incentive revenue certainty and market stability. The legislation also explicitly supports community-shared solar facilities, solar for the benefit of low-income customers, and solar for municipal and other government facilities.

The Department of Public Utilities (DPU) issued an Order in Docket No. 17-140-A on September 26, 2018, that implements the SMART program. Massachusetts utilities were directed to file new tariffs in compliance with the Order, by October 15, 2018. The Order (p. 72) addresses data collection and monitoring for the SMART program, and indicates the Commission will direct changes to the program if necessary to achieve the legislated goals.

The program calls for compensation rates to be set for blocks of capacity for each distribution company, and to decline by four percent as each block of capacity is filled. Extra credits called compensation rate adders will be available based on: (a) the location of solar generators (e.g., building mounted, floating, on brownfields, or landfills); (b) off-takers for the solar energy, such as solar projects for community-shared, low-income, or public entities; (c) systems co-located with energy storage; and (d) systems using two-axis solar tracking. In addition, the program includes provisions for subtracting from the base compensation level for systems located on greenfield properties (225 CMR 20.7).

Also, in Docket 17-146, the Massachusetts DPU is investigating "the eligibility of energy storage systems to net meter… and the participation of certain net metering facilities in the Forward Capacity Market… ." In its initial Order, the Commission asked parties to respond to a series of questions about both issues (October 3, 2017 Order in D.P.U. 17-146).

MICHIGAN – Public Act 341 of 2016 (MCL 460.1173) directs the Michigan PSC (MPSC) to establish a new DG tariff, to replace the previous net metering program based on 2008 legislation. The new law specifically calls for the Commission to "conduct a study on an appropriate tariff reflecting an equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program… ."

A February 2018 MPSC Staff Report recommended that the successor to NEM should be an inflow/outflow billing mechanism, with retail rates paid for on-site consumption delivered by the utility, retail rate offsets for on-site production used on-site, and another rate paid for grid exports. In its April 18, 2018, Order in Case No. U-18383

9 See also the Massachusetts DPO press release on the SMART Program Order, at https://www.mass.gov/news/department-of-public-utilities-issues-order-to-continue-solar-development, and Massachusetts Department of Energy Resources (DOER) information on the SMART Program, at https://www.mass.gov/solar-massachusetts-renewable-target-smart.

(p. 18), the Commission "requires the rate-regulated utilities to file the inflow/outflow tariff in their next post-June 1, 2018 rate case… [but] will also permit a rate-regulated utility to file an alternative DG tariff if desired, to enable a thorough evaluation of all viable DG tariff options."

Detroit Edison's rate case, in Docket No. U-20162, is the first following that Commission Order. Detroit Edison proposes in Rider 18 that DG customers pay the full retail price for electricity inflow, and that outflow would be credited at the company's monthly average real-time locational marginal price for energy. The company also proposes instituting a monthly "system access charge" for DG customers, based on the installed nameplate capacity (see Gearino 2018).

Upper Peninsula Power Company is the second Michigan utility, in Docket No. U-20276, filing proposed tariffs for DG customers, following the Commission Order. The utility's proposal is to charge the full retail rate for inflow, and credit outflows according to the power supply charge for the relevant rate class. The power supply charge represents an average annual value for energy only. The company also proposes that outflow credits could not be used to offset non-energy customer charges. And, the utility proposes that all new DG customers would pay a system access charge based on DG system capacity, but the company did not specify the amount of that charge.

NEVADA – New state legislation passed in June 2015 revised net metering provisions (SB374, NRS 774.773 et seq.). Nevada's net metering law initially passed in 1997, and was amended in 2001, 2005, 2007, 2011, 2013, 2015, and 2017. The 2015 amendments (SB374) revised the cap on cumulative capacity for utilities to offer net metering, required utilities to submit tariffs by July 31, 2015, and directed the Commission to review and approve or disapprove of the tariffs by December 31, 2015.

In Dockets Nos. 15-07041 and 15-07042 the PUC of Nevada took action to end net metering and replace it with net billing. The initial decision by the PUC did not grandfather pre-existing net metering customers, but instead moved them to the new tariffs. However, in September 2016, in an approved settlement agreement in Dockets Nos. 16-07028 and 16-07029, grandfathering would be allowed for 20 years.

In February 2016, the Commission issued a Modified Final Order on net metering tariffs for Nevada Energy Companies in Dockets Nos. 15-07041 and 15-07042. In that order, the Commission determined that non-NEM customers were subsidizing NEM customers by an average amount per residential customer of $471 to $623 per year. The Commission stated, "[T]he Legislature expressly prohibited the Commission from adopting rates that unreasonably promote NEM and authorized the Commission to avoid, reduce, or eliminate an unreasonable shifting of costs from NEM ratepayers to non-NEM ratepayers" (Order, p. 167).

The Modified Final Order created separate rate classes for NEM customers and the basic service charge was increased to include additional distribution costs, compared to non-NEM tariff rates. Additionally, net metering was replaced by net billing, in which NEM customers would get a credit for all excess energy delivered to the grid after hourly netting. The credit was based on the long-term avoided energy cost with an adder for avoided distribution line losses.

The Modified Final Order set up a process for a gradual transition to cost-based rates (for both the increased basic service charge and the reduced credit for excess energy) for all NEM customers. The order established a 12-year process for a gradual transition to cost-based rates for all NEM customers, with changes occurring in five steps that each would increase prices and reduce net excess energy credits by 2028. By 2028, NEM customer billing would include fixed charges comprised of customer and distribution costs from the most current cost-of-service study, resulting in an increase in the basic service charge compared to non-NEM customers, of as much as about $25 to $30 per month. The Commission stated:

> A 12-year timeframe for all NEM customers to date represents an approximately $100 million subsidy that non-NEM ratepayers will have to pay to cover the costs to serve NEM ratepayers that are not recovered from NEM ratepayers during the transition period (Order, pp. 160-161).

The Commission also directed NV Energy to include a separate line item titled "net energy metering subsidy" on non-NEM customer electric bills until the transition is completed on January 1, 2028 (Order, p. 162).

In December 2016, in Docket No. 16-06006, the PUC called for: (a) restoring retail rate net metering in Sierra Pacific Power's territory; (b) authorizing up to 6MW of new net metering using full retail rates, until the new general rates would be set by the start of 2020; (c) grandfathering new NEM customers through November 2036; and (d) retaining a separate rate class for NEM customer-generators (Order, p. 56). A stipulation in that Docket covered all aspects of Sierra's rate case except net metering. A hearing was held regarding the NEM portion of rate design and the Commission, through its order, restored retail rate net metering.

Legislative amendments in 2017 (AB405) provide for net metering for small customers (not more than 25 kW), beginning with credits based on 95 percent of the full retail rate that the customer would have otherwise paid for energy when excess energy was delivered to the utility, and then decreasing in percentage terms for new customers as small-net-metering capacity is added in 80MW blocks, until the credit reaches 75 percent of the full retail rate. The bill also directs the PUC to report to the legislature about the impact of net metering by June 30, 2020, and biennially thereafter. Among other things, the reports are to include calculations showing: (a) if net metering has an impact on rates; (b) the amount of rate increase or decrease, if applicable; and (c) data used to determine the rate impacts, including avoided generation capacity, avoided transmission capacity, avoided system upgrades, and the impacts on utility capital expenditures (Act 405, §28.5).

That law also created a Renewable Energy Bill of Rights for Nevada residents. The Bill of Rights provides, in part, that customer-generators have the right to:

1. Generate, consume, and export renewable energy and reduce his or her use of electricity that is obtained from the grid;
2. Use technology to store energy at his or her residence;
3. Receive "fair credit for any energy exported to the grid"; and
4. Belong to the same existing broad rate class as if in the absence of a net metering system, without any different fees and charges.

On September 1, 2017, in Docket No. 17-07026, the PUC approved tariffs pursuant to AB405. Separate rate classes for NEM customers were eliminated and monthly net metering was restored, with net excess energy delivered to the grid credited at the amount determined by the percentage of retail rates established by AB 405. On March 14, 2018, the PUC approved a stipulation regarding TOU rates pursuant to AB 405.

NEW HAMPSHIRE[10] – In a 2016 law, the New Hampshire legislature directed the state Public Utility Commission "to develop a new alternative net metering tariff or tariffs" (Order No. 26029, p. 2). The stated purpose of the legislation is "to continue 'reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation…while ensuring costs and benefits are fairly and transparently allocated among all customers.'" (Order No. 26029, pp. 70-71). The legislation specified eight factors for

10 See also Appendix, p. A-19.

Commission consideration, including: (1) costs and benefits of customer-generation facilities; (2) avoidance of unjust and unreasonable cost-shifting; (3) rate effects on all customers; (4) alternative rate structures including time-based tariffs; (5) limitations on the amount of eligible generating capacity; (6) the size of facilities eligible for net metering; (7) timely recovery of utility lost revenues, using a lost-revenue adjustment mechanism; and (8) utility administrative processes required for the new tariff implementation (Order No. 26029, pp. 68-70).

The Commission adopted an interim alternative NEM tariff in December 2016 in Order No. 25972, and a successor tariff in June 2017 in Order No. 26029. The Commission states the successor tariff is "in effect for a period of years while further data is collected and analyzed, pilot programs are implemented, and a distributed energy resource (DER) valuation study is conducted" (Order No. 26029, p. 2). In its order, the Commission directs parties to develop and propose for implementation four pilot projects, including: (1) a time-of-use pilot; (2) a program using monetary bill credits "to make the benefits of solar DG system ownership available to low and moderate income customers"; (3) a real-time pricing pilot; and (4) at least one non-wire alternative pilot program in each utility service territory (Order No. 26029, pp. 62-64, 72).

In addition to those actions, New Hampshire is one of six jurisdictions participating in a U.S. Department of Energy supported *Multistate Initiative to Develop Solar in Locations that Provide Benefits to the Grid*. That project is a collaborative effort among several states and the Clean Energy States Alliance, with support from the National Renewable Energy Laboratory.

NEW YORK[11] – A March 2017 New York PSC Order in Case No. 15-02703 directed regulated utilities to file new tariffs "implementing the transition from net energy metering (NEM) to a Value of Distributed Energy Resources (VDER) Phase One Tariff… to become effective on April 1, 2017" (Order, p. 151). The Commission established a temporary Phase One NEM mechanism for service during an interim time period until the Commission implements a "Value Stack" (Order, p. 23). Utilities were directed to develop "locationally-granular prices to reflect the full value to their distribution systems from DER additions" (Order, pp. 19, 155). The Order also set levels for each regulated utility, for capacity to be provided by community distributed generation projects (Order, p. 154). The Commission endorsed a time frame calling for developing a Phase Two VDER methodology and presenting a report on that work, with recommendations to the Commission, by the end of 2018 (Order, pp. 137, 150).

In September 2017, the New York PSC issued another order in the same Docket No. 15-E-0751, implementing VDER tariffs, including the methodology for determining the "Value Stack." The regulated utilities were directed to file new tariffs to become effective on November 1, 2017. The Commission stated, in part:

> Phase Two will include, at a minimum, the following topics: (1) inclusion of DER projects in VDER tariffs on a technology-neutral basis; (2) development of methods to provide equal compensation for reduced consumption and injected generation; (3) a framework for the development and consideration of grid access charges, nonbypassable fees, or other methods to mitigate costs imposed on non-participants; (4) potential changes to default rate design and development of optional rates for VDER participants; (5) improvements and modifications to the Value Stack, including components related to the bulk system, distribution system and societal values; and, (6) transitioning of mass market projects to VDER (Order, p. 137).

Phase Two proceedings began in June 2017 with the formation of stakeholder working groups. Phase Two proceedings are taking place in Docket No. 15-E-0751 and three related Dockets: No. 17-01276, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack; No. 17-01277, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design; and No. 17-01278, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Low and Moderate Income. In July 2018, New York PSC Staff issued reports summarizing comments received from interested parties and "suggesting improvements to the VDER tariff."

11 See also Appendix, p. A-23.

UTAH – The Utah legislature, in 2014, added a provision to the state's utility code chapter on net metering, UC 54-15-105, which directs the Public Service Commission to: "(1) determine… whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits."

The Commission opened Docket No. 14-035-114 in August 2014, regarding the Investigation of the Costs and Benefits of PacifiCorp's [Rocky Mountain Power's] Net Metering Program.[12] In that case, the Commission issued a November 2015 Order which "establishes an analytical framework for assessing the costs and benefits of net metering" (Order, p. 3). In response to that Order, Rocky Mountain Power (RMP) filed requested Cost of Service studies in November 2016. The November 2016 filings also included a proposed tariff to replace net metering, which would include a net billing mechanism with reduced export credit rates, demand charges, and increased fixed charges for small net metering customers.

In September 2017, the Commission issued an Order Approving Settlement Stipulation, which creates a limited-time "Transition Program" to replace net metering for the time being, pending a decision "to determine the compensation for exported power" and then establish a new tariff (Order, pp. 5-6). The settlement parties agreed that RMP would file an application to open a proceeding for determining the appropriate Export Credit rate, and support a schedule for completing that proceeding and establishing the rate, within no more than three years. RMP also agreed "to facilitate a workshop to discuss the type and scope of data expected to be considered in the proceeding" (Order, p. 20).

The proceeding to establish new export credit rates is Docket No. 17-035-61. The Commission issued a Phase I Order in Docket No. 17-035-61, in May 2018. The order instructs RMP to continue load research studies, gathering data from samples of residential and commercial customers for up to 12 months, beginning in the 2019 calendar year.

A 2018 Utah law, S.B. 141, repeals the state's existing net metering provisions on January 1, 2036. RMP's net metering tariff was amended in April 2018 to indicate the December 31, 2035 termination date.

VERMONT[13] – In Act 99 of 2014, the General Assembly directed the Vermont PUC to design a revised net-metering program.[14] A proposed rule was published in October 2016, and a final rule was adopted, effective July 1, 2017. Related documents are indexed on a PUC web page, *Revised Net-Metering Program Pursuant to Act 99*.

The final rule, Rule 5.100, allows pre-existing net metering customers to be grand-fathered for 10 years, and sets up a net metering program where export credits are based on a "blended residential rate" (Rule 5.127). Net metering customers can also receive credit adjustors, plus or minus, depending on REC ownership (whether retained by the customer-generator or transferred to the electric company), and whether systems are installed on "appropriate and beneficial" sites (Rule 5.127).

In Vermont, net metering applications are submitted to the Commission, and the Commission determines whether to grant a Certificate of Public Good, which is required before net metering commences. As part of that review, the Commission checks site plans for compatibility and consistency with state and local land use regulations and aesthetics. The rule also includes provisions for group net metering (Rule 5.130). Rule 5.128 directs the Commission to engage in biennial updates, for the review of REC adjustors, siting adjustors, the statewide blended residential

12 Rocky Mountain Power is the only investor-owned utility operating in the State of Utah.

13 See also Appendix, p. A-11.

14 Previously, Vermont PUC was known as the Vermont Public Service Board. The name was changed, effective July 1, 2017. See https://puc.vermont.gov/news/name-change-public-utility-commission.

rate, and eligibility criteria for four different categories of NEM. The first biennial update is in Docket No. 18-006-INV, where the Commission issued its Order on May 1, 2018. Green Mountain Power submitted net metering tariff revisions on May 15, 2018, in Docket 18-1356-TF. The Commission approved revisions in a June 29, 2018 Order. The definitions for "preferred site" for NEM are being reviewed in Docket No. 17-5202-PET. A July 20, 2018 Commission Memorandum summarizes results from a workshop and sets a schedule for the next steps in the process.

VIRGINIA – The Virginia General Assembly, in 2018 SB 966, initiated many changes to electric utility regulation. Among the many topics addressed in this *Grid Transformation and Security Act* are:

- Exempting electricity storage companies from the definition of "public utility";
- Increasing the capacity of utility-constructed solar and wind generation facilities from 50 to 5,000 MW, including rooftop solar installations of not less than 50kW capacity;
- Authorizing utilities to petition the State Corporation Commission (SCC) for a predeclaration of prudence for a solar or wind project;
- Requiring each electric utility, in its integrated resource plan, to evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects and develop a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, reduction in emissions, and reduction in carbon intensity;
- Directing the SCC to conduct pilot programs for deploying battery storage;
- Requiring electric utilities to investigate potential improvements to NEM programs; and
- Requiring the SCC to submit reports to the legislature after each triennial review proceeding, describing and quantifying the electric utility investments in solar and wind projects and in electric distribution grid transformation projects.

Virginia electric utility, Dominion Energy, hired a consultant to "facilitate a stakeholder engagement process," focusing on four major topics raised in the new Act. The consultant report (Meridian Institute 2018) was submitted to the utility in September 2018. The report focused on four major topics raised in the new *Act*:

- Potential improvements to net metering programs;
- Potential improvements to community solar pilot programs;
- Expanding options for customers with corporate clean energy procurement targets; and,
- Impediments to the siting of new renewable energy projects.

B. Related actions in two additional states

In addition to the nineteen states discussed above, significant actions are also underway in one state that had never adopted NEM, Georgia, and in another, Mississippi, that only recently established an NEM program. Those actions are briefly described here.

GEORGIA[15] – A 2001 Georgia law, O.C.G.A. § 46-3-50, includes basic provisions for cogeneration and distributed generation, including net metering. The Georgia Cogeneration and Distributed Generation Act of 2001 allows, but does not require, net metering. Customers can choose a net metering arrangement or can opt to enter into a buy-all, sell-all relationship. (DSIRE-USA, 2015).

15 See also Appendix, p. A-4.

In August 2016 in Docket No. 20161, the Georgia PSC accepted a settlement agreement for Georgia Power's integrated resource plan. The order accepting that agreement directed Georgia Power to work with PSC Staff and a developer to propose a pilot project for a one megawatt solar installation in the right-of-way of a Georgia Interstate highway, and for Georgia Power and PSC staff to "work collaboratively to finalize a three megawatt community solar project to be brought before the Commission for approval (Order, p. 12). The approved settlement agreement also included provisions for a Renewable Energy Development Initiative (REDI), in which Georgia Power is using competitive solicitations to procure renewable energy, including 150 MW of DG and 1,050 MW of utility-scale resources. The order also approves a renewable cost benefit (RCB) framework to be used in evaluating bids for renewable energy supply.

The Commission has issued several additional orders in this same docket, including:

- December 2016 Order Approving Joint Recommendation Regarding the Renewable Cost Benefit Framework;
- June 2017 Order Approving Georgia Power Company's Community Solar Program and Related Tariff;
- June 2017 Order Approving the Application of the RCB Framework to Behind the Meter Solar Technologies and the Request to Adjust the REDI DG Program Schedule; and
- August 2017 Order Approving Renewable Energy Development Initiative Commercial and Industrial Program.

Georgia Power is filing quarterly status reports in this docket and the Commission has also issued orders regarding specific solar projects. An initial VOS study is complete; Georgia identified nine distributed generation cost components providing a net benefit, six components providing a cost, and two components providing either a cost or a benefit.

MISSISSIPPI – In December 2010, the Mississippi PSC opened Docket 2011-AD-2 to investigate establishing and implementing net metering and interconnection standards for Mississippi. A 2014 Mississippi VOS study concluded that VOS was positive under all but one of the scenarios and sensitivities studied. A net billing law passed in 2015, and the Commission established rules in 2016. The Mississippi program calls for net billing, with compensation based on the utility's wholesale electricity rate, plus an incentive of 2.5¢/kWh to reflect the value of distributed energy. In addition, the rule directs Entergy and Mississippi Power to credit an additional 2¢/kWh to the first 1,000 low-income customers who install NEM solar projects.

The Mississippi PSC had initially required the state's electric cooperatives to provide NEM. However, a new law enacted in 2016, HB 1139 (Miss. Code Ann. § 77-5-235), authorizes the PSC to require cooperatives to adopt NEM programs, but also states that the PSC may not establish the level of compensation or credits for these programs.

In addition, the Mississippi PSC is presently considering an application from Entergy Mississippi, in Docket No. 2018-UA-133, which includes a proposal for the utility to offer a new *Smart Energy Services Program*, in which one of the services the utility could provide to residential customers would be distributed solar PV systems.

III. Inventory of Related State Regulatory Actions

In addition to the specific actions that states have undertaken to update or replace NEM programs, many other related actions have been taken that affect DG. We summarize these actions briefly here.[16] They include:

- Comprehensively reviewing utility rate designs, not only NEM or DG rates;
- Changing fixed charges, minimum bills, or both;
- Adding demand or standby charges;
- Making TOU rates optional or mandatory for new DER customers;
- Establishing a separate customer class;
- Ruling on third-party or utility-owned DG; and,
- Adding community solar provisions.

In some cases, these actions would apply only to NEM customers or customers with distributed generation, whereas in other cases they might apply to all residential and small commercial customers. For example, many utilities have proposed changes to fixed charges for all small customers; some have proposed demand charges only for NEM customers; and of course stand-by charges would apply only to customers using on-site generation. In addition, some utilities have proposed establishing a separate rate class for NEM customers or for all customers with DG. Some of these actions apply only to new NEM customers, with pre-existing customers grandfathered for some time under the NEM program rates that were in effect at the time the customers were initially accepted into the program.

At last count:

- Comprehensive reviews of rate designs for customers both with and without self-service power are underway in 14 states;
- Commission decisions have been made in at least 34 states, affecting about 125 utility companies, changing fixed charges for small customers (mostly increases including a few large increases, but recently a few decreases, too);
- Eleven states have added system-capacity based demand charges, as-used demand charges, flat grid-access fees, or standby charges for customers with distributed generation;
- Six states have taken actions towards treating customers with distributed generation as a separate class for ratemaking purposes;
- Third-party ownership of DG is approved in 34 states, and utility ownership is approved in seven states, with decisions pending in four others; and,
- Twenty states have taken legislative or regulatory actions to enable community solar projects, and many additional states have approved specific utility-run community solar projects.

Table 3 indicates which actions have been taken in recent years on a state-by-state basis. Table 3 does not include additional related actions taken by non-state-regulated utilities. As Table 3 shows, one or more of these actions has been taken in almost every state, and 17 states have undertaken three or more of the six actions.

16 Unless otherwise noted, the information presented in this Inventory comes from the *50 States of Solar* quarterly report series, for calendar years 2015 through 2017 and through the first three quarters of 2018, published by North Carolina State University, Clean Energy Technology Center (NCSU-CETC). The reports can be found at https://nccleantech.ncsu.edu/our-work/policy/the-50-states-reports/. Table 3 does not include related actions taken by non-state regulated utilities, but those actions taken by the country's larger publicly owned and self-regulated utilities are included in the NCSU-CETC reports.

Table 3: States with Recent Laws and Completed Regulatory Proceedings, by Policy Type (years enacted)

State[1]	Comprehensively reviewing utility rate designs	Increasing (decreasing) fixed charges	Adding demand, standby, or grid-access charges	Establishing a separate customer class	Ruling on third-party or utility-owned DG	Adding community solar provisions
Alabama		2016	2013			
Alaska		2017				
Arizona		2015	2016, 17,[2] 18		2015, 16, 17	
Arkansas	2017	2017	2017[3]			
California	2015		2016			2015, 18
Colorado		2015, 16, (18)				2015
Connecticut	2016, 17	(2018)				2015
Delaware		2017				2015
District of Columbia	2017	2016, 17			2018	**2016**,[4] 17
Florida	2017	2017			2018	
Georgia	2016[5], 17[5]				2015	
Hawaii		2015				2015, 17
Idaho		2015, 16		2017		
Illinois	2017					**2016**, 17, 18
Indiana		2016				
Iowa				2017		
Kansas		2015	2018	2017		
Kentucky		2015, 17				
Louisiana					2016, 17	
Maine						2015, 17
Maryland						2015
Massachusetts		2016, 17, 18	**2016**, 18, **18**			2015, 17
Michigan[6]		2015, 17				
Minnesota	2018	2015, 17				**2013**, 15,16, 17
Mississippi[7]						
Missouri	2017, 18	2015, 17			2016	
Montana	2018			**2017**		
Nebraska[8]						
Nevada		2015, 16[2], (17)		2015		
New Hampshire		2017	2017[3]			2015, **17**
New Jersey		2016, 17				**2018**
New Mexico		2015, 16, 18	2016, 17		2015, 16, 17	

[1,2,3,4,5,6,7,8] See Table Notes at the end of the table.

Table 3 (continued): States with Recent Laws and Completed Regulatory Proceedings, by Policy Type (years enacted)

State[1]	Comprehensively reviewing utility rate designs	Increasing (de-creasing) fixed charges	Adding demand, standby, or grid-ac-cess charges	Establishing a separate customer class	Ruling on third-party or utility-owned DG	Adding community solar provisions
New York	2014	2015, 16, (18)			2015, 17	2015, 17
North Carolina		**2017**	2016, **17**		**2017**, 18	**2017**, 17
North Dakota		2017, 18				
Ohio	2018	2018				
Oklahoma		2015, 17				
Oregon[6]		2015				**2015**
Pennsylvania	2017	2015, 17				
Rhode Island	2018	2016, 18			**2016**, 16	**2016**, 16
South Carolina[8]		2015, 16, 17	2017[2]		2015	
South Dakota		2015, 16				
Tennessee		2016				
Texas		2016, 17		2017	2016	
Utah			2017[3]		2016	
Vermont						**2013**, 15, 16, 17
Virginia					**2017**	**2017**, 18
Washington						2015, 17, 18
West Virginia		2015				
Wisconsin		2015, 16, 17				
Wyoming						

Source: NCSU CETC *50 States of Solar Reports,* 2015 through third quarter 2018. https://nccleantech.ncsu.edu/the-50-states-reports/

[1] Jurisdictions that have restructured electric industries, so that generation service is a competitive business and customers are able to choose their generation service provider from among multiple competitive suppliers, are identified by rows shaded in blue.

[2] This is a voluntary demand rate for new NEM customers, who can decide whether to opt in.

[3] These states enacted new tariffs as successors to NEM programs. Rules vary about the rate treatment for customers that were already participating in pre-existing NEM programs, prior to when the new programs were adopted. The term commonly applied to those situations is called "grandfathering," meaning that the customers with pre-existing NEM relationships with their providers are allowed to continue under that program until some predetermined term, date, or capacity limit is reached.

[4] Actions implemented through legislation are indicated in **bold, dark-red ink**. All other actions are the result of state regulatory commission orders or other state executive branch actions.

[5] The Georgia PSC, in Docket No. 39372 and Docket No. 40161, is reviewing Georgia Power Company rates for utility-scale and distributed renewable energy resources, not all rate designs.

[6] Michigan and Oregon are two states that are mostly vertically integrated, but do have some competitive generation services. In Oregon only large non-residential customers are eligible for what is termed "direct access" service (Oregon Administrative Rules Database – OARD Chapter 860-038: Direct Access Regulation) and Michigan restricts what it calls "Electricity Choice" to not more than 10 percent of each utility's annual sales (MCL 460.10a).

[7] Legislation in 2014 initiated NEM in South Carolina (SC Code Title 58, Chapter 40), as did a Commission Order in Mississippi (in a December 3, 2015 Order in Docket No. 2011-AD-2).

[8] Nebraska has only publicly owned electric distribution utilities, which are not state regulated. The State PSC regulates high-voltage electric transmission lines.

A. Comprehensive reviews of utility rate designs

As shown in Table 3, 11 states have engaged in comprehensive reviews of all utility rates, not just rates for DG. This reflects in part the many different factors affecting utility sales and revenues, the many different state policies toward different DER technologies, and the rapid changes of those technologies, including technical capabilities for DER technologies to produce and deliver utility system benefits.

In several of those states, the comprehensive rate design reviews are just one component of broad grid-modernization proceedings. Rate reviews typically include considerations of potential changes related to time and possibly location-varying rates, and the emergence of multiple cost-effective energy storage technologies. (See NCSU-CETC *50 States of Grid Modernization* quarterly report series, 2017–2018).

Rate design studies have been completed in New Hampshire and Rhode Island. The New Hampshire report considers, among other things, customer charges, demand charges, time-varying rates for both transmission and distribution, locational pricing, and potential roles for advanced metering functionalities. It also includes a list of principles to guide rate design (pp. 13-16). The Rhode Island report is broader in content but more preliminary, characterized as a Phase I report. It includes proposals for studying and developing rate designs for time-varying rates, electric vehicles, and beneficial electrification.

In Missouri, a 2017 Staff Report proposes stakeholder workshops to explore modified rate design proposals (pp. 13-14), and a 2018 Staff Report includes recommendations about "rate design to enhance DER" (p. 3, 50-53).

As part of its PowerForward initiative, Ohio, held a multi-day fact-finding "Phase 3" hearing with a major focus on ratemaking. In its PowerForward Roadmap, the Ohio Commission notes its desire to implement performance-based ratemaking and its intention to evaluate and address the utility "throughput incentive." The Commission also notes that distribution utilities should propose time-of-use rates for standard service offer customers (Roadmap, pp. 26-30, 35).

A Pennsylvania Utility Commission May 2018 Order in Docket No. M-2015-2518883 includes a policy statement with a list of considerations the Commission intends to employ when considering rate proposals, and describes examples of the kinds of rates electric distribution companies "may propose," including: critical-peak pricing or other demand-based rates; a critical peak volumetric price or average demand component for some distribution costs, and volumetric on-peak and off-peak rate recovery for other distribution costs; and other optional rate designs, possibly including locational pricing.

Stakeholder processes addressing rate reforms are also underway in Minnesota (Docket No. 15-662) and Montana. Dockets that include a specific focus on rate design are also ongoing in New Mexico, New York, and West Virginia (NCSU-CETC 2018d, pp. 32-34, 38).

B. Increasing fixed charges

Going back to 2014, over 125 utility companies have requested fixed charge increases, and by mid-2018 state commissions had acted on almost exactly 100 of those requests. Utilities requested fixed charge increases ranging from as little as roughly a dollar or two per month (in 25 cases), three to six dollars per month (in 40 cases), more than six to ten dollars per month (in 25 cases), and more than 10 dollars per month (in 10 cases). Regarding the cases decided by mid-2018:

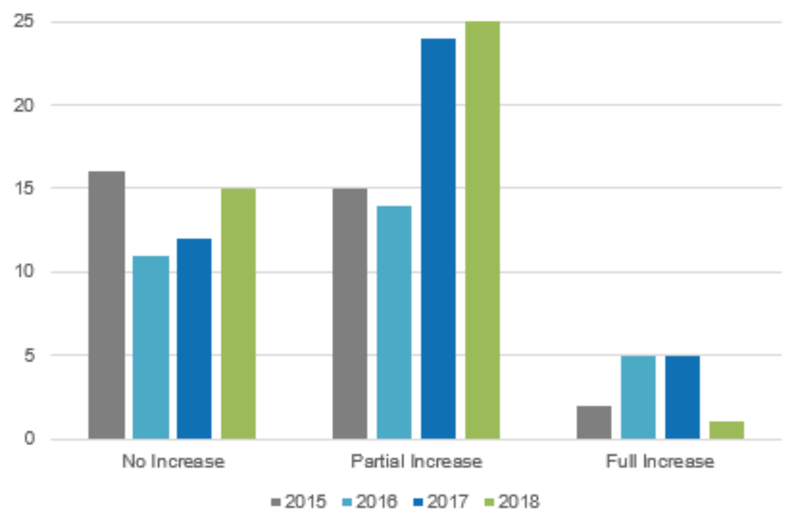
- Regulators rejected just over two dozen of the requests and utilities withdrew two others;
- Of the requests rejected, six resulted from partial or full settlement agreements;
- In a bit more than half of all the requests, the regulators approved a partial increase in the fixed charge, less than what the utility had requested;

- Of the partial increases approved, the previous fixed charge increased by: less than $1 per month for 15 decisions; another 15 ranged from $1 to less than $2; 16 ranged from $2 to $3.50; and only four raised the previous fixed charges by $5 or more per month; and,
- In about a dozen cases, the utility's requested increase was approved in full.

Figure 3 presents a summary of commission decisions on fixed charges for calendar years 2015, 2016, and 2017. Although this small sample of 100 decisions might not indicate any particular trends, the changes could reflect a growing willingness on the part of state commissions to grant at least partial increases. The trend could also be related to utilities tempering their requests based on perceptions of what they believe their state commission might accept. A new development, in 2018, has been state commissions deciding to reduce fixed charges, as happened in Colorado, Connecticut, and New York, in each case reducing the level of distribution costs included in the fixed charges.[17] Fixed charges are limited to specific components of customer-related costs, by statute in Connecticut (12 CA 499, Chapter 283§16-243bb) and California (AB 327 of 2013) and by a state administrative rule in Iowa (IAC 199–20.10(2)).

Looking at the cases decided from 2014 through 2017, where utilities had requested increases in fixed charges, there were nine states where four or more cases were decided. Pennsylvania had ten such decisions, Wisconsin had seven, and New York and Missouri had six each. Five such cases were decided in New Mexico and five in Kentucky, plus four each in Indiana, Michigan, and Texas. Together, these nine states represent 53 decisions in the past four years, just a little more than half of the total cases decided in all states. Just over 30 decisions were in vertically integrated states and the other 20 in the restructured states of New York, Pennsylvania, and Texas. Although the total number of cases decided is too small to support any definitive statistical analysis, a few patterns do appear. For example, six of those nine states have vertically integrated utility structures. Two of those cases were dismissed and one was withdrawn. Of the others, partial increases were approved in fifteen of the cases, the full increases requested by the utilities in six cases, and no increase was approved in the other eight cases. Where increases were granted, the new fixed charges range from a low of slightly less than $12 per month to a high of $21 per month.

Figure 3: Results of IOU Residential Fixed Charge Decisions, 2015–2018



Note: This chart excludes decisions made by municipal and cooperative utilities to increase residential fixed charges.

Source: NCSU-CETC *50 States of Solar: 2018* Policy Review and Q4 2018 Quarterly Report, January 2019, p. 35.

17 All of the data reported here, unless otherwise cited, were collected by NCSU CETC for the *50 States of Solar* report series, 2015-2018.

The review of these early decisions reflects what can be thought of as a kind of Goldilocks question, where utilities apply for monthly fixed-charge increases and state regulators ultimately decide what is too big, too small, or just right.

One important aspect of those decisions is how much the proposals deviate from existing rates. Whited et al. (2017, p. 24) report on fixed charges for customers in 43 major U.S. cities. That review, based on 2016 data, shows that fixed charges ranged from a low of $4 per month in Cleveland to a high of nearly $20 per month in Sacramento: Eight of the cities had fixed charges of $6 or less per month; 21 cities had charges more than $6 and up to $10 per month; five more cities had charges greater than $10 and up to $15 per month; and five others had charges more than $15 per month. As these authors point out, adding two dollars a month in Cleveland would mean a 50 percent increase, but adding the same dollar amount in Sacramento would represent only a 10 percent increase. None of the requested increases in fixed charges were approved in New York; one case was settled and five others were decided by Commission order. In Pennsylvania, partial increases were approved in nine out of ten commission orders, and the tenth case was settled with no increase. The maximum monthly increases approved in Pennsylvania were all less than $2.25. In Texas, one case was dismissed with no increase to the fixed charge, two others in 2015 and 2016 were decided, each with a monthly increase of $1.90, and then in 2017 one of the same utilities requested an additional $1 per month increase and the Commission approved an increase of $0.50 per month.

A second type of fixed charge might apply only to customers with DG or even more narrowly only to customers with PV generators. Those are commonly called "grid access charges," and they can be set on a per-kW basis, similar to a demand charge but in this case a fixed charge that is added to the monthly bills of only particular customer-generators. The per-kW charges can be set based on the installed capacity of the DG system, or can be determined by measuring demand to determine a maximum flow of power in either direction, inflow or outflow.

C. Adding demand or standby charges to small-customer rates

Decisions about demand or standby charges have been reached in 15 states: Arizona; California; District of Columbia; Kansas; Montana; Nevada; New Hampshire; New Mexico; North Carolina; Oklahoma; South Carolina; South Dakota; Tennessee; Texas; and Utah. The most common type is a demand charge based on the nameplate capacity of installed DG, usually called a grid-access fee.

The Kansas Commission approved Westar Energy's proposed mandatory residential demand charge for distributed generation customers in late September 2018. That decision follows a 2017 Commission order finding that additional fees for customer-generators are acceptable. The approved charge will be determined by a customer's peak demand during system peak hours, and will vary seasonally.

In Massachusetts, the Commission approved a demand charge in early 2018, but that decision was later overturned by newly passed state legislation. The new law does not disallow demand charges, though; it only establishes new requirements for their design.

The New Mexico Public Regulatory Commission ended a standby charge for Xcel Energy customers, but the Commission has also indicated it plans to open a rulemaking to address standby charges.

D. Community solar provisions

At least 19 states and the District of Columbia have taken either legislative or regulatory commission actions to establish community-based solar programs, and all but three of those 20 jurisdictions already have working projects. In addition to those jurisdictions, one or more individual utilities in 23 more states have already developed their own community solar programs or projects, and have sought and received approval from their regulators. **Figure 4** shows the timeline of state actions establishing community solar.

Many of these programs are treated as what is called "virtual" or "remote" net metering, with bill credits accruing monthly for each participating customer according to each customer's share of the total output of a community solar project, with virtual net metering rules approved by the state Commission.

Part of the impetus for community solar programs is extending solar access opportunities to customers who would not otherwise be able to install their own systems. For example, renters and residents of multi-family buildings might not be able to install solar PV systems on their properties. Many states are also working on techniques for including low- and middle-income customers in community solar programs (Stanton and Kline, 2016).

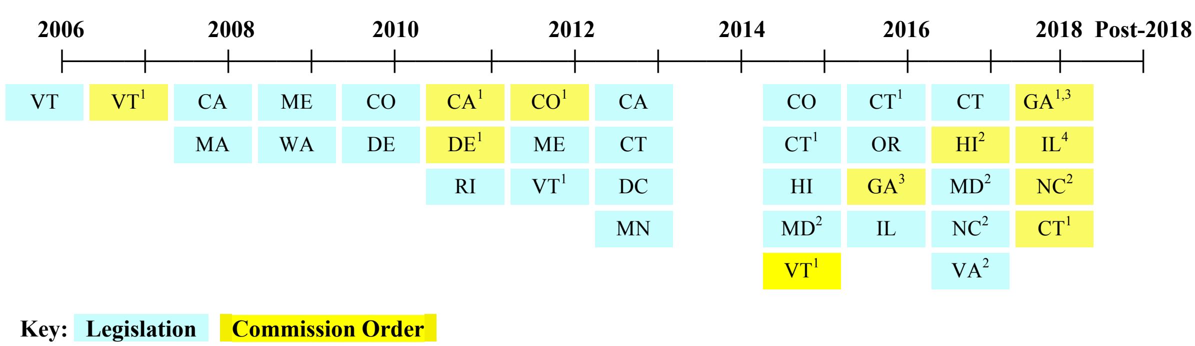
SIDEBAR 2: WHAT'S THE DIFFERENCE BETWEEN A "SALE" AND AN "EXCHANGE" OF ENERGY?

The Internal Revenue Service, by individual letter rulings, has acknowledged that when customer benefits constitute a simple exchange of energy like individual net metering, with the bill credits subject to annual caps closely related to the customer's annual energy usage, the benefits do not have to be included in calculating gross income.

Depending on the design details of NEM replacement and community solar programs, it is possible that payments from a utility for purchasing energy could be construed as income for the participating customer, subject to taxation as income, as opposed to an exchange of energy that is not taxed.

With several states considering a move to buy-all, sell-all rates for at least some self-generators, it will be important to know what specific rate design details might cause federal or state tax authorities to treat the revenues as a sale to the utility, subject to taxation as income.

Figure 4: Timeline of States Adopting Community Solar Programs



Notes: [1] Indicates additional state legislative or regulatory actions, subsequent to the enabling laws or rules.
[2] Indicates a pilot program.
[3] Indicates a decision affecting only one utility company.
[4] Indicates pending regulatory decisions.

Source: Authors' construct based on Stanton and Kline 2016.

E. Creating a separate rate class for customers using DG

Actions taken in several states could create a separate rate class for customers with DG. As shown in Table 3, that topic is being addressed in states in the Midwest (Iowa and Kansas), Northwest (Idaho, Montana, Oregon, and Washington), and Southwest (Nevada). In Montana, the legislature authorizes regulators to approve a separate rate class for DG customers, but the Commission has not yet determined whether to establish a separate class. In Kansas, an approved stipulated agreement in a Westar rate case allows for a separate DG class.

In some other states where legislators or regulators have not yet considered any statewide action on this issue, at least one utility company has sought regulatory approval for creating a separate rate class for DG customers. Such requests received commission approvals in Idaho and Texas, but commissions denied similar proposals in Colorado, Iowa and New Mexico. A court ruling also denied a utility request in Wisconsin (NCSU-CETC 2016-2018).

The effect of establishing a separate rate class for DG customers varies substantially, depending on the cost allocation methodology a state employs. Many states use the Basic Customer method to determine customer-related costs, including in fixed charges only costs quite directly associated with metering, billing, and collection.[18] Other states use a minimum-system or zero-intercept method, which assigns a share of distribution-circuit and transformer costs on a per-customer basis; that method will have a more significant impact on DG customers.

F. Third-party ownership rules for DG resources

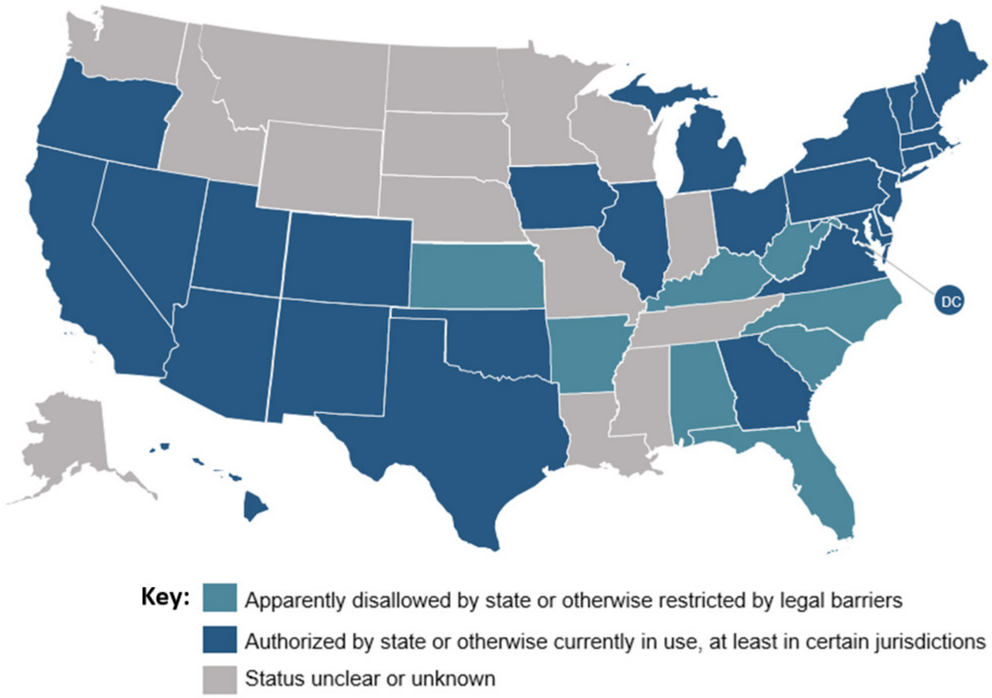
Since 2015, eight states have taken actions on whether third parties shall be eligible to own and operate DG resources installed behind the meter in customer facilities. They include Arizona, Georgia, Louisiana, Missouri, New Mexico, North Carolina, Oklahoma, and Texas. As shown in **Figure 5**, third-party ownership of customer-sited DG is presently allowed in at least 27 states and the District of Columbia, but in 15 states the status of third-party ownership for providing self-service power is still unclear. At last count, eight states had laws or rules in place that prohibit third-party ownership (NCSU-CETC 2018e).

The barrier preventing third party ownership is typically found in state laws that declare that regulated utility companies are the only entities that can sell electricity to end-use customers. Third parties can produce electricity as a merchant function, and can then sell the electricity into a wholesale market or directly to a utility company under a PPA, but the laws and rules for producing and delivering wholesale power are different from those affecting retail sales. In some jurisdictions, it could be legal for a third party to sell or lease a solar-PV system to a retail consumer, while it is not legal for the third party to enter into a contract for the sale of electricity to the same customer through a PPA. This might appear to be a subtle distinction, but there are important ramifications for accounting and tax treatment that make both solar developers and particular customers prefer one approach instead of another (Bolinger and Holt 2015; Burger and Luke 2017).

18 For example, the Washington Commission recently ruled:

> We determine that neither [the utility's] proposal to increase basic charges for residential customers, nor Staff's recommendations to add a minimum bill to basic charges and establishing seasonal rates, should be adopted. We are not persuaded on the basis of the current record that transformer costs should be recovered in basic charges, or through a minimum bill. We have never approved such a proposal and continue to believe these costs are not customer-related costs as that term is generally understood. Transformer costs should be recovered as distribution charges subject to [the Company's] electric decoupling mechanism, which adequately protects the Company's recovery of its fixed costs. (Dockets UE-170033 and UG-170034, at Paragraph 355)

Figure 5: Map of State Status on Third-Party Ownership of Self-Service Generation



Source: NCSU-CETC, 2018e, *The 50 States of Solar: Q3 2018 Update.*

SIDEBAR 3:
SHOULD SCHOOLS BE A SEPARATE RATE CLASS?

A decision by the California PUC directs San Diego Gas & Electric Company to develop a "schools-only rate . . . considering schools as a rate class" separate from other commercial and industrial customers, including "appropriate rate design for net energy metering and non-net-energy metering members of this class" (Decision 17-08-030, ¶ 36 on p. 93).

The reasoning is that school facilities typically have non-coincident peaks, and large portions of school electrical usage are generally "off-hour" and "off-season."

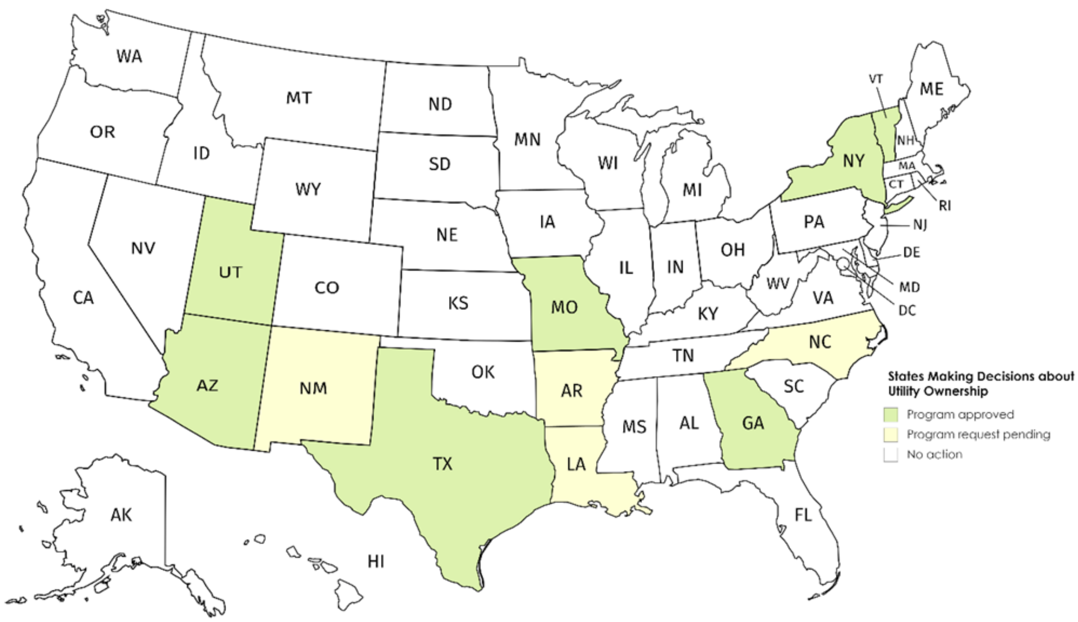
Commissions in several states are grappling with the question whether DG customers have usage patterns that are so different from other customers that it could be appropriate to consider them as a separate rate class. In a similar vein, though, there could be many other subsets of customers with usage patterns that diverge far from broad class averages. So, a relevant question is how different must usage patterns be, in order to warrant separation of rate classes.

G. Utility-led programs for customer-sited DG

In a utility-led rooftop solar program, a utility typically pays the upfront cost of a solar installation located at a customer site and compensates customers for hosting the system through a special DG rate, a flat monthly payment, or through another type of incentive. **Figure 6** shows, highlighted in green, the states that took action on rooftop solar programs led by regulated utility companies, in 2015 through 2018. States that are highlighted in yellow are currently considering proposals for utility-led programs.

Among the states highlighted, only New York and Texas have restructured electric utility industries. In Georgia, the program offer is through an unregulated utility-affiliate. In almost every instance, state commissions are treating these as pilot programs, which are limited in scope (e.g., in terms of numbers of participating customers, utility costs eligible for rate recovery, or both), and subject to monitoring and evaluation to determine costs and benefits, and the extent to which benefits accrue to non-participating customers (NCSU-CETC 2016-2018).

Figure 6: Map of States Authorizing Utility-Led Rooftop Solar Programs, 2014-2018



Source: NCSU-CETC, *50 States of Solar* report series, 2015-2018.

SIDEBAR 4:
WHAT'S THE DIFFERENCE BETWEEN A "SALE" OR "LEASE" OF AN ELECTRICITY GENERATING SYSTEM

Laws in some states differentiate between a sale or lease of an electricity generating system itself: Some state laws state that only a regulated utility can sell electricity, so it could be legal for a customer to purchase what is essentially an appliance that generates electricity, but not legal for the same customer to enter into a PPA to purchase electricity. Figure 5, on page 37, shows the current status of this issue in the states.

In May 2018, the Florida PSC approved a request for declaratory ruling, which allows one solar installer to employ a "residential solar equipment lease" without that constituting a "sale of electricity," nor deeming the solar company as a "public utility" under Florida law. The North Carolina Utilities Commission adopted leasing rules in January 2018 in Docket No. E-100 Sub 156, pursuant to a new law (HB 589, G.S. 62-126.7) that passed in 2017. In Wisconsin, the PSC declined to open Docket No. 9300-DR-102 in a December 2017 Order stating "the petition for declaratory ruling raises significant public policy considerations that are best left for the Legislature's determination rather than for the Commission's . . . ." (Order, p. 11).

IV. Conclusions

The issues reviewed in this paper are dynamic and challenging. As outlined here and in the series of quarterly reports from the North Carolina State University Clean Energy Technology Center (2015-2018), the interested parties in nearly all states, including state regulatory commissions and staff, are devoting much time and attention to decisions about updating NEM rates or developing NEM successor tariffs. As one observer explains, "In the search for the right successor tariff, stakeholders face the challenge of balancing uncertain costs and benefits with the right mix of detail and flexibility in a new kind of rate" (Trabish 2018).

Many parties have characterized the current situation as a war-like conflict that is inherently a zero-sum game. It has been described as "reflecting a combative 'all or nothing' approach"—in zero-sum, win-lose terms, as if utilities are on one side and DG proponents on another, waging "battles" or engaged in a "showdown" over what could be an "existential threat" to utilities (Hess 2016; Leslie 2017; Smith and MacGill 2016, pp. 354-355; Stanton 2015, pp. 4-5, 9-11). Observers might think of this as what policy makers call a "wicked" problem, which is one characterized by diverse viewpoints reflecting conflicting value frameworks, and fundamental disagreements about both ends and means, which make the problem "inherently resistant to a clear definition and an agreed solution" (Head and Alford 2013, pp. 712-714).

Much uncertainty remains about both means and ends: There is little consistency among states about exactly what policy changes to make to update or replace traditional NEM programs. In fact, it is safe to say that each of the major topics reviewed in this report deserves its own future study:

- How do NEM rate changes affect the rate of adoption of DG or even broader DER technologies? Are the markets for DG and DER still in the earliest stages of consumer adoption, or are some technologies already starting to emerge into uninhibited market growth?
- How big are the potential markets for community solar? What kind of offerings work best for low- and middle-income participants?
- In states that create a separate rate class for DG customers, what can we learn about the class usage patterns? How similar are they to non-DG customers? How do the class usage patterns affect utility costs of service?
- Are studies of VOS, VDER, and utility costs of service measuring the right benefits and costs? Are they measuring all of them? And are the measuring methods valid and reliable?
- Are there marked differences in DG markets between jurisdictions allowing versus prohibiting third-party ownership? If yes, what are those differences?
- In jurisdictions with utility-led programs, utility ownership, or both, what happens to market growth rates? And, what happens to competition?
- If the policy approaches are different in vertically integrated and restructured states, how are they different?

In any case, all interested parties can observe what happens over time to NEM and DG markets and utility financial stability in each state that implements these kinds of changes, and hopefully all can start discerning what works best under what circumstances. As one observer points out, the situation is likely to get even more complicated, and quickly, as more and more DER technologies come into play (Peskoe 2016). Already service providers are offering multiple DER options, including demand-response, on-site thermal and electrical storage, energy management systems with load management capabilities, electric vehicles with vehicle-to-grid capabilities, and more. Peskoe observes:

> PV is not the only decentralized technology or service that has disruptive potential— a combination of several complementary technologies and services is more likely to transform the electricity industry than a single technology… (Peskoe 2016, pp. 102-103).

Leslie explains that solar PV is perhaps "the vanguard of DERs," that could, in combination with other DER, upend the traditional electric utility business model and further says,

> DERs . . . include not just rooftop solar, but wind power, batteries, electric vehicles, smart meters, smart water heaters, smart thermostats, on and on. They promise not just emission-free, fuel-less electricity, but far greater energy efficiency, thus reducing consumer costs and environmental damage. Their expanding use increasingly will determine how the grid functions (Leslie 2017).

Similarly, Smith and MacGill note that the electric utility industry could already be on a technological and economic trajectory in which DER combines in new ways to serve consumer wants and needs. They foresee the possibility of "Schumpeter's 'creative destruction' view of innovation meeting Schumacher's 'small is beautiful' and 'appropriate technology' philosophy," such that increasing numbers of consumers could start to view electricity from the traditional grid as an "inferior good," at least for certain purposes (Smith and MacGill 2016, pp. 349, 354).

In this context, it could be helpful for policy makers and interested parties alike to think of the present challenges surrounding NEM 2.0 and successor tariffs as just one piece in a much larger puzzle. Additional pieces are already becoming visible, through many states' interests in what is generally becoming known as grid modernization, including comprehensive rate reforms, as well as through changes to utility business models, major updates to integrated resource planning and distribution system planning to incorporate DER, advancing non-wire alternatives, enabling microgrids, and more. In the not-too-distant future, attention could shift from what are just and reasonable tariff arrangements for individual customers with on-site generation, to how DER ensembles can produce multiple benefits for multiple customers, the utility system as a whole, and society at large. A question worth exploring, sooner rather than later, is: What kinds of policy changes might be needed to enable that technological evolution, and how do the policy changes for individual customers relate to and combine with the similar kinds of policies designed to affect groups of customers?

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Appendix

Summaries of Recent State Actions on Net Energy Metering Policies in Five Vertically Integrated and Five Restructured States

by

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The Appendix is available for download from http://nrri.org/download/appendix-nem-policies.

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