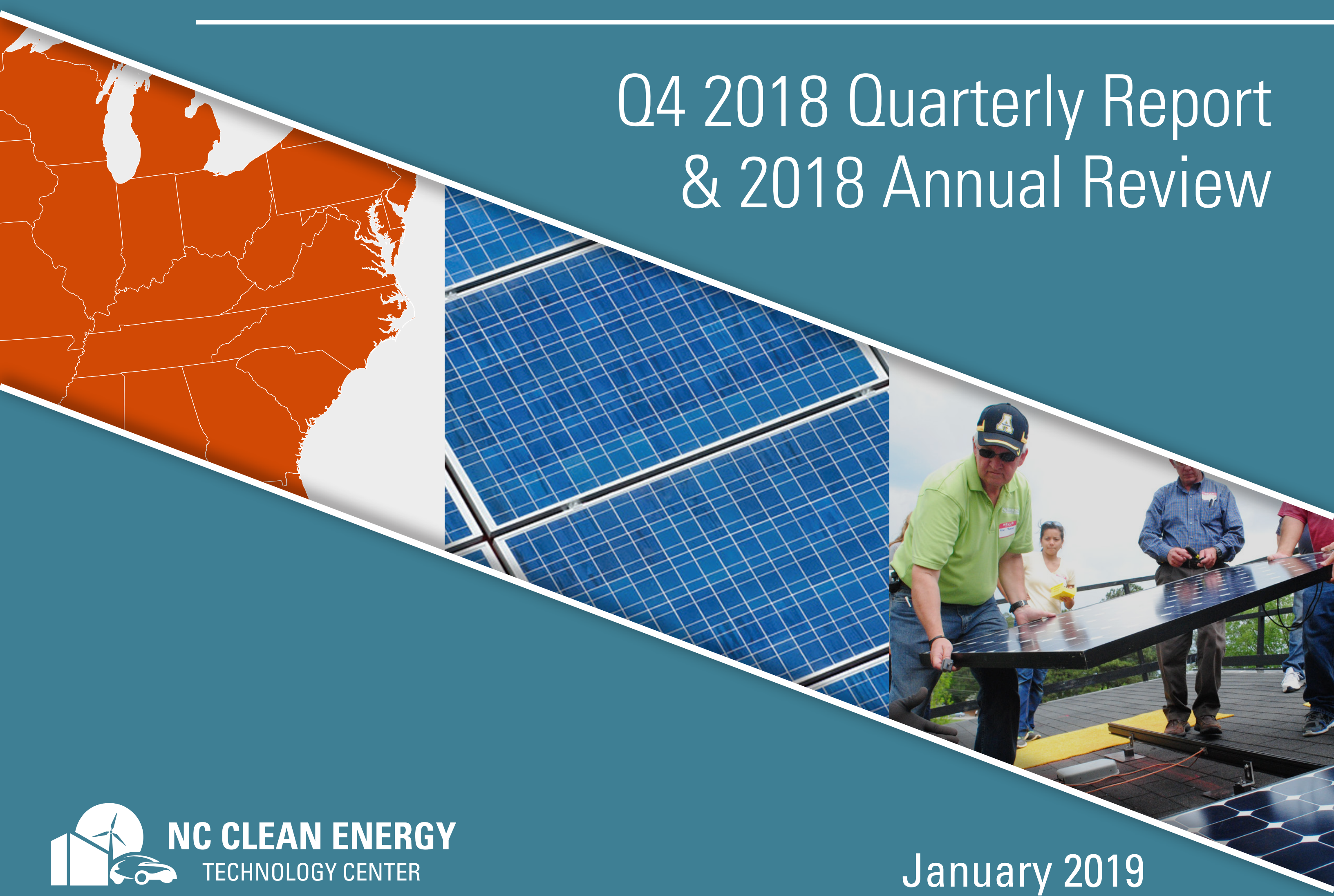
50 States of SOLAR

Q4 2018 Quarterly Report & 2018 Annual Review



NC CLEAN ENERGY
TECHNOLOGY CENTER

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The NC Clean Energy Technology Center is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating and providing support for clean energy technologies, practices, and policies. The Center provides service to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, the Center envisions and seeks to promote the development and use of clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy and mitigating the environmental impacts of fossil fuel use.

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PREVIOUS EDITIONS

The *50 States of Solar* is a quarterly publication. Previous executive summaries and older full editions of the *50 States of Solar* are available here.

The NC Clean Energy Technology Center also publishes the *50 States of Grid Modernization* and the *50 States of Electric Vehicles* on a quarterly basis. Executive summaries of these reports may be found here. Please contact us for older issues of the *50 States of Solar*.

TABLE OF CONTENTS

GLOSSARY OF ABBREVIATIONS

ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
d/b/a	Doing Business As
DER	Distributed Energy Resources
DG	Distributed Generation
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatt-Hour
MW	Megawatt
NEM	Net Energy Metering
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RFP	Request for Proposals
TOU	Time of Use

OVERVIEW

PURPOSE

The purpose of this report is to provide state lawmakers and regulators, electric utilities, the solar industry, and other energy stakeholders with timely, accurate, and unbiased updates on state actions to study, adopt, implement, amend, or discontinue policies associated with distributed solar photovoltaics (PV). This report catalogues proposed and enacted legislative, regulatory policy, and rate design changes affecting the value proposition of distributed solar PV during the most recent quarter, with an emphasis on the residential sector.

The 50 States of Solar series provides regular quarterly updates of solar policy developments, keeping stakeholders informed and up to date on a timely basis.

APPROACH

The authors identified relevant policy changes through state utility commission docket searches, legislative bill searches, popular press, and direct communication with stakeholders and regulators in the industry.

Questions Addressed

This report addresses several questions about the changing U.S. solar policy landscape:

- How are (1) state legislatures and regulatory authorities and (2) electric utilities addressing fast-growing markets for distributed solar PV?
- What changes to traditional rate design features and net metering policies are being proposed, approved, and implemented?
- Where are distributed solar markets potentially affected by policy or regulatory decisions on community solar, third-party solar ownership, and utility-led residential rooftop solar programs?

Actions Included

This report series focuses on cataloguing and describing important proposed and adopted policy changes affecting solar customer-generators of investor-owned utilities (IOUs) and large publicly-owned or nonprofit utilities (i.e., those serving at least 100,000 customers). Specifically, actions tracked in these reports include:

- Significant changes to state or utility **net metering** laws and rules, including program caps, system size limits, meter aggregation rules, and compensation rates for net excess generation
- Changes to statewide **community solar** or **virtual net metering** laws and rules, and individual utility-sponsored community solar programs arising from statewide legislation
- Legislative or regulatory-led efforts to study the **value of solar**, **net metering**, or **distributed solar generation policy**, e.g., through a regulatory docket or a cost-benefit analysis
- Utility-initiated rate requests for **charges applicable only to customers with solar PV** or other types of distributed generation, such as added monthly fixed charges, demand charges, stand-by charges, or interconnection fees
- Utility-initiated rate requests that propose a 10% or larger increase in either **fixed charges** or **minimum bills** for all residential customers
- Changes to the legality of **third-party solar ownership**, including solar leasing and solar third-party solar power purchase agreements (PPAs), and proposed **utility-led rooftop solar** programs

In general, this report considers an "action" to be a relevant (1) legislative bill that has been passed by at least one chamber or (2) a regulatory docket, utility rate case, or rulemaking proceeding. Introduced legislation related to third-party sales is included irrespective of whether it has passed at least one chamber, as only a small number of bills related to this policy have been introduced. Introduced legislation pertaining to a regulatory proceeding covered in this report is also included irrespective of whether it has passed at least one chamber.

Actions Excluded

In addition to excluding most legislation that has been introduced but not advanced, this report excludes a review of state actions pertaining to solar incentives, as well as more general utility cost recovery and rate design changes, such as decoupling or time-of-use tariffs. General changes in state implementation of the Public Utility Regulatory Policies Act of 1978 and subsequent amendments, including changes to the terms of standard contracts for Qualifying Facilities or avoided cost rate calculations, are also excluded unless specifically related to the policies described above. The report also does not cover changes to a number of other policies that affect distributed solar, including solar access laws, interconnection rules, and renewable portfolio standards. Details and updates on these and other federal, state, and local government policies and incentives are available in the NC Clean Energy Technology Center's Database of State Incentives for Renewables and Efficiency, at **www.dsireusa.org**.

2018 POLICY REVIEW

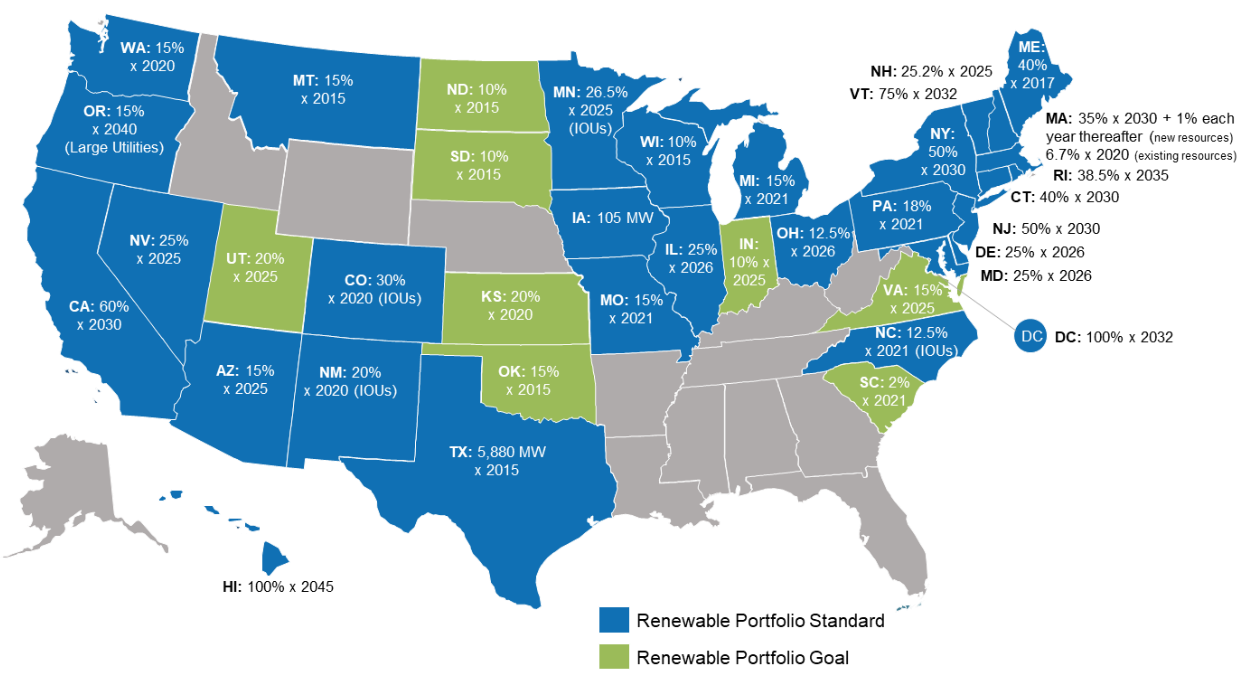
U.S. DISTRIBUTED SOLAR MARKET

The U.S. residential solar market was relatively flat over the course of 2018, and the majority of mature state markets saw a flat or declining rate of installations.[1] However, analysts anticipate overall growth in 2019, with 60% of residential capacity installed between 2018 and 2023 predicted to be in California, Illinois, and Florida.[2] Growth is expected to slow for overall solar installations in the non-residential sector, although increased growth in community solar projects is expected.[3] In the first three quarters of 2018, 400 MW of community solar was installed, and analysts predict that by 2023, 30% of annual non-residential installations will be community solar projects.[4]

Spotlight on the States

While 2017 was characterized by increased federal policy activity related to distributed solar, 2018 put the spotlight back on state policy action following the announcement of President Trump's decision to adopt tariffs on imported crystalline silicon photovoltaic (PV) modules and cells. Several states took bold steps to grow markets for solar and other renewable energy technologies, often motivated by a desire to decarbonize the electric system.

Figure 1. State Renewable Portfolio Standard Policies



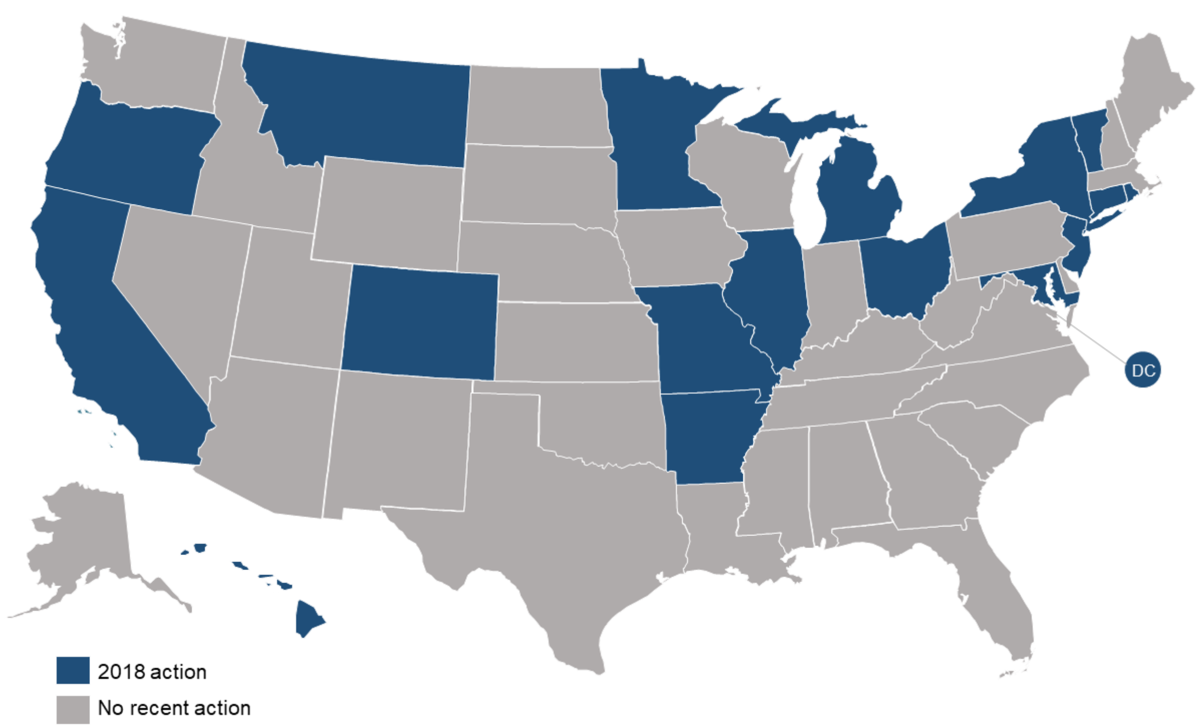
Notably, the California Building Standards Commission established the first residential solar mandate in the country during 2018. Beginning in 2020, in order to comply with state building codes all new homes in California will be required to have solar PV installed and sized to the building's annual energy usage. Community solar options can also be developed to comply with the new requirements.

Several states also increased their renewable energy targets in 2018, favorably impacting the solar market. The California State Legislature enacted a bill increasing the state's renewable portfolio standard (RPS) to 60% by 2030 and establishing a 100% clean energy target to be met by 2045. The DC City Council approved a bill calling for 100% renewable energy by 2032. Connecticut lawmakers also increased the state's RPS to 40% by 2030, while New Jersey legislators increased the state's RPS to 50% by 2030.

Broader Discussions and Reforms

Interest in broader grid modernization efforts increased across the country during 2018, and many states are choosing to consider solar policy reforms within the broader context of grid modernization. For example, net metering and rate design issues are being considered in expansive grid modernization proceedings in Arkansas, Colorado, DC, Illinois, Maryland, and other states. A study quantifying the value of solar was also conducted within a grid modernization proceeding in Maryland during 2018.

Figure 2. States Engaged in Broad Grid Modernization Efforts in 2018



As more solar facilities are being paired with energy storage systems, the solar policy framework itself is also broadening. Many states are considering policies applicable to distributed energy resources as a whole, rather than solar specifically. In Missouri, Nevada, and Washington, distribution system planning rules considered during 2018 include provisions to determine the locational value of distributed energy resources, including solar. Some states, such as New York, are also considering the larger set of distributed energy resources in designing net metering successor tariffs, while some utilities, such as Arizona's investor-owned utilities, are piloting rate structures designed for customers with multiple distributed technologies.

Granular Approaches and Increased Complexity

Although many states are taking a broad view to electric grid and solar policy issues, the majority of rule changes being adopted by states are focused on the more intricate details, incorporating more granularity into rate structures and program designs. States and utilities are increasingly moving toward time-varying rates and distributed generation compensation rates tied more closely to the value of these resources. States are also examining opportunities to incorporate the locational value of distributed energy resources into compensation frameworks and customer-facing programs. While these approaches provide more accurate price signals to consumers, they add significantly more complexity to rate designs.

2018 SOLAR POLICY ACTION

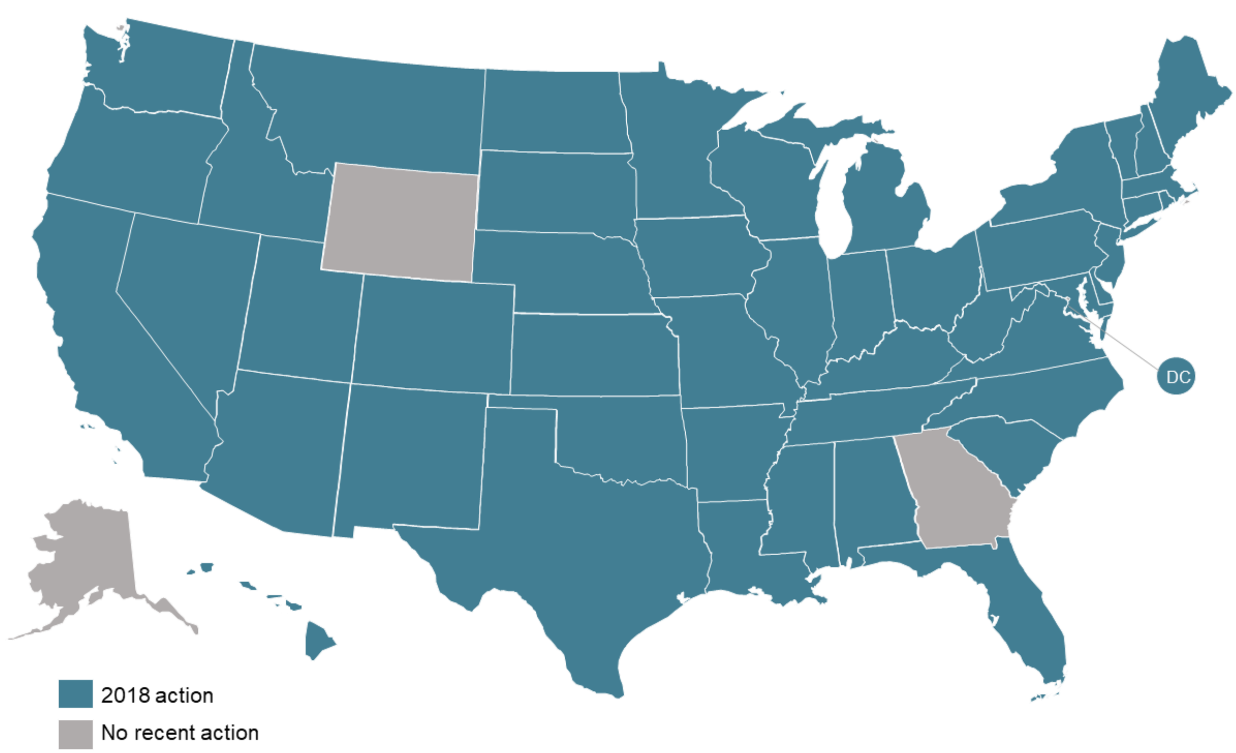
Table 1 provides a summary of state actions related to DG compensation, rate design, and solar ownership during 2018. Of the 264 actions catalogued, the most common were related to residential fixed charge and minimum bill increases (77), followed by DG compensation policies (71), and community solar (39). In 2018, the actions occurred across 47 states plus DC (Figure 3). Box 1 highlights the states that saw some of the most impactful solar policy actions during 2018, described in greater detail in the following sections.

Table 1. 2018 Summary of Policy Actions

Policy Type	# of Actions	% by Type	# of States
Residential fixed charge or minimum bill increase	77	30%	36
DG compensation policies	71	27%	33 + DC
Community solar	39	15%	19 + DC
Solar valuation or net metering study	31	12%	20 + DC
Residential demand or solar charge	23	9%	8 + DC
Third-party ownership of solar	14	5%	6 + DC
Utility-led rooftop PV programs	9	3%	8
Total	**264**	**100%**	**47 States + DC**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 3. 2018 Action on Net Metering, Rate Design, & Solar Ownership Policies



Box 1. Top Ten Most Active States of 2018

1. Michigan

The Michigan Public Service Commission approved a net metering successor tariff in 2018, which will move the state to an "inflow/outflow" compensation structure, with exported energy being credited at either the locational marginal price or power supply rate. The change is currently being implemented in DTE's and UPPCO's general rate cases, with the utilities both also proposing additional fees based on distributed generation system capacity.

2. South Carolina

South Carolina legislators considered bills addressing the state's aggregate cap on net metering and a successor tariff, although the proposals did not move forward. Later in the year, Duke Energy announced that it reached the aggregate cap and would be closing net metering to new customers. Duke Energy and stakeholders later reached an agreement that keeps net metering open until March 2019. Duke Energy Carolinas and Duke Energy Progress also filed general rate cases in 2018, with proposals to increase their residential fixed charges to $28.00 and $29.00.

3. New York

The New York Public Service Commission continued to consider refinements to its Value of Distributed Energy Resources tariff and approved a "Hybrid Tariff" in late 2018 for solar facilities paired with energy storage. The Commission also considered options to increase low-income participation in the Community Distributed Generation program and approved a reduction in Central Hudson Gas & Electric's residential fixed charge.

4. Massachusetts

Massachusetts regulators approved the first mandatory demand charge for residential distributed generation customers of an investor-owned utility in early 2018. The charge was part of Eversource's Monthly Minimum Reliability Contribution (MMRC). However, legislation enacted later in the year rendered the design of this demand charge no longer permissible. In November 2018, National Grid proposed an MMRC, with the charge taking the form of a fixed fee.

5. Arizona

The Arizona Corporation Commission issued a decision on Tucson Electric Power's and UNS Electric's distributed generation rate design proposals in 2018, approving initial export rates of 9.64 cents per kWh and 11.5 cents per kWh, respectively, while rejecting the additional fees put forward by the utilities. Later in the year, Salt River Project proposed two new rate options for distributed solar customers, including one without a demand charge component.

(Cont’d) Top Ten Most Active States of 2018

6. Connecticut

The Connecticut General Assembly enacted legislation in 2018 creating a new shared clean energy program and requiring a transition to a net metering successor tariff, in addition to increasing the state’s renewable portfolio standard. The Public Utilities Regulatory Authority opened proceedings to implement the legislation and is also conducting a broad review of distribution system issues.

7. Maine

Maine’s Governor vetoed proposed legislation making substantial changes to the state’s new solar compensation policy in 2018. The Public Utilities Commission approved significant changes to the policy, though, first amending the date of implementation and later addressing metering costs and restoring traditional net metering for medium and large non-residential customers. The Commission also considered general rate cases from Emera and Central Maine Power.

8. New Jersey

In 2018, New Jersey became the 19th state to adopt a community solar policy with the enactment of A.B. 3723. The Board of Utilities worked to establish many of the program details throughout the remainder of the year. A.B. 3723 also increased the aggregate cap on net metering and enabled public entities to host remote net metering projects. The Board also considered general rate cases from Atlantic City Electric and PSE&G New Jersey.

9. Virginia

Legislation enacted early in 2018 initiated a stakeholder process to consider changes to the state’s net metering and community solar programs, and the group’s facilitator published a final report later in the year. The Virginia General Assembly also considered legislation related to third-party power purchase agreements, and the State Corporation Commission approved net metering rule changes related to small agricultural generators and meter aggregation.

10. Montana

NorthWestern Energy published its net metering cost-benefit study in 2018, finding a cost shift from net metering to non-net metering customers. Later in the year, NorthWestern Energy filed a general rate case, including a proposal to place residential net metering customers into a separate customer class and apply a demand charge to these customers. NorthWestern Energy also held a series of workshops throughout 2018 as part of its Customer Vision stakeholder process.

Box 2. Top Solar Policy Trends of 2018

Compensation Frameworks and Program Designs Growing Increasingly Complex

A record number of states considered net metering changes in 2018, with compensation structures becoming increasingly complex. Some programs feature separate rates for energy imports and exports, while others include time-varying rates, value-based rates, and locational components. Some community solar programs are also adopting more complex credit structures.

States Expanding Opportunities for Low-Income Customer Participation in Community Solar Programs

Much of the community solar activity occurring in 2018 focused on expanding opportunities for low-income customers to participate in these programs. New community solar rules in Connecticut and New Jersey include provisions to encourage low-income participation, while states with existing programs, such as Colorado and New York, considered changes to increase the number of low-income subscribers.

Policymakers and Regulators Authorizing Solar-Plus-Storage Net Metering

A growing number of states are considering the net metering eligibility of solar facilities paired with energy storage. In 2018, New York approved a tariff with multiple compensation options for systems paired with energy storage, and a proposed decision in California establishes equipment requirements for larger solar-plus-storage facilities to participate in net metering. Legislation enacted in Colorado also permits solar-plus-storage projects to net meter, and the Massachusetts Department of Public Utilities is currently considering the issue.

Regulators Approving Residential Demand Charges for Distributed Solar Customers

Until 2018, investor-owned utilities' requests to adopt mandatory demand charges for residential solar customers were continually denied. However, regulators approved three utilities' (Kansas City Power & Light – KS, Westar Energy – KS, and Eversource – MA) residential demand charge proposals in 2018. The Massachusetts General Assembly enacted legislation creating new requirements for demand charges, though, effectively repealing Eversource's charge.

Mixed Decisions on Separate Customer Classes for Distributed Generation Customers

Several states and utilities are considering the option of placing distributed generation customers into a separate customer class. Regulators are reaching mixed decisions on this concept, though, with Idaho and Kansas regulators approving requests from Idaho Power and Kansas City Power & Light for a separate customer class, and the Iowa Utilities Board rejecting Interstate Power & Light's proposal. The Michigan Public Service Commission also determined, in its April 2018 net metering decision, that a separate customer class was not warranted.

(Cont'd) Top Solar Policy Trends of 2018

Requests to Significantly Increase Residential Fixed Charges Slowing

Since 2016, the number of investor-owned and large public power utilities proposing residential fixed charge increases of at least 10% has steadily declined. In 2016, 47 utilities filed such requests, while this number dropped to 41 in 2017 and 34 in 2018. The median increase requested has also decreased since 2016. Among proposals filed in 2016, the median requested increase was $4.07, while the median request was $4.00 in 2017 and $3.87 in 2018.

Solar Policies Being Addressed Within the Scope of DERs and Grid Modernization

States are increasingly taking a more holistic view to energy policy discussions, with several states considering solar policy issues as part of expansive grid modernization proceedings. For example, Arkansas, Colorado, Illinois, Maryland, and New York are considering distributed solar as part of their grid modernization efforts. Furthermore, states are often considering policies applicable to distributed energy resources more broadly, rather than considering solar exclusively.

Companies Seeking Clarity on Solar Leasing Legality

Although solar leases are commonly used in many states, the legal status of solar leasing is still unclear in some states. In 2018, solar companies filed petitions for declaratory rulings on the legality of their residential solar equipment leases in Florida and Wisconsin. The Florida Public Service Commission approved two companies' leasing agreements, while a decision is pending in Wisconsin

Increasing Options for Customer-Generators

Several states and utilities are creating multiple compensation and rate options for distributed solar customers to choose from. In Massachusetts, the new Alternative On-Bill Credit mechanism provides an alternative to net metering. In Arizona, Salt River Project proposed two new rate options for solar customers, including a demand charge free option. Arizona and Maryland are rolling out pilots featuring time-varying credit rates, and New York's new hybrid tariff for facilities paired with storage includes four compensation options.

Exploring the Locational Value of Distributed Generation

In 2018, several states made efforts to determine the locational value of distributed generation, with the goal of eventually incorporating locational value into compensation frameworks. Regulators in Missouri, Nevada, and Washington considered distribution system planning rules addressing locational value, and the New Hampshire Public Utilities Commission decided to undertake a distribution-level locational value study. United Illuminating in Connecticut also rolled out a pilot program providing an adder for distributed resources on particular circuits.

Figure 4. 2018 Solar Policy and Rate Design Action, by Number of Actions

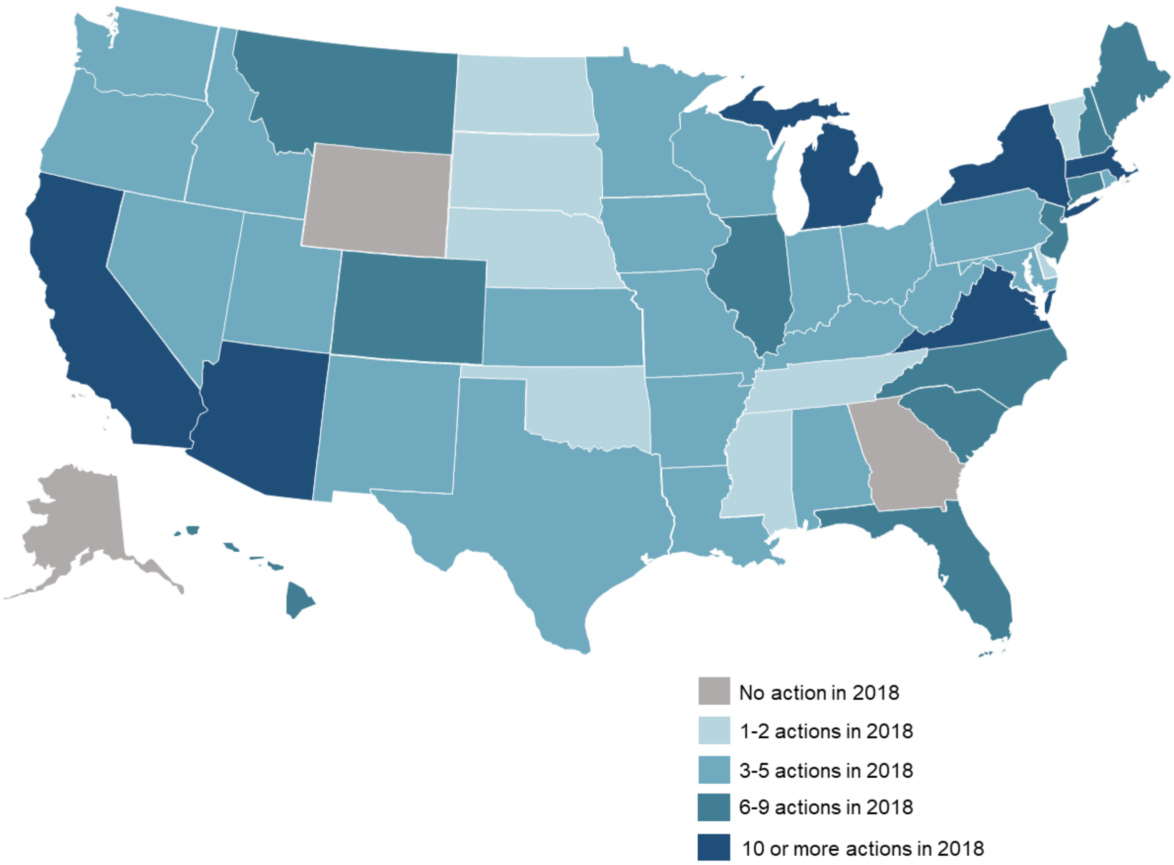


Figure 5. 2018 Pending and Concluded Solar Policy Actions

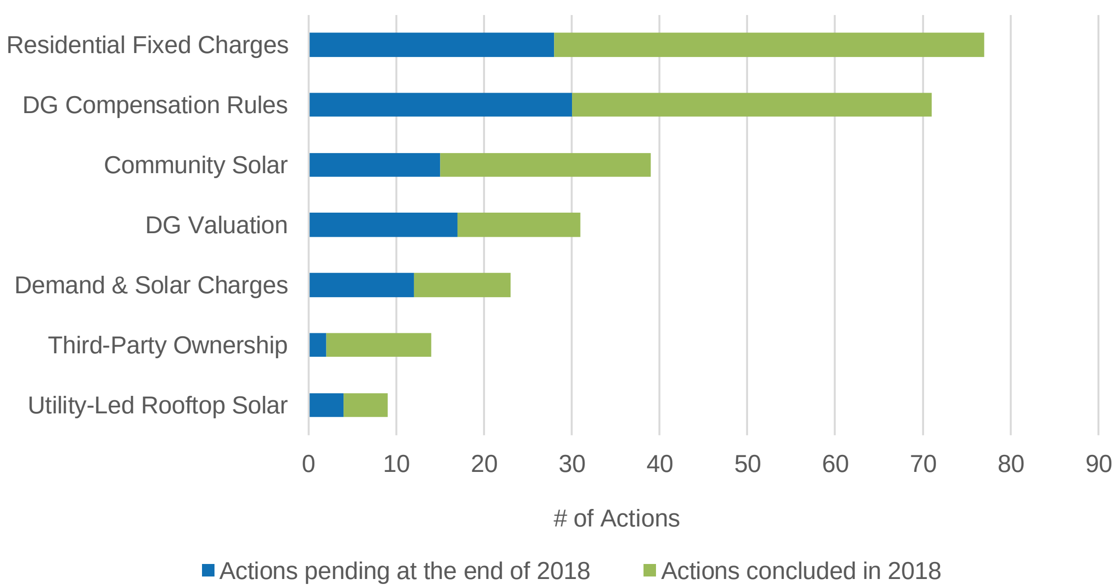
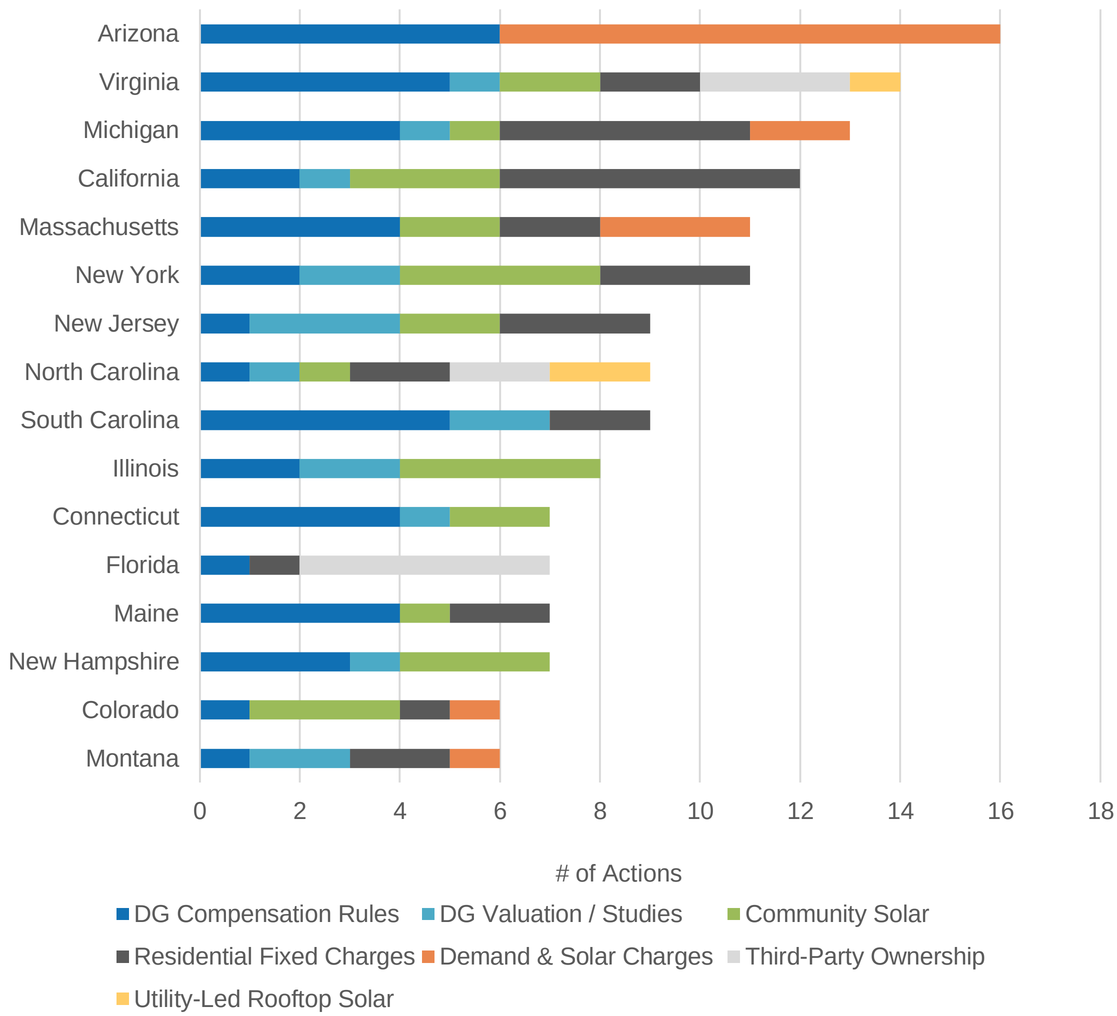


Figure 6. Most Active States of 2018, by Type of Action

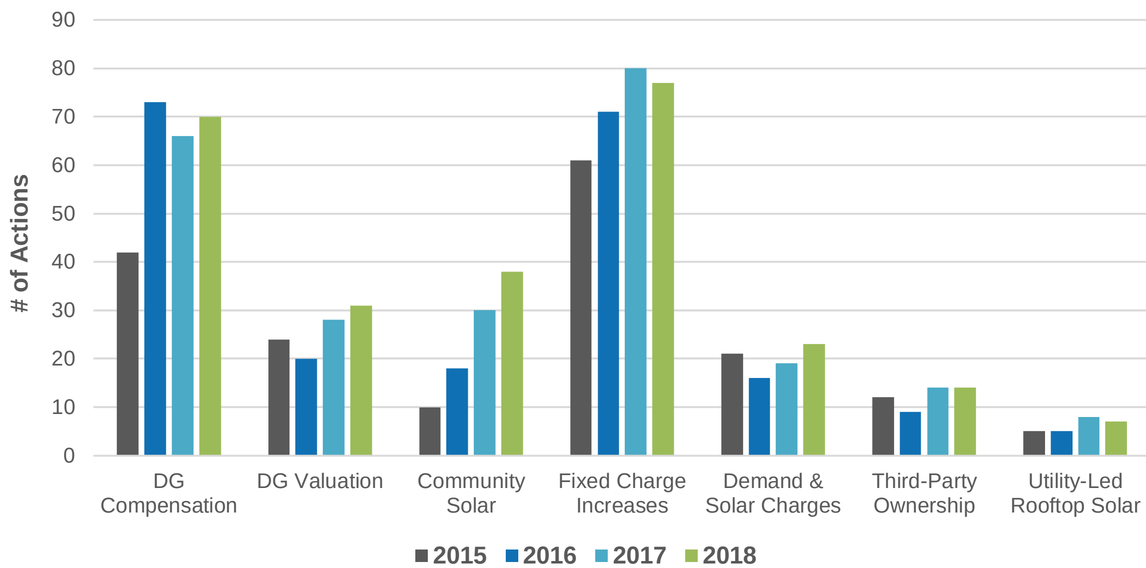


LOOKING BACK: 2015 - 2018

Distributed solar policy action has steadily increased over the past few years, with states and utilities taking approximately 175 actions in 2015, 212 actions in 2016, 249 actions in 2017, and 260 actions in 2018. Figure 7 shows the total number of solar policy actions taken in each year, by category, while Figure 8 displays the number of states taking action in each category. Note that several actions were considered over multiple years.

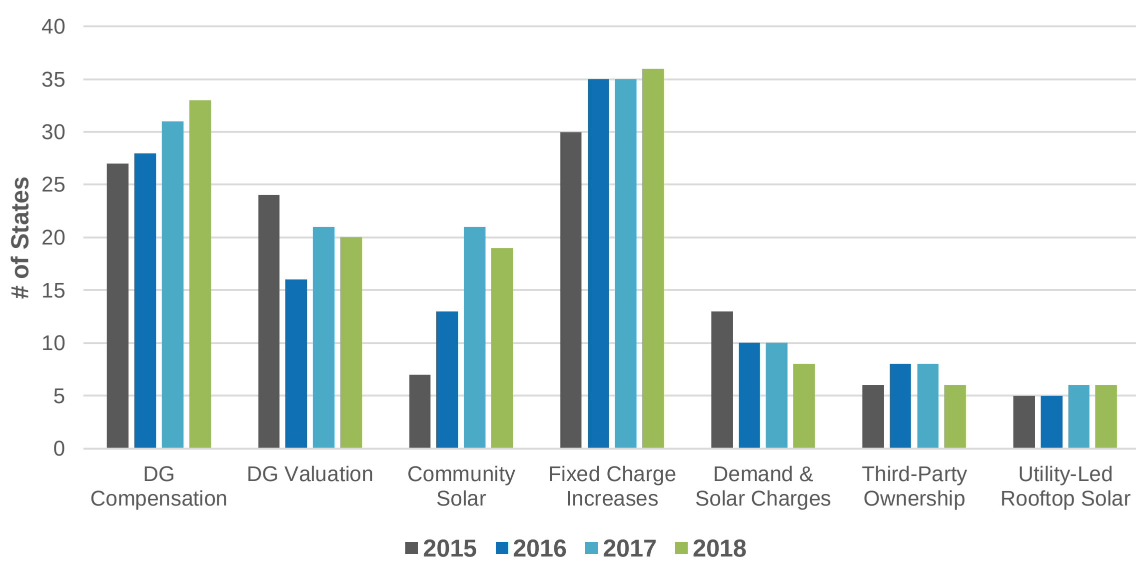
In 2018, activity increased in most categories. There was a slight decline in proposals to increase residential fixed charges, while actions related to third-party ownership held constant from 2017. Community solar is the only category showing a consistent increase in actions from 2015 to 2018, although 2018 was categorized by certain states taking a greater number of actions related to community solar, rather than activity spreading to a greater number of states.

Figure 7. Number of Solar Policy Actions 2015-2018



Distributed generation (DG) compensation is the only category showing a consistent increase in the number of states taking action from 2015 to 2018, with consideration of net metering successor tariffs, in particular, spreading to new states. The number of states considering demand and solar charges declined in 2018, although the number of actions increased. This is largely attributable to the high number of proposals under consideration from three Arizona utilities, Tucson Electric Power, Salt River Project, and UNS Electric. Although the number of states where utilities proposed significant increases in residential fixed charge grew, the number of new proposals filed in 2018 declined from previous years.

Figure 8. Number of States Taking Solar Policy Action 2015-2018



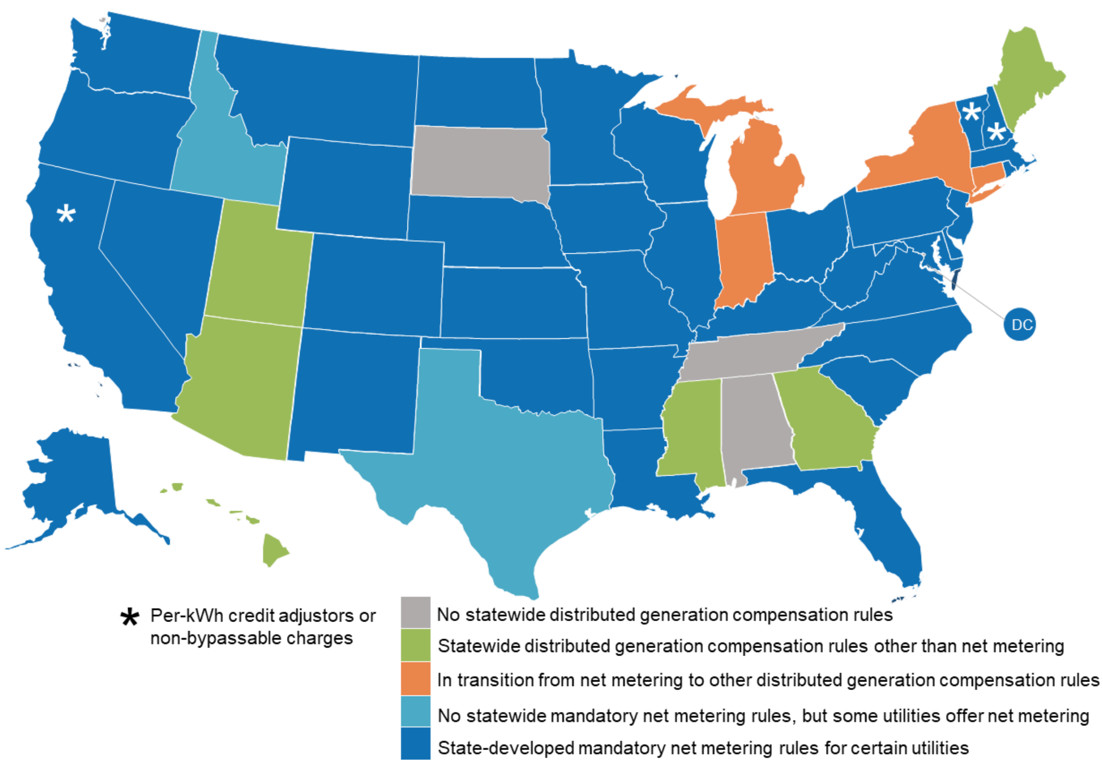
DG COMPENSATION POLICIES REVIEW

Key Takeaways:

- In 2018, 33 states plus DC considered or adopted changes to net metering policies.
- Connecticut and Michigan adopted net metering successor policies in 2018, while Maine made significant changes to its successor program.
- As of January 2019, 35 states plus DC have mandatory net metering rules, and 10 states have or are in transition to other statewide distributed generation compensation rules.

While fewer states officially adopted net metering successor tariffs this year, compared to 2017, 2018 was still a very busy year for the development of successor tariffs. Thirty-three states and DC considered changes to distributed generation (DG) compensation rules during the year, with 21 states considering successor tariff or credit rate issues. Connecticut and Michigan officially approved net metering successor policies in 2018.

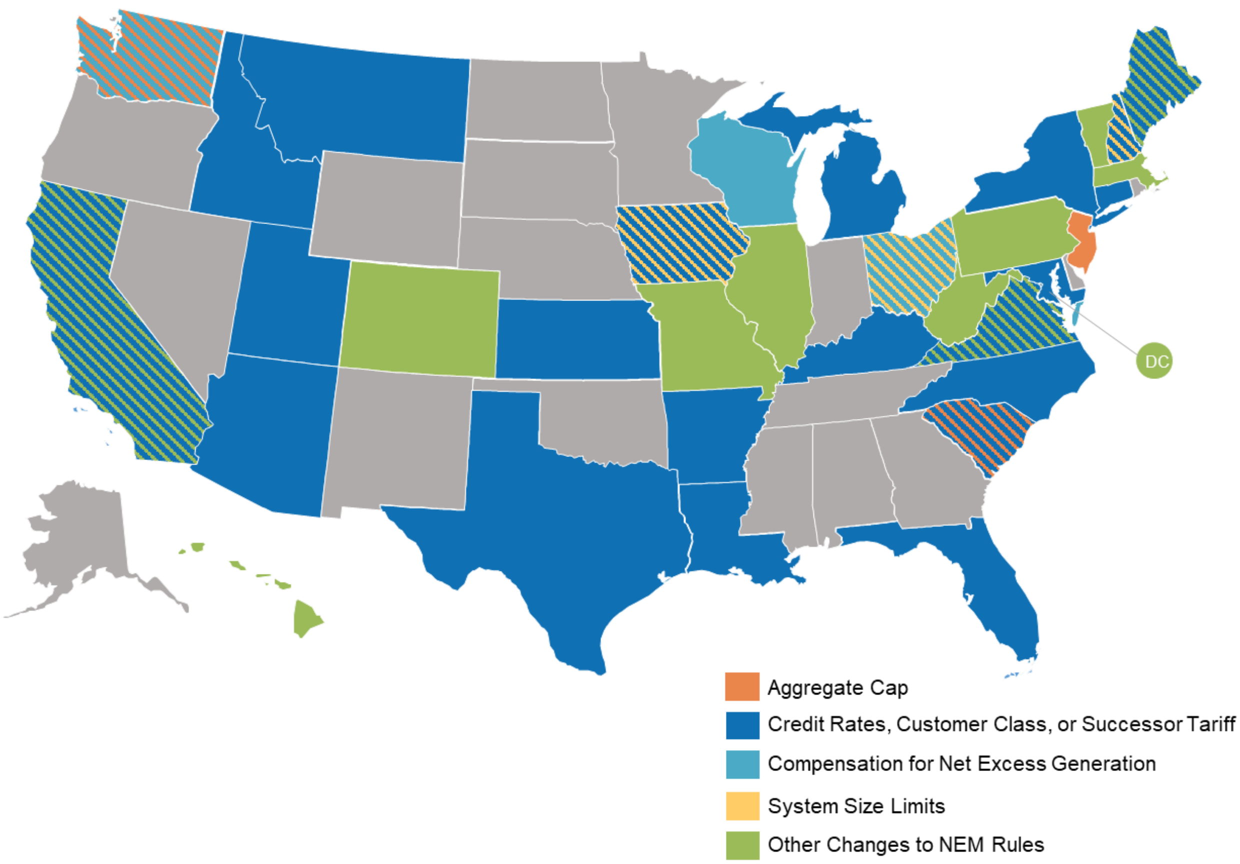
Figure 9. Current Net Metering and DG Compensation Policies



Notes: Arizona, Georgia, Hawaii, Maine, Mississippi, and Utah offer alternative compensation mechanisms, such as net billing, for small DG customers. Maine offers net metering for medium and large DG customers. Connecticut, Indiana, Michigan, and New York currently offer net metering for at least certain customers, but are in transition to alternative DG compensation rules. The Idaho Public Utilities Commission has required investor-owned utilities in the state to offer net metering through separate docket proceedings; however, no statewide net metering policy exists.

Connecticut, Indiana, Michigan, and New York have committed to move from net metering to a successor tariff, but have not yet completed the transition to their new policies, meaning that net metering is still available for at least certain types of new customers in these states. In Indiana, the new successor policy was established by legislation enacted in 2017, but it will not go into effect until either January 2022 or when the 1.5% aggregate cap is reached, whichever occurs sooner. In Michigan, the basic design for the successor tariff was established by the Public Service Commission in 2018 (called the “inflow-outflow” model, which is considered net billing by this report’s definition), but the outflow compensation rates are being determined in individual utility rate cases, none of which have yet reached completion as of the end of 2018.

Figure 10. 2018 Proposed and Enacted Changes to Net Metering Policies by Type



The Connecticut General Assembly enacted legislation committing to move to a system that offers net billing and buy-all, sell-all tariff options, but the tariff details have not yet been established. New York has already moved larger-scale customers to a net billing system with credit rates based on the state’s Value of Distributed Energy Resources (VDER) methodology, but net metering is still available for residential and small commercial customers; new tariffs for these customers are currently under consideration.

Other states are currently considering the adoption of a net metering successor tariff, but have not yet approved any changes. Proceedings are ongoing in Arkansas and Louisiana, where some parties, including the Louisiana Public Service Commission Staff, have proposed a transition to a net billing system, but neither state's regulators have issued a decision. The Future Energy Jobs Act, enacted in Illinois in late 2016, commits the state to adopting a net metering successor tariff when it reaches its 5% aggregate cap on net metering, but the tariff design has not yet been established.

In South Carolina, multiple legislative attempts to increase the state's aggregate cap on net metering or adopt a successor tariff were unsuccessful in the earlier part of the year. Duke Energy Carolinas later reached the aggregate cap in the summer of 2018 and announced that it would be closing net metering to new customers, offering a buy-all, sell-all program at the avoided cost rate instead. However, Duke Energy and solar stakeholders reached an agreement to keep net metering open to new customers until March 15, 2019 in order to allow more time for stakeholders to discuss a successor program.

Table 2. DG Compensation and Credit Rate Structures

Compensation Structure	Description
Net Metering	Production and consumption is credited at a one-to-one ratio over the entire billing period. Net excess generation – any generation in excess of total consumption during the billing period – may be credited at a different rate.
Net Billing	Customer may consume energy behind the meter, effectively receiving a retail rate credit for this portion of production. All energy exported to the grid (typically measured using 15-minute netting periods) is credited at a rate other than retail (e.g., value of solar, avoided cost). Also referred to as "2-channel billing" or "inflow-outflow."
Buy-All, Sell-All	Gross energy consumption is charged at the applicable retail rate, while gross energy production is credited at a rate other than retail.
Credit Rate	**Description**
Retail Rate	Total per-kWh rate charged for energy consumed by the customer. May include seasonal variation.
Time-Varying	Rate varies based on day of week and time of day, and is more closely tied to the utility's actual cost. May also include seasonal variation.
Value-Based	Rate is based on the value of solar or distributed generation. Many different methodologies exist for calculating value-based rates.
Location-Based	Typically an adder or a component of a value-based rate; rate varies by location on the distribution system or may be a flat rate available to customers in certain zones of the distribution system.
Avoided Cost	Rate that the utility would otherwise pay for an additional unit (kWh) of generation. Several different methodologies exist for calculating avoided cost rates. Typically the lowest type of compensation rate.

The Maine Public Utilities Commission, which adopted a buy-all, sell all successor tariff in 2017, restored traditional net metering for medium and large non-residential customers in late 2018 due to concerns about the cost of additional metering equipment required by the successor tariff. The Commission previously determined that utilities are responsible for the additional metering costs, and since larger customers have a significant demand component and smaller per-kWh component of their rates, the Commission determined that the additional metering requirements to implement the new policy create a cost shift for these customers. As such, Maine's policy currently takes the opposite approach as New York's, with residential customers on the successor tariff and larger customers eligible for traditional net metering.

Table 3. 2018 Net Metering Successor Tariff Action

State	Status	New/Proposed Policy
Arizona (TEP & UNS)	Approved	Net billing; excess generation credited at an avoided cost rate, which is stepped down no more than 10% each year. Utility-specific initial export rates have been determined (TEP = 9.64 cents per kWh; UNS: 11.5 cents per kWh). TEP and UNS must develop a time-of-generation pilot.
Arkansas	Under Consideration	Changes are being considered in a PSC proceeding. One working group sub-group proposed net billing at avoided cost, while the other sub-group proposed continuing net metering.
Connecticut	Approved / Under Consideration	Net billing and buy-all, sell-all options. Details are being determined in a regulatory proceeding. Successor will take effect at the end of the state's residential solar investment program.
Idaho (Idaho Power)	Under Consideration	Separate DG customer class approved for Idaho Power; new export credit rates and rate design to be considered following a cost-benefit study.
Louisiana	Under Consideration	Changes are under consideration in a PSC proceeding. PSC Staff proposed net billing at avoided cost, but innovative avoided cost methodologies may be proposed by the utilities.
Maine	Approved	Residential and small non-residential customers: buy-all, sell-all; amount of production able to offset T&D charges will be reduced by an additional 10% per year. Existing customers are grandfathered for 15 years. Medium and large non-residential customers: net metering.
Michigan	Approved	"Inflow-outlow" model (net billing); excess generation credited at either the power supply rate or locational marginal price. Implementation is occurring in individual utility rate cases.
New York	Approved / Under Consideration	Net billing with value-based credit rate structure approved for larger systems. Net metering is still available for new mass market systems (smaller systems) until 2020. Further changes to the value-based credit methodology are under consideration.
Texas (SWEPCO)	Approved	The Texas Public Utilities Commission approved SWEPCO's proposal to replace retail rate net metering with an avoided cost buy-all, sell all program.
Utah (Rocky Mountain Power)	Approved / Under Consideration	Transition tariff is net billing, with excess generation credits at a rate set slightly below retail. Further export credit rate changes under consideration.

Among states considering net metering reforms, three basic compensation structures have emerged: net metering, net billing, and buy-all, sell all. Net metering has been the dominant compensation scheme for many years, and so far four states considering successor policies – California, Nevada, New Hampshire, and Vermont – have opted to continue with or return to net metering. However, California is set to consider further changes to its tariff in 2019, and New Hampshire is conducting studies and pilots to inform future changes to its policy.

Meanwhile, net billing is emerging as the dominant successor framework, with seven states approving net billing structures so far – Arizona, Connecticut, Hawaii, Indiana, Michigan, New York, and Utah. The buy-all, sell-all compensation structure has thus far only been implemented by one state – Maine. However, Connecticut's successor policy calls for both a net billing and buy-all, sell-all option to be offered.

Table 4. Examples of Solar-Plus-Storage Net Metering Provisions

State	Rules
California	Customers with solar facilities paired with energy storage are eligible for net metering. Storage devices 10 kW and smaller are not required to be sized to the customer's demand or generator. Storage devices larger than 10 kW must be sized to 150% of the generator's maximum output and include additional metering equipment. A proposed decision would allow DC-coupled solar-plus-storage systems to net meter using power control systems to ensure that only energy generated by the net metering system receives net metering credits.
Colorado	S.B. 18-009, enacted in March 2018, declares that utility customers have the right to install energy storage systems. As part of Docket No. 17M-0694E, parties proposed changes to the Public Service Commission's net metering rules implementing this legislation and providing additional detail.
Hawaii	Customers with solar facilities paired with storage may participate in the Smart Export Tariff. Customers receive credits ranging from 11.00 to 20.79 cents per kWh (differs by island) for energy exported to the grid between 4 pm and 9 am.
New York	Customers with solar facilities paired with storage may participate in the Hybrid Tariff. The Hybrid Tariff includes four options: Option A: Facility is charged exclusively from the renewable generator and may inject energy into the grid. Facility is eligible to receive the environmental credit value. Option B: Storage facility serves on-site load only and does not inject energy into the grid. Facility is eligible to receive the environmental credit value. Option C: Storage facility is co-located with an energy consumer and is charged by both the renewable generator and the grid and injects energy into the grid. Option D: Storage facility is not co-located with an energy consumer charged by both the renewable generator and the grid and injects energy into the grid.

While net billing is currently the most common successor framework, there are substantial differences in the methodologies used to determine the export credit rates employed by each states' net billing tariff. The most commonly used approaches to date are avoided cost rates, modified avoided cost rates (for example, Indiana's rate is 1.5 times the average wholesale rate and Mississippi's rate includes a non-quantifiable benefits adder on top of the avoided cost rate), and value-based rates. Oftentimes, net billing export credit rates are set somewhere between the retail rate and avoided cost rate. See Table 2 for a description of these compensation and credit rate structures.

Several states are also taking steps to determine the locational value of distributed energy resources, with the intent of eventually incorporating locational value into compensation frameworks. Connecticut's United Illuminating rolled out a non-wires alternatives adder for distributed energy resources on particular circuits, while the New Hampshire Public Utilities Commission is conducting a distribution-level locational value study to inform future changes to its net metering rules. On the other hand, the New York Public Service Commission Staff recommended in 2018 that the locational value component of the state's Value of Distributed Energy Resources tariff be removed.

Regulators in a few states considered utility requests to place DG customers in a separate customer class during 2018. Regulators in Idaho and Kansas approved requests from Idaho Power and Kansas City Power & Light, respectively, to move DG customers to a separate class, with only Kansas City Power & Light implementing a separate rate structure for the new customer class at this time. The Idaho Public Service Commission opened proceedings to study the costs and benefits of on-site generation and the fixed costs of providing electric service in order to inform future rate changes to the new DG customer classes.

The Montana Public Service Commission is considering a similar request from NorthWestern Energy, following 2017 legislation authorizing the Commission to place DG customers into a separate class, following a net metering cost-benefit study. The Iowa Utilities Board rejected a request from Interstate Power & Light to create a separate customer class for DG customers, finding the proposal premature, given that the utility was not proposing any rate changes for the separate class. The Michigan Public Service Commission also determined in its 2018 net metering successor tariff order that a separate customer class is not warranted.

During 2018, states also continued to address the question of whether distributed solar generation paired with energy storage is eligible for net metering. Colorado passed legislation explicitly making residential solar-plus-storage projects eligible for net metering, while California is addressing the interaction of larger energy storage systems with net metering through a regulatory proceeding. Massachusetts continues to consider this question in a regulatory proceeding, and the New York Public Service Commission approved a tariff for solar-plus-storage facilities with several options for compensation, based on the system usage and whether or not the project exports only renewable energy. See Table 4 for some examples of states' solar-plus-storage net metering provisions.

Box 3. 2019 Watch List for Net Metering Action

- ✓ **Arkansas:** A net metering proceeding remains ongoing at the Arkansas Public Service Commission, and a decision is expected in 2019.
- ✓ **California:** Regulators are to consider changes to the state's net metering successor tariff in 2019.
- ✓ **Connecticut:** Pursuant to S.B. 9 (enacted in May 2018), the details of Connecticut's net metering successor tariff will be considered in 2019.
- ✓ **Louisiana:** The Public Service Commission staff published final proposed net metering rules in January 2019, which take the form of net billing, crediting exported energy at an avoided cost rate.
- ✓ **Maine:** In late 2018, the Public Utilities Commission ordered a move back to traditional net metering for medium and large customers. Given the repeated legislative efforts to amend the state's net metering successor and the state's recent political changes, net metering legislation is likely to be enacted in 2019.
- ✓ **Massachusetts:** There is increasing pressure for the legislature to take action on the state's net metering aggregate caps. Other net metering reforms may be considered in addition to the caps, as they were in previous years.
- ✓ **Michigan:** Utilities will continue implementing the state's net metering successor policy in individual rate cases. The credit rate for excess generation will be determined in these proceedings, and additional fees for DG customers may also come under consideration.
- ✓ **Montana:** NorthWestern Energy proposed a new tariff for residential net metering customers in 2018, as part of its general rate case.
- ✓ **New York:** New York's Reforming the Energy Vision process will continue in 2019, with the Public Service Commission considering further changes to the Value of Distributed Energy Resources tariff that was approved in 2017.
- ✓ **North Carolina:** Legislation enacted in 2017 directs the state's investor-owned utilities to file new net metering credit rates, following a cost-benefit study. A proceeding has not yet been opened, but may be initiated in 2019.
- ✓ **South Carolina:** Utilities have reached or are nearing their aggregate caps, and Duke Energy Carolinas' net metering extension ends in March 2019. Legislation addressing net metering was introduced in January 2019.

(Cont'd) 2019 Watch List for Net Metering Action

- ✓ **Virginia:** A stakeholder process taking place in 2018 considered the state's net metering policy, with participants having diverse opinions. A number of net metering legislative proposals are currently under consideration.

- ✓ **Washington:** Utilities in Washington are growing closer to reaching the state's aggregate cap on net metering. A number of net metering bills were introduced in January 2019.

- ✓ **West Virginia:** The Public Service Commission opened a proceeding in September 2018 to consider net metering rule changes. The proceeding will continue in 2019.

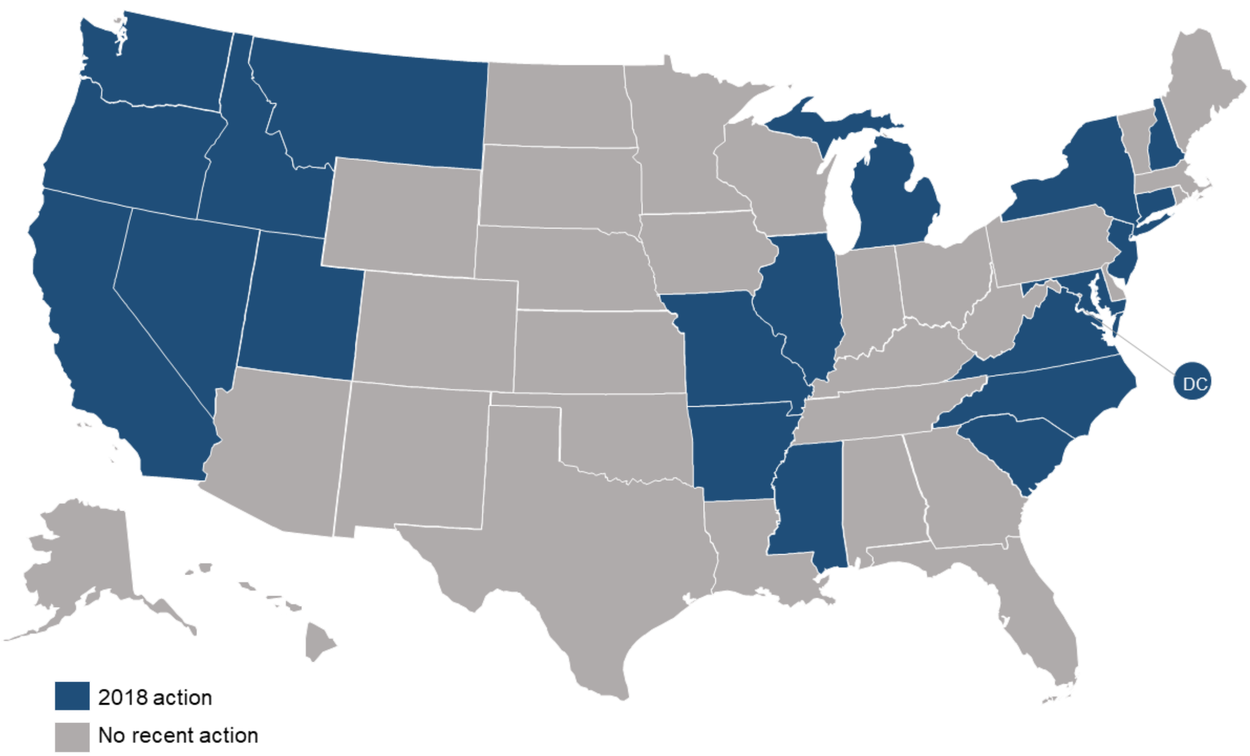
DISTRIBUTED SOLAR VALUATION STUDIES REVIEW

Key Takeaways:

- In 2018, 20 states plus DC were in the process of examining some element of the value of distributed generation.
- Final studies quantifying the value of distributed solar were published in Maryland and Montana, while Oregon utilities calculated the resource value of solar in their service territories.
- Several states considered distributed generation valuation as part of broader grid modernization proceedings or distribution system planning rules.

Several states examined the costs and benefits of distributed generation (DG) during 2018, with some states completing studies quantifying the value of solar and other states considering issues related to DG valuation. Some states have initiated regulatory proceedings examining DG valuation and solar policy issues as part of broader grid modernization discussions; these proceedings are often considering how the value of distributed energy resources (DERs), including solar and energy storage, should be incorporated into resource planning or the evaluation of non-wires alternatives.

Figure 11. Action on DG Valuation or Net Metering Studies in 2018



Consultants in two states – Maryland and Montana – completed studies quantifying the value of distributed solar during 2018, with stark differences in the values reached by the two studies reflecting differences in the states' electric systems, the cost-benefit components included in the studies, and the valuation methodologies employed by each report. The Maryland study found a behind-the-meter solar value of approximately 30 to 38 per kWh in 2019 (varying by utility territory), declining to approximately 25 to 30 cents per kWh in 2028 and includes benefits associated with the bulk power system, local distribution system economy, and society. When economic benefits are excluded, the values range from approximately 7 cents per kwh in 2019 to 11 cents per kWh in 2028. The Montana study, on the other hand, includes a more limited set of benefits, finding a value of 4.2 to 4.6 cents per kWh when avoided CO_2 costs are included. When CO_2 costs are excluded, the value is 3.5 to 3.8 cents per kWh.

Figure 12. Value of Solar Study Components

		Costs		Benefits									
Year	Study	Integration Cost	Admin. Cost	Avoided Energy	Avoided Gen. Capacity	Avoided Transmission	Avoided Distribution	System/Line Losses	Ancillary Services	Risk/Price Hedging	Market Price Suppression	Env. Benefits	Other
2006	Austin Energy (CPR)												
2009	Arizona Public Service (R.W. Beck)												
2012	Michigan (NREL)												
2012	New Jersey/Pennsylvania (CPR)												
2013	CPS Energy												
2013	Arizona Public Service (SAIC)												
2013	Xcel Energy – CO (CPR)												
2013	Arizona Public Service (Crossborder)												
2013	North Carolina (Crossborder)												
2013	Austin Energy (CPR)												
2014	Utah (CPR)												
2014	Xcel Energy – MN (CPR)												
2014	Nevada (E3)												
2014	Mississippi (Synapse)												
2014	Vermont (Public Service Dept.)												
2015	Maine (CPR)												
2015	Massachusetts (Acadia Center)												
2015	Louisiana (Acadian Consulting)												
2015	Tennessee Valley Authority (EPRI)												
2015	South Carolina (E3)												
2016	Arizona Public Service (Crossborder)												
2016	Nevada (SolarCity)												
2016	Nevada (E3)												
2017	Georgia Power (Georgia Power)												
2017	District of Columbia (Synapse)												
2017	Oregon (PUC)												
2017	Entergy Arkansas (Crossborder)												
2018	NorthWestern Energy – MT (Navigant)												
2018	Maryland (Daymark)												

Oregon utilities published utility-specific calculations for the resource value of solar, based on the valuation framework established in 2017. The values range from 4.5 to 5.2 cents per kWh, but do not yet include grid services or RPS compliance benefits. In Illinois, Pacific Northwest National Laboratory published a report intended to kick off the state's solar valuation efforts.

While the report does not quantify the value of distributed solar, it examines key considerations for calculating the value of solar and summarizes approaches taken by other states. A draft final report was also released for Illinois' NextGrid process, which addresses DG valuation and rate design.

Multiple states took steps toward identifying the locational value of distributed energy resources (DERs) in 2018. The New Hampshire Public Service Commission determined that instead of conducting a non-wires alternative pilot program, it would conduct a distribution-level locational value study. Some states, including Missouri, Nevada, and Washington, considered provisions to identify the locational value of DERs within distribution system planning rules. Meanwhile, the New York Public Service Commission Staff recommended removing the locational value component of the state's Value of Distributed Energy Resources tariff.

Table 5. Comparison of Maryland, Montana, and Oregon DG Valuation Scopes

Maryland	Montana	Oregon
Public Service Commission Value of Solar Study (Daymark)	**NorthWestern Energy Net Metering Cost-Benefit Study (Navigant Consulting)**	**Resource Value of Solar Framework**
• Avoided Energy • Energy Market Price Effects • Avoided Capacity • Avoided RECs • Avoided Transmission Investment • Avoided Transmission Charge • Non-Monetized CO_2 Social Benefit • Health Benefits • Economic Benefits	• Avoided Energy • Avoided Capacity • Avoided T&D Capacity • Avoided System Losses • Avoided Environmental Compliance Costs • Administrative Costs Assumed to be zero: • Avoided RPS Compliance Costs • Avoided Fuel Hedging • Reduced Price Volatility • Avoided Grid Support Services Costs • Avoided Outages Costs • Interconnection Costs • Integration Costs	• Energy • Generation Capacity • T&D Capacity • Lines Losses • Administration • Market Price Response • RPS Compliance • Integration & Ancillary Services • Hedge Value • Environmental Compliance • Security, Reliability, & Reserves

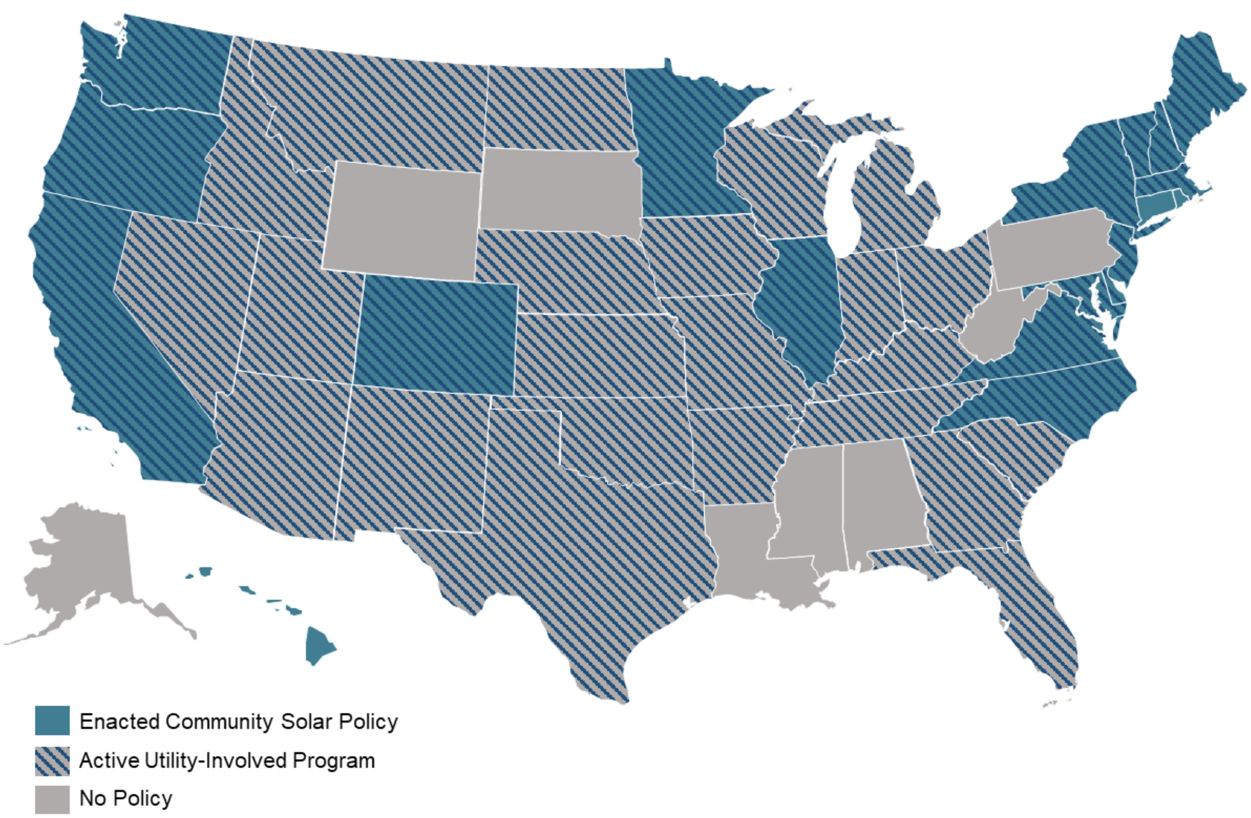
COMMUNITY SOLAR REVIEW

Key Takeaways:

- In 2018, 19 states and DC took a total of 39 actions on community solar policy and implementation of statewide community solar programs.
- New Jersey adopted a community solar policy in 2018, becoming the 19th state to do so.
- Two of the most common issues addressed by states in 2018 were participant credit rates and low income-access.

Community solar continues to grow in popularity as a way to expand solar access to larger potential target markets of individuals and businesses. The community solar model meets the needs of customers who want to utilize solar energy, but may not have the physical, financial, or situational ability to install rooftop panels on their residence or workplace. Community solar facilities also have the potential to take advantage of economies of scale to help bring the cost of these projects lower than that of rooftop solar. Furthermore, careful siting of community solar facilities can generate important locational benefits that can increase the value for both participating customers and the utility system as a whole.

Figure 13. State Community Solar Policies & Utility Community Solar Programs

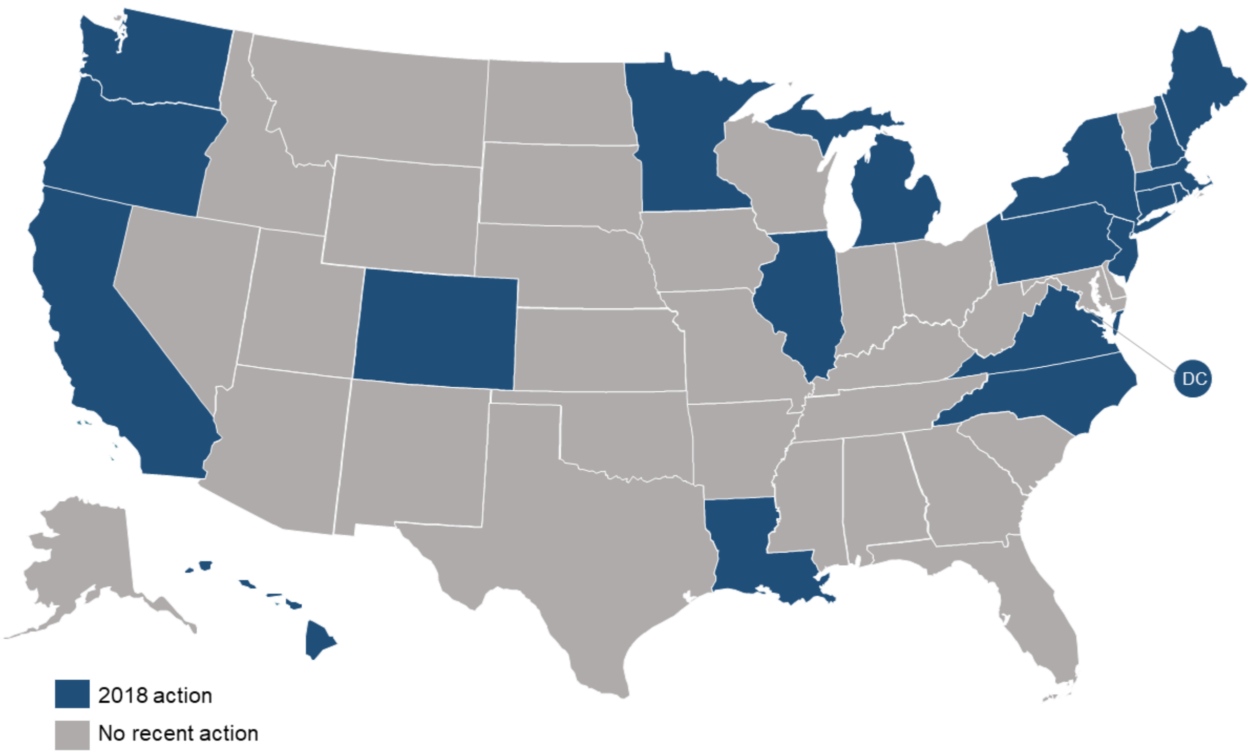


Source: NC Clean Energy Technology Center; Smart Electric Power Alliance[5]

Community solar activity increased for the third year in a row, with a total of 39 actions taken by 19 states and DC. At the end of 2018, 19 states and DC had policies enabling community solar. Utilities in at least 41 states have active community solar programs, according to the Smart Electric Power Alliance (SEPA).[6] SEPA found that 229 utilities have active community solar programs, as of the end of 2017.[7] Notably, this is up from the 171 active programs SEPA identified at the end of 2016.[8]

During the 2018 legislative session, lawmakers in several states, including Colorado, Connecticut, Maine, Minnesota, New Jersey, and New York, considered bills to either authorize new community solar programs or expand existing programs. Legislatures in Connecticut and New Jersey enacted bills, each creating new community solar programs, while the Minnesota Legislature enacted a bill increasing the size limit for Xcel Energy's Solar*Rewards program, which community solar projects are eligible for.

Figure 14. 2018 Action on Community Solar Policy



Credit rate design for community solar participants continued to be one of the focal points of community solar activity in 2018. The value of credits offered to participants ultimately determines the cost-effectiveness of program participation. In 2018, the Oregon Public Utility Commission decided to initially use a retail rate credit for its community solar program until the utilities' resource value of solar rates are finalized. In Minnesota, Xcel Energy updated its value of solar rate, which is used as the credit rate for its community solar program, while the Public Utilities Commission approved a $0.015 per kWh adder for residential community solar subscribers. New York continues to revise its value of distributed energy resources rate, which is also used as the credit rate for its community solar program.

Table 6. Examples of State Community Solar Credit Rate Approaches

State	Credit Rate Description
Colorado	Total aggregate retail rate
Hawaii	Phase I: Flat credit rates, based on mid-day rates; Phase II: Time-varying credit rates
Minnesota	Value of solar rate
New Jersey	Retail rate
New York	Value-based rate plus market transition credit
North Carolina	Avoided cost rate; utilities may propose avoided cost methodology
Vermont	Blended residential retail rate; all production is subject to credit adjustors based on system size, site location, and REC ownership
Virginia	Market value of energy and capacity

One of the most significant trends in community solar action during the year was states evaluating program design options to increase low-income customer participation. Both Connecticut's and New Jersey's new programs include carve-outs for low-income customers. Connecticut's program reserves 10% of total program capacity and 10% of each project's capacity for low to moderate income customers or low-income service organizations, while New Jersey's program includes a 40% carve-out for low to moderate income customers.

Table 7. Examples of Low-Income Community Solar Provisions

State	Low-Income Provisions
California	The CPUC directed Pacific Gas & Electric and Southern California Edison to solicit Community Solar Green Tariff projects to serve disadvantaged communities in the San Joaquin Valley.
Connecticut	Connecticut's program reserves 10% of total program capacity and 10% of each community solar project's capacity for low to moderate income customers or low-income service organizations.
Illinois	The Illinois Solar for All program includes an additional 6 to 13 cents per kWh for low-income community solar projects.
Maryland	Maryland's pilot program includes a 60 MW carve-out for projects focused on low to moderate income customers.
Massachusetts	The SMART program includes an adder of 6 cents per kWh for community solar projects serving low to moderate income customers.
Minnesota	Xcel Energy's Rehabilitation and Efficiency: Neighborhood Energy Works (RENEWs) pilot program combines community solar subscriptions with energy efficiency improvements for certain low-income customers.
New Jersey	New Jersey's community solar pilot program rules include a 40% carve-out for low to moderate income customers.

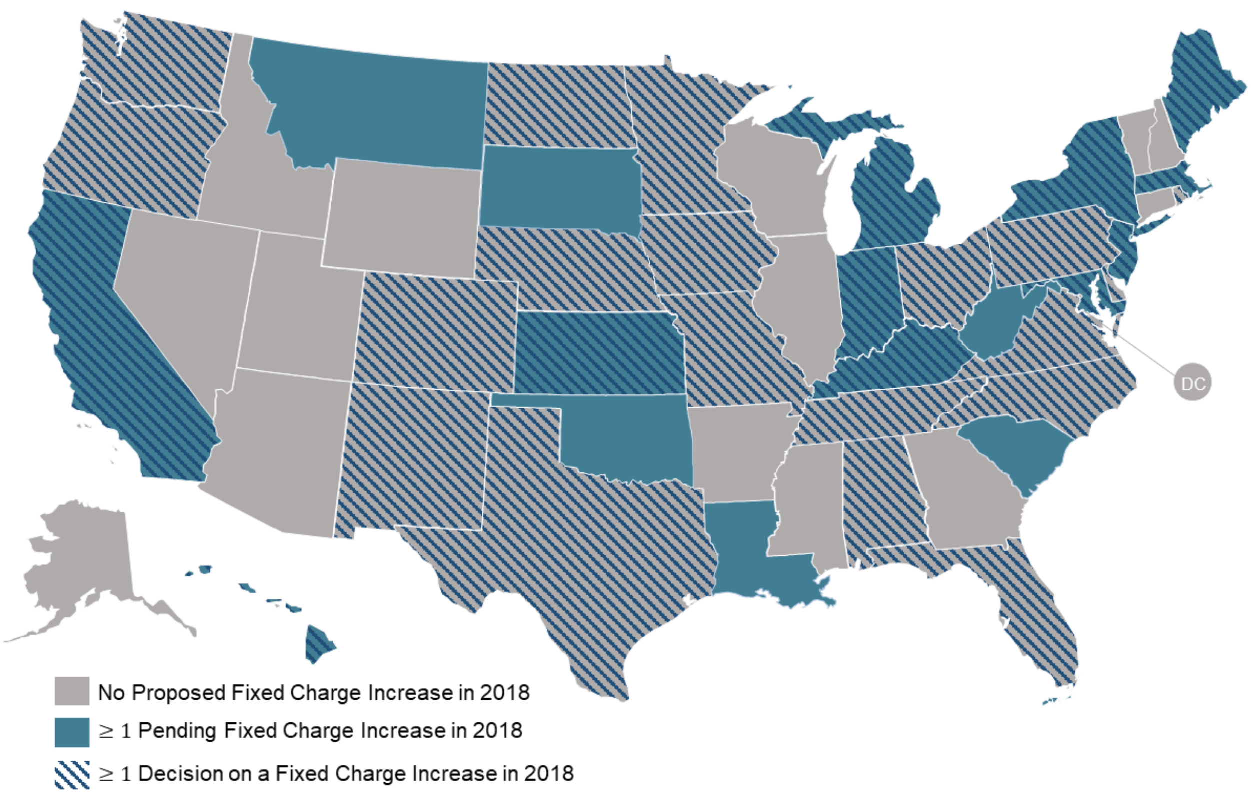
FIXED CHARGES REVIEW

Key Takeaways:

- In 2018, there were 77 pending or decided utility proposals in 36 states to increase residential fixed charges or minimum bills by at least 10%.
- Thirty-four utilities in 22 states filed new requests to increase residential fixed charges by at least 10% during 2018.
- Overall, the median increase requested in 2018 was $4.00, with proposals ranging from $0.71 to $19.94. The median percentage increase requested in 2018 was 44%.
- Of the fixed charge decisions made in 2018, 5 requests were fully approved, 12 were denied, and 26 were partially approved. Regulators ordered decreases in 3 utilities' fixed charges.

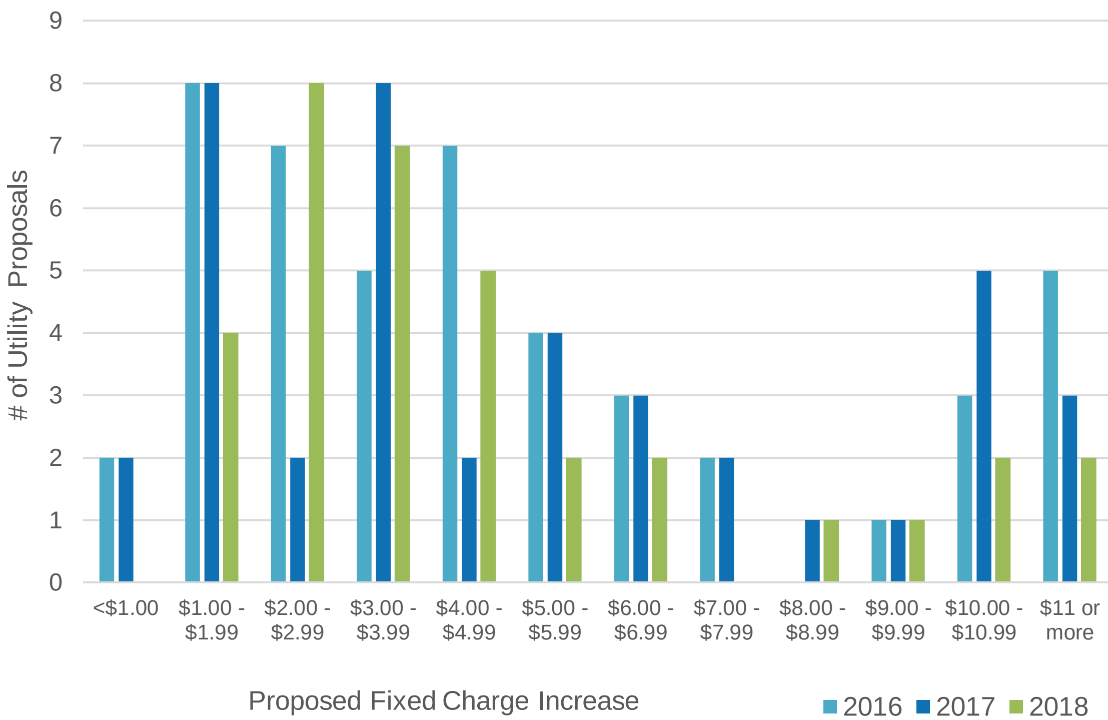
Requests to increase residential fixed charges were the most common type of solar policy action for the second year in a row. While these charges are applied to all residential customers, they are particularly impactful for customers with distributed generation because the fixed charge portion of a customer's bill typically cannot be offset by net metering credits. This, in turn, reduces the financial value to the customer of a distributed solar system.

Figure 15. Active Proposals to Increase Residential Fixed Charges in 2018



In 2018, there were 72 utility proposals pending or decided in 36 states and DC to increase residential fixed charges by at least 10% (plus 5 proposals to increase residential customer minimum bills). While the number of increases under consideration declined from 2017, increases were under consideration in a slightly larger number of states. The requested increases ranged from $0.71 to $19.94, with a median requested increase of $4.00 or 44%.*
Considering only utilities that filed new requests for fixed charge increases during 2018, there were 34 proposals from utilities in 22 states and DC.

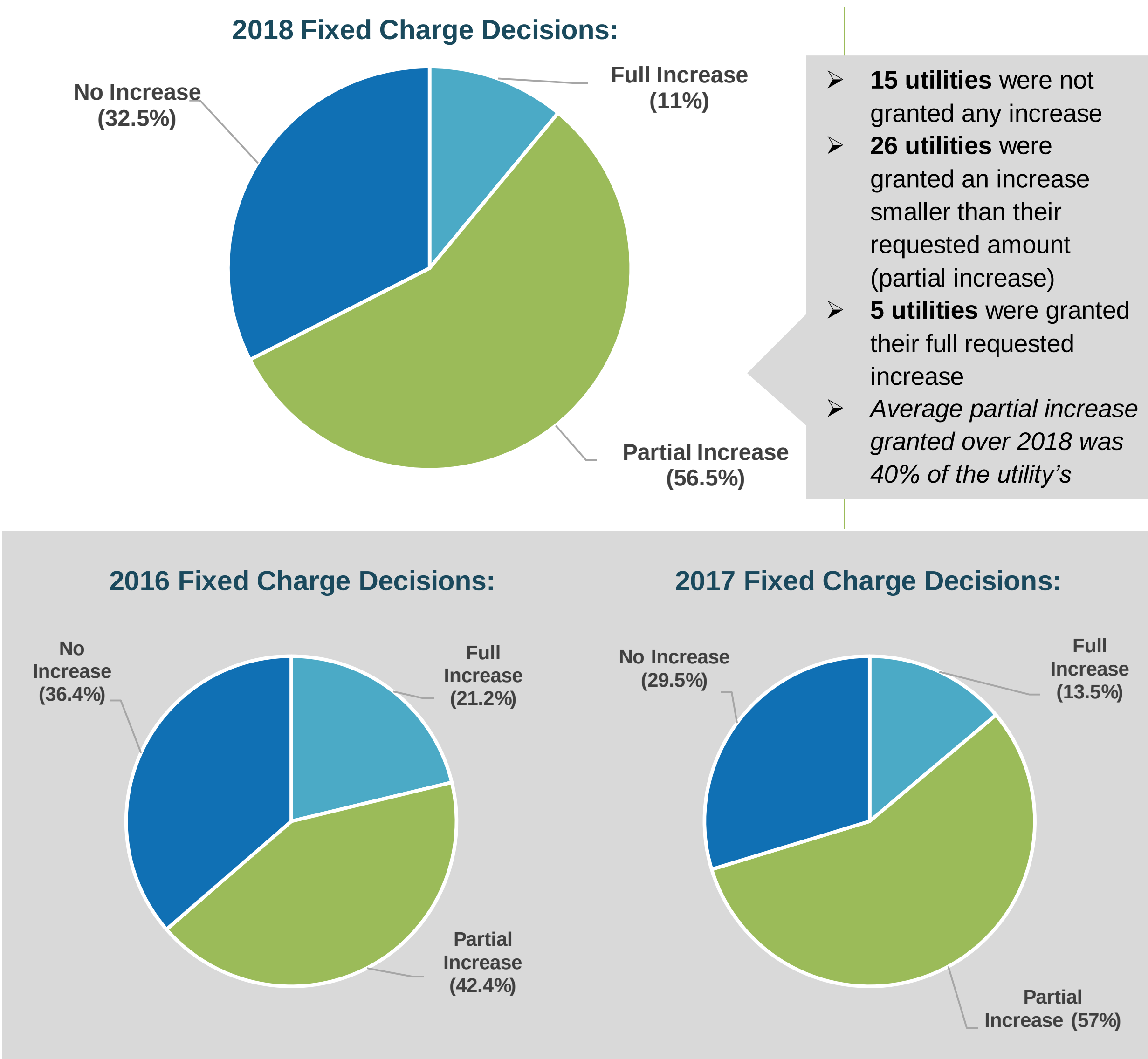
Figure 16. Distribution of Proposed Fixed Charge Increases 2016 - 2018



Proposals from investor-owned and large public power utilities to increase residential fixed charges by at least 10% have declined over the past few years. In 2016, 47 utilities proposed significant increases in residential customer fixed charges, while 41 requests were filed in 2017 and 34 in 2018. The median increase requested by these utilities has also decreased since 2016. Among new proposals filed in 2016, the median requested increase was $4.07, while the median requested increase among proposals filed in 2017 was $4.00, and among proposals filed in 2018 was $3.87.

* PG&E and SCE requested increases are omitted from the percentage increase calculation, as they currently do not have residential fixed charges, only minimum bills.

Figure 17. Residential Fixed Charge Decisions Breakdown



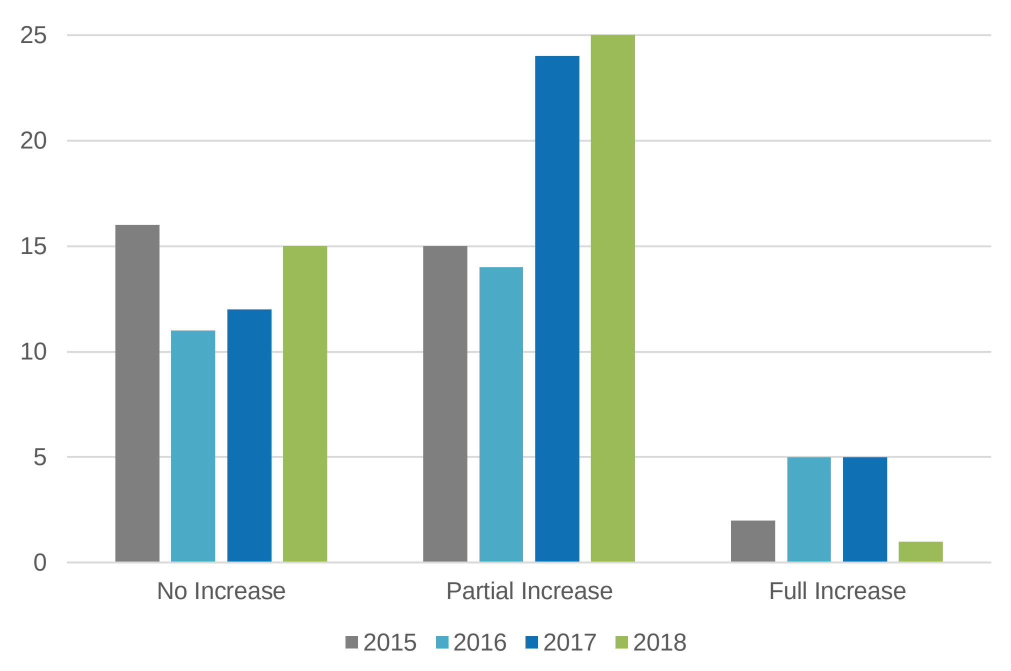
Forty-six proposals were decided in 2018, with approximately 11% of utilities receiving their full requested increase, 56.5% receiving a partial increase, and 32.5% receiving no increase. Of partial increases granted, the average increase granted was 40% of the utility's initial request (median of 20%). This is an increase from 2017, where the average partial increase granted was 26% of the utility's request.

Notably, regulators ordered a decrease in the fixed charges of three utilities that had requested increases – Black Hills Energy – CO, Kansas City Power & Light – MO, and Central Hudson Gas & Electric – NY.† Connecticut regulators also ordered a reduction in Eversource's residential fixed charge, although the utility had not requested an increase. In Colorado,

† This is counted as "no increase" in Figures 15 and 16.

regulators rejected Black Hills Energy's use of the minimum intercept cost allocation method (which the utility had used in its two previous rate cases), citing public policy concerns related to the degree to which the method increases the fixed charge. The Commission noted that the impact on low-income customers and energy conservation require consideration of the level at which fixed charges are set. In New York, the Public Service Commission approved a settlement agreement reducing the fixed charge, and in Missouri, the Commission decreased Kansas City Power & Light's fixed charge and increased Kansas City Power & Light Greater Missouri Operations' fixed charge so that they are now equal.

Figure 18. IOU Residential Fixed Charge Decisions Breakdown: 2015 – 2018

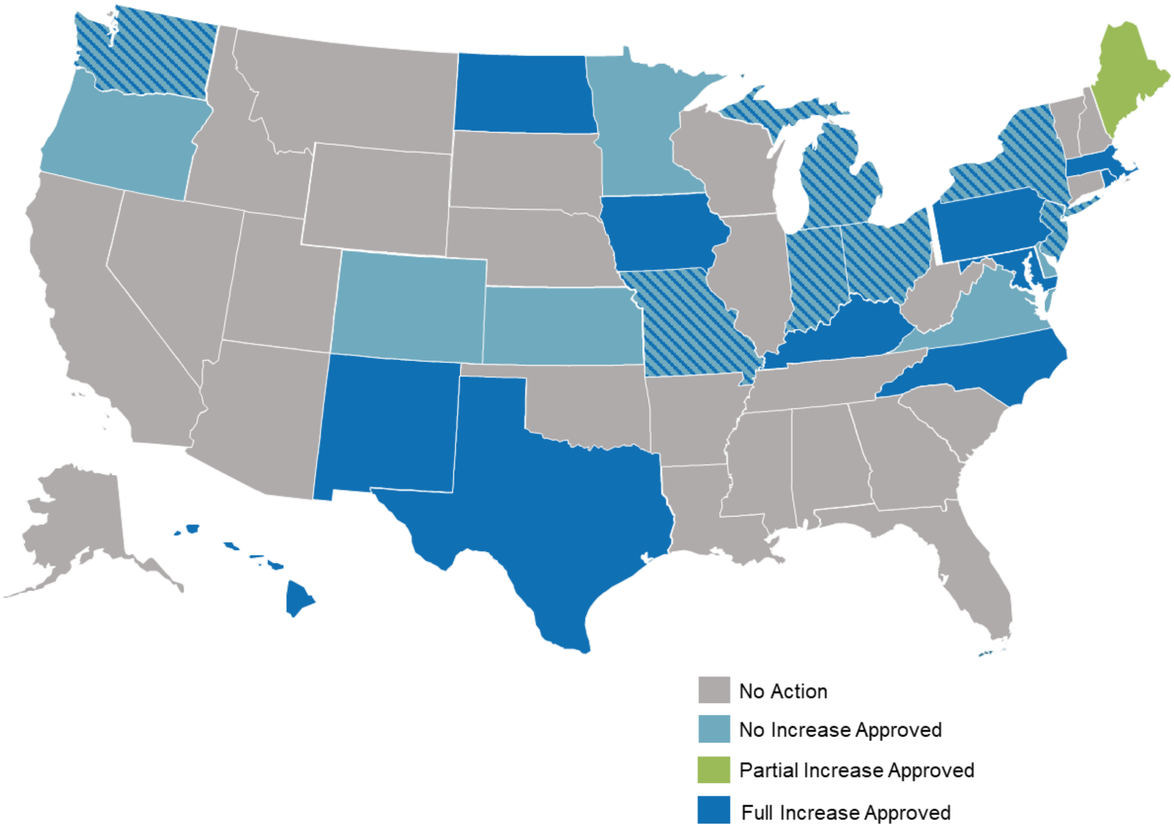


Note: This chart excludes decisions made by municipal and cooperative utilities to increase residential fixed charges. These decisions are included in Figure 12.

Minimum Bills

In addition to the 72 requests to increase residential fixed charges by at least 10%, five utilities also proposed increases in their residential minimum bills The Hawaii Public Service Commission considered requests from all three of Hawaii's investor-owned utilities to increase minimum bills, as well as residential fixed charges. All three utilities proposed increasing the monthly minimum charge to $25.00. In 2018, regulators approved Hawaiian Electric Company's (HECO) and Hawaii Electric Light Company's (HELCO) full requested increases in their minimum bills, while approving only a partial increase in the utilities' fixed charges. Maui Electric Company's proposal remained pending at the end of 2018. In California, both Pacific Gas and Electric and San Diego Gas and Electric had minimum bill increases under consideration, in addition to fixed charge increases. These five actions are not included in the fixed charge analysis and figures in this section.‡

Figure 19. 2018 IOU Residential Fixed Charge Decisions



‡ This is why some of the discussions in this report refer to the total number of actions in this category as 77, while the total number of fixed charge actions is 72.

Figure 20. Active Proposals to Increase Residential Fixed Charges in 2018

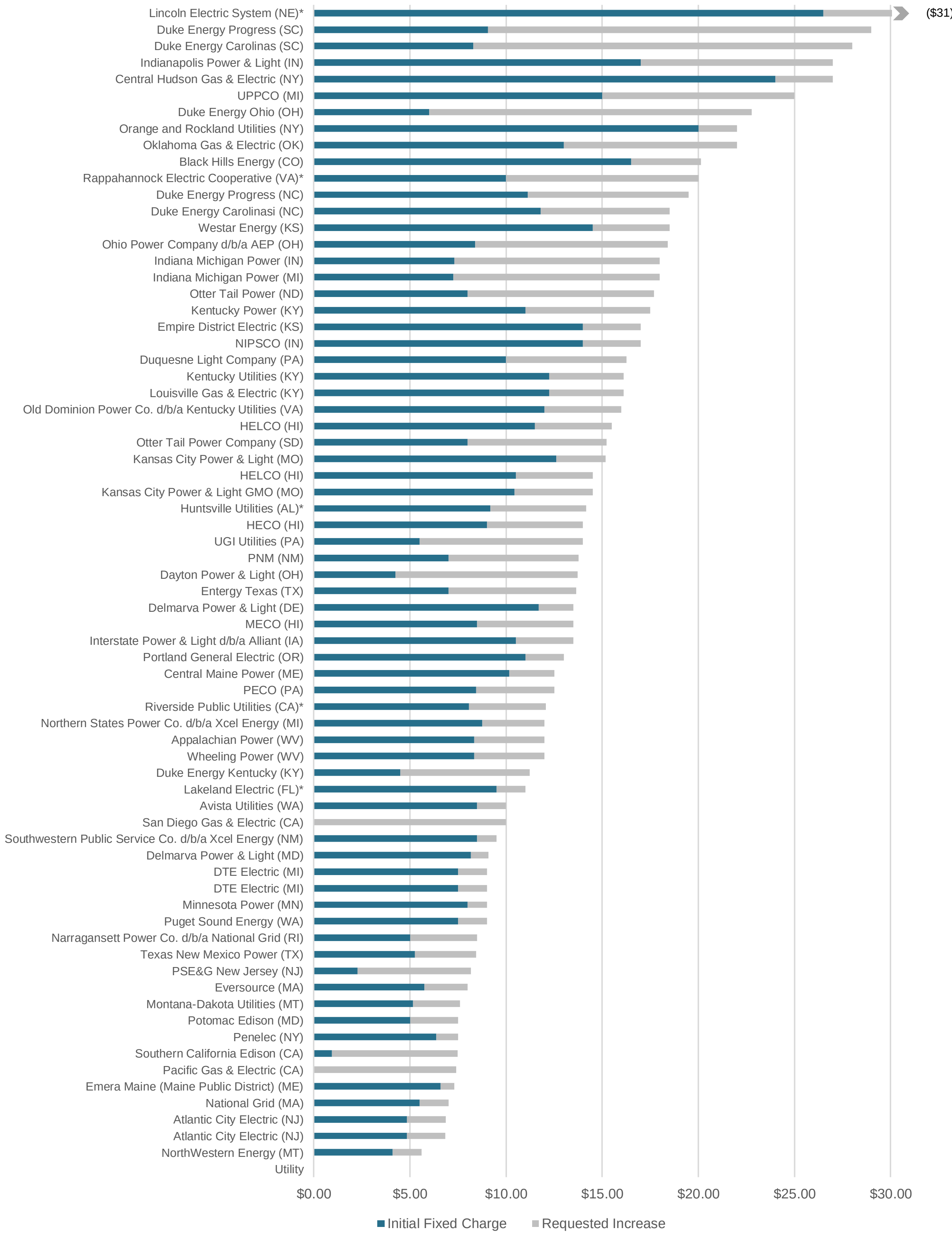
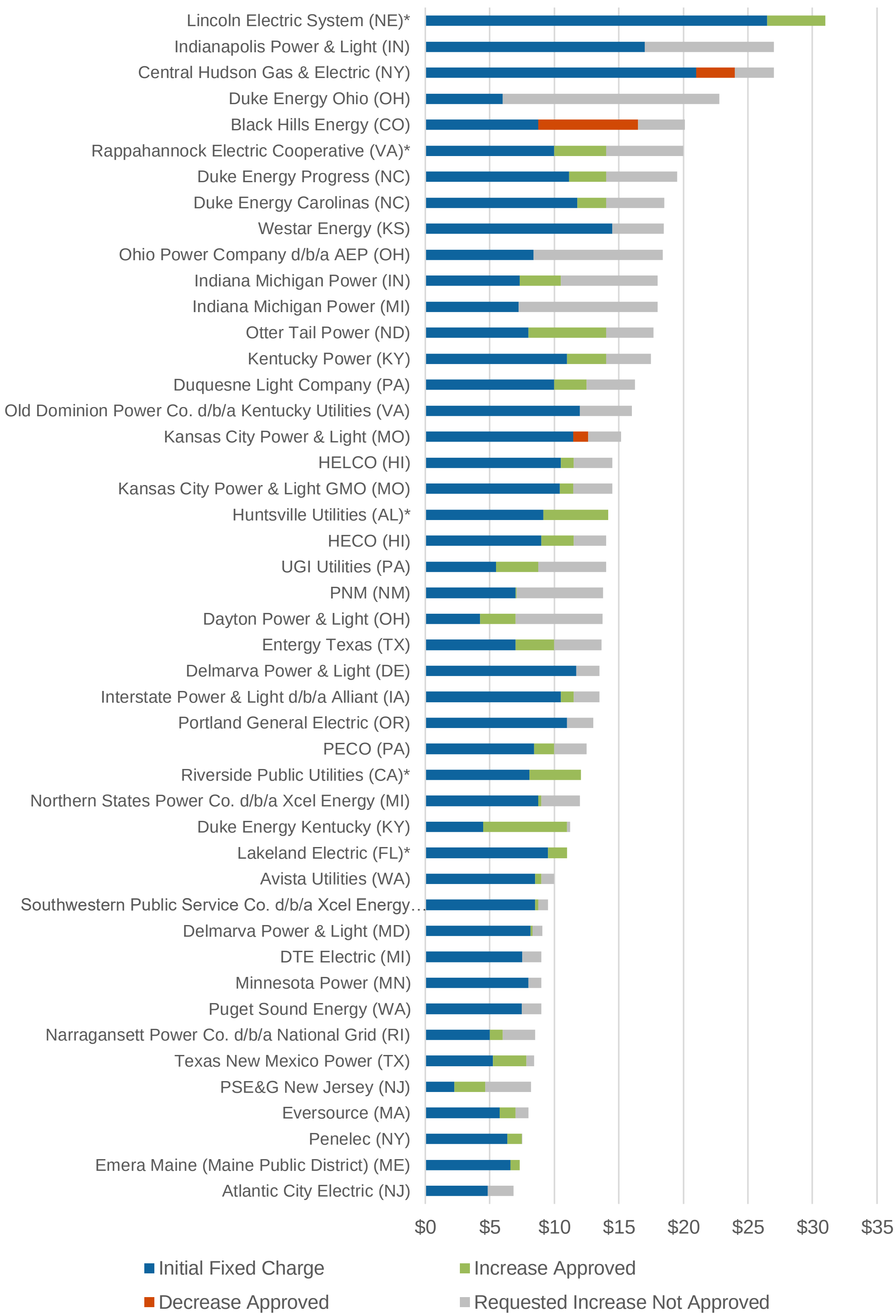


Figure 21. Residential Fixed Charge Decisions in 2018



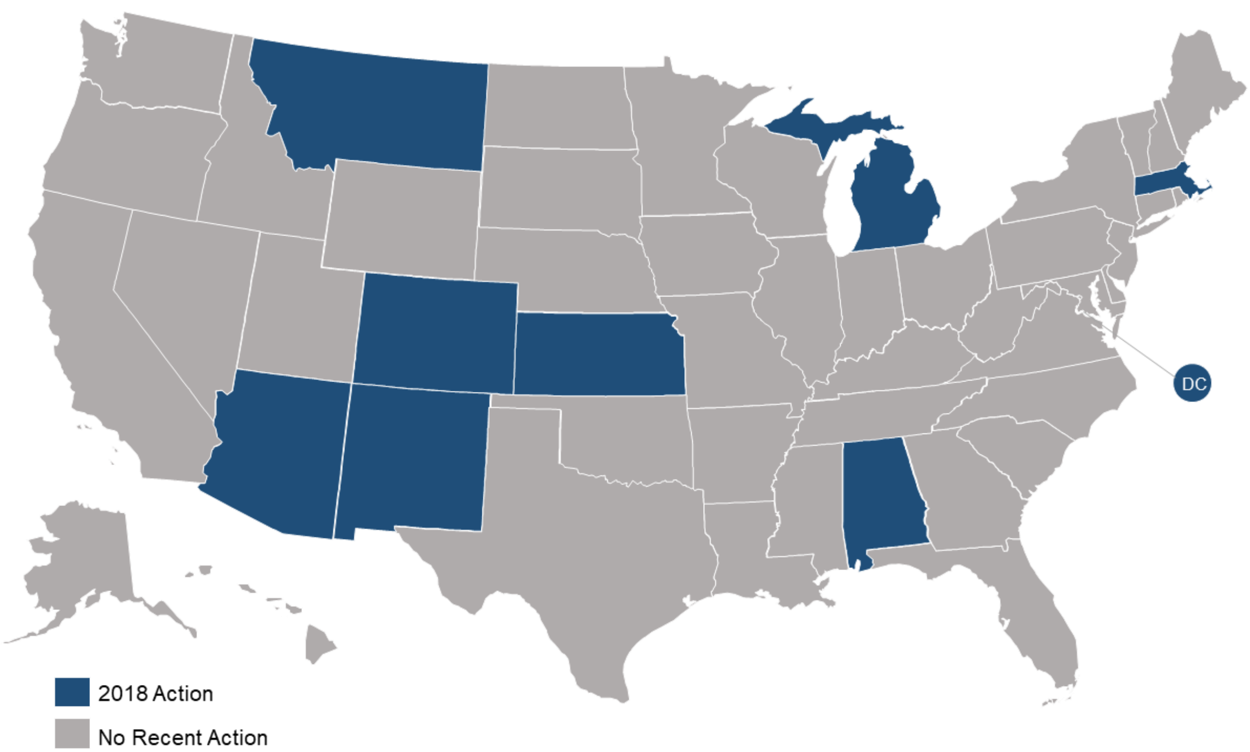
DEMAND AND SOLAR CHARGES REVIEW

Key Takeaways:

- In 2018, 23 actions related to demand charges or other charges on distributed generation customers were pending or decided in 8 states plus DC.
- Of these actions, 10 related to demand charges, 6 to flat fees, 6 to system capacity charges, 1 to a standby charge.
- Regulators approved three utilities' requests to adopt residential demand charges for distributed solar customers and eliminated one utility's existing standby charge.

Several states were actively considering residential demand and other solar charges in 2018, with six utilities filing requests for new charges and regulators approving three utilities' proposed fees. Before 2018, no state regulatory body had approved an investor-owned utility's request to implement a mandatory residential demand charge.§

Figure 22. 2018 Action on Residential Demand and Solar Customer Charges



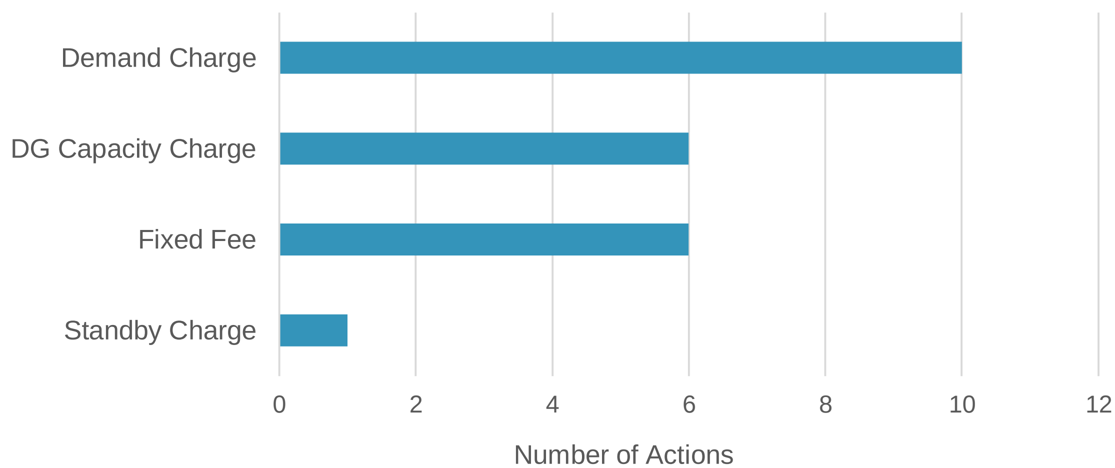
In January 2018, the Massachusetts Department of Public Utilities approved the first mandatory demand charge for residential distributed generation (DG) customers of an investor-owned utility (Eversource). However, the Massachusetts General Assembly enacted legislation later in

§ The exception is a mandatory demand charge for Arizona Public Service residential customers with refrigerated air conditioning approved in 1980. The charge was changed after initial implementation to no longer be mandatory.

the year establishing certain requirements for demand charges that effectively repealed the approved charge. The bill requires demand charges to be based on demand during system peak hours, while Eversource's charge was based on non-coincident peak demand. Eversource's demand charge was part of its Monthly Minimum Reliability Contribution (MMRC), an extra charge authorized by Massachusetts legislation enacted in 2016.

The Kansas Corporation Commission also approved mandatory demand charges for residential DG customers of Westar Energy and Kansas City Power & Light. In 2017, the Commission approved a non-unanimous settlement agreement determining that demand charges and other types of additional fees are appropriate for DG customers. Both utilities now have separate customer classes for DG customers as well.

Figure 23. Solar Charge Actions Considered in 2018 by Type

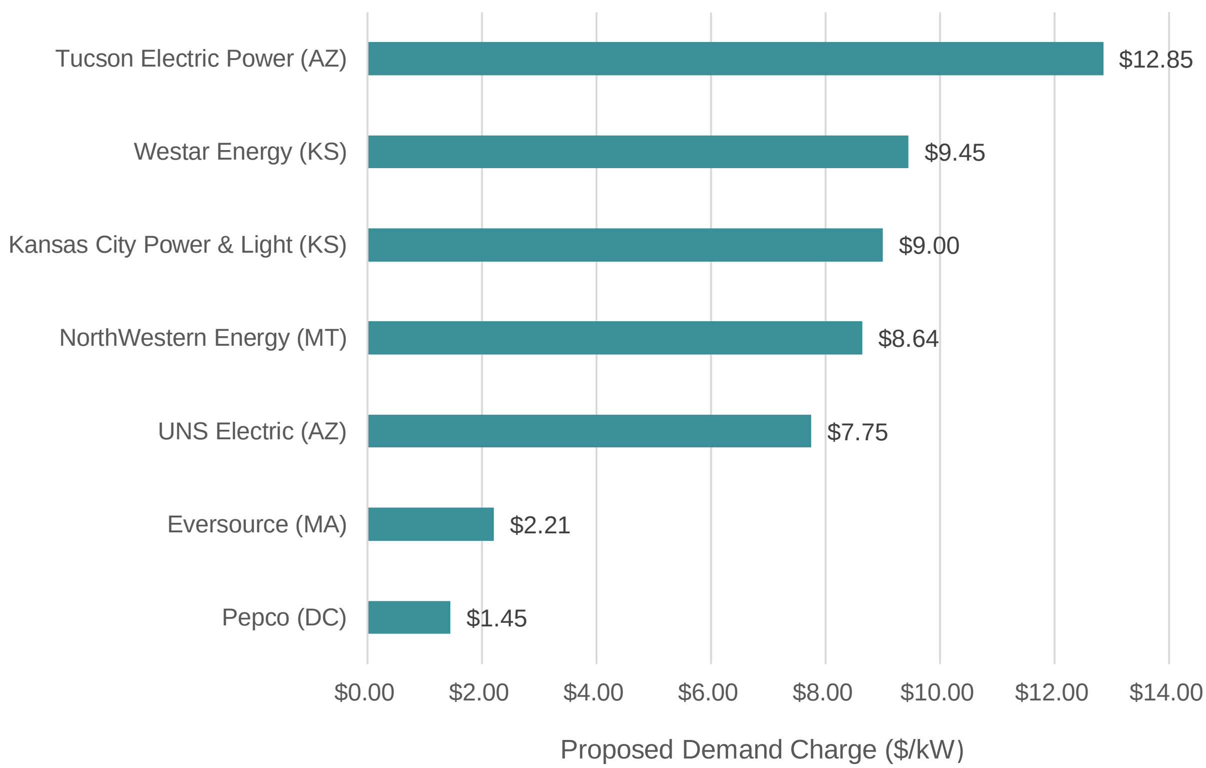


These approvals highlight the impact of state policy support or explicit pre-authorization to adopt additional charges for DG customers. Massachusetts' legislation authorizing utilities to propose MMRCs for net metering customers and Kansas' order on DG rate design both played a significant role in the approval of utilities' residential demand charges. NorthWestern Energy in Montana has also proposed a mandatory demand charge for residential net metering customers, following 2017 legislation authorizing the Public Service Commission to make a determination, as part of a utility's general rate case, to place customer-generators into a separate customer class and establish separate rates, following the completion of a cost-benefit study.

While Kansas and Massachusetts regulators approved utilities' additional solar customer charges, the New Mexico Public Regulation Commission eliminated Xcel Energy's standby charge for DG customers. Xcel Energy had requested an increase in the fee, but regulators determined that there was no basis for the charge. Another utility's additional solar charge was reconsidered in 2018 as well. The Southern Environmental Law Center filed a complaint and petition for a declaratory ruling on the legality of Alabama Power's capacity reservation charge.

Several fee requests were under consideration in Arizona in 2018. Tucson Electric Power and UNS Electric both proposed demand charge and system capacity charge options for DG customers. The Arizona Corporation Commission approved the Administrative Law Judge's recommendation to not approve these charges, based on an unsatisfactory cost of service study approach. The Judge did, however, provide support for a three-part rate if the demand charge begins at a minimum demand of 7 kW.

Figure 24. Residential Demand Charge Proposals Pending or Decided in 2018



In late 2018, Salt River Project, a large municipal utility in Arizona, proposed two new rate options for DG customers. Salt River Project currently requires DG customers to pay a demand charge. However, one of the proposed options would include time-varying energy rates only and no demand charge, while the other option would include a demand charge based on an average of daily demand during system peak hours, rather than a customer's maximum monthly demand during system peak hours.

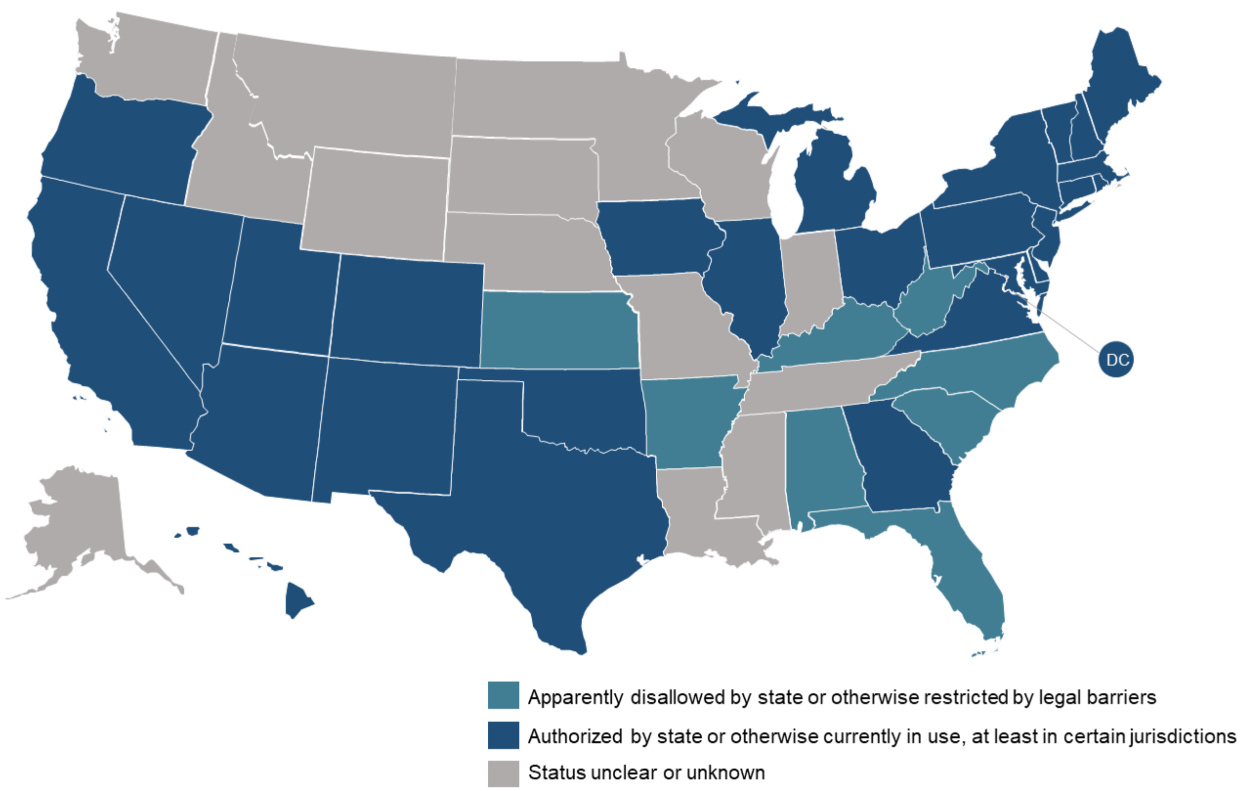
THIRD-PARTY OWNERSHIP REVIEW

Key Takeaways:

- In 2018, six states plus DC took actions related to the legality of third-party solar ownership models.
- An Attorney General's ruling in Oklahoma clarified that third-party power purchase agreements are permissible in certain parts of the state and leasing is allowable in all parts of the state.
- The Florida Public Service Commission opened the door to solar leasing by authorizing Sunrun's third-party solar equipment lease in 2018.

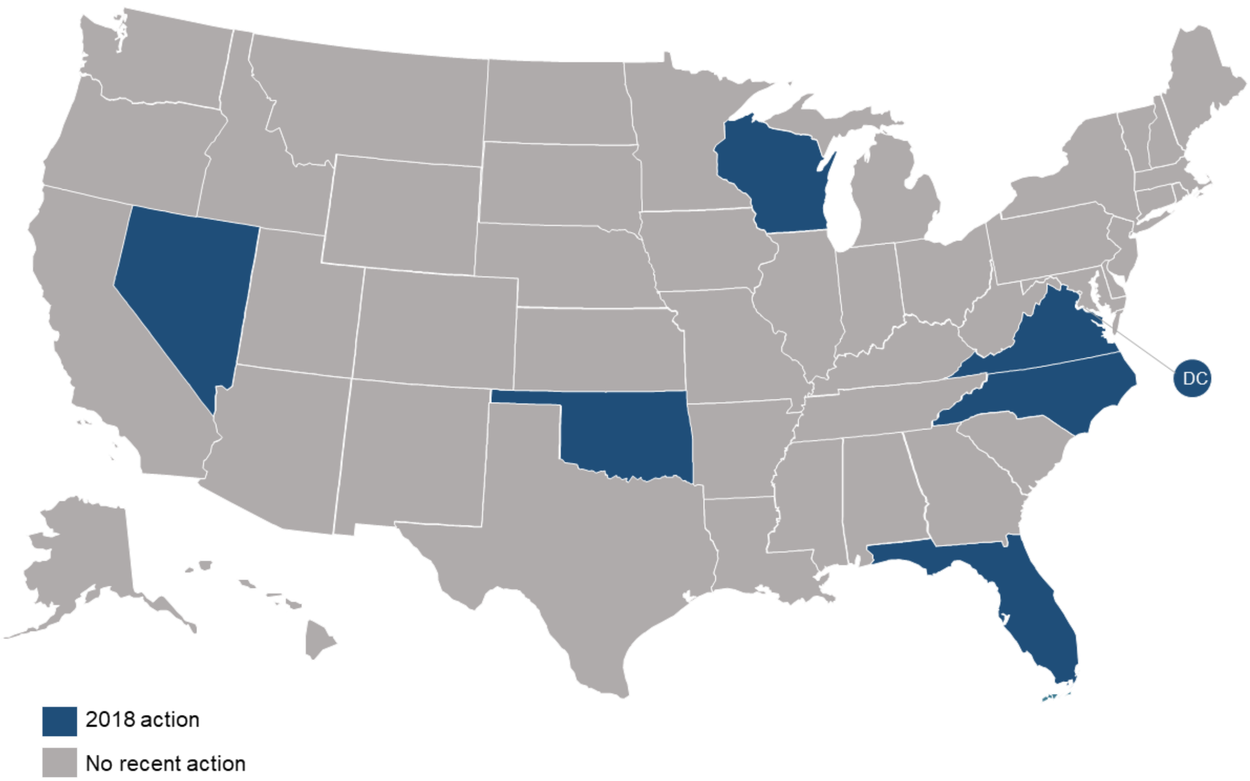
Third-party ownership models for residential solar include both leases and power purchase agreements (PPAs). Under a solar lease, the lessee typically pays a monthly fee to use solar equipment installed on their rooftop, but owned by a solar company. Under a third-party PPA, the customer pays a solar company for the electricity generated by a solar system installed on their rooftop and owned by the solar company.

Figure 25. Third-Party Solar PPA Legality



Six states and DC considered actions regarding the legality of third-party solar ownership options in 2018. A ruling from Oklahoma's Attorney General clarified that third-party power purchase agreements are legal in incorporated areas of Oklahoma, while leases are legal in all areas of the state. The North Carolina Utilities Commission approved solar leasing rules in 2018, following legislation enacted in 2017 that explicitly authorizes leasing in the state. Florida and Virginia considered legislation that would have authorized third-party solar ownership in at least some circumstances, but these bills were ultimately unsuccessful.

Figure 26. 2018 Action on Solar Third-Party Ownership



In Florida and Wisconsin, solar companies filed requests for declaratory rulings on the legality of solar leasing. The Florida Public Service Commission authorized Sunrun's residential solar equipment lease, and similar requests were subsequently filed by Vivint and Tesla. Sunrun also filed the request pending in Wisconsin. Last year, the Wisconsin Public Service Commission considered the legality of third-party power purchase agreements and determined that this is an issue better addressed by the state legislature.

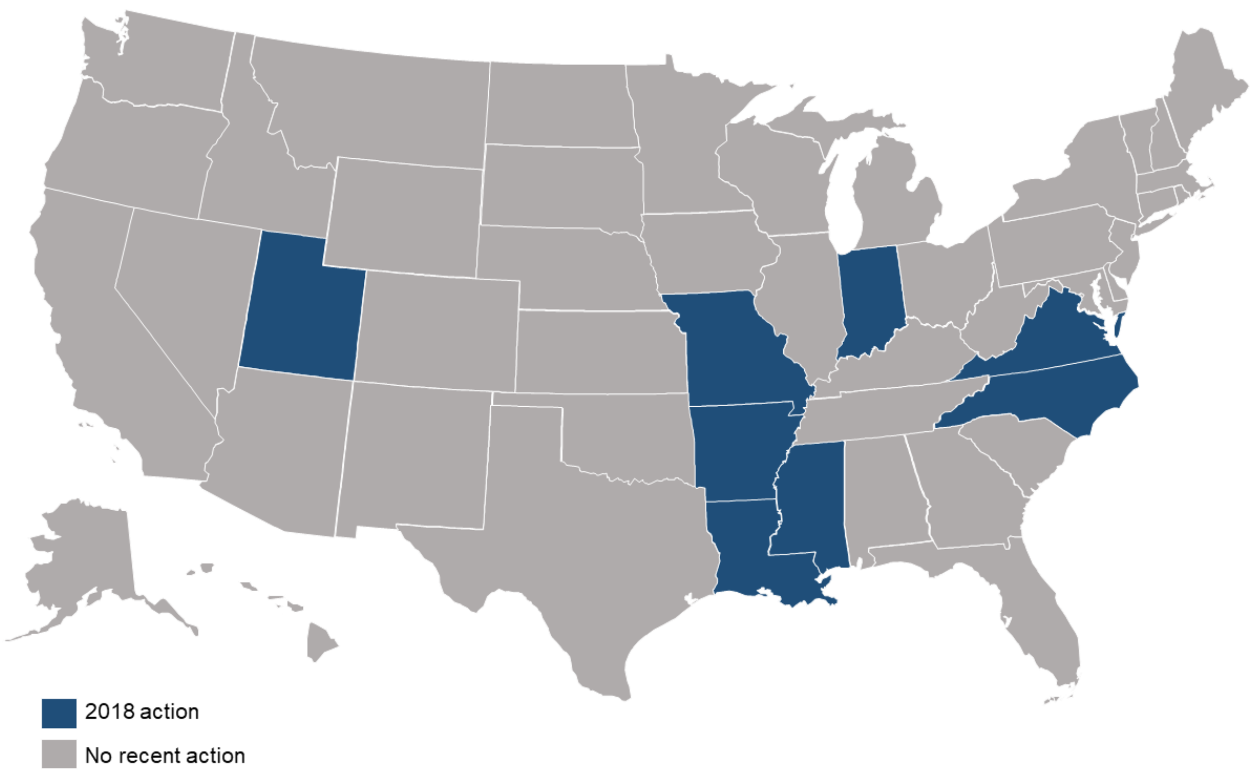
UTILITY-LED ROOFTOP SOLAR REVIEW

Key Takeaways:

- Eight states took action related to utility-led rooftop solar programs during 2018.
- Utility-led rooftop solar programs are coming under consideration in a growing number of states.
- Duke Energy filed applications to become a non-residential solar lessor in two states – Indiana and North Carolina.

Although utility-led rooftop solar programs have not been widely implemented to date, they came under consideration in an increased number of states in 2018. Duke Energy filed proposals in two states – Indiana and North Carolina – to offer solar leases to non-residential customers. In North Carolina, the Utilities Commission finalized solar leasing rules, which allow investor-owned and municipal utilities to become solar lessors as well as third parties.

Figure 27. 2018 Action on Utility-Led Rooftop Solar Programs



Meanwhile, Entergy proceeded with its Self-Build program in New Orleans and filed planned changes to its Smart Energy Services program in Mississippi to offer a variety of distributed energy resources to customers. The expansive Smart Energy Services program may signal an opportunity for utilities to offer rooftop solar to customers as a set of broader technologies and services.

Q4 QUARTERLY REPORT

OVERVIEW OF Q4 2018 POLICY CHANGES

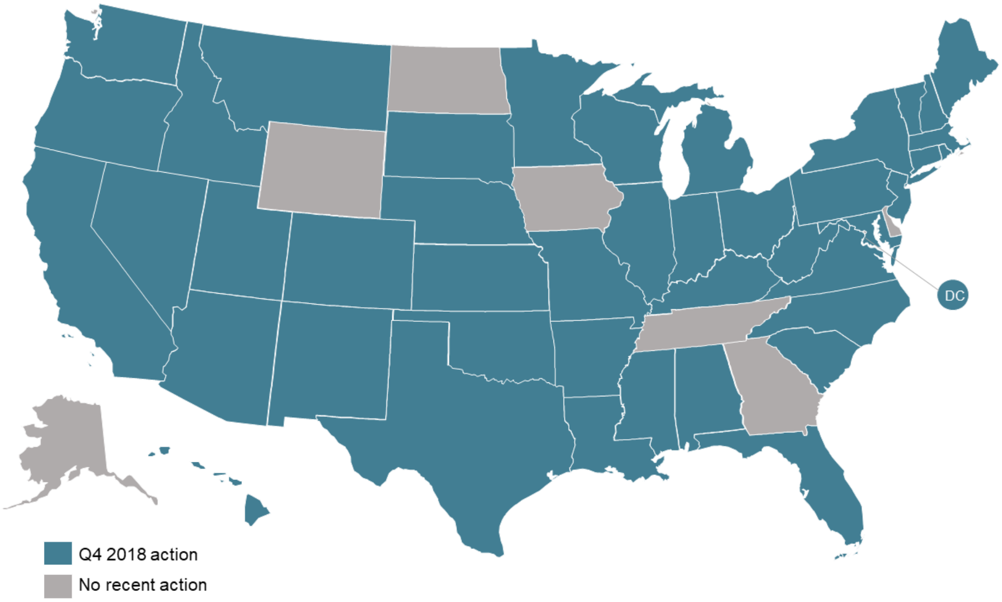
Table 8 provides a summary of state actions related to DG compensation, rate design, and solar ownership during Q4 2018. Of the 152 actions catalogued, the most common were related to residential fixed charge and minimum bill increases (41), followed by DG compensation rules (39), and community solar (29). The actions occurred across 43 states plus DC in Q4 2018 (Figure 28). Box 4 highlights some of the key actions of Q4 2018, described in greater detail in the following sections.

Table 8. Summary of Policy Actions (Q4 2018)

Policy Type	# of Actions	% by Type	# of States
Residential fixed charge or minimum bill increase	41	27%	24
DG compensation rules	39	26%	25 + DC
Community solar	29	19%	16 + DC
DG valuation or net metering study	21	14%	14
Residential demand or solar charge	13	9%	7
Utility-led rooftop PV programs	5	3%	5
Third-party ownership of solar	3	2%	3
Total	**152**	**100%**	**43 States + DC**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 28. Action on Net Metering, Rate Design, & Solar Ownership Policies (Q4 2018)



Box 4. Top Five State Solar Policy Developments of Q4 2018

Maine PUC Restores Net Metering for Medium and Large Customers

In December 2018, the Maine Public Utilities Commission (PUC) exempted medium and large non-residential net billing customers from the gross metering provisions of the state's new DG compensation rules. The PUC found that the cost of installing a second meter to implement the gross metering provisions is not justified for these customers due to the demand charge component of their bills.

Wisconsin Regulators Consider Residential Solar Leasing

In December 2018, Sunrun filed a request for a declaratory ruling on the legality of its residential solar equipment lease. Currently, the legality of solar leasing and third-party power purchase agreements is unclear in Wisconsin. In 2017, the Public Service Commission determined that the issue of third-party power purchase agreements would be better addressed by the state legislature.

New York PSC Approves Compensation Tariff for Solar Plus Storage Systems

The New York Public Service Commission approved a new "Hybrid Tariff" for customers with value stack eligible generators that are paired with energy storage. The Hybrid Tariff includes four options based on different usage models and distinguishes between renewable and non-renewable energy injected into the grid, so that renewable energy injections may receive compensation for environmental benefits.

Kansas Regulators Approve Mandatory Demand Charge for KCP&L Residential DG Customers

The Kansas Corporation Commission approved Kansas City Power & Light's request to implement a mandatory demand charge of $9.00 per kW (summer) / $2.00 per kW (winter) for residential DG customers in December 2018. This is the third mandatory residential DG customer demand charge approved in 2018, although Eversource's charge has since been overturned by legislation enacted in August.

Salt River Project Proposes New Rate Options for Customer-Generators

Salt River Project, a large municipal utility in Arizona, proposed two new rate options for customer-generators in December 2018. Currently customer-generators are required to pay a demand charge based on maximum monthly demand during system peak hours. One of the new options includes a demand charge based on an average of daily demand, while the other option does not include a demand charge, but provides a reduced credit rate for energy delivered to the grid.

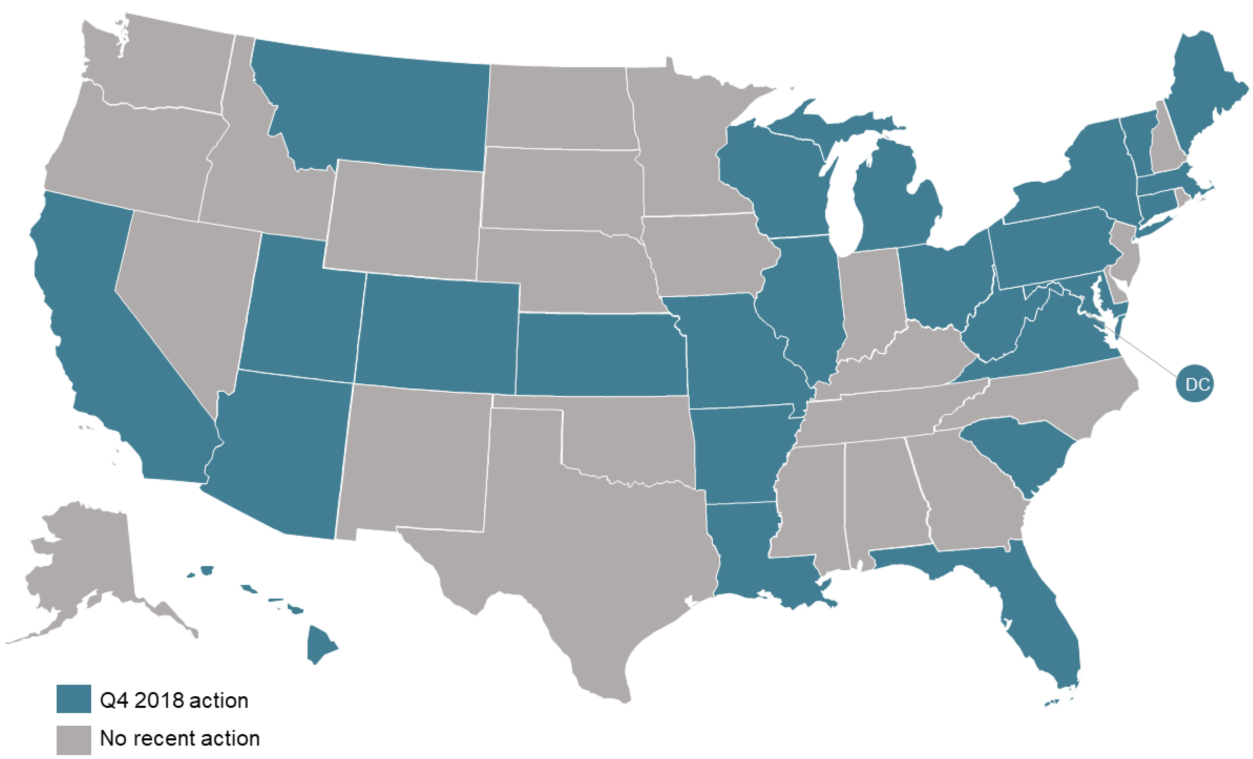
DG COMPENSATION POLICY CHANGES

Key Takeaways:

- In Q4 2018, there were 39 actions ongoing or under consideration in 25 states plus DC related to DG compensation policy changes.
- The Maine Public Utilities Commission restored net metering for medium and large customers in December 2018, due to concerns about additional metering costs.
- Net metering changes are currently under consideration in several utilities' general rate cases.

In Q4 2018, there were 39 actions ongoing or under consideration in 25 states plus DC related to distributed generation (DG) compensation policies. Of these, 16 states considered changes to credit rates (for either monthly net excess generation or all excess generation) or considered the adoption of net metering successor policies.

Figure 29. Action on DG Compensation Policies (Q4 2018)

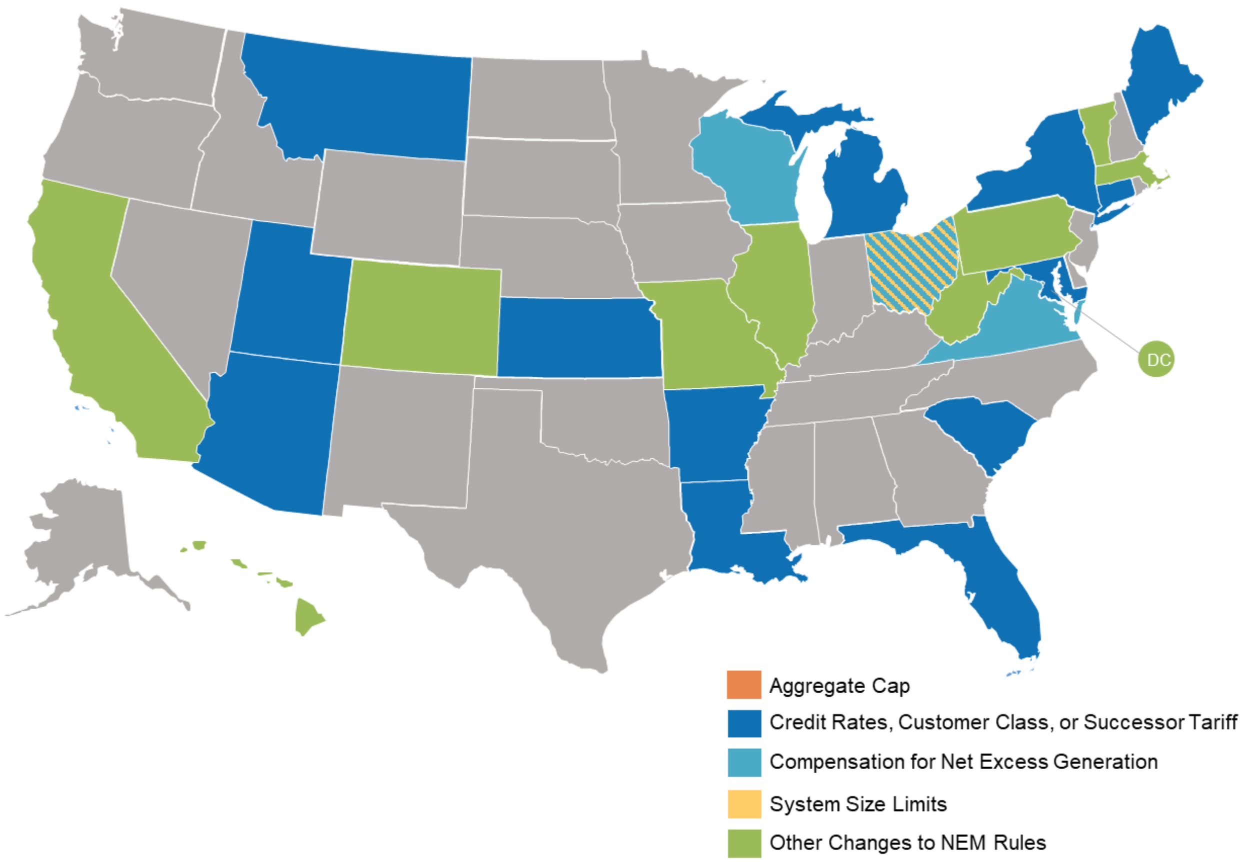


Net Metering Successor Tariffs

New York and Connecticut are developing net metering successor tariffs through regulatory proceedings, and both states appear likely to resolve their proceedings in 2019 (New York already has a successor tariff in place for larger DG customers). Michigan regulators adopted a net metering successor framework earlier this year, and are currently evaluating utility proposals based on that framework in individual rate cases.

The Maine Public Utilities Commission, which adopted a buy-all, sell-all successor tariff in 2017, reinstated traditional net metering for larger customers in late 2018. This change was motivated by concerns about the cost of additional metering equipment necessitated by the successor tariff and a determination that demand charges likely make up for any cost shift for these larger customers.

Figure 30. Proposed and Adopted Changes to DG Compensation Policies by Type of Change (Q4 2018)



While Illinois has not yet moved to implement a statewide net metering successor tariff, two utility programs approved this quarter will introduce a net billing system for some customers. These programs (from Ameren and Commonwealth Edison) provide rebates for solar installations with smart inverters, but require that customers taking the rebates not use net metering rates. Instead, these customers are credited for hourly net exported energy.

Separate Customer Classes

Kansas regulators approved Kansas City Power & Light's proposal to move DG customers to a separate customer class subject to a demand charge in December 2018. A similar demand charge was approved for Westar Energy earlier this year, after Westar had created a new customer class for DG customers in 2017. NorthWestern Energy in Montana has also requested approval for a new customer class and demand charge for DG customers.

Solar-Plus-Storage

New York approved a hybrid tariff for solar-plus-storage systems in December 2018, which offers several different compensation options based on the system usage and whether energy exported by the storage system comes solely from renewable sources or not. California regulators considered equipment requirements for larger solar-plus-storage systems to be eligible for net metering, issuing a proposed decision that would allow DC-coupled systems to use power control systems to ensure only renewable electricity exported to the grid receives net metering credits.

Box 5. A Note on Net Metering Terminology

Credit rates refers to changes to compensation for all electricity exported to the grid, either instantaneously or netted over a period shorter than the billing period (e.g., 15-minute or 60-minute intervals.) **Net excess generation** includes changes to compensation for excess production at the end of a billing period after a one-to-one netting of production and consumption has occurred. An **aggregate cap** refers to the maximum amount of capacity allowed to participate in a state or a utility's net metering program, whereas the **system size limits** are capacity limits for individual systems to net meter. **Meter aggregation** is a type of aggregate net metering in which a single customer may offset electrical use from multiple meters on his or her property. **REC ownership** refers to rules that specify whether renewable energy certificates/credits generated by a net-metered system accrue to the solar PV system owner or the utility. **Net metering rules** encompass other policy changes to net metering not covered by any of these other categories.

New Legislation

Legislation related to DG compensation has already been introduced in a number states, as of mid-January 2019. Among bills introduced in late Q4 2018 or early Q1 2019, the majority relate to credit rates for excess generation (12), aggregate caps (8), and system size limits (7). Several bills have also been carried over in New Jersey and Virginia, where the states' current legislative sessions run from 2018 to 2019. Bills relating to community solar and third-party ownership have also been introduced in a number of states.

Table 9. New Legislation Related to DG Compensation[**]

State	Bill #	Status	Topics
Arkansas	S.B. 145	I	System Size
Indiana	H.B. 1421	I	Aggregate Cap, Credit Rates
	S.B. 430	I	Aggregate Cap, Credit Rates
Maine	L.D. 41	I	Credit Rates, Study
	L.D. 91	I	Credit Rates
	L.D. 143	I	Credit Rates
Nebraska	L.B. 509	I	Fees, System Size
New Hampshire	H.B. 365	I	System Size
	H.B. 466	I	System Size
	S.B. 13	I	Energy Storage, System Size
New York	A.B. 309	I	Credit Rates
North Dakota	S.B. 2322	I	Aggregate Cap, Net Excess Generation, Study, System Size
Oklahoma	S.B. 952	I	Credit Rates, Study
South Carolina	H.B. 3659	I	Aggregate Cap, Credit Rates, Energy Storage, Fees
	S.B. 332	I	Aggregate Cap, Credit Rates, Energy Storage, Fees
Virginia	S.B. 1456	I	Aggregate Cap, Fees, Meter Aggregation
	S.B. 1483	I	Meter Aggregation, Net Excess Generation
	S.B. 1714	I	Meter Aggregation, Net Excess Generation
Washington	H.B. 1129	I	Aggregate Cap, Credit Rates, System Size
	S.B. 5118	I	Credit Rates
	S.B. 5223	I	Aggregate Cap, Net Excess Generation, Study
West Virginia	H.B. 2202	I	Credit Rates

[**] Includes legislation introduced between 10/1/2018 and 1/19/2019.

Box 6: Net Metering and Net Billing Terminology

Terminology for distributed generation compensation systems can be confusing, and with a large number of recent and proposed policy changes, the potential for confusion is especially high right now. One point of confusion is the distinction between net metering and net billing. These terms are often used interchangeably by governments and utilities,[††] but the two systems have important differences. After reviewing the definitions of these terms used in the academic literature,[‡‡] we have devised definitions for net metering and net billing. These definitions should help to standardize the use of these terms and add clarity to the distributed generation policy discussion.

Net Metering is a billing mechanism that compensates a customer for excess generation from an on-site energy system through credits that offset electricity usage at other times during the billing period. Electricity generated on-site first supplies the customer's real-time use of electricity. Any electricity generated on-site in excess of the amount used in real time is exported to the grid. Under net metering, this excess generation is used to offset the customer's usage at other times during the billing period; credits for exported energy are deducted from the amount of electricity purchased from the utility during the billing period, in effect moving the customer's electricity meter backward. This means that customers are compensated at the retail rate for electricity exported to the grid, at least as long as total on-site generation during the billing period is less than the customer's total electricity usage during the billing period. When generation exceeds total usage during the billing period, different crediting schemes may be used.

Net Billing is a billing mechanism that compensates a customer for excess generation from an on-site energy system by payment of a separate rate for electricity generated in excess of real-time use (or excess remaining after netting production and consumption over intervals shorter than the billing period – e.g., 15-minute or 60-minute intervals.) Electricity generated on-site first supplies the customer's real-time electricity use. Any electricity generated on-site in excess of the amount used in real time is exported to the grid. Under net billing, the utility pays the customer for this excess generation at a separate rate rather than crediting the generation against usage at other times in the billing period. Under net billing, a customer's meter is essentially "stopped" when on-site generation is meeting real-time demand, but unlike with net metering, it does not go "backward". The rate of compensation for exported electricity under net billing 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. Effectively, net billing customers still receive the retail rate for on-site generation that supplies their electricity usage in real time because it displaces grid-supplied electricity they would otherwise have to purchase at the full retail rate.

[††] For example, Mississippi calls its new system "Net Metering" even though it more closely resembles net billing.
[‡‡] Hughes, L. & Bell, J., 2006; Yamamoto, Y., 2012; Dufo-Lopez, R. & Bernal-Agustin, J., 2015.

Table 10. Updates on DG Compensation Policies (Q4 2018)

State	Type of Change	Description	Source
AR	Credit Rates, Net Metering Rules	In April 2016, the Arkansas Public Service Commission (PSC) opened a docket, pursuant to Act 827 of 2015, to ensure net metering rates, terms, and conditions are appropriate to recover the full utility costs to serve net metering customers, net of any quantifiable benefits. The proceeding was also initiated to investigate guidelines for approving non-residential net metering facilities over 300 kW. In August 2016, the PSC approved a unanimous proposal to bifurcate and establish a separate procedural schedule for issues relating to rates, terms, and conditions for net metering ("rate issues"). The PSC also approved a proposal to establish a Net Metering Working Group to address these rate issues. In March 2017, the PSC completed Phase I of the proceeding, and in June 2017, the Net Metering Working Group submitted a progress report. In September 2017, the Working Group submitted its final joint report and recommendations. As two schools of thought exist within the working group, two sub-groups were formed and provided separate recommendations within the report. Sub-Group 1 consists of multiple solar advocacy organizations, environmental groups, and individuals, while Sub-Group 2 consists of many utilities, the Attorney General, the PSC staff, and Arkansas Electric Energy Consumers. Sub-Group 1 recommended that the current net metering credit structure be continued until a complete study of the costs and benefits of net metering has been conducted. Sub-Group 2 recommended a move to net billing (also called "2-channel billing"), crediting excess generation at an embedded cost-of-service rate rather than the retail rate. A hearing was held during November/December 2017, and the PSC directed parties to file briefs on nine issues in January 2018. These issues include: (1) if there is a burden of proof or persuasion in this docket, and upon which issues and party does it lie; (2) if Act 827 of 2015 requires the use of an embedded cost-of-service approach; (3) to what extent benefits outside of the embedded cost-of-service approach may be considered, and how these may be quantified; (4) if the state's statutory definition of net metering requires netting of kWhs, precluding 2-channel billing; (5) if converting kWhs to a monetary value permit or impede the use of time-of-use rates by net metering customers; (6) if the PSC is required to address any cost-shifts found to exist, or does the	Docket No. 16-027-R Joint Report and Recommendations of the Net-Metering Working Group

		PSC have the discretion not to act if it finds a de minimis cost shift; (7) if there is a legal risk that FERC would consider exported kWhs a wholesale sale to the utility or that the Internal Revenue Service would consider the exported energy a wholesale sale to the utility, impacting the customer's eligibility of the federal investment tax credit; (8) if the Mississippi PSC's adder approach is consistent with Act 827; and (9) if any other states are utilizing 2-channel billing with an embedded cost of service approach. Initial briefs were filed in February 2018, and reply briefs were filed in March 2018. No action occurred during Q2, Q3, or Q4 2018.	
AZ	Credit Rates, Fees	In December 2018, Salt River Project proposed new rate plans for residential DG customers. One new option is a Customer Generation Time-of-Use Export Price Plan. This plan does not include a demand charge, includes a fixed charge equal to that of the existing Customer Generation Price Plan, and features energy consumption rates equal to those of the SRP Time-of-Use Price Plan. This plan also includes a net billing compensation framework, crediting customers for energy exported to the grid at 2.81 cents per kWh. Another proposed option is the Customer Generation Average Demand Price Plan, which includes a demand charge based on the average of the daily on-peak maximum demands, rather than the maximum monthly peak demand during on-peak hours. This plan also has a fixed charge equal to that of the Customer Generation Price Plan and has energy rates equal to those of the Customer Generation Price Plan. Public comment sessions are scheduled for January 2019, and a presentation will be made at the board meeting on February 18, 2019.	SRP Proposed Solar Options
	Net Metering Rules	In August 2017, the Utilities Division Staff requested that the Commission open a rulemaking docket to amend net metering rules, based on changes in circumstances since their adoption. In February 2018, the Staff solicited comments from stakeholders on revisions to the existing rule, specifically on 11 questions. The questions include how export rates are addressed, which Phase II proceeding rulings to include in the revised rules, and if provisions for non-residential customers and non-solar technologies should be included. Several parties filed responses in March 2018. No action occurred during Q2, Q3, or Q4 2018.	Docket No. RE-00000A-17-0260
	Net Metering Rules	In August 2018, the Arizona Corporation Commission opened a rulemaking docket to evaluate proposed modifications to many of the state's energy rules, including net metering. Other rules to be addressed in	Docket No. RU-00000A-18-0284

		the proceeding include the renewable energy standard, energy efficiency standards, resource planning and procurement, retail electric competition, electric vehicles, DG interconnection, blockchain technology, technological developments, forest bioenergy, baseload security, and the biennial transmission assessment. The Commission is currently considering an electric vehicle policy and policies related to retail choice for large commercial customers.	
CA	Credit Rates, Net Metering Rules	In late June 2018, the Riverside County Board of Supervisors introduced an ordinance establishing net metering rules for irrigation districts. The ordinance requires Imperial Irrigation District to offer a net metering program that is at least as expansive as and no more restrictive than the California Public Utilities Commission's net metering rules applicable to Southern California Edison. The ordinance was approved unanimously in July 2018. Imperial Irrigation District has sued Riverside County, suggesting that the ordinance conflicts with state law. In November 2018, a judge issued a preliminary injunction, which blocks implementation of the ordinance until the case is resolved.	Ordinance No. 943 Summary Court Filing Preliminary Injunction
	Energy Storage, Net Metering Rules, System Size	A January 2016 decision from the California Public Utilities Commission (CPUC) established a successor tariff to replace net metering. Since the successor tariff was adopted, the CPUC has continued to use this docket to explore other issues related to customer generation, several of which have already been decided. A Fourth Scoping Ruling, filed in March 2018, identified and established the schedule for the remainder of the issues in the docket. Two of the remaining issues are related to net metering-eligible facilities paired with energy storage. A proposed decision issued in August 2018 addressed a petition for modification of a pervious decision to modify the definition of "small" net metering paired with energy storage from "less than or equal to 10 kW" to "less than or equal to 30 kW." A decision issued in October 2018 denied this petition. As it stands, systems 10 kW or smaller paired with storage can participate in net metering without needing to install additional metering equipment to measure the actual storage or renewable output. Larger systems paired with storage can net meter, but need to install certain metering equipment. A proposed decision issued in late December 2018 sets the requirements for equipment for larger DC-coupled systems; these systems will be able to net meter if they install power control equipment to prevent storage systems from charging from or exporting to the grid. An earlier proposed decision would have allowed the use of an ex post	Docket No. R14-07-002 Decision No. 18-10-005 (Denial of modification of small NEM paired with storage)

		data verification option, which is not allowed in this decision.	
CO	Customer Class, Energy Storage, Net Metering Rules, System Size	The Colorado Public Utilities Commission (PUC) opened a proceeding in October 2017 to consider changes to rules concerning the Renewable Energy Standard, as well as net metering, electric resource planning, and acquisitions from qualifying facilities, and distribution system planning. One question the Commission noted it is particularly interested in is the eligibility of net metering for solar systems paired with storage. A scoping workshop was held in early April 2018 to create working groups to address the various issues under consideration. Working groups met several times throughout the summer, and parties submitted comments and proposed rule changes in early September 2018. A law enacted in March 2018 established that solar-plus-storage systems are eligible for net metering. In Xcel Energy's final comments, the utility proposed language amending Colorado's net metering rule to implement the new law's requirements. The language would not require the installation of an additional load meter for monitoring an energy storage system. The Joint Solar Parties recommended several amendments to the state's net metering rules, including revising the system size limit to be 120% of the customers' *expected* average annual electricity consumption in kWh AC and require this calculation to be based on both historic usage data and forecast usage. The Joint Solar Parties also proposed language allowing customer generation facilities paired with energy storage to net meter as long as the storage is charged exclusively from the generating facility or the storage system is designed to not export energy, excluding inadvertent exports. The solar parties also suggested requiring the costs of duplicative metering required by the utility be treated as distribution system costs, rather than customer-specific costs. Additionally, the solar parties proposed language prohibiting IOUs from creating a separate rate class for net metering customers. The proceeding was closed on October 31, 2018; the PUC indicated that it is considering issuing a Notice of Proposed Rulemaking related to the suggestions from this docket.	Docket No. 17M-0694E
CT	Credit Rates, Net Metering Rules	In May 2018, Connecticut's Governor signed S.B. 9 into law. The bill increases the state's renewable portfolio standard, while making significant changes to net metering. The bill closes net metering to new customer-generators when the state's residential solar investment program ends or when regulators establish the new compensation program - whichever occurs first. Existing net metering customers will be grandfathered until December 31, 2039. The Public	Docket No. 18-06-15 S.B. 9

	Utilities Regulatory Authority (PURA) is to establish a per-kWh rate for electric distribution companies to purchase electricity generated by these customers after December 31, 2039. Upon closure of the existing net metering program, new DG customers will be able to select a buy-all, sell-all option or a net billing option. The PURA is tasked with determining the netting period for the net billing option, which must either be: real time, one day, or a fraction of a day. The PURA opened a proceeding in June to review the requirements of the new legislation and develop a strategy and procedural roadmap for implementation. Technical meetings were held in July and August 2018. The July meeting addressed the DG tariff rate, including incorporation of system benefits and the netting period. By September 2019, PURA will initiate a proceeding to develop the new DG compensation tariffs, the compensation rate, and the netting period. By July 2019, the Department is to submit these requirements and tariffs to the Public Utilities Regulatory Authority (PURA) for approval.	
Credit Rates, Net Metering Rules	This proceeding was opened in late August 2018 to establish procurement plans and tariffs pursuant to Act 18-50 (S.B. 9), enacted in May 2018. The Public Utilities Regulatory Authority (PURA) accepted comments on several questions related to a net metering successor tariff during October 2018, including whether an interim residential tariff should be established before the expiration of the residential solar investment program. A technical meeting was held in mid-October 2018 to discuss the Department of Energy and Environmental Protection's (DEEP) solar PV tariff calculator and the net metering successor comments filed. In late October 2018, Eversource and the United Illuminating Company filed their proposed procurement plan for non-residential zero-emission and low-emission projects up to 2 MW. The two proposed compensation structures include a buy-all, credit-all option and a real-time net metering option. A residential tariff is not addressed in the plan. A technical meeting was held in early December 2018 to discuss the utilities' proposed procurement plan. In mid-December, several parties, including the DEEP, utilities, Office of Consumer Counsel, and Green Bank, filed a Joint Interim Rate Proposal for establishing an interim residential tariff. The goal of the interim tariff is to ensure a smooth transition after the end of the Residential Solar Investment Program and to provide the utilities with a timeline for implementing changes to their billing and metering systems. The group did not reach consensus on the specific details of the tariff, but the proposal provides two options: a buy-all, sell-all tariff and a netting tariffs (two structures - instantaneous with a high $/kWh rate	Docket No. 18-08-33

		or monthly netting with a cap for $/kWh compensation). A final decision from the PURA on this issue is expected around mid-January 2019.	
	Net Metering Rules	In August 2018, Solar Connecticut filed a petition for a declaratory ruling on whether any project awarded a Zero-Emission Renewable Energy Credit (ZREC) or Low-Emission Renewable Energy Credit (LREC) contract will retain net metering until the end of 2039 and the benefits of the contract for its full 15-year duration. Solar Connecticut requested that the Public Utilities Regulatory Authority expedite the decision, but the Authority denied this request, instead directing the state's IOUs to extend the bid deadline for Year 7 ZRECs and LRECs by one month (until October 7, 2018). The Authority issued a final decision in September 2018, determining that LREC and ZREC projects awarded in Solicitation Years 5, 6, 7, and 8 will be eligible to receive net metering compensation up to December 31, 2039. In October 2018, the PURA requested comments on the utilities' proposals to conduct Years 7 and 8 of the LREC/ZREC program and terminating the program at the start of the new procurement process to be developed in Docket No. 18-08-033. Comments were due in November.	Docket No. 18-08-10
DC	Net Metering Rules, System Size	The Public Service Commission is examining interconnection issues in Formal Case No. 1050. A September order in the rulemaking established a Net Energy Metering Working Group to address system upgrade costs related to the interconnection of community renewable energy facilities (CREFs), review the Commission's current net metering rules, and propose CREF-specific rules changes for the Commission's consideration. Another decision, issued later in September tasked the Net Energy Metering Working Group with considering whether the system capacity limit should be increased beyond 100% of a customer's historical usage. The working group held a meeting in early December 2018.	Formal Case No. 1050 Order No. 19676 Order No. 19692
FL	Credit Rates, Net Metering Rules	In April 2018, Solar United Neighbors and the League of Women Voters of Florida filed a complaint for declaratory judgment and injunctive relief regarding the legality of JEA's revised DG compensation program. The petitioners contend that the new rules do not comply with the state's net metering law and are requesting an injunction requiring the utility to offer a net metering program that meets state statutory requirements.	Complaint
HI	Credit Rates, Energy Storage, Net	The Hawaii Public Utilities Commission (PUC) is investigating the technical, economic, and policy issues associated with distributed energy in two	Docket No. 2014-0192

Metering Rules	phases. Phase 1 resulted in the transition from traditional net metering to new interim tariff options. Phase 2 was launched in December 2016 and includes a Technical Track with two issues and a Market Track with five issues. The two Technical Track issues are: (1) how utility DER integration analyses can be improved to more accurately characterize grid capacity from various DERs and (2) how interconnection standards can be modified to promote the safe integration of increasing levels of DERs onto the grid. The five Market Track issues are: (1) a longer-term competitive market structure for DER exports and services, including the development of a successor tariff to replace the interim tariffs, (2) alternative rate designs to facilitate safe and beneficial DER integration, (3) expansion of DER options to customers not able to participate directly, including low-income customers, (4) utility participation in DER markets, and (5) mechanisms to facilitate the secure flow of market data between utilities and third parties (including customers). The parties submitted stipulations addressing the Technical Track issues and the Market Track issues in August 2017. An October 2017 order approved changes to Hawaii's net metering successor tariffs. A "smart export" tariff replaced the self-supply option. This tariff is designed for solar plus storage customers and compensates participants for exports during non-daytime hours. A "controllable grid-supply" (CGS+) option succeeds the grid-supply option, and is available to solar customers without battery storage. Systems enrolled in the CGS+ tariff will be equipped with communication and control features allowing the utility to curtail the systems when the utility is at risk of violating an operational constraint on the system. The HECO companies filed their new tariffs in December 2017. In a March 2018 order, the Commission required the HECO companies to make changes to both tariffs related to control equipment. HECO resubmitted its new tariffs and its policy and procedure for allowing net metering customers to add non-exporting energy storage systems. The PUC issued an order in June 2018, addressing a number of outstanding issues. Through that order, the PUC: (1) approved HECO's smart export tariff sheets and net metering policy proposal, (2) invited comments on the CGS+ tariff, and (3) modified the procedural schedule. A September 2018 order approved HECO's CGS+ tariff with certain modifications. An October 2018 order also approved in part HECO's revised tariff for enabling existing net metering customers to install non-export technology and remain in the

		traditional net metering program. In October, HECO filed a petition for partial reconsideration related to the definition of technical system size, and in late November, the PUC denied HECO's petition.	
IL	Credit Rates, Net Metering Rules	The Future Energy Jobs Act, enacted in December 2016, calls for a transition to a net metering successor once the state's 5% aggregate cap is reached. The legislation also creates a rebate program for non-residential and community solar systems that utilize smart inverters. The rebate is equal to $250 per kW of system capacity. Customers receiving the smart inverter rebate are not permitted to net meter. Instead, these customers will be credited for hourly net exported energy at a rate equal to the hourly energy charge and purchased electricity adjustment factor. The utilities will be able to operate and control the smart inverters installed on participating customers' projects. Commonwealth Edison (ComEd) filed its proposal to implement this program in April 2018, and parties filed testimony in July. The joint solar parties expressed concern that ComEd would be able to revise the smart inverters' required functions and settings without regulatory approval after receipt of the rebate. The solar parties also recommended that Volt-VAR with reactive power priority be compensated as a grid service beyond the rebate value, that solar plus storage projects be eligible for the rebate, and that third parties be allowed to provide smart inverter communication devices. ComEd proposed an automatic adjustment clause tariff, Rider DG Rebate Adjustment, to recover rebate costs through a per-kWh surcharge. In late November 2018, the Commission issued a final order approving ComEd's proposal.	Docket No. 18-0753 Future Energy Jobs Act
	Credit Rates, Net Metering Rules	The Future Energy Jobs Act, enacted in December 2016, calls for a transition to a net metering successor once the state's 5% aggregate cap is reached. The legislation also creates a rebate program for non-residential and community solar systems that utilize smart inverters. The rebate is equal to $250 per kW of system capacity. Customers receiving the smart inverter rebate are not permitted to net meter. Instead, these customers will be credited for hourly net exported energy at a rate equal to the hourly energy charge and purchased electricity adjustment factor. The utilities will be able to operate and control the smart inverters installed on participating customers' projects. Ameren filed its proposal to implement this program in April 2018, and parties filed testimony in July. The joint solar parties expressed concern that Ameren would be able to revise the smart inverters' required functions and settings without regulatory approval after receipt of the rebate.	Docket No. 18-0537 Future Energy Jobs Act

		The solar parties also recommended that Volt-VAR with reactive power priority be compensated as a grid service beyond the rebate value, that solar plus storage projects be eligible for the rebate, and that third parties be allowed to provide smart inverter communication devices. Ameren proposed an automatic adjustment clause tariff, Rider CGC – Customer Generation Charge, to recover rebate costs through a monthly fixed charge. In early November 2018, the Commission issued a final order approving Ameren's proposal. In early December 2018, the Attorney General of Illinois filed a petition for rehearing, arguing that Ameren's proposal should be aligned with ComEd's Docket No. 18-0753) and that both programs should incorporate a non-bypassable volumetric charge to ensure that program participants pay their fair share of program costs. Later in December, the Commission denied the petition for rehearing.	
KS	Credit Rates, Customer Class, Fees, Net Metering Rules	As part of a general rate case filed in May 2018, Kansas City Power & Light proposed the creation of a residential sub-class for new DG customers. The new residential DG sub-class tariff would include lower energy rates (6.70 to 8.68 cents per kWh, compared to 9.00 to 11.66 cents per kWh for traditional residential customers), a slightly lower monthly fixed charge ($14.00 compared to $15.18 for traditional residential customers), and a demand charge. In October 2018, the parties filed for approval of a unanimous settlement agreement. The settlement agreement contains energy rates of 7.69 cents per kWh for DG customers (6.53 to 10.68 for traditional customers), a customer charge of $14.25 per month (the same as for traditional customers), and a demand charge of $9.00 per kW (summer) and $3.00 per kW (winter) based on a 60-minute interval between 2 PM and 7 PM (traditional customers would not have a demand charge). The Commission issued an order approving the settlement agreement on December 13, 2018.	Docket No. 18-KCPE-480-RTS Order
LA	Aggregate Cap, Credit Rates, Fees, Net Excess Generation, Net Metering Rules, Virtual Net Metering	In December 2015, the Louisiana Public Service Commission (PSC) initiated a two-phase rulemaking proceeding to (1) modify the state's current net metering rule once a utility reaches the state's existing net metering aggregate cap, and (2) examine appropriate changes to solar policies in Louisiana. In December 2016, the PSC adopted the staff's recommendation filed in April 2016, reducing the credit rate for net excess generation from retail to avoided cost. Parties filed initial Phase II comments in February 2017. Entergy Louisiana, SWEPCO, Cleco, and the	Docket No. R-33929 Proposed Modified Rules

Association of Louisiana Electric Cooperatives all proposed moving from retail rate net metering to “net billing" or “2-channel billing,” where all excess generation is credited at the avoided cost rate. Entergy and SWEPCO acknowledged that time-varying rates are another option to examine, although they state the utilities would potentially propose an increased fixed charge or a demand charge to accompany them and there are additional metering costs involved. SWEPCO also proposed reducing the residential system size limit from 25 kW to 10 kW to prevent oversized systems and is supportive of establishing a new aggregate cap. Cleco suggested the Commission could set system size limits based on an average usage study. The Alliance for Affordable Energy proposed maintaining retail rate net metering and considering an increase to the aggregate cap, as well as time-varying or location-based credit rates. The Alliance also suggested consideration of community solar or aggregation options. The Sierra Club also supports maintaining retail rate net metering, but re-evaluating the basis for the current aggregate cap and clarifying that existing customers are grandfathered under current rules. The Sierra Club proposed consideration of a moderate minimum bill to ensure fixed cost recovery. Solar leasing and efficiency services company Posigen proposed that an independent consultant specializing in clean energy deployment and IT infrastructure be hired to analyze demand-side management resources, including residential solar, before any changes be made to net metering.

In November 2017, the Commission staff published proposed modified net metering rules. The new rules take the form of net billing, rather than net metering, crediting customers at the avoided cost rate for excess generation. The rules provide for two possible methods of avoided cost calculation: (1) the method established by the PSC's February 1998 order, or (2) innovative avoided cost rates including allowances for environmental and avoided peak capacity benefits. Existing DG customers, as of January 1, 2018, would be grandfathered under the former net metering policy for five years (until December 31, 2022). If a customer significantly modifies their system, it would no longer be grandfathered. The proposed rules establish a system size limit of 100% of the customer's expected annual electricity consumption and broaden eligibility from renewable only to all types of DG facilities.

The rules also allow additional fees or customer charges to be assessed on DG customers, following notice and opportunity for comment, as well as evidence supporting the fee request. The proposed

		rules also allow for community DG facilities up to 300 kW and require DG to be incorporated into integrated resource planning. Customers may carry over net excess generation, and will be monetarily compensated annually for any remaining excess. The proposed rules state that DG customers will not be charged for meter replacement, only if the DG customer requests an additional meter themselves. Comments were filed in January 2018, and an open session was held in February 2018. The Commission Staff filed final proposed modified rules in January 2019, with include most of the same provisions as the previous version of the Staff's proposed rules.	
MA	Net Metering Rules	In January 2017, the Department of Energy Resources (DOER) released its final program design for the solar incentive program that will succeed the SREC II Program. In August 2017, DOER filed the final version of the regulation. In addition to incentives, the SMART Program creates a new compensation option - the Alternative On-Bill Credit (AOBC). This option is available to incentive recipients in addition to the net metering and qualifying facility buy-all, sell-all options. This new on-bill crediting option offers a single rate for all facilities, allows the transfer of credits to off-takers without net metering, and does not have an aggregate cap or public entity system size cap. In September 2017, the state's distribution utilities jointly filed a model SMART tariff. The AOBC option provides a credit rate for generation at the applicable Basic Service Rate. The AOBC allows for the transfer of credits, but limits these transfers to each recipient's annual kWh consumption. The proposed SMART tariff also includes a SMART Factor to recover program costs; the SMART Factor takes the form of a fixed charge in the distribution utilities' proposal. The Department of Public Utilities (DPU) issued a final order in September 2018, approving the SMART program tariff. The order sets the AOBC credit rate at the basic service rate, although the DPU noted that this does not indicate the Department's position regarding conducting or directing a value of solar study. The DPU declined to set a separate AOBC credit rate for low-income customers. The DPU found that there is not sufficient evidence to implement an AOBC usage cap and directed stakeholders to determine whether a cap may be appropriate in the future and the necessary transfer limit threshold per customer. The order also allows AOBC allocation to two decimal points and disallows the utilities to recover SMART program costs through a fixed charge. Instead, the DPU directed the utilities to use a	DOER Next Solar Incentive Landing Page 225 CMR 20.00 Docket No. 17-140 Order Approving Model SMART Provision

	non-bypassable volumetric SMART Factor. In late November 2018, the DPU directed each distribution company to file company-specific SMART provisions for review. The companies filed their SMART tariffs in early December 2018. The DPU requested certain modifications to the tariffs, and the companies refiled their tariffs later in December.	
Energy Storage, Net Metering Rules	In October 2017, the Department of Public Utilities (DPU) opened an inquiry into the net metering eligibility of solar plus storage systems (or energy storage paired with other types of eligible net metering systems), as well as the eligibility of net metering facilities to participate in the Forward Capacity Market (FCM). Comments and reply comments were accepted on six questions related to storage eligibility: (1) Should energy storage systems be allowed to net meter? (2) Should only certain types of energy storage systems be allowed to net meter? (3) What technical requirements would be necessary so that the storage system and net metering facility can both participate in the ISO New England energy and capacity markets? (4) What process could ensure that the storage system is only charged by the net metering facility and does not export power to the grid? (5) What other requirements would be necessary to safeguard against gaming and manipulation of net metering rules? (6) Should the net metering cap allocation reflect the combined capacity of the net metering facility and storage system, and should there be a distinction between existing and new net metering facilities? Comments on six FCM questions were filed in February 2018: (1) To whom does the title to capacity rights revert if the distribution utility does not assert it within the 30-day window? (2) Does the 30-day window reset when a new Schedule Z is filed? (3) If the distribution utility does not assert title to capacity rights, does it have an obligation to work with the customer to provide information necessary to qualify the asset in the FCM? (4) Once the distribution utility asserts title, is there an obligation to qualify and bid the asset into the FCM? (5) Is it appropriate for distribution utilities to collect a fee to manage risk associated with FCM obligations? (6) Should distribution utilities be required to qualify and bid all Class II and III net metering facilities into the FCM? A technical conference on the eligibility of net metering facilities to participate in the Forward Capacity Market was held in June 2018, following the release of a straw proposal from the DPU Staff. Following the conference, the Staff published a revised straw proposal and solicited comments on	Docket No. 17-146

		several questions, including if a host customer or SMART project owner should have sole authority to assert title to an energy storage system's capacity rights and if the DPU should treat a storage system's capacity differently than the capacity of a net metering SMART program facility it is co-located with. The DPU also requested comments on a definition for inadvertent export to the electric distribution system, and what types of configurations could experience this. Following the conference, the DPU accepted comments and reply comments on its revised straw proposal during July.	
MD	Credit Rates	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to make sure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The proceeding is addressing rate design, costs and benefits of DERs, advanced metering infrastructure, valuing energy storage, streamlining the interconnection process, evaluating distribution system planning, and protecting limited income customers. A consultant was hired to study the benefits and costs of distributed solar in Exelon-PHI territory, including solar's health and environmental benefits, an examination of geographic and grid location, and how advancing energy storage technology and cost-effectiveness can enhance distributed solar's benefits. In August 2017, the rate design working group submitted a report detailing its two proposed TOU rate pilots, both of which net metering customers would not be eligible to participate in. In November 2017, the PSC published an order stating that the materials submitted during the workgroup and report are not sufficiently specific to approve the pilot programs. The PSC directed the workgroup leaders to continue convening the group to refine the design of the two pilot programs – one for customers who wish to receive standard offer service, and another for customers wishing to receive service from a retail supplier. The workgroup submitted a report in response to this order in February 2018. The report includes a consensus approach for net metering customer participation in the pilot programs. The approach tracks on-peak and off-peak consumption and production separately, and nets each separately. Any excess in either category will be carried forward to the next month, while any net consumption in either category will be due at that time. At the end of the annual period, any remaining net excess generation	Public Conference 44

		in either category will be compensated at the non-TOU supply-only rate currently paid to net metering customers. In June 2018, the PSC approved the workgroup's proposed timeline for the development of the TOU pilots, which includes a deadline of April 1, 2019 for the new tariffs to be rolled out. The utilities filed their marketing and outreach plans in July 2018, and parties provided comments. The workgroup filed an interim report in November 2018, identifying areas were consensus was and was not reached. The utilities filed a revised implementation, marketing, and outreach plan in November as well. In December 2018, the PSC directed the utilities to proceed with implementing the TOU pilots as proposed in the utilities' November filing.	
ME	Credit Rates, Net Metering Rules	In September 2018, the Conservation Law Foundation filed a lawsuit against the Public Utilities Commission, challenging the legality of the new buy-all, sell-all DG compensation rules adopted in 2017 and implemented in early 2018. The Foundation and other petitioners (Industrial Energy Consumer Group, ReVision Energy, and Natural Resources Council of Maine) are seeking a declaration that the new rules are arbitrary, capricious, and an abuse of discretion. The suit was previously filed with the Maine Supreme Judicial Court, which dismissed the challenge, finding that it should go to a lower court. The September 2018 petition was filed with a Maine Superior Court.	Complaint
	Net Metering Rules	In June 2018, Insource Renewables filed a motion for the Commission to require Central Maine Power to conform to the Chapter 313 net billing rules and a Commission advisory ruling confirming that customers are not responsible for the cost of additional metering equipment. Insource wrote that Central Maine Power is refusing to reimburse customers for additional metering costs incurred to comply with the new rules. The Commission published an order in August 2018, directing Central Maine Power to reimburse all necessary costs of installing a second meter. The order also directs Commission Staff to establish a rapid response process to settle disputes between solar installers and the utility over these costs. Finally, the order directs Commission Staff to initiate a process to explore the feasibility of using inverters that include revenue-grade meters and other emerging technologies to reduce the cost to measure gross output. In October 2018, Insource Renewables filed a motion requesting that the Commission require Central Maine Power and Emera Maine to exclude medium and large net billing customers from the nettable energy provisions in the state's new net billing rules. This request is based on the high metering costs (installation of additional meters)	Docket No. 2018-00037

		required to implement these provisions for these customers and the fact that these customers have low volumetric rates because of the demand component of their bills. In December 2018, the Commission issued an order, exempting medium and large non-residential net billing customers from the nettable energy provisions of the new rules. The Commission noted that there is very little cost shift associated with these customers, due to the demand charge component of their bills, and that the costs of installing a second meter to implement the nettable energy provisions are not justified.	
MI	Credit Rates, Fees, Net Metering Rules	In July 2018, as part of a general rate case, DTE Electric proposed a rate structure for new DG customers based on Michigan's new "inflow/outflow" methodology for DG compensation (see Docket No. 18383). All inflows will be charged at full retail rate, while outflows from a customer's DG system will be credited at the monthly average real-time locational marginal price (LMP) at the relevant DTE node. Outflow credits will not be allowed to offset non-energy customer charges. Unused outflow credits will be carried over to the next month indefinitely. New DG customers will also pay a system access charge of $2.31 per kW of DG system capacity. Parties filed testimony in November 2018, and a cross-examination hearing was held in December 2018.	Docket No. U-20162 Docket No. 18383
	Credit Rates, Fees, Net Metering Rules	In September 2018, as part of its general rate case, UPPCO proposed a rate structure for new DG customers based on Michigan's new "inflow/outflow" methodology for DG compensation (see Docket No. 18383). All inflows will be charged at the full retail rate, while outflows will be credited according to the power supply charge for the relevant rate class. Outflow credits will not be allowed to offset non-energy customer charges. Unused outflow credits would be carried over to the next month indefinitely. New DG customers will also pay a system access charge based on DG system capacity, although the amount of this charge was not specified in the initial filings. Initial testimony is due by February 21, 2019, and a final order is expected by August 21, 2019.	Docket No. U-20276 Docket No. 18383
	Net Metering Rules	On November 8, 2018, the Michigan Public Service Commission opened this docket to conduct an investigation of interconnection rules, legally enforceable obligations under PURPA, distributed generation (including energy storage), and legacy net metering rules. A stakeholder meeting was held in December 2018.	Docket No. U-20344
MO	Net Metering Rules	In September 2017, the Missouri Public Service Commission (PSC) opened a docket to review the	Docket No. EW-2018-0078

		Commission's rules on cogeneration and net metering. The docket is intended to gather information and conduct a workshop. Stakeholders submitted comments on the effectiveness of the current rules and suggested changes to the rules through mid-November 2017. Utility comments generally recommended against changing current net metering rules, while noting potential cost-shift issues, and argued against undertaking a new value of solar study. Renew Missouri agreed that current net metering rules are not in need of revision and argued that any cost-shift issues should be addressed only after a value of solar study is undertaken. In May 2018, the PSC published a draft rule change pertaining to net metering. The rule changes would make it so that net metering rates for systems larger than 100 kW would not have to be the same as the utility's cogeneration rates. The amended rules would also require utilities to maintain an information database for resource planning containing information on net-metered systems, and require that the process for calculation of net energy be specified in net metering tariffs. The proposed changes would delete existing language specifying the manner for determining net electrical energy, defining net metering, and stating that customer-generators own RECs unless receiving solar rebates. The draft also deletes language including the aggregate cap and prohibiting additional fees from being imposed on only customer-generators. These deleted sections are, however, included in the state's net metering statute (386.890 RSMo), and would, therefore, not impact current net metering requirements. The draft rules would also allow the liability insurance requirement to be waived for "good cause." Action in these matters in Q3 and Q4 2018 focused on PURPA standard offer contracts; there has not been further action on the draft net metering rule revisions.	Proposed Net Metering Amendment
MT	Customer Class, Fees, Net Metering Rules	In NorthWestern Energy's general rate case, filed in late September 2018, the utility proposed the separation of future residential net metering customers into a new customer class. The proposal retains monthly netting of production and consumption, but includes an $8.64/kW demand charge for future residential net metering customers.	Docket No. D2018.2.12
NY	Credit Rates, Net Metering Rules, System Size	A.B. 10474 allows any utility customer who begins net metering before December 31, 2021 to continue net metering under current rules for the life of the generating equipment. The bill also requires the Public Service Commission to develop a new value of DER methodology that includes various social, economic, and environmental benefits. It also	A.B. 10474

	increases the net metering system size limit for non-residential net metered systems from 2 MW to 5 MW. This bill passed the Assembly in June 2018, but died at the end of the 2017-2018 legislative session.	
Credit Rates, Fees, Net Metering Rules	In March 2017, the New York Public Service Commission (PSC) issued a net metering transition order, addressing Phase I of the Value of Distributed Energy Resources (VDER) proceeding and outlining a procedure for Phase II of the proceeding. In May 2017, the PSC created working groups and protocols for Phase II of the VDER proceeding. Three working groups are looking at: (1) the value stack, (2) rate design, and (3) low and moderate income issues. The working groups will support the PSC Staff to develop recommendations. The PSC published a schedule with working group meetings going from January 2018 to December 2018, culminating in a white paper from the PSC staff. In April 2018, the utilities published a Rate Design Handbook to define and explain the uniform approach they developed for parties to submit rate design proposals. During Q2 2018, stakeholders submitted proposals based on the framework established by the PSC. In late June 2018, the PSC announced which rate design proposals will be evaluated. The proposals to be evaluated include a TOU rate proposal submitted by the clean energy parties, a TOU rate proposal from PSC Staff, a demand rate proposal from the joint utilities, and a combined demand and TOU rate proposal from the joint utilities. In July 2018, the Department of Public Service Staff published a white paper on VDER compensation for avoided distribution costs. In the paper, Staff proposed replacing the de-averaged demand reduction value with system-wide marginal cost estimates used for energy efficiency benefit-cost calculations. The tariff would be updated every two years, as opposed to annually. Staff recommended two options for customers: (1) provide a $/kWh rate for the 460 peak summer hours used for the tariff's Capacity Value Option 2 or (2) establish a call signal to provide a $/kW-year value over 10 peak load hours (this option would be aimed at dispatchable resources, like storage). The Staff filed final versions of the white papers in December 2018. In December 2018, the PSC issued an order accepting the hybrid tariff for Distributed energy systems that include battery storage (hybrid facilities). The tariff includes four options: Options A and B offer an environmental credit value, the market transition credit, and capacity credit value for all grid exports by	Matter No. 17-01276 (Value Stack) Matter No. 17-01277 (Rate Design) NYSERDA VDER Resources

		ensuring that only renewable energy is injected to the grid. Option C uses multiple meters to determine whether injections are from renewable energy or not, and Option D uses monthly netting.	
OH	Net Excess Generation, System Size	The Public Utilities Commission of Ohio approved amendments to the state's net metering rules in November 2017. The new rules set the maximum system size limit at 120% of a customer's average annual usage. Customers receiving standard service from a regulated utility will be compensated monthly for net excess generation at the utility's standard service offer rate for energy. Competitive retail electric suppliers may offer net metering to their customers and compensate excess generation at any price, rate, credit, or refund amount agreed to between the supplier and the customer. Various parties filed applications for rehearing, which the Commission granted in January 2018. An additional hearing was held in January 2018. No significant action has taken place since.	Docket No. 12-2050-EL-ORD PUCO Order
PA	Net Metering Rules	In April 2018, as part of Duquesne Light Company's general rate case, the utility proposed a new requirement for a generation meter to be installed for net metering customers completing the Part 1 Interconnection Application January 1, 2019 and later. The generation meter will measure the total system output and be paid for by the utility. A settlement agreement was filed in September 2018, which includes the proposed generation meter requirement. A recommended decision, filed in October, would not approve the generation meter requirement. The Commission issued an order in December 2018, accepting the ALJ's recommendation, which does not approve the generation meter requirement.	Docket No. R-2018-3000124 Settlement Agreement
SC	Net Metering Rules	In May 2018, the South Carolina Legislature's Public Utilities Review Committee tasked the Energy Office with leading a stakeholder process to look broadly at the future of electricity in the state within the context of Act 236 and with a particular focus on renewable energy. Approximately 50 stakeholders are part of the process, and seven meetings have taken place since June 2018. A wide variety of issues have been considered by the group including net metering and rate design. The group's October meeting focused on energy storage.	Stakeholder Group Website
UT	Credit Rates, Net Metering Rules	In September 2017, the Public Service Commission (PSC) approved a settlement agreement between Rocky Mountain Power and solar advocates on the future of net metering in the state. The settlement agreement closed net metering to new DG customers on November 15, 2017. Customers beginning to net	Docket No. 17-035-61 (Export Credit Rate Proceeding)

	meter by this date are grandfathered under the current rules through December 31, 2035. If ownership of the property changes during this period, the system remains grandfathered. An Export Credit Proceeding will be conducted to determine the credit rate for energy exported to the grid by new DG systems, while on-site consumption will be permitted. The PSC established a transition program for new customer-generators to participate in after the close of retail rate net metering and before the new export credit rate is decided. The transition program takes the form of net billing, rather than net metering, with an export credit rate of 9.2 cents/kWh for residential customers, netted in 15-minute intervals. The settlement established an aggregate cap for the transition program of 170 MW for residential and small non-residential customers. As part of the agreement, the parties agreed not to advocate for any changes to rates, charges, and fees for grandfathered net metering or transition customers that do not apply to the entire customer class. Customers submitting a complete interconnection application after this cap is reached will receive the transition credit rate until the new export rate is determined through the Export Credit Proceeding. The Commission opened a new docket for the Export Credit Proceeding in December 2017. A load research study workshop was held in January 2018, and RMP filed its proposed load research study plan in February 2018. A hearing was held in April 2018, and the Commission issued an order on Phase I of the proceeding in May. The study period will run for 12 months, beginning no later than January 1, 2019. Parties disagreed on the type and scope of data to be collected through the study. Based on parties' criticisms and recommendations, the Commission directed RMP to increase its sample size to accommodate the separate study of residential and commercial customers and to select new samples from both classes that give each member of the class an equal chance of being selected, rather than mixing an existing sample drawn from a subset of the class with a new sample from the entire class. The Commission also directed RMP to collect production, export, and import data from existing net metering customers. Vote Solar, Utah Clean Energy, and Vivint Solar filed a petition for rehearing in June on certain sample design and data collection issues. The Commission addressed the petition and issued an order on review in July 2018. The order clarifies the Commission's Phase I order, but does not modify it. Rocky Mountain Power gave an update on Phase II of the proceeding in early October 2018. In late	Docket No. 14-035-114 Docket No. 16-035-T14 Order on Review (July 2018) Phase I Order (May 2018) RMP Proposed Load Study Plan (February 2018) Order Approving Settlement Stipulation (September 2017)

		November 2018, several solar advocates filed a joint motion to amend the procedural schedule to hold at least two additional technical conferences in the first half of 2019. The parties also requested that the Commission agree to accept no-cost technical assistance from relevant experts at multiple national laboratories. A hearing on Phase II of the proceeding is scheduled for September 2020.	
	Net Excess Generation	In October 2018, the Public Service Commission opened an investigation into expiring excess generation credits from Rocky Mountain Power's Schedule 135 (net metering tariff that closed to new applicants in November 2017). Currently, the value of expiring excess generation credits is applied to the Home Electric Lifeline Program, but several parties recommended applying these credits to an alternative program. Parties filed comments in November 2018.	Docket No. 18-035-39
VA	Meter Aggregation, Net Excess Generation	H.B. 1451, enacted in March 2018, requires Dominion Energy to conduct a pilot program to provide compensation to any school that generates excess electricity from wind or solar on an annual basis. Dominion filed its Draft Guidelines with the Commission in June 2018. In August 2018, the Commission began accepting comments on the draft guidelines. Parties proposed that the formula for calculating the compensation rate include the full cost of generation, including certain generation-related rate adjustment clauses. In November 2018, the Commission approved the guidelines, including the parties' proposed modifications.	H.B. 1451 Docket No. PUR-2018-00061 Order
VT	Net Metering Rules	In December 2017, the Vermont Department of Public Service, Natural Resources Board, and Agency of Natural Resources requested that the Public Utility Commission hold a workshop related to the definition of the term "preferred site" in the state's net metering rules. A prehearing conference was held in March 2018, and workshops were held in June and July 2018. The Commission will issue guidance regarding the definitions of preferred sites, and draft rule changes will be published for comment at a date to be determined. The proceeding remains open.	Docket No. 17-5202-PET
WI	Net Excess Generation	In February 2018, as part of a general rate case, North Central Power Company requested to change its net excess generation compensation rate for DG customers with systems smaller than 20 kW to avoided cost from retail rate. Although the rate is called "net energy billing," the rate nets energy across the month and is therefore still considered net metering by this report's definition. In December 2018, the Public Service Commission of Wisconsin approved the rate change.	Docket No. 4190-ER-107

	Net Excess Generation	In late December 2018, Northwestern Wisconsin Electric Company filed a petition to adjust its compensation rate for net excess generation to net metering customers from retail rate to avoided cost. This petition references a similar adjustment made to North Central Power Company's rates made in Docket No. 4190-ER-107.	Docket No. 4280-TE-101
WV	Fees, Net Metering Rules	The Public Service Commission opened a new docket in September 2018 to consider revisions to net metering and interconnection. To begin the proceeding, the Commission provided a draft of revisions to the existing net metering rules based on the recommendations of the Net Metering Task Force. The draft revisions include a provision that the charges for energy consumption in the net metering tariff should be the same as those in the standard service tariff. The rules also require that fixed charges and other charges not related to energy consumption should not exceed comparable charges in the standard service tariff by more than the costs directly incurred by the utility to accommodate the net metering system. The rules maintain retail rate net metering, but include a provision that net metering credits may not reduce the bill below the fixed monthly minimum bill plus any charge for the Incremental Cost of Connection, which is defined in the proposed rules. The rules also change the financial responsibility for a bi-directional meter from the utility to the customer. The Commission received comments on the proposed rule changes from a number of parties.	GO 258.3 Proposed Rules

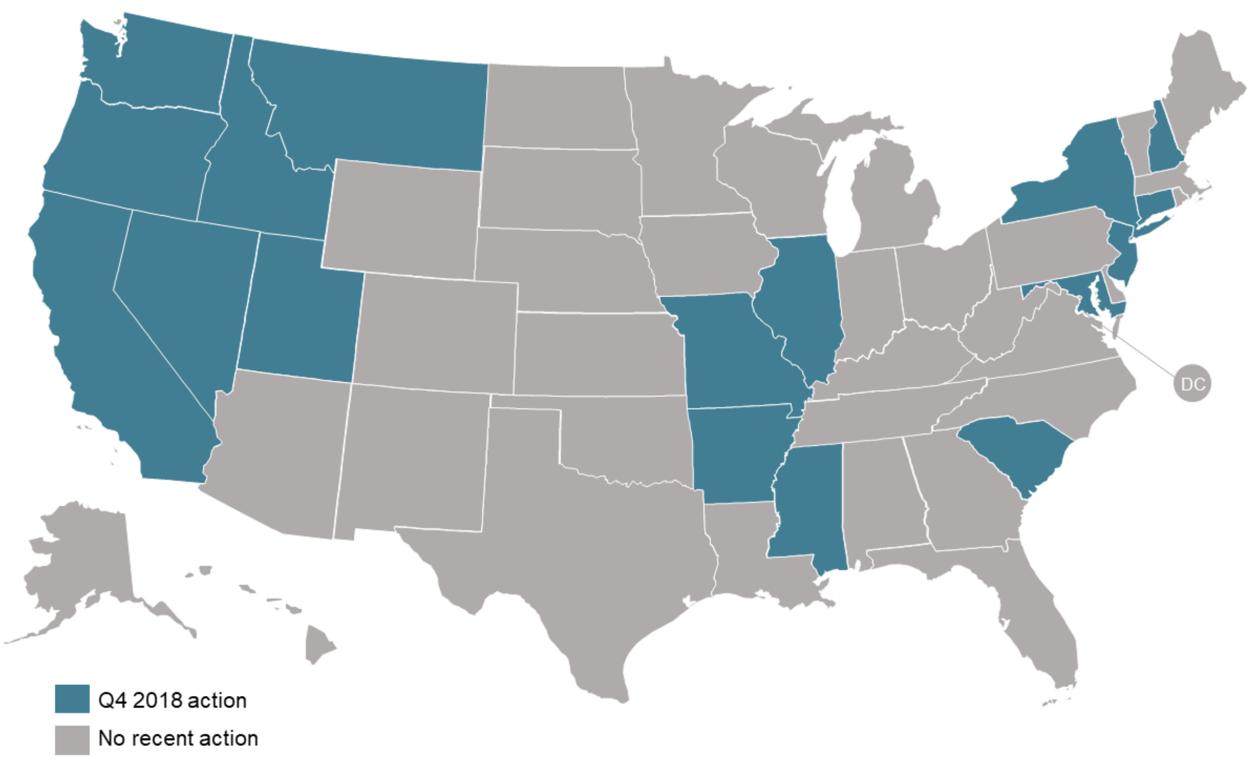
DISTRIBUTED SOLAR VALUATION STUDIES

Key Takeaways:

- In Q4 2018, 17 states were in the process of examining some element of the value of distributed generation.
- Illinois published two studies – the draft final NextGrid report and the Pacific Northwest National Laboratory review of DG valuation considerations.
- The Idaho Public Service Commission opened two new dockets – one to conduct a cost-benefit study of on-site generation and one to conduct a study of the fixed costs of service.

In Q4 2018, 17 states were engaged in the process of examining some element of the value of distributed generation (DG). Illinois, Mississippi, and New York released draft or final reports during Q4 2018 addressing DG valuation, while other states continued to take steps in conducting their studies or proceedings.

Figure 31. Action on Distributed Solar Valuation and Net Metering Studies (Q4 2018)



Illinois released two reports during Q4 2018 pertaining to the value of DG. The first is a draft version of the final report for the NextGrid proceeding, a wide-ranging examination of energy issues in the state. The NextGrid report discusses many factors relevant to determining the value of DG, but does not recommend a specific valuation process or methodology for Illinois.

Chapters 1 and 7 of the report address DG valuation, with Chapter 1 focusing on the distribution system and Chapter 7 discussing ratemaking for DG systems.

Acadian Consulting filed a draft of Mississippi's report on the benefits of DG during Q4 2018, which will inform the non-quantifiable benefits credit adder that is currently a part of the state's net billing policy. The New York Department of Public Service Staff also published two reports related to DG valuation during the quarter. One of the reports provides a proposed methodology for calculating capacity compensation, and the other provides a proposed method for calculating compensation for distribution system benefits.

Other states began or continued conducting DG valuation studies during the quarter. The Idaho Public Service Commission initiated two new proceedings in October 2018, one examining the costs and benefits of on-site generation and one studying the fixed costs of providing electric service. The New Hampshire Public Service Commission is expected to begin its study examining the locational value of DG in the second quarter of 2019. A proceeding to establish a net billing export credit rate is continuing in Utah, with a study set to begin in 2019. Each of these proceedings are intended to inform future changes to the states' DG compensation rules and rate designs.

Table 11. Updates on Distributed Solar Valuation and Net Metering Studies (Q4 2018)

State	Description	Source
AR	In April 2016, the Public Service Commission (PSC) opened a general proceeding regarding DERs. In November 2017, the PSC issued an order outlining specific topics and questions to address during this proceeding, including many related to advanced metering infrastructure (AMI) deployment, pursuant to the final order in Entergy Arkansas' AMI deployment proceeding. These issues include identification of the benefits and costs of DERs (including rate and bill impacts) for customers that participate measures and programs, as well as non-participants. Benefits to individual customers should be distinguished from system benefits. The PSC issued an order in July 2018 with an initial list of issues to be considered during the proceeding. These issues include the appropriate roles for distribution utilities, third-party DER providers, and customers; tariff-based DER programs; net metering and rate design; and DER compensation and program design for low-income participation among many other specific DER and grid modernization issues. Comments on the proposed issues were accepted until late September, and the Commission intends to schedule an initial educational workshop on procedural issues.	Docket No. 16-028-U Order No. 10
CA	California has an ongoing proceeding to consider the development of a consistent regulatory framework for the planning and evaluation of DERs. The proceeding is addressing two activities: (1) the establishment of a Competitive Solicitation Framework, which involves creating cost-effectiveness methods for evaluating bids and (2) the adoption of a Utility Regulatory Incentive Pilot for the procurement of DERs that displace or defer the need for capital expenditures on traditional distribution infrastructure. The Commission's Energy Division revised its proposal on the Societal Cost Test, which could help build upon the cost-effectiveness methods for evaluating bids from the Competitive Solicitation. A March 2018 ruling requested comments on several issues related to the Societal Cost Test. In June 2018, the Commission issued a decision modifying a prior decision related to the funding of the Utility Regulatory Incentive Pilot. As part of the Pilot, the utilities were required to procure one or more DER projects and evaluate the effectiveness of the solicitation process and the performance of the DERs. The modified decision addressed the possibility of a pilot project involving distribution equipment funded through a general rate case. The decision states that in such a case, the funding for the pilot project should come from the general rate case funds and not be funded separately. In September 2018, the ALJ requested comments on whether it is reasonable for the Commission to approved a utility-administered contract for future cost-effectiveness modeling work. In November 2018, San Diego Gas and Electric (SDG&E) filed an evaluation report for its Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism pilot. The report indicates that SDG&E launched its Pilot Request for Offers in January 2018 and did not receive any conforming bids that were cost effective. The report presents a series of recommendations for improving the	Docket No. R14-10-003 Decision No. 18-06-010 ALJ Ruling

	process, and the Commission opened a comment period on the report. Also in November 2018, the ALJ issued a ruling directing parties to file proposed DER tariffs by February 15, 2019.	
CT	In December 2017, the Public Utilities Regulatory Authority (PURA) opened a docket for its investigation into distribution system planning. Among the specific topics to be addressed is rate design alternatives. In March 2018, the PURA sought comments focusing on the integration of DERs, grid modernization, implementing an appropriate rate design to optimize system benefits, and other topics. Technical meetings were held in April, July, and October 2018. Phase II of the proceeding will include assessing the costs, benefits, and implications of specific solutions and implementing these in appropriate proceedings. A public hearing was held in late October, and the PURA closed the record in the proceeding on November 26th.	Docket No. 17-12-03
ID	In October 2018, Idaho Power filed a petition to open a docket to study the cost and benefits of on-site generation. This follows an order in Docket No. IPC-E-17-13 approving Idaho Power's request to separate DG customers into a separate customer class and evaluate credit rates for excess generation. Rates, rate design, transitional rates, and net excess generation compensation will be considered in this proceeding. In December 2018, the Commission Staff proposed an initial schedule, with a broad list of issues being provided to the Staff in early January 2019, followed by two settlement meetings in January.	Docket No. IPC-E-18-15
	In October 2018, Idaho Power filed a petition to open a docket to study the fixed costs of providing electric service to customers. This information will be considered in future rate design changes for DG customers, per Docket No. IPC-E-17-13. A prehearing conference is scheduled for early January 2019.	Docket No. IPC-E-18-16
IL	In March 2017, the Illinois Commerce Commission opened a proceeding to investigate grid modernization and the creation of a 21st century regulatory model. The NextGrid proceeding is being conducted as a facilitated stakeholder process. Topics include, but are not limited to (1) consumers, communities, and economic development; (2) grid design, digital networks and markets; (3) regulation and encouraging innovation; and (4) climate change and the environment. A conference and launch event for the proceeding took place in late September 2017, and working groups were formed on seven topics: (1) new technology deployment and grid integration, (2) electricity markets, (3) customer and community participation, (4) regulatory, environmental, and policy issues, (5) metering, communications, and data, (6) reliability, resiliency, and cyber security, and (7) ratemaking. Draft reports from all seven working groups were published on the NextGrid website in September 2018. The draft reports for Working Groups 1, 6, and 7 contain discussion of DERs, with Working Group 1 focusing on DER integration and valuation. Working Group 6 focuses on the environmental benefits of DERs, and Working Group 7 summarizes the aspects of DER valuation that need to be considered in ratemaking. Working groups 1 and 7 discuss the need to recognize	Docket No. 17-0142 NextGrid Website Draft Final Report (Dec. 2018) Working Group 1 Draft Report Working Group 6 Draft Report Working Group 7 Draft Report

	how DER value can differ depending on location and grid factors. The draft reports do not make specific policy proposals. A draft final report compiling the working group reports was published in December 2018; public comments were due by January 10, 2019.	
	The Illinois Commerce Commission initiated its investigation into DG valuation and compensation in February 2018 with the publication of a white paper summarizing issues and considerations in DG valuation, as well as approaches taken by other states. The report was prepared by staff at the Pacific Northwest National Laboratory (PNNL). A stakeholder workshop was held in March 2018. A second workshop was held in late June 2018, at which the participants discussed a second version of the PNNL white paper. In November 2018, Pacific Northwest National Laboratory published the final white paper.	Distributed Generation Valuation and Compensation
MD	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to ensure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The proceeding is considering topics including rate design, costs and benefits of DERs, maximizing advanced metering infrastructure, valuing energy storage, streamlining the interconnection process, evaluating distribution system planning, and protecting limited income customers. A consultant was hired to study the benefits and costs of distributed solar in Exelon-PHI territory, including solar's health and environmental benefits, an examination of geographic and grid location, and how advancing energy storage technology and cost-effectiveness can enhance distributed solar's benefits. Following the release of a draft report in April 2018, Daymark Energy Advisors published the final report in November 2018 on the benefits and costs of utility-scale and behind-the-meter solar resources in Maryland. The report, funded by the PSC, provides an analysis of the costs and benefits of solar within each of the four electric utilities in the state. The values of behind-the meter solar vary by utility and decrease over time from a current value of approximately 30 - 38 cents per kWh to approximately 25 - 30 cents per kWh in 2028. The values for utility-scale solar also vary by utility and increase over time from a current value of approximately 15 - 19 cents per kWh to approximately 19 - 21 cents in 2028. Parties filed comments on the final report in December 2018.	Public Conference 44 Draft: Benefits and Costs of Utility Scale and Behind The Meter Solar Resources in Maryland Final: Benefits and Costs of Utility Scale and Behind The Meter Solar Resources in Maryland
MO	In March 2017, the Missouri Public Service Commission (PSC) staff requested that the Commission open a workshop docket to gather information related the PSC's role in shaping the solar landscape, including the Public Utility Regulatory Policies Act (PURPA), Missouri statutory provisions, net metering and cogeneration rules, avoided cost calculations, value of solar calculations, development and construction of utility-scale or community solar projects, and other states' activities. Information regarding the PSC's role in implementing modified rate design proposals, such as residential TOU rates, is also requested. The proceeding is also intended to examine issues surrounding advanced metering infrastructure,	Docket No. EW-2017-0245 July 2017 Staff Report April 2018 Staff Report May 2018 Draft Rule

	property assessed clean energy financing, and the electric vehicle market. The PSC Staff released its report on DERs in early April 2018. The report does not specifically recommend that a value of solar study be conducted, but did find that studies conducted in other states may not be fully informative for Missouri. Rather than recommending a full value study, Staff recommended that stakeholders focus on incorporating DERs into distribution system planning, as this may help provide a framework for DER valuation. In May 2018, the PSC Staff filed a draft rule for comment, and in late May 2018 a workshop was held to discuss the draft rule. In late June 2018, the PSC Staff published an updated version for comment. The current version of the draft rule requires utilities to maintain a database on current DERs on their grids, assess the market potential for DERs as part of their triennial compliance filings, and evaluate DERs as part of the resource planning process, including their integration with the transmission and distribution system. Action in these matters in Q3 and Q4 2018 focused on PURPA standard offer contracts; there has not been further action on the draft rules for DERs.	June 2018 Draft Rule
MS	Earlier in 2018, the Mississippi Public Service Commission issued an RFP for a consultant to conduct a study of the benefits of DG, as required by the state's net metering rule. In July 2018, the Sierra Club, Gulf States Renewable Energy Industries Association, and 25 x '25 Alliance filed a motion to amend the timeframe for the study and consolidate it with the 5-year review docket, due to the state's limited solar development. Acadian Consulting was hired to conduct the study, and a public meeting was held in early August for interested parties and stakeholders to provide information relevant to the study. Acadian Consulting published a draft report in November 2018, which the Commission is accepting comments on for 45 days from the date of its order. The Commission extended the deadline for comments until February 2, 2019.	Docket No. 2011-AD-2
MT	In April 2018, NorthWestern Energy held the first meeting of its Customer Vision stakeholder group. The group will address potential products and services customers would be interested in, pricing models that align utility and customer needs, and the future of the power grid. The group also met in May, June, and September 2018, with presentations about Minnesota's e21 Initiative, the Illinois NextGrid process, and Green Mountain Power's programs. An October 2018 meeting discussed Ontario's electricity pricing and rate design, as well as NorthWestern Energy's infrastructure initative goals and alternatives. A meeting was held on November 30th to discuss a decoupling proposal and force-field analysis.	Customer Vision Stakeholder Group
NH	Pursuant to H.B. 1116 of 2016, the Public Utilities Commission (PUC) issued a final order approving a net metering successor tariff in June 2017. In the decision, the PUC ordered a value of DER study to be conducted by a qualified consultant under the Commission's guidance in order to inform "Phase 2" changes to the state's DG compensation policy. The study is to be a long-term	Docket No. DE 16-576 Order No. 26,029 DER Study Scope

avoided cost study using marginal cost concepts and incorporating both the Total Resource Cost and Ratepayer Impact Measure test criteria, as well as consideration of demonstrable and quantifiable net benefits associated with relevant externalities. The study period is to be 10-15 years - a compromise between the 3-5 years proposed by the coalition of utility and consumer parties and 25 years proposed by the coalition of solar and sustainable energy interests. The study will focus on solar PV and hydroelectric facilities. A stakeholder working group met throughout the rest of 2017 and beginning of 2018, and filed its proposed DER study scope in May 2018.

The proposed study scope includes hourly avoided cost calculation, as well as a distribution-level valuation study conducted either as a separate study or as part of the DER study to evaluate locational value. The study period will be 15 years, with 3 to 5 years of historic data reviewed. The study will not include a high DG penetration scenario. The avoided cost components to be evaluated in the study include energy, capacity market costs, ancillary services and load obligation charges, renewable portfolio standard (RPS) compliance, transmission charges, transmission capacity, distribution capacity, distribution system operating expenses, transmission and distribution line losses, wholesale market price suppression, hedging/wholesale risk premium, distribution utility administration costs and expenses, transmission and distribution system upgrades required, utility lost revenues, externality benefits, distribution grid support services, resilience services, and customer installed net costs. Consensus among stakeholders was achieved on methodologies for energy, capacity market costs, ancillary services and load obligation charges, RPS compliance, transmission charges, distribution capacity, line losses, wholesale market price suppression, administrative costs, transmission and distribution system upgrade costs, distribution grid support services, and resilience services. The group did not reach consensus on the inclusion of and/or methodologies for transmission capacity, distribution system operating expenses, hedging, utility lost revenues, externality benefits, and customer installed net costs. The study will be conducted by an independent consultant and is expected to be completed in 2020. The distribution locational value study is expected to be completed in 2019. A public comment hearing on the proposed study scope was held in late June 2018, with written comments submitted in July. In mid-July 2018, Eversource filed a marginal cost of service study to be used in the valuation study. In late November 2018, the Commission Staff filed a report with a proposed scope and timeline for the distribution-level locational DG valuation study. The proposed study scope covers only technologies eligible for net metering and will examine the value of avoided or deferred distribution investment costs resulting from elimination of capacity constraints. The study is expected to begin in Q2 2019 and be completed by the end of 2019. The Staff scheduled a public comment hearing on the locational value study scope for January 2, 2019.

[Locational Value of Distributed Generation Study Scope Proposal]

NJ	In May 2018, New Jersey Governor Murphy signed the Clean Energy Act into law, which directed the Board of Public Utilities (BPU) to complete a study on the SREC program transition and successor to encourage efficient and orderly development of solar in the state. In December 2018, the BPU released a staff straw proposal on the New Jersey Solar Transition. The proposal includes several questions about the New Jersey solar market that the staff is seeking comments on from stakeholders. Among these questions is if the SREC program cost cap should be based on net costs and include a valuation of associated benefits and if the transition to the SREC successor program should also encompass changes to the net metering program. Comments from stakeholders are being accepted until February 22, 2019. A proposed rule is expected to be presented to BPU in September 2019, with timeline to adopt the rule by March 2020.	Staff Straw Proposal on the New Jersey Solar Transition
NV	A.B. 405, signed into law in June 2017, requires the Public Utilities Commission of Nevada (PUCN) to open an investigatory docket to establish a methodology to determine the impact of net metering on electricity rates. The PUCN is required to submit a summary report of its findings to the legislature by June 30, 2020, and biennially thereafter. A docket was opened in July 2017, and no action has taken place since.	Docket No. 17-07013 A.B. 405
	S.B. 146, signed into law in June 2017, requires NV Energy to submit a Distributed Resources Plan to the Public Utilities Commission of Nevada (PUCN) by April 1, 2019 as an addendum to its integrated resource plan due June 1, 2018. The plan must (1) evaluate the locational benefits and costs of DERs, (2) propose standard tariffs for the deployment of cost-effective DERs, (3) propose cost-effective methods of coordinating existing programs to maximize the locational benefits of DERs, (4) identify additional spending necessary to integrate distributed resources into distribution planning, and (5) identify barriers to the deployment of DERs. The PUCN opened an investigation and rulemaking docket in July 2017 to implement S.B. 146. NV Energy submitted its proposed regulations in June 2018. Alternative regulations were also filed by the Bureau of Consumer Protection and a group of stakeholders led by the Interstate Renewable Energy Council. The PUCN published draft temporary regulations in July 2018, which it later approved in October 2018. The temporary regulations establish the filing, content, approval, and updating process for distributed resource plans.	S.B. 146 Docket No. 17-08022 Temporary Regulations
NY	A.B. 10474 allows any utility customer who begins net metering before December 31, 2021 to continue net metering under current rules for the life of the generating equipment. The bill also requires the Public Service Commission to develop a new value of DER methodology that includes various social, economic, and environmental benefits. It also increases the system size limit for non-residential net-metered systems from 2 MW to 5 MW. The bill passed the Assembly in June 2018, but died at the end of the 2017-2018 legislative session.	A.B. 10474

	In March 2017, the Public Service Commission issued an order on the future of net metering in the New York. The order is one of the major milestones in New York's Reforming the Energy Vision proceeding, addressing the transitional steps from traditional net metering to a Value of Distributed Energy Resources (VDER) tariff that aims to accurately value and compensate DERs. Community solar, remote net-metered projects, and large distributed energy projects began to be compensated through the Phase I Value Stack tariff in March 2017. The VDER tariff includes energy (based on LMP), capacity, environmental, and demand reduction credits. Mass market DER projects are able to continue with the Phase I net metering tariff, which is identical to the previous net metering tariff, except that it includes a 20-year contract term. All projects interconnected prior to March 9, 2017 are able to continue with traditional net metering. In September 2017, the PSC issued an order finalizing Phase I VDER implementation. Phase II of the VDER proceeding, initiated in June 2017, is working to refine and improve the value stack, address rate design issues, and support participation for low to moderate income ratepayers. The PSC formed two parallel working groups addressing the value stack and rate design. Working groups are meeting from January 2018 to December 2018, culminating in a white paper from the PSC staff. In April 2018, the utilities published a Rate Design Handbook to define and explain the uniform approach they have developed for parties to submit rate design proposals. During Q2 2018, stakeholders submitted proposals based on the framework established by the PSC. In late June 2018, the PSC announced which rate design proposals will be evaluated. The proposals to be evaluated include a TOU rate proposal submitted by the clean energy parties, a TOU rate proposal from the PSC Staff, a demand rate proposal from the joint utilities, and a combined demand and TOU rate proposal from the joint utilities. In December 2018, the Department of Public Service Staff field white papers on (1) VDER Capacity Value Compensation and (2) VDER Compensation for Avoided Distributed Costs. The goal of the VDER Phase II proceeding is to establish a new method of compensation for distributed generators based on the actual, calculable value these systems provide. The two white papers present the Staff's proposed methods to calculate capacity value and avoided distributed costs.	Docket No. 15-02703/15-E-0751 Matter No: 17-01276 (Value Stack) Matter No: 17-01277 (Rate Design) VDER Resources
OR	The Public Utility Commission (PUC) is investigating the resource value of solar (RVOS). The RVOS will be used to compensate systems enrolled in the Solar Volumetric Incentive Program after their 15-year payment schedule has expired. However, the RVOS could be utilized in other ways in the future as well. The PUC held several workshops and hearings throughout 2015, 2016, and 2017 to identify elements to include in the valuation and the methodology for calculating them. In September 2017, the PUC issued Order No. 17-357, formally closing Phase I of the proceeding and adopting the RVOS. The RVOS utilizes eleven elements (energy, generation capacity, transmission and distribution capacity, line losses, administration, market price response, RPS compliance, integration and ancillary services, hedge value,	Docket No. UM 1716 Order No. 17-357 Docket No. UM 1912 (Portland General Electric) Docket No. UM 1910 (Pacific Power) Docket No. UM 1911 (Idaho Power)

	environmental compliance, and security, reliability, and reserves) for calculating an hourly avoided cost load profile for each year of the life of a solar PV system. The order outlines the methodology for valuing nine out of the eleven elements, resolving to value RPS compliance and grid services at a later date. To initiate Phase II of the proceeding, the PUC directed the utilities to make their RVOS filings in utility-specific dockets. The utility calculations resulted in the following RVOS values: Pacificorp - $49.72 to $52.00 per MWh, Idaho Power - $45.01 per MWh (utility-scale), and Portland General Electric - $49.88 per MWh. These calculations do not include values for RPS compliance or grid services. The PUC issued a scheduling memorandum in January 2018, establishing the schedule for the next seven months, with a target date of July 2018 for final approval of the RVOS calculations. The PUC conducted an examination of witnesses in each of the utility-specific dockets in June 2018 regarding the RVOS calculations, and parties submitted briefs in August 2018.	
SC	In May 2018, the South Carolina Legislature's Public Utilities Review Committee tasked the Energy Office with leading a stakeholder process to look broadly at the future of electricity in the state within the context of Act 236 and with a particular focus on renewable energy. Among the topics under consideration is value of solar/DER methodology. Approximately 50 stakeholders are part of the process, and seven meetings have taken place since June 2018. The October 2018 meeting focused on energy storage and also included a presentation from E3, which prepared the state's previous value of solar study.	Stakeholder Group Website
UT	In November 2016, Rocky Mountain Power (RMP) proposed a new tariff for net metering customers. In a settlement agreement approved in September 2017, parties agreed that a separate proceeding will be initiated to determine a new export compensation rate for DG systems. Participating parties will be able to present "evidence addressing reasonably quantifiable costs or benefits or other considerations they deem relevant." The Public Service Commission will determine the study period length for quantifying and modeling credit rate components. A new docket for the Export Credit Proceeding was opened in December 2017. A load research study workshop was held in January 2018, and RMP filed its proposed load research study plan in February 2018. The Commission issued an order on Phase I of the proceeding in May 2018. The study period will run for 12 months, beginning no later than January 1, 2019. Parties disagreed on the type and scope of data to be collected through the study. Based on parties' criticisms and recommendations, the Commission directed RMP to increase its sample size to accommodate the separate study of residential and commercial customers and to select new samples from both classes that give each member of the class an equal chance of being selected, rather than mixing an existing sample drawn from a subset of the class with a new sample from the entire class. The Commission also directed RMP to collect production, export, and import data from existing net metering	Docket No. 14-035-114 Docket No. 17-035-61 Order Approving Settlement Stipulation Scheduling Order RMP Proposed Load Study Plan Order on Review

	customers. Vote Solar, Utah Clean Energy, and Vivint Solar filed a petition for rehearing in June on certain sample design and data collection issues. The Commission addressed the petition and issued an order on review in July 2018. The order clarifies the Commission's Phase I order, but does not modify it. Rocky Mountain Power gave an update on Phase II of the proceeding in early October 2018. In late November 2018, several solar advocates filed a joint motion to amend the procedural schedule to hold at least two additional technical conferences in the first half of 2019. The parties also requested that the Commission agree to accept no-cost technical assistance from relevant experts at multiple national laboratories.	
WA	In April 2018, the Utilities and Transportation Commission Staff filed draft distribution system planning rules. The proposed rules require utilities to file forecasts of customer-owned DERs on the utility system and to identify potential tariffs and rate designs that compensate customers for the value of their DERs and provide accurate price signals for acquiring and using these resources. The Commission has held a series of stakeholder meetings and filed several Notices of Opportunity to File Comments, most recently in November 2018.	Docket No. U-161024 Distribution Planning Draft Rules

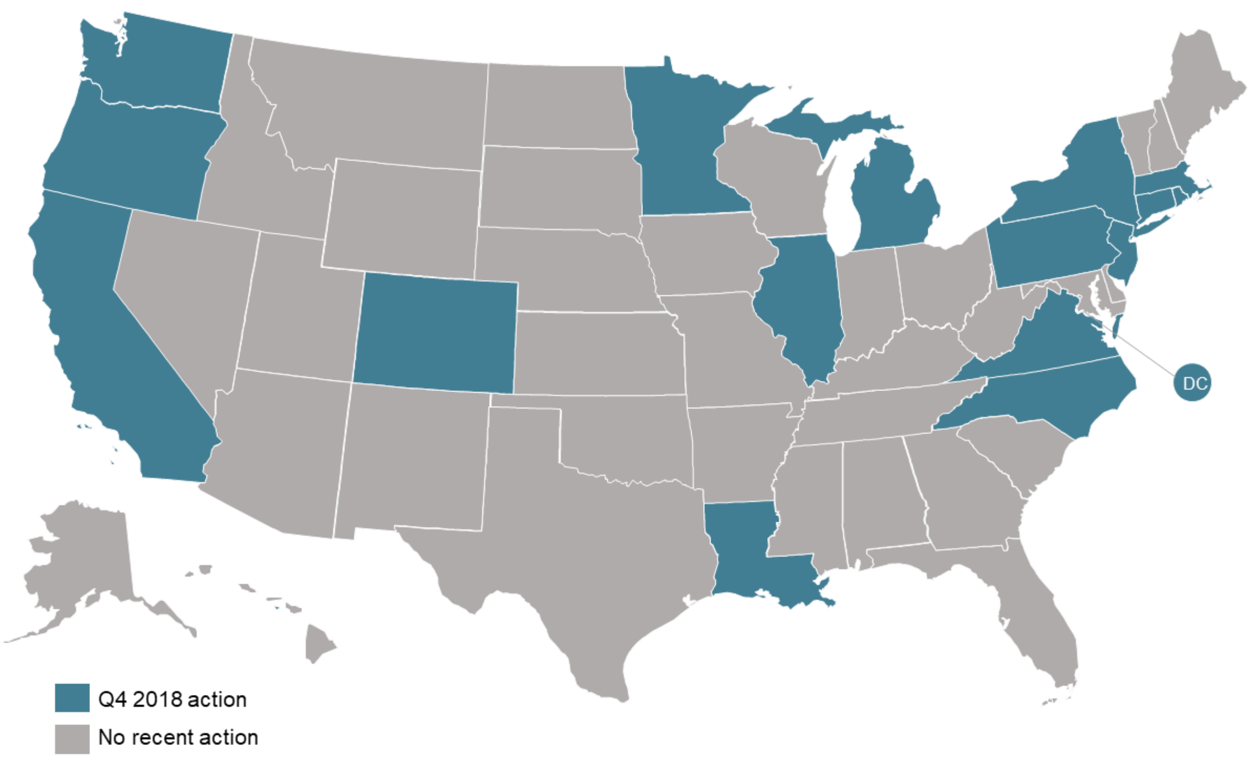
COMMUNITY SOLAR POLICY

Key Takeaways:

- In Q4 2018, 16 states and DC considered changes to state community solar policy or community solar programs arising from state policy.
- New York's Solar for All program launched in Q4 2018, providing 9 MW of community solar to eligible low to moderate income customers at no cost.
- Regulators in California, Illinois, Minnesota, and New York issued orders on topics related to community solar programs during Q4 2018.

Community solar programs offer the potential to expand solar access to a greater number of individuals and businesses. The community solar model often meets the needs of customers who desire access to solar energy, but may not have the physical, financial, or situational ability to install rooftop panels on their residence or workplace. Community solar facilities also have the potential to utilize economies of scale, making the cost of these projects typically cheaper than that of rooftop solar.

Figure 32. Action on Community Solar Policy (Q4 2018)



In the final quarter of 2018, state regulators published several orders related to community solar program implementation. The California Public Utilities Commission (CPUC) issued an order regarding a community solar program for disadvantaged communities in the San Joaquin Valley, while another order from the CPUC clarified issues related to the Community Solar

Green Tariff program. As a part of the program, eligible customers may receive a 20% bill discount, and 25% of subscriptions are reserved for low to moderate income (LMI) customers.

The New York Public Service Commission (PSC) issued multiple decisions related to community solar during Q4 2018. The Commission announced that New York's Solar for All program will provide 9 MW of community solar subscriptions program to eligible LMI customers at no cost. The state's investor-owned utilities also filed a tariff for the Bill Discount Pledge program, which allows LMI customers to receive free community solar subscriptions in lieu of bill discounts that have traditionally been offered to LMI customers. The PSC staff also published a paper regarding the Market Transition Credit (MTC) that is currently offered to community solar customers. The MTC is an additional value added to New York's value stack compensation framework.

Box 7. What is Community Solar?

Community solar refers to a voluntary program for customers where a solar PV system "provides power and/or financial benefits to, or is owned by, multiple community members."[9] While some community solar projects share similarities with utility-scale solar projects (e.g., large in size, located off-site from consumption, ground-mounted systems, utility-side of the meter), this report, which focuses on distributed solar, includes policy actions related to these programs because they are community-focused and provide residential customers a way to invest in solar energy. Community solar programs included in this report may be administered by a utility or third party, but are enabled or mandated under state rules encouraging the development of such programs. Community solar is also sometimes referred to as "shared solar," or "solar gardens." Policies that enable these programs include "virtual" or "remote" net metering, in which net metering is expanded to apply to customers who have invested in an offsite PV system.

Community solar program rules remained under consideration in New Jersey and the City of New Orleans during Q4 2018. While the programs take different approaches to participant credit rates, they both include provisions to encourage low-income customer participation. The New Orleans City Council's Utilities Committee approved New Orleans' community solar rules in December 2018, while the New Jersey Board of Public Utilities approved the state's community solar pilot program rules in January 2019.

Table 12. Updates on Community Solar Policies (Q4 2018)

State	Description	Source
CA	A.B. 2672 of 2014 required the California Public Utilities Commission (CPUC) to initiate a proceeding to identify disadvantaged communities in the San Joaquin Valley and analyze the economic feasibility of alternative energy options that would increase access to affordable energy. Phase I of the proceeding identified disadvantaged communities. Phase II will address the authorization and implementation of pilot projects intended to provide cleaner and more affordable energy for some of the disadvantaged communities identified in Phase I. The CPUC is considering community solar as a possible pilot project. In a December 2017 Scoping Ruling, the CPUC directed parties to answer a series of questions related to a potential community solar pilot project. Parties filed their responses to the questions during Q1 2018, and Southern California Edison stated its interest in developing community solar pilot projects. The CPUC hosted a status conference and an all-party workshop in April 2018 to discuss the pilot proposals submitted by the utilities. A ruling issued in June 2018 required the parties to develop a joint proposal addressing economic feasibility standards for the proposed pilot projects, and to present the proposal at a workshop in late July. Following that workshop, an August ruling requested comments on eight questions drawn from workshop discussions related to the pilot projects. A proposed decision filed in November 2018 authorizes the proposed pilot projects, which include an expansion of the Community Solar Green Tariff program, which was authorized under Docket No. R-14-07-002 (see above). A final decision issued December 13, 2018, approved the pilot projects.	Docket No. R15-03-010 Final Decision
	An open docket is currently examining the future of net metering in California. One of the issues addressed in that docket is DG alternatives in disadvantaged communities. The California Public Utilities Commission approved an Alternative Decision in June 2018, which established three new programs for disadvantaged communities, one of which is a Community Solar Green Tariff program with an aggregate cap of 41 MW. The Commission issued a proposed decision in September 2018, clarifying several issues related to the Community Solar Green Tariff program (the issues include which tariff would serve as the baseline from which discounts are applied for the program, the definition of "permission to operate" under the program, and the process for selection of a program administrator). The Commission issued a final decision on the matter in October 2018.	Docket No. R14-07-002 Proposed Decision Final Decision
	In late September 2018, Southern California Edison filed an application for approval of five new Green Energy Programs, which will replace the existing Green Tariff Shared Renewables Program in 2021. In its application, Southern California Edison cited several challenges associated with the Green Tariff Shared Renewables Program, which has hampered its adoption by customers. The proposed programs aim to avoid these challenges. One of the proposed programs is a New Community Renewables Program. One or more large business or government customers in the community must sponsor the facility and commit to purchase a minimum of 80 percent of the facility's output, with the remainder made available to residential and small business	Docket No. A-18-09-015

	customers in the community. Numerous parties filed protests to the application. A prehearing conference took place in December 2018.	
CO	The Colorado Public Utilities Commission opened this proceeding in October 2017 to consider changes to rules concerning the Renewable Energy Standard, as well as net metering, electric resource planning, acquisitions from qualifying facilities, and distribution system planning. A specific topic to be addressed is the competitive bidding process for community solar gardens and the rules calculating bill credits for certain customer classes involved in these projects. A scoping workshop was held in early April 2018 to create working groups to address the various issues under consideration. Several parties proposed new rules to provide incentives for low-income residents to participate in community solar programs. In early September 2018, many parties submitted final comments and suggested rule changes. The joint solar parties suggested allowing community solar garden interconnections outside of utility resource plans and to allow community solar participants to donate unused credits to low-income customers. Energy Outreach Colorado, a low-income energy advocacy organization, also supported the latter change. The Colorado Energy Office supported allowing transfer of community solar credits contingent on processes being created to qualify and approve third-party administrators (which would distribute the credits). Xcel Energy's comments generally opposed these proposed changes, arguing that current community solar and low-income participation programs are sufficient, the utility suggested that additional low-income programs could be proposed as part of the normal Renewable Energy Standard resource planning process. The proceeding was closed on October 31, 2018; the PUC indicated it is considering issuing a Notice of Proposed Rulemaking related to the suggestions from this docket.	Docket No. 17M-0694E
CT	In May 2018, Connecticut's Governor signed S.B. 9 into law. The bill increases the state's renewable portfolio standard, while making significant changes to net metering and shared clean energy programs. The bill directs the Department of Energy and Environmental Protection (DEEP) to initiate a proceeding by September 2018 to develop program requirements and tariff proposals for shared clean energy facilities. By July 2019, the Department is to submit these requirements and tariffs to the Public Utilities Regulatory Authority (PURA) for approval. These program requirements are to include the subscriber credit rates, consumer protections for subscribers, and a maximum 20-year term length. Subscribers are to be limited to low and moderate income customers, small business customers, state or municipal customers, commercial customers, and residential customers who can demonstrate that they are unable to utilize the net metering successor tariff to be developed. At least 10% of the total capacity of each shared clean energy facility is to be reserved for low-income customers, in addition to a requirement that at least 10% of each facility's capacity must be reserved for low or moderate income customers or low-income service organizations. DEEP is allowed to provide preference for projects that serve low-income customers or benefit customers in environmental justice communities, and DEEP is also allowed to create incentives and financing mechanisms for low-income customers and limit commercial customer participation in each facility to 50%. The PURA opened a proceeding in June 2018 to review the requirements of	Docket No. 18-06-15 S.B. 9

	the new legislation and develop a strategy and procedural roadmap for implementation. Technical meetings were held in July and August 2018. The tentative schedule has the DEEP submitting program requirements and tariff proposals by July 2019.	
DC	The Public Service Commission is examining interconnection rules in Formal Case No. 1050. A September 2018 order in this rulemaking established a Net Energy Metering Working Group to address system upgrade costs related to the interconnection of community renewable energy facilities (CREFs), review the Commission's current net metering rules, and propose CREF-specific rules changes for the Commission's consideration. Another decision, issued later in September in Formal Case No. 1130 additionally tasked the Net Energy Metering Working Group with considering whether the system capacity limit should be increased beyond 100% of a customer's historical usage. The working group met in early December 2018.	Formal Case No. 1050 Order No. 19676 Order No. 19692
IL	The Future Energy Jobs Act, which went into effect in June 2017, created a community renewable generation program. In September 2017, the Illinois Power Agency (IPA) published its Long-Term Renewable Resources Procurement Draft Plan, which sets out details of the community solar program. Community solar projects are included in the adjustable block purchasing program for renewable resources and community solar subscribers are eligible for net metering, with IOUs being required to submit community solar net metering tariffs by September 27, 2017. The plan also describes a low-income community solar incentive plan that provides extra funding of \$69.23-\$129.56 per REC (depending on utility and total capacity of the project) for community solar projects subscribed to by low-income customers. The plan also includes a competitive-bid procurement process for low-income community solar pilot projects, which will be a separate program from the incentive program. A final version of the plan was filed in December 2017, and the plan was adopted in early April 2018. In May 2018, the Commission issued an amendatory order, slightly changing the original order to allow the IPA to investigate possible cost savings from co-location of projects of total size larger than 2 MW and to include such projects in REC pricing tiers. In June 2018, Commonwealth Edison appealed the Commission's order to the Appellate Court of Illinois, Second Judicial District. In August 2018, the IPA published the final version of the long-term plan incorporating the changes made by the Commission. In December 2018, Commission Staff submitted a report to the Commission on the standards, process, and timing for review of the Adjustable Block Program and Illinois Solar for All batch contract/confirmation approval.	Docket No. 17-0392 IPA Long-Term Renewable Resources Procurement Plan Final Order
	In August 2018, the Illinois Power Agency filed a petition for approval of its Supplemental Funding Plan for the Illinois Solar for All program, a low-income solar incentive program aimed at encouraging development of distributed solar and community solar projects that will benefit low-income residents. An order approving the plan was issued in October 2018. Stakeholder engagements for the program began in November 2018, with the program launch anticipated to occur in the spring of 2019.	Docket No. 18-1457 Solar for All Program Website

	The Future Energy Jobs Act, enacted in December 2016, calls for a transition to a net metering successor once the state's 5% aggregate cap is reached. The legislation also creates a rebate program for non-residential and community solar systems that utilize smart inverters. The rebate is equal to $250 per kW of system capacity. Customers receiving the smart inverter rebate are not permitted to net meter. Instead, these customers will be credited for hourly net exported energy at a rate equal to the hourly energy charge and purchased electricity adjustment factor. The utilities will be able to operate and control the smart inverters installed on participating customers' projects. Commonwealth Edison (ComEd) filed its proposal to implement this program in April 2018, and parties filed testimony in July. The joint solar parties expressed concern that ComEd would be able to revise the smart inverters' required functions and settings without regulatory approval after receipt of the rebate. The solar parties also recommended that Volt-VAR with reactive power priority be compensated as a grid service beyond the rebate value, that solar plus storage projects be eligible for the rebate, and that third parties be allowed to provide smart inverter communication devices. ComEd proposed an automatic adjustment clause tariff, Rider DG Rebate Adjustment, to recover rebate costs through a per-kWh surcharge. In late November 2018, the Commission issued a final order approving ComEd's proposal.	Docket No. 18-0753 Future Energy Jobs Act
	The Future Energy Jobs Act, enacted in December 2016, calls for a transition to a net metering successor once the state's 5% aggregate cap is reached. The legislation also creates a rebate program for non-residential and community solar systems that utilize smart inverters. The rebate is equal to $250 per kW of system capacity. Customers receiving the smart inverter rebate are not permitted to net meter. Instead, these customers will be credited for hourly net exported energy at a rate equal to the hourly energy charge and purchased electricity adjustment factor. The utilities will be able to operate and control the smart inverters installed on participating customers' projects. Ameren filed its proposal to implement this program in April 2018, and parties filed testimony in July. The joint solar parties expressed concern that Ameren would be able to revise the smart inverters' required functions and settings without regulatory approval after receipt of the rebate. The solar parties also recommended that Volt-VAR with reactive power priority be compensated as a grid service beyond the rebate value, that solar plus storage projects be eligible for the rebate, and that third parties be allowed to provide smart inverter communication devices. Ameren proposed an automatic adjustment clause tariff, Rider CGC – Customer Generation Charge, to recover rebate costs through a monthly fixed charge. In early November 2018, the Commission issued a final order approving Ameren's proposal. In early December 2018, the Attorney General of Illinois filed a petition for rehearing, arguing that Ameren's proposal should be aligned with ComEd's Docket No. 18-0753) and that both programs should incorporate a non-bypassable volumetric charge to ensure that program participants pay their fair share of program costs. Later in December, the Commission denied the petition for rehearing.	Docket No. 18-0537 Future Energy Jobs Act
LA	In December 2015, the Louisiana Public Service Commission (PSC) initiated a two-phase rulemaking proceeding to I) modify the state's	Docket No. R-33929

	current net metering rule once a utility reaches the net metering aggregate cap, and II) examine appropriate changes to solar policies in Louisiana. In November 2017, as part of Phase II of the proceeding, the PSC staff published proposed modified net metering rules. The proposed rules also allow for community DG facilities up to 300 kW, which will be compensated at the avoided cost rate for any excess generation sold to the utility. Comments were filed in January 2018, and an open session was held in February 2018. The Commission Staff filed final proposed rules in January 2019, which include most of the same provisions as the previous version of proposed rules.	Proposed Modified Rules
	In June 2018, the New Orleans City Council opened a rulemaking proceeding to establish rules for community solar projects. The City Council's Utility Advisors also published a white paper on community solar and shared DERs in June. The Advisors recommend that: (1) both utilities and third parties be allowed to develop community solar projects, (2) each project must have at least three participants, (3) each participants may be allowed to subscribe to no more than 40% of the project capacity, (4) 30% of program capacity be reserved for facilities providing at least 10% of output to low-income subscribers, (5) no minimum subscription amount be applied to low-income customers, (6) solar, solar plus storage, and other DERs be considered; (7) projects be limited to 2 MW; (8) an aggregate program cap of 5% of the utility's annual peak MW (approximately 55 MW) be established for the first three years; (9) bills credits be set at a rate equal to the avoided capacity, energy, and other directly quantifiable costs; and (10) RECs should be owned by the subscribers. The white paper includes additional recommendations of the Advisors. An advisors' report with revised recommendations was filed, and the Utility, Cable, Telecommunications, and Technology Committee passed a resolution establishing rules in December 2018. The revised rules passed in December require 50% of the program capacity to be reserved for community solar facilities providing at least 30% of their output to low-income subscribers. The rules include the aggregate cap, system size limit, and participant credit rates (a rate reflecting avoided energy and capacity costs) as proposed. The Committee approved an individual participation limit of 100% of the customer's annual baseline energy use.	City Council Docket No. UD-18-03 Resolution R-18-538
MA	In January 2017, the Department of Energy Resources (DOER) released its final program design for the solar incentive program that will succeed the SREC II Program. The new program, called Solar Massachusetts Renewable Target (SMART), is a 1,600 MW declining block program. Small projects will receive a 10-year fixed price term, and large projects will receive a 20-year fixed price term. The maximum eligible project size is 5 MW. Base incentive rates vary by project size, and adders are included for community solar projects ($0.03) and low-income community solar projects ($0.06). In August 2017, DOER published the final version of the regulation. The SMART program also creates a new compensation option - the Alternative On-Bill Credit (AOBC) - for incentive recipients in addition to net metering and a qualifying facility buy-all, sell-all arrangement. This new on-bill crediting option offers a single rate for all facilities, allows the transfer of credits to off-takers without net metering, and does not	DOER Next Solar Incentive Landing Page 225 CMR 20.00 Docket No. 17-140 Order Approving Model SMART Provision

have an aggregate cap or public entity system size cap. The AOBC is expected to be a useful mechanism for the development of community shared solar facilities. In September 2017, the state's distribution utilities jointly filed a model SMART tariff. The AOBC option provides a credit rate for generation at the applicable Basic Service Rate. The AOBC allows for the transfer of credits, but limits these transfers to each recipient's annual kWh consumption. The Department of Public Utilities (DPU) issued a final order in September 2018, approving a SMART program tariff. The order sets the AOBC credit rate at the basic service rate, although the DPU noted that this does not indicate the Department's position regarding conducting or directing a value of solar study. The DPU declined to set a separate AOBC credit rate for low-income customers. The DPU found that there is not sufficient evidence to implement an AOBC usage cap and directed stakeholders to determine whether a cap may be appropriate in the future and the necessary transfer limit threshold per customer. The order also allows AOBC allocation to two decimal points. In late November 2018, the DPU directed each distribution company to file company-specific SMART provisions for review. The companies filed their SMART tariffs in early December 2018. The DPU requested certain modifications to the tariffs, and the companies refiled their tariffs later in December.	
In March 2017, the Department of Public Utilities (DPU) opened an inquiry into the current standards and procedures for seeking exceptions to net metering regulations, specifically relating to the Single Parcel Rule that requires net metering systems to be associated with a single parcel of land and interconnected at a single point, behind a single meter, as well as the Subdivision Rule, which requires customers seeking to net meter on a parcel of land subdivided after January 1, 2010 to file a petition with the DPU demonstrating that the subdivision was not created for the purpose of creating multiple parcels to support multiple net metering facilities. Also under consideration is the procedure for net metering credit allocation, where host customers may designate offtakers who are customers of the same distribution utility and located within the same load zone. A technical conference was held in May 2017, and comments were accepted through July 27th. The DPU issued an order in late May 2018, which addresses these credit allocation procedures. In the order, the DPU requires host customers designating offtakers to include an Excel spreadsheet detailing net metering credit transfers after July 31, 2018, but allows distribution companies to make exceptions to this rule for those without the ability to use or access Excel. The DPU also established a two-decimal place limit for credit allocation beginning July 31, 2018 (there was previously no decimal limit). The order also allows distribution companies to issue one-time refund payments to remedy net metering credit allocation delay if (1) the accumulation of credits on the customer's account was outside of the customer's control, net metering credit were accumulated for at least three billing period following authorization to interconnect, and the host customer agrees to the one-time refund to remedy the multi-month credit allocation delay. In June 2018, The Coalition for Community Solar Access filed a motion for reconsideration of the two-decimal place limitation. In early November 2018, the Commission denied CCSA's motion for reconsideration.	Docket No. 17-22 Order Announcing Net Metering Blanket Exceptions and Streamlining Process

MI	In October 2018, the Michigan Public Service Commission issued orders in Dockets U-18351 and U-18352 (which primarily concern green tariff programs proposed by Consumers Energy Company and DTE Electric, respectively) directing Commission Staff to conduct a stakeholder workgroup to examine opportunities for and barriers to third-party community energy projects and integration of these projects into utility planning and procurement processes. A workgroup meeting took place on January 24, 2019, and additional meetings are scheduled for March, May, and July 2019.	Third Party Community Energy Projects Workgroup
MN	Minnesota has an ongoing proceeding related to community solar gardens. A September 2016 decision transitioned the credit rates for subscribers from the retail rate to the value of solar rate. The Commission also called on the Department of Commerce to comment on whether the credit rate should be adjusted with a positive or negative adder for seven categories, some location-specific and others customer-specific. The Department of Commerce filed its recommendations in March 2017, suggesting that only residential subscribers receive an adder to make community solar more attractive. The Commission issued an order related to the proposal in December 2017, declining to approve or deny the Department's proposal. Instead, the Commission asked Xcel Energy for an analysis of the potential rate impact of the Department's proposal, and how a solar carve-out for community solar projects would be implemented and enforced. Xcel Energy provided its analysis in February 2018. After receiving comments and reply comments, the Commission scheduled a meeting for October 11th to discuss Xcel's analysis. The Commission then issued an order in November 2018, approving a $0.015/kWh adder to the value of solar rate for residential subscribers. The adder will be available for a two-year term as a pilot, and available to projects with a 2019 or 2020 value of solar vintage year. Also in this proceeding, Xcel filed its 2019 Value of Solar rate in August 2018. The proposed rate is a decrease from the rate used in previous years and would negate the adders applied by the Commission's November order. The Commission accepted comments on the rate in December 2018. Later in December, Xcel filed for approval of its proposed community solar tariffs. On January 4, 2019, the Commission opened the comment period on Xcel's proposed tariff changes; initial comments will be accepted through February 4, 2019, and reply comments through February 22, 2019.	Docket No. 13-867
	H.B. 3232, signed into law in May 2018, increased the size limit for Xcel's Solar*Rewards incentive program from 20 kW to 40 kW. Community solar projects that are below this size threshold are also eligible for the incentive. In June 2018, Xcel filed tariff revisions for its Solar*Rewards program in a separate docket (No. 18-381) to incorporate the changes. The Commission received comments on Xcel's tariff, revealing a possible discrepancy in the way the tariff would treat existing customers choosing to increase their system's size. Solar companies argued that the 40 kW cap is on the portion of the system that is eligible for the incentive. The companies suggested that larger systems should be allowed to be installed, but only receive the incentive on the first 40 kW. The Commission issued an order in early November 2018, which agreed with the solar companies.	H.B. 3232 Docket No. 18-381

NC	H.B. 589, enacted in July 2017, authorizes and establishes rules for community solar. The proposed legislation directs Duke Energy Carolinas and Duke Energy Progress to file plans for community solar programs limited to 20 MW. Each community solar facility may be up to 5 MW, and must have at least five subscribers. A single subscriber may not have more than a 40% interest in the facility, each subscription must be at least 200 W, and a participant may only subscribe up to 100% of their maximum annual peak demand. Community solar facilities must be located in the offering utility's service territory, and participants must be located in the same county or contiguous county to the community solar facility (exceptions for distances up to 75 miles may be granted by the Utilities Commission if it is in the public interest). Participants will be credited at the utility's avoided cost rate, and the program must hold non-participating customers harmless. Subscribers must also be offered the option to own the RECs associated with the energy produced by the community solar facility. In late August 2017, the North Carolina Utilities Commission (NCUC) initiated a rulemaking to implement the legislation, and the NCUC adopted Rule R8-72 in December 2017. In January 2018, Duke Energy Carolinas and Duke Energy Progress filed their joint petition for approval of a community solar program. The program plans include an upfront payment for participants (estimated around $500), who will be credited at the applicable avoided cost rate, following the methodology approved by the Commission at the time the companies open the program to participants. After a round of comments, Duke filed a revised program plan in June 2018. The revised tariffs reflect a move to a subscription model and the inclusion of monthly charges and credits on the customer bill, as well as a modified procedure for customers to subscribe to the program. The revised tariffs also increase the size of a block from 220 Watts to 1 kW and clarify that monthly subscription credits will be variable based on the actual production of the facility. Various parties filed comments and reply comments during Q2 and Q3 2018.	H.B. 589 Docket E-100 Sub 155 (Rule Development) Order and Rule R8-72 Docket E-2 Sub 1169 (Utility Proposals) Proposed Community Solar Program Plan Revised Community Solar Program Plan
NJ	A.B. 3723, signed into law in May 2018, creates a Community Solar Energy Pilot Program. The bill directs the Board of Public Utilities to establish a capacity limit for individual projects to a maximum of 5 MW, an annual aggregate capacity limit for the pilot program, geographic limitations for projects and participants, a minimum number of participants per project, the participant bill credit rate, standards to limit land use impact of projects, ways to provide access to low and moderate income customers, standards to ensure residential and commercial customers may participate, interconnection standards, and provisions to minimize distribution system impacts. The bill also authorizes the Board to restrict projects to those located on brownfields, landfills, areas designated in need of redevelopment, in underserved communities, or on commercial rooftops. Within 3 years of adoption of final program rules, the pilot program is to be converted to a permanent program. At this point, the Board is to adopt rules for the permanent program and standards for projects owned by utilities, special purpose entities, and non-profits. These rules are also to limit the project size limit to a maximum of 5 MW, establish a goal of at least 50 MW in aggregate community solar capacity per year, establish a method for	A.B. 3723 S.B. 2314 Community Solar Energy Pilot Program Community Solar Energy Pilot Program Rule Proposal

	determining participant bill credit rates, establish and require transferability, portability, and buy-out provisions for participants. The Board formed a community solar stakeholder group, with information available on its website. In September 2018, the Board of Public Utilities released proposed community solar pilot program rules, which were published in the New Jersey Register in early October. The proposed rules include retail rate bill credits, a 40% low-to-moderate income customer carve-out, and a maximum program cap of 75 MW for year 1 and a minimum of 75 MW of program capacity for years 2 and 3. In November 2018, a draft of the Community Solar Program Application form, Subscriber Organization Registration form, and Subscriber Disclosure form were published for public comment. Comments were accepted until December 21, 2018. The Board of Public Utilities approved the pilot program rules in January 2019.	
	A.B. 3723, enacted in May 2018, directs the Board of Public Utilities (BPU) to develop a process for public entities to serve as host customers for remote net metering projects. Public entities hosting remote net metering projects may allocate net metering credits to other public entities in the same service territory. The BPU Staff received stakeholder input and developed recommendations for remote net metering rules. The Staff recommend limiting the size of a host customer's facility to the annual total average usage of the host customer. The Staff also recommend that the credit rate for remote net metering projects be roughly equal to the generation, transmission, and distribution value of the energy produced and offset all variable charges except the system benefits charge. The Staff recommend that excess generation be carried over from month to month over an annual period. In September 2018, the BPU adopted the Staff recommendations and directed the Staff to initiate a rulemaking process to incorporate the remote net metering provisions into the state's administrative code.	BPU Order (Docket No. QO018070697) A.B. 3723 S.B. 2314
NY	A.B. 10474 allows any utility customer who begins net metering before December 31, 2021 to continue net metering under current rules for the life of the generating equipment. It also requires the Public Service Commission to develop a new value of DER methodology that includes various social, economic, and environmental benefits. It would also increase the system size limit for non-residential net-metered systems from 2 MW to 5 MW. The changes included in the bill also apply to customers participating in community distributed generation systems. This bill passed the Assembly in June 2018, but died at the end of the 2017-2018 legislative session.	A.B. 10474
	In March 2017, the Public Service Commission (PSC) issued an order addressing the steps to transition from traditional net metering to a Value of Distributed Energy Resources (VDER) tariff. In March 2017, community solar, remote net-metered projects, and large distributed energy projects began to be compensated through the Phase I Value Stack tariff that includes energy (based on LMP), capacity, environmental, and demand reduction credits. Community distributed generation (CDG) projects are eligible for market transition credits (MTCs) that decline as certain thresholds of installed capacity (tranches) are reached.	Docket No. 15-02703/15-E-0751 Docket No. 15-E-0082 Matter No. 17-01278 NYSERDA VDER Resources

An organizational conference on Phase II of the VDER proceeding was held in May 2017. Phase II includes discussion of several topics, including improvements and modifications to the value stack (including components related to the bulk system, distribution system, and societal values). In June 2017, the PSC established three working groups: one each to cover the value stack, rate design, and low to moderate income issues. In December 2017, the Commission Staff published a report on the low-income community DG proposal, which includes the positions of the intervenors and the staff's analysis on (1) the interzonal credit, which would provide benefits to low-income customers from projects interconnected in other load zones, (2) the bill discount pledge program, providing a direct incentive to subsidize subscription prices through utility low-income funds, (3) the role of NYSERDA programs, (4) the loss reserve, and (5) environmental justice location incentives. In May 2018, PSC Staff proposed to reduce the subscription size necessary for participation in Community Distributed Generation from 1000 kWh to 500 kWh. In September 2018, the Commission issued an order keeping the minimum subscription size at 1000 kWh and making interzonal crediting available for CDG projects. Community distributed generation (CDG) projects are eligible for market transition credits (MTCs) that decline as certain thresholds of installed capacity (tranches) are reached. In July 2018, Commission Staff released a white paper with recommendations for compensation of CDG projects beyond current tranches. Staff recommendations differed for different utility service territories; Staff recommended a reduction in MTC rates for National Grid, NYSEG, and RG&E service territories for new Tranches 5 and 6 (3 cent per kWh and 2.5 cent per kWh, respectively), an increase in MTC rates for Con Edison service territory for Tranches 1, 2, and 3, and a reduction in MTC rates and reallocation of credit funding responsibility from utility ratepayer funds to state funds for Orange and Rockland and Central Hudson service territories. Technically, new CDG projects in Orange and Rockland and Central Hudson territory would stop receiving MTCs, but would have those credits replaced with state incentives equivalent to the Tranche 5 and 6 levels for the other territories, with some of the incentive amount coming from the Value Stack mechanism.	
This proceeding was originally opened in 2015 to establish a Community Distributed Generation (CDG) program, with Phase I of that program taking place between October 19, 2015, and April 30, 2016. Although many CDG projects were initiated under this program, no projects were undertaken in the low-income category, which had been an area of priority for the program. In June 2017, a working group was established to address low and moderate income (LMI) customer programs under Phase II of the Value of Distributed Energy Resources (VDER) process. One topic addressed by this working group was LMI participation in CDG programs. In December 2017, the Public Service Commission Staff issued a report proposing several measures to increase LMI participation in CDG projects, including the creation of a bill discount pledge program, income verification services for CDG project customers, and creation of a loss reserve fund to support LMI-	Docket No. 15-00348/15-E-0082

	focused CDG projects. In July 2018, the Commission issued an order approving the three programs recommended in the Staff report. In August 2018, Sandy Hollow Power Company filed a petition asking the Commission to enable VDER credits for CDG projects to be given to the utility rather than the customer, in order to facilitate participation in CDG projects by low-income customers, for whom the small credit amounts and administrative difficulties associated with collecting the credit may inhibit participation in CDG projects. In July 2018, PSC Staff published a white paper proposing several changes to CDG rules. In September 2018, the PSC issued an order based on the staff white paper; the order makes all proposed VDER-eligible technologies eligible for CDG, allows interzonal crediting for CDG projects using Value Stack compensation, and retains the 1,000 kWh minimum subscription size for CDG. The July white paper also proposed expanding incentives for CDG in utility territories where existing incentives have been fully subscribed, and in October 2018, the PSC issued a request for comments on this proposal. In November 2018, several environmental organizations filed comments supporting the proposal. In early December, National Grid reported that Tranche 1 of its CDG program was filled. In December, the joint utilities filed an implementation plan for the Bill Discount Pledge Program to assist LMI customers in receiving CDG program subscriptions. Under the Bill Discount Pledge Program, an LMI customer may choose to use the bill discount toward purchasing shares of CDG, which will in turn lower their utility bills. The utility will pay the CDG owner for the LMI customer's subscription.	
OR	S.B. 1547 of 2016 established a community solar program for the state. The legislation set basic criteria and directed the Public Utility Commission (PUC) to establish rules for the program, which must require utilities to enter into 20-year power purchase agreements with certified projects and incentivize customers to participate while minimizing cost shifts and financial burdens. The PUC adopted community solar rules in June 2017. While the rules provide guidance on many aspects on community solar, certain issues will not be fully addressed until the Program Implementation Manual is developed and adopted by the PUC. The PUC is also continuing to develop the Resource Value of Solar (see DG Valuation section), which will be the bill credit basis for community solar participants. There are multiple implementation actions that must be taken before the community solar program is launched, including selection of a third-party administrator for the program. In September 2017, the PUC approved the Staff's recommendation to commence a stakeholder process to identify and scope all of the implementation actions that must be taken. The PUC hosted a community solar workshop in October 2017, where the remaining implementation actions were discussed. In February 2018, the PUC issued an order accepting the staff's recommendation to continue investigations directly related to rulemaking in the existing docket, but also open a new docket to explore program implementation. The PUC issued an order in the new docket in March 2018 stating its interest in adopting a temporary alternative credit rate structure while the RVOS is continuing to be developed, and directed the staff to present no less than two proposals in April. The Staff presented three options: a simple retail rate option,	S.B. 1547 Docket No. AR 603 (Rulemaking) Docket No. UM 1930 (Implementation) Order No. 18 088 Order No. 18 177

	an adjusted retail rate option, and an adjusted RVOS option. Both of the “adjusted” rates would be adjusted by applying several adjustment factors to reflect the guiding principles developed by the Staff, which include simplicity, accessibility, minimization of cost-shifting, locational value, and ease of transition to an RVOS-based rate. In May 2018, the Commission issued an order accepting the Staff's simple retail rate proposal as an interim bill credit rate for the first 25% of each utility's initial capacity tier. The Commission remains undecided on the credit rate for the remaining 75% of the initial capacity tier. The Staff filed status update reports in July, September, and November 2018. In the most recent update report, the Staff discussed the competitive solicitation for a program administrator and cost recovery for program start-up costs.	
PA	In July 2018, the Pennsylvania Department of Environmental Protection published a draft for public review of its Finding Pennsylvania's Solar Future report. The draft report recommends that customer-generators have the opportunity to use virtual net metering and that barriers to the deployment of community solar be identified and removed. Comments on the draft were accepted until mid-August 2018, and the final plan was published in November 2018. The final report includes the same recommendations as the draft regarding community solar and virtual net metering.	Finding Pennsylvania's Solar Future
RI	In December 2018, Energy Development Partners (EDP) LLC filed a petition before the Public Utilities Commission for a declaratory judgment seeking a determination that for a net metering financing arrangement with a public entity the requirement that the "net metering resource is located on property owned or controlled by the public entity" is satisfied when the public entity has an irrevocable license over the property. Site control must be satisfied before a third party owned system can qualify as an eligible net metering system. In this particular case, EDP is unable to provide a ground lease or an easement to the public entity, given restrictions in place on the land, but it can grant an irrevocable license. EDP is seeking declaratory judgement that an irrevocable license satisfies the definition of "property owned or controlled by the public entity" under the net metering act.	Docket No. 4917
VA	In January 2018, Dominion Virginia Energy filed a tariff to establish a community solar pilot program, pursuant to legislation enacted in 2017. Dominion would solicit PPAs for solar generation from facilities up to 10 MW in size. Participation in the program would be available to retail customer in 100 kWh blocks at an annually updated fixed price per kWh for a period of three years. The initial rate is 5.95 cents per kWh. Participants would be credits at a rate reflecting the market value of the energy and capacity generated. Participants’ bills will reflect the net between these two rates, which is 1.55 cents per kWh for the first year. Large non-residential customers may subscribe to up to 100% of their monthly usage. There would be no application fee to subscribe to the program. Dominion amended its application in May 2018, based on higher than expected interconnection costs for the projects. Dominion now proposes a fixed rate of 6.42 cents per kWh for subscribers, bringing the net rate to 2.01 cents per kWh. A September 2018 order approved	Docket No. PUR-2018-00009 Order

	Dominion's program pending certain minor revisions. Dominion must file revised tariffs within 30 days of the order and make subscriptions available to its customers within six months. Dominion filed its revised tariff in October 2018.	
WA	S.B. 5939 of 2017 requires community solar companies to register with the Utilities and Transportation Commission before engaging in business in the state or applying for certification from the Washington State University extension energy program. The Commission opened a docket in October 2017 to create new rules for the registration process. The Commission accepted comments throughout Q4 2017 regarding the Commission's rulemaking authority, then held a workshop in March 2018 to discuss the draft rules developed by the Commission Staff. The Commission accepted comments and issued an order in October 2018 adopting the draft rules.	Docket No. UE-171033 Final Rules Order

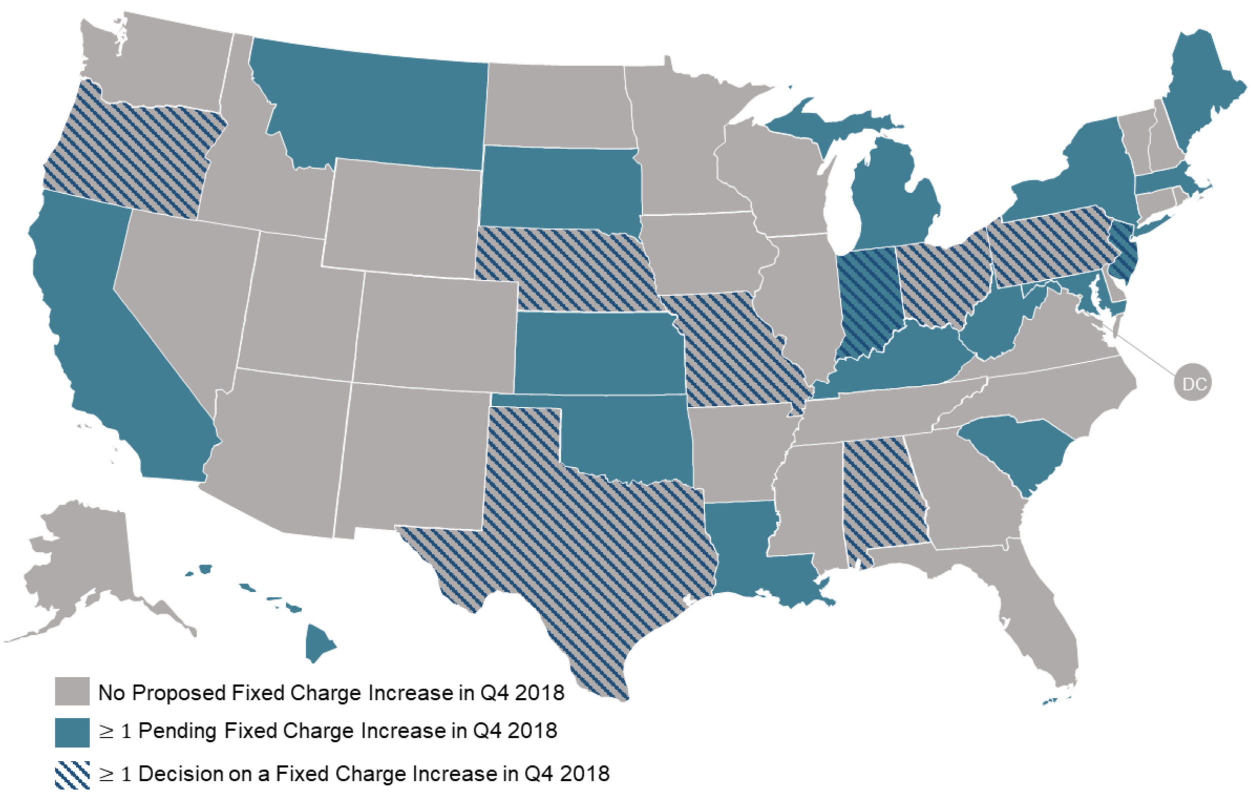
FIXED CHARGES AND MINIMUM BILLS

Key Takeaways:

- In Q4 2018, 41 utility requests in 24 states to increase residential fixed charges or minimum bills by at least 10% were pending or decided.
- Thirteen fixed charge decisions were made in Q4 2018, with three utilities receiving no increase, seven utilities receiving a partial increase, two municipal utilities receiving their full requested increases, and one utility receiving a fixed charge reduction.
- Overall, the median increase requested was $4.05, and the median percentage increase requested was 47% (average of 90%).[§§] Proposals ranged from an increase of $1.50 to $19.94.

Utility requests to increase residential fixed charges continued in Q4 2018, with 38 utilities in 24 states having pending or decided proposals to increase residential fixed charges by at least 10% during the quarter (plus three requests to increase minimum bills). Eight utilities proposed new fixed charge increases of at least 10% during Q4 2018.

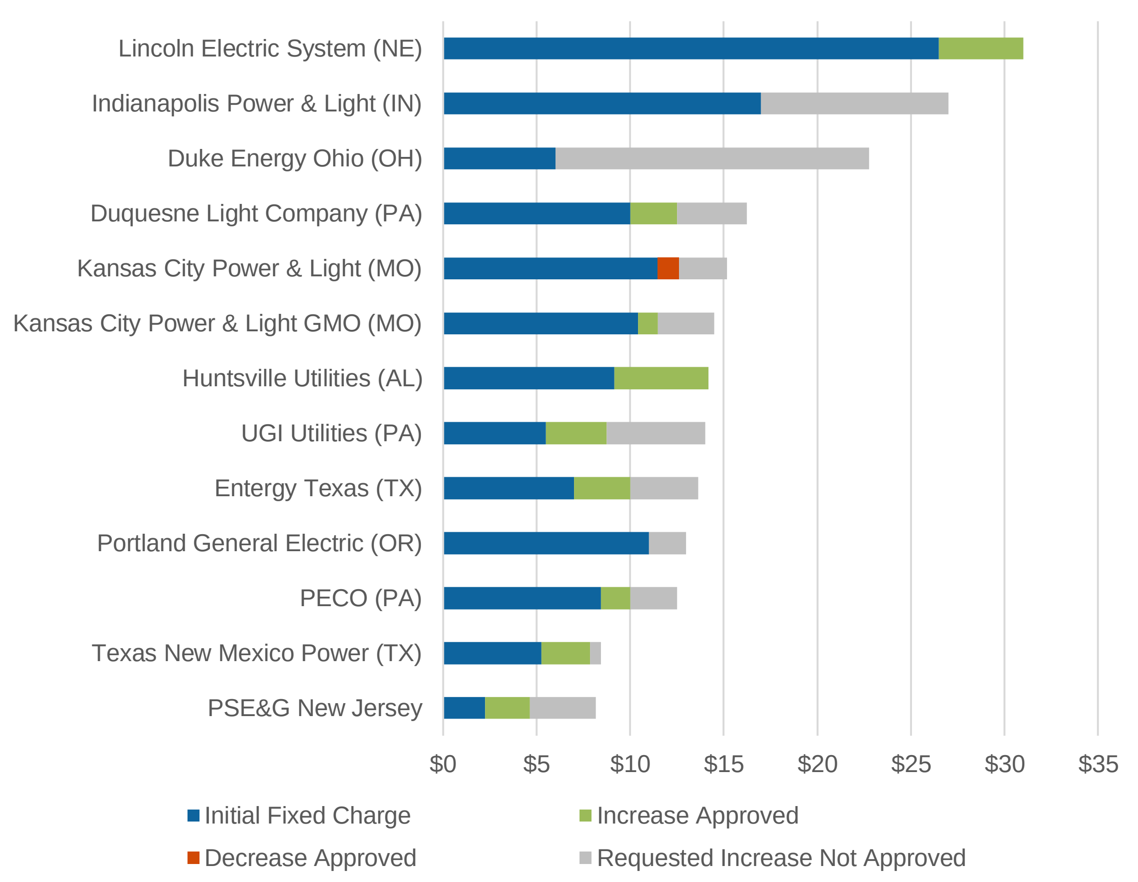
Figure 33. Proposed Increases to Residential Fixed Charges (Q4 2018)



[§§] PG&E and SCE requested increases are omitted from the percentage increase calculation, as they currently do not have residential fixed charges, only minimum bills.

The median percentage increase requested among new, pending, and decided proposals was 47% during Q4 2018, while the average was 90%. Eight utilities proposed new fixed charge increases of at least 10% in Q4 2018. Among these proposals, the average requested increase was $7.81 (median of $3.50).

Figure 34. Residential Fixed Charge Decisions in Q4 2018



Thirteen decisions were made during Q4 2018, with three utilities (*Indianapolis Power & Light – IN, Duke Energy Ohio, Portland General Electric – OR)* receiving no increase and seven utilities (*Kansas City Power & Light GMO – MO, PSE&G New Jersey, Duquesne Light Company – PA, PECO – PA, UGI Utilities – PA, Entergy Texas, and Texas New Mexico Power – TX)* receiving a partial increase. Two large municipal utilities (*Huntsville Utilities – AL and Lincoln Electric System – NE)* received their full requested increases, while the Missouri Public Service Commission ordered a reduction in Kansas City Power and Light's residential fixed charge.

The average increase granted in Q4 2018 was 29%, with utilities receiving 36% of their requested increase on average. There were 28 requests to increase residential fixed charges or minimum bills pending at the end of Q4 2018. The largest pending requests, by percent, are: (1) Southern California Edison ($6.54; 696%) (2) Duke Energy Carolinas – SC ($19.71; 238%), (3) Duke Energy Progress – SC ($19.94; 220%), (4) Energy New Orleans ($10.41; 129%), and (5) Otter Tail Power – SD ($7.23; 90%).

Table 13. Residential Fixed Charge Decisions (Q4 2018)

State	Utility	Amount of Increase Granted	% Increase Granted	% of Initial Request Granted
AL	Huntsville Utilities	$5.00	55%	100%
IN	Indianapolis Power & Light	$0.00	0%	0%
MO	Kansas City Power & Light	- $1.15	-9%	-45%
MO	Kansas City Power & Light GMO	$1.04	10%	26%
NE	Lincoln Electric System	$4.50	17%	100%
NJ	PSE&G New Jersey	$2.37	104%	40%
OH	Duke Energy Ohio	$0.00	0%	0%
OR	Portland General Electric	$0.00	0%	0%
PA	Duquesne Light Company	$2.50	25%	40%
PA	PECO	$1.55	18%	38%
PA	UGI Utilities	$3.24	59%	38%
TX	Entergy Texas	$3.00	43%	45%
TX	Texas New Mexico Power	$2.60	50%	82%
Q4 2018 MEDIAN		**$2.37**	**18%**	**38%**
Q4 2018 AVERAGE		**$1.90**	**29%**	**36%**

Figure 35. New Residential Fixed Charge Increase Proposals in Q4 2018

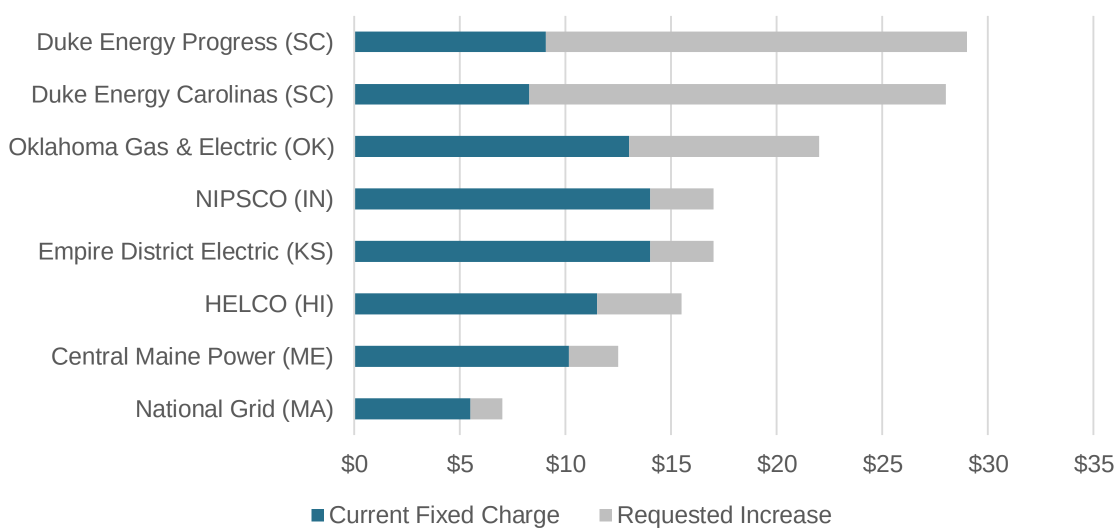


Figure 36. Active Proposals to Increase Residential Fixed Charges in Q4 2018

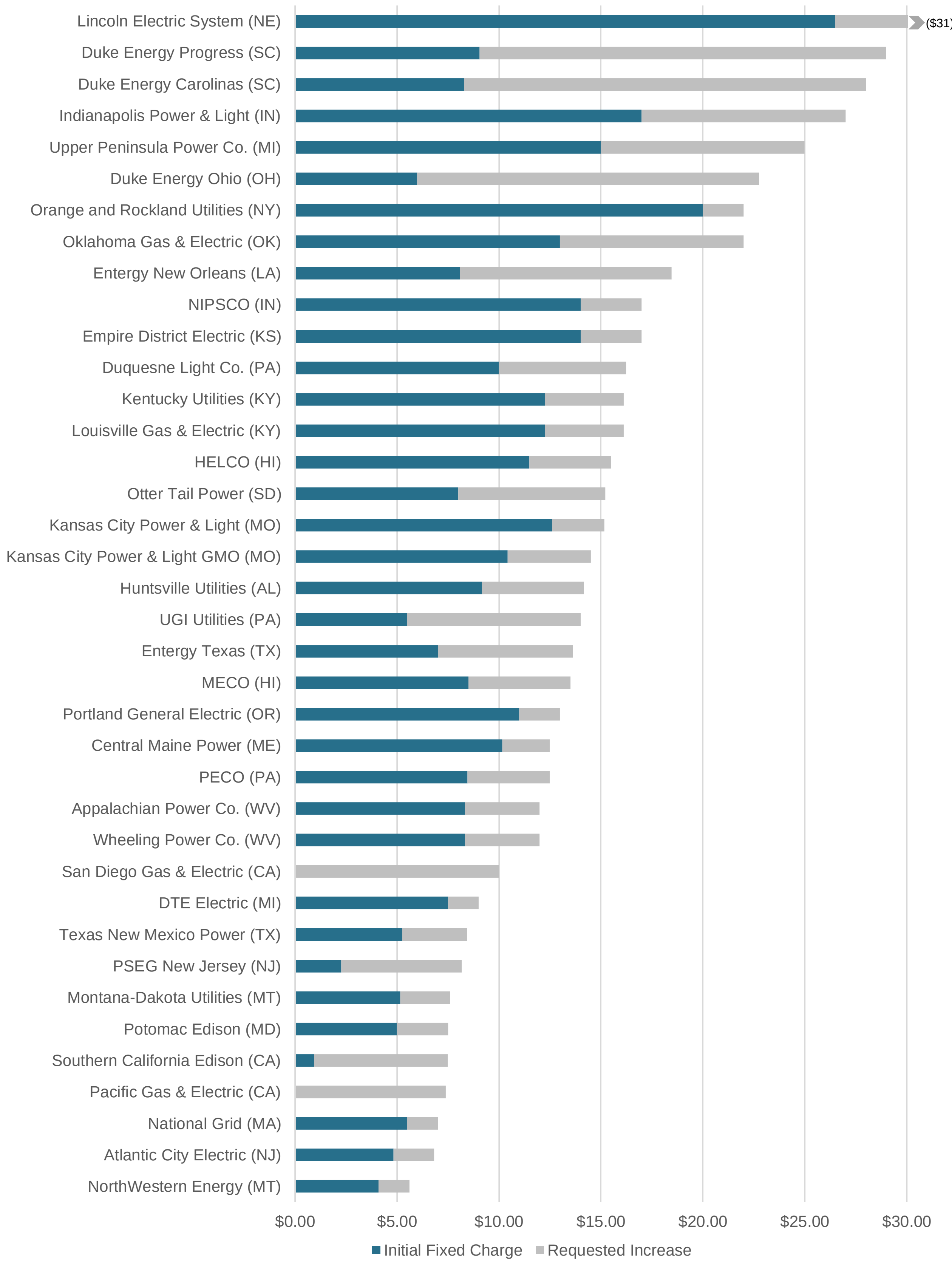


Table 14. Updates on Increases to Residential Fixed Charges (Q4 2018)

State	Utility	Monthly Residential Fixed Charge			Description	Source
		Existing	Proposed	Approved		
AL	Huntsville Utilities	$9.17	$14.56 OR $14.17 OR $11.42	$14.17	In September 2018, Huntsville Utilities presented its three 5-year rate strategy options. The first option increases the residential fixed charge to $14.56 by 2021, where it would remain until 2023. The second option increases the residential fixed charge by $1.00 per year until reaching $14.17 in 2023. The third option keeps the residential fixed charge at $9.17 until 2021, when it begins increasing up to $11.42 by 2023. In October 2018, the City Council approved option 2, which increases the residential fixed charge by $1 per year for the next five years.	Rate Actions Present-ation
CA	Pacific Gas & Electric	$0.00	$7.40	*Pending*	Pacific Gas & Electric (PG&E) applied for a fixed charge to be implemented in two phases, starting at $3.70 for one year, then increasing to $7.40 in the second year. The California Public Utilities Commission issued a resolution in January 2018, making a preliminary determination in favor of a hearing on PG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start	Docket No. 17-12-011

				date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed fixed charge increase. A decision was issued for Phase IIa in December 2018; this decision stated that the fixed charge issue will be addressed in Phase III of the proceeding.	
Pacific Gas & Electric	$10.00 (Min. Bill)	$15.00 (Min. Bill)	*Pending*	Pacific Gas & Electric (PG&E) applied for an increase in its monthly minimum bill. The California Public Utilities Commission issued a resolution in January 2018, making a preliminary determination in favor of a hearing on PG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed minimum bill increase. A decision was issued for Phase IIa in December 2018; this decision stated that the minimum bill issue will be addressed in Phase III of the proceeding.	Docket No. 17-12-011
San Diego Gas & Electric	$0.00	$10.00	*Pending*	San Diego Gas and Electric (SDG&E) applied for a $10 monthly fixed charge in a December 2017 rate design window filing. The California Public Utilities Commission issued a Resolution in	Docket No. 17-12-013

				January 2018, making a preliminary determination in favor of a hearing on SDG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed fixed charge increase. A decision was issued for Phase IIa in December 2018; this decision stated that the fixed charge issue will be addressed in Phase III of the proceeding.	
San Diego Gas & Electric	$10.00 (Min. Bill)	$37.25 (Min. Bill)	*Pending*	San Diego Gas and Electric (SDG&E) applied for a minimum bill increase in a December 2017 rate design window filing. The California Public Utilities Commission issued a Resolution in January 2018, making a preliminary determination in favor of a hearing on SDG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate	Docket No. 17-12-013

					designs, including the proposed minimum bill increase. A decision was issued for Phase IIa in December 2018; this decision stated that the minimum bill issue will be addressed in Phase III of the proceeding.	
	Southern California Edison	$0.94*	$7.48*	*Pending*	Southern California Edison (SCE) applied for an increase in its monthly fixed charge in a December 2017 filing. The California Public Utilities Commission issued a Resolution in January 2018, making a preliminary determination in favor of a hearing on SCE's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed fixed charge increase. A decision was issued for Phase IIa in December 2018; this decision stated that the fixed charge issue will be addressed in Phase III of the proceeding.	Docket No. A17-12-012
HI	Hawaii Electric Light Company	$11.50	$15.50	*Pending*	In December 2018, Hawaii Electric Light Company proposed an increase in its residential monthly fixed charge.	Docket No. 2018-0368
	Maui Electric Company (MECO)	$8.50	$13.50	*Pending*	In October 2017, Maui Electric Company (MECO) proposed an increase in its residential monthly fixed	Docket No. 2017-0150 Order

					charge. In a February 2018 order, the Commission instructed MECO to submit revised schedules to reflect the effects of the corporate tax cut enacted by Congress. MECO's revised schedules include the same fixed charge increase as its original proposal. A settlement agreement between MECO and the Consumer Advocate filed in June 2018 includes a smaller increase in the fixed charge to $11.50. In August 2018, the Commission approved the stipulated rates on an interim basis.	
	Maui Electric Company (MECO)	$18.00 (Min. bill)	$25.00 (Min. bill)	*Pending*	In October 2017, Maui Electric Company (MECO) proposed an increase in its residential monthly minimum bill. In a February 2018 order, the Commission instructed MECO to submit revised schedules to reflect the effects of the corporate tax cut enacted by Congress. MECO's revised schedules include the same minimum bill increase as its original proposal. A settlement agreement between MECO and the Consumer Advocate filed in June 2018 retains the increase in the minimum bill to $25.00. In August 2018, the Commission approved the stipulated rates on an interim basis.	Docket No. 2017-0150 Order
IN	Indianapolis Power & Light	$17.00	$27.00	$17.00	In December 2017, Indianapolis Power & Light requested an increase in its monthly residential customer charge as part of a general rate case. IP&L charges a different monthly customer charge depending on whether a customer uses less or more than 325	Docket No. 45029

					kWh/month. For the less than 325 kWh charge the proposed increase is from $11.25 to $16.00; for the greater than 325 kWh charge the increase is from $17.00 to $27.00. In August 2018, the parties filed a settlement increasing the <325 kWh charge from $11.25 to $12.50 while leaving the higher-usage charge at $17.00. The Commission approved the settlement agreement in October 2018.	
	Northern Indiana Public Service Company (NIPSCO)	$14.00	$17.00	*Pending*	In October 2018, as part of a general rate case, Northern Indiana Public Service Company (NIPSCO) requested an increase in its residential monthly fixed charge from $14.00 to $17.00. An evidentiary hearing is set for April 11-25, 2019.	Docket No. 45159
KS	Empire District Electric	$14.00	$17.00	*Pending*	In December 2018, as part of a general rate case, Empire District Electric Company requested an increase in its residential monthly fixed charge from $14.00 to $17.00.	Docket No. 19-EPDE-223-RTS
KY	Kentucky Utilities	$12.25	$16.12*	*Pending*	In September 2018, Kentucky Utilities proposed an increase in its residential fixed charge. The charge would go from a monthly rate of $12.25 to a daily rate of $0.53 (averaging $16.12 per month). A hearing is scheduled for March 2019.	Docket No. 2018-00294
	Louisville Gas & Electric	$12.25	$16.12*	*Pending*	In September 2018, Louisville Gas & Electric proposed an increase in its residential fixed charge. The charge would go from a monthly rate of $12.25 to a daily rate of $0.53 (averaging $16.12 per	Docket No. 2018-00295

					month). A hearing is scheduled for March 2019.	
LA	Entergy New Orleans	$8.07	$18.48	*Pending*	In July 2018, Entergy New Orleans filed a general rate case application, but withdrew the application shortly thereafter. Entergy refiled its rate case application in September 2018, which includes an increase in the residential monthly fixed charge.	City Council Docket No. 18-07
MA	National Grid	$5.50	$7.00	*Pending*	In November 2018, National Grid proposed an increase in its residential monthly fixed charge.	Docket No. 18-150
MD	Potomac Edison	$5.00	$7.50	*Pending*	In August 2018, Potomac Edison proposed an increase in its residential monthly fixed charge.	Docket No. 9490
ME	Central Maine Power	$10.17	$12.50	*Pending*	In October 2018, Central Maine Power proposed an increase in its residential monthly fixed charge.	Docket No. 2018-00194
MI	DTE Electric	$7.50	$9.00	*Pending*	In July 2018, DTE Electric proposed an increase in its monthly residential fixed charge. A cross-examination hearing took place in December 2018.	Docket No. U-20162
	Upper Peninsula Power Company (UPPCO)	$15.00	$25.00	*Pending*	In September 2018, UPPCO proposed an increase in its monthly residential fixed charge. Initial testimony is due by February 21, 2019, and a final order is expected by August 21, 2019.	Docket No. U-20276
MO	Kansas City Power & Light	$12.62	$15.17	$11.47	In January 2018, Kansas City Power & Light requested an increase in its residential monthly fixed charge. In September 2018, a non-unanimous settlement agreement was filed in which the parties agreed that the customer charge increase would be	Docket No. ER-2018-0145

					abandoned (or turned into a decrease) if the Commission ordered that residential revenues be decreased. No agreement was reached on what to do in the event of a revenue increase. In October 2018, the settlement agreement was approved, including a fixed charge decrease to $11.47.	
	Kansas City Power & Light Greater Missouri Operations	$10.43	$14.50	$11.47	In January 2018, Kansas City Power & Light Greater Missouri Operations requested an increase in its residential monthly fixed charge. In September 2018, a non-unanimous settlement agreement was filed in which the parties agreed that the customer charge increase would be abandoned (or turned into a decrease) if the Commission ordered that residential revenues be decreased. No agreement was reached on what to do in the event of a revenue increase. In October 2018, the settlement agreement was approved, including a fixed charge increase to $11.47.	Docket No. ER-2018-0146
MT	Montana-Dakota Utilities	$5.17*	$7.60*	*Pending*	In September 2018, Montana-Dakota Utilities proposed an increase in its daily basic service charge from $0.17 per day to $0.25 per day.	Docket No. D2018.9.60
	North-Western Energy	$4.10	$5.60	*Pending*	In September 2018, NorthWestern Energy proposed an increase in its residential monthly fixed charge.	Docket No. D2018.2.12
NE	Lincoln Electric System	$26.50*	$31.00*	$31.00*	In September 2018, Lincoln Electric System proposed an increase in its residential monthly fixed charge. For level 2 customers (usage	Press Release Proposed Rates

					between 800 kWh and 1,500 kWh per month), the charge would increase from $26.50 to $31.00. The LES Administrative Board approved the increase in October 2018.	
NJ	Atlantic City Electric	$4.83	$6.83	*Pending*	In August 2018, Atlantic City Electric proposed an increase in its residential monthly fixed charge.	ACE Petition (Docket No. ER18080925)
	PSEG New Jersey	$2.27	$8.18	$4.64	In January 2018, PSEG New Jersey requested an increase in its residential monthly fixed charge. The proposal would increase the charge to $4.24 in the first year, $6.21 in the second year, and finally to $8.18 in the third year. The Board of Public Utilities approved a settlement agreement in October 2018, increasing the fixed charge to $4.64.	PSEG Regulatory Filings (Docket No. ER18010029)
NY	Orange and Rockland Utilities	$20.00	$22.00	*Pending*	In January 2018, Orange and Rockland Utilities requested an increase in its residential monthly fixed charge. Evidentiary hearings have been postponed as parties continue settlement negotiations.	Docket No. 18-00253/18-E-0067
OH	Duke Energy Ohio	$6.00	$22.77	$6.00	In March 2017, Duke Energy Ohio proposed an increase in its residential monthly fixed charge. The Commission Staff filed a written report of its investigation of Duke Energy's proposal in September 2017 and recommended maintaining the customer charge of $6.00. Duke Energy filed a stipulation in April 2018, and multiple parties submitted testimony. The Commission	Case No. 17-0032-EL-AIR Final Order

					issued a final order in December 2018.	
OK	Oklahoma Gas & Electric	$13.00	$22.00	*Pending*	In December 2018, Oklahoma Gas & Electric proposed an increase in its residential monthly fixed charge.	Docket No. PUD-201800140
OR	Portland General Electric	$11.00	$13.00	$11.00	In February 2018, Portland General Electric requested an increase in its residential monthly fixed charge. The third partial stipulation agrees to maintain the $11.00 residential basic charge. The Commission approved the stipulation in December 2018.	Docket No. UE 335 Third Partial Stipulation Order No. 18-464
PA	Duquesne Light Company	$10.00	$16.25	$12.50	In April 2018, Duquesne Light Company requested an increase in its residential monthly fixed charge. A settlement agreement was filed in September 2018, which would increase the residential fixed charge to $12.50. The Commission approved the fixed charge agreed upon in the settlement agreement in December 2018.	Docket No. R-2018-3000124 Settlement Agreement
	PECO	$8.45	$12.50	$10.00	In February 2018, PECO requested an increase in its residential monthly fixed charge. The Commission issued a final order in December 2018, increasing the charge to $10.00.	Docket No. R-2018-3000164
	UGI Utilities	$5.50	$14.00	$8.74	In January 2018, UGI Utilities requested an increase in its residential monthly fixed charge. A partial stipulation was filed in June 2018, but it does not address the residential fixed charge. The ALJ's recommended decision was filed in August 2018, which would grant the utility's full requested increase. In October 2018, the	Docket No. R-2017-2640058 Recommended Decision

					Commission approved UGI's proposed fixed charge increase, but reduced according to the scaled back revenue increase approved by the Commission. UGI filed compliance tariffs including a $8.74 residential fixed charge.	
SC	Duke Energy Carolinas	$8.29	$28.00	*Pending*	In November 2018, Duke Energy Carolinas proposed an increase in its residential monthly fixed charge.	Docket No. 2018-319-E
	Duke Energy Progress	$9.06	$29.00	*Pending*	In November 2018, Duke Energy Progress proposed an increase in its residential monthly fixed charge.	Docket No. 2018-318-E
SD	Otter Tail Power Company	$8.00	$15.23	*Pending*	In April 2018, Otter Tail Power Company proposed an increase in its residential monthly fixed charge.	Docket No. EL 18-021
TX	Entergy Texas	$7.00	$13.64	$10.00	In May 2018, as part of a general rate case, Entergy Texas proposed an increase in its residential monthly customer charge. An unopposed settlement agreement filed in October 2018 sets the customer charge at $10.00. A December 2018 order adopted the settlement agreement.	Docket No. 48371
	Texas New Mexico Power	$5.25	$8.44	$7.85	In May 2018, Texas New Mexico Power (TNMP) requested an increase in its total residential monthly fixed charge. The portion of this charge referred to as a customer charge would be reduced from $4.00 to $1.17, while the portion referred to as a metering charge would increase from $1.25 to $7.27. A settlement agreement filed in November 2018 includes a fixed charge of $7.85, and a	Docket No. 48401

					December 2018 order approved the settlement.	
WV	Appalachian Power Company	$8.35	$12.00	*Pending*	In May 2018, Appalachian Power requested an increase in its residential monthly fixed charge.	[Docket No. 18-0646-E-42T]()
	Wheeling Power Company	$8.35	$12.00	*Pending*	In May 2018, Wheeling Power requested an increase in its residential monthly fixed charge.	[Docket No. 18-0646-E-42T]()

* Denotes that the utility uses a daily fixed charge for residential customers instead of a monthly fixed charge. All daily charges are converted into monthly charges for this table using the following formula: [(365 days/year)*($[fixed charge]/day)]/(12 months/year) = $[fixed charge]/month. If the charge varies by kWh consumption, it is assumed that the customer uses 900 kWh.

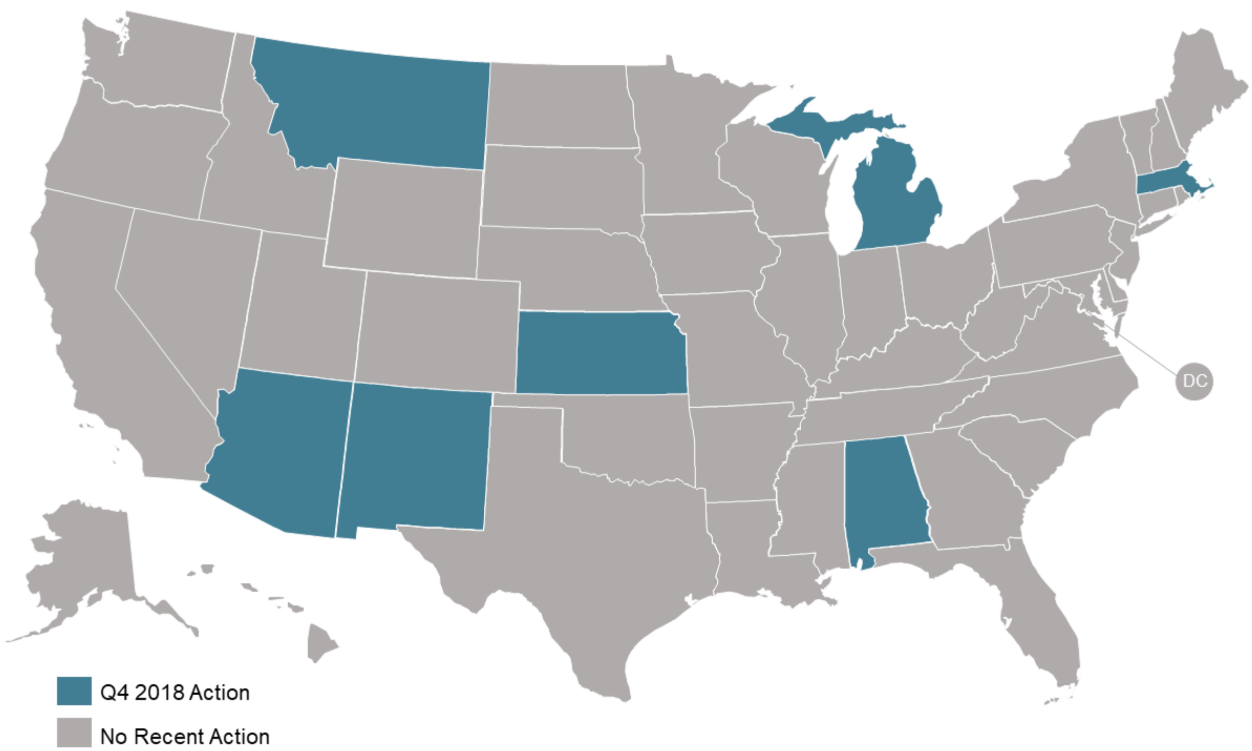
DEMAND AND SOLAR CHARGES

Key Takeaways:

- In Q4 2018, 13 actions related to demand charges or other charges on distributed generation customers were pending or recently decided in 7 states.
- National Grid in Massachusetts proposed a new fee for net metering customers in Q4 2018, while Salt River Project in Arizona proposed changes to its DG customer fees.
- The Kansas Corporation Commission approved Kansas City Power & Light's proposed demand charge for residential DG customers in Q4 2018.

In Q4 2018, there were 13 actions related to demand or other distributed generation (DG) customer charges under consideration, including 6 utility proposals to adopt new charges. Other actions relate to modifications of or challenges to previously approved charges.

Figure 37. Action on Demand or Solar Customer Charges (Q4 2018)



National Grid in Massachusetts filed a proposal for a Monthly Minimum Reliability Contribution (MMRC) as part of its general rate case. Massachusetts statute authorizes MMRCs for net metering customers, subject to certain requirements. National Grid's proposed fee takes the form of a fixed charge. Meanwhile, the Kansas Corporation Commission approved Kansas City Power & Light's proposed demand charge for residential DG customers. This is the third mandatory residential DG customer demand charge approved in 2018, although the Massachusetts General Assembly enacted legislation overturning Eversource's charge.

Table 15. Summary of DG Fee Proposals (Q4 2018)

State	Utility	Type of Charge	Proposed Amount
AL	Alabama Power	DG Capacity Charge	$5.42 per kW
AZ	Salt River Project	Demand Charge (avg. daily demand during peak hours)	$8.13 - $21.94 per kW
KS	Kansas City Power & Light	Demand Charge (peak hours)	$2.00 - $9.00 per kW
MA	National Grid	Fixed Charge	$4.20
MI	DTE Electric	DG Capacity Charge	$2.31 per kW
MI	Upper Peninsula Power Company	DG Capacity Charge	Not Specified
MT	NorthWestern Energy	Demand Charge (non-coincident)	$8.64 per kW

Salt River Project, a large municipal utility in Arizona, announced a suite of proposed rate changes in December 2018, including two new rate options for customers with DG systems. Currently, DG customers must pay a demand charge based on their monthly maximum demand during system peak hours. Salt River Project is requesting approval for two additional options, including one tariff with a demand charge based on an average of daily demand during system peak hours. The other option features time-varying consumption rates, a net billing compensation framework with an export compensation rate of 2.81 cents per kWh, and no demand charge.

Box 7. Demand Charges, Standby Charges, & Grid Access Fees

A **demand charge** is a charge that varies based on a customer's maximum rate of energy consumption, or demand, during a billing period. A customer's demand is measured in kilowatts (kW), and is typically calculated based on the average rate of energy consumption over a 15, 30, or 60 minute interval. The charge is then based on the interval with the highest average demand. In certain cases, only a customer's highest demand during the utility's system peak periods is used in calculating a demand charge, also known as "**coincident peak demand**." Most often, demand charges are based on a customer's "**non-coincident peak demand**", which may occur at any time during the billing period, regardless of when they utility's system peak occurs. Demand charges are common for commercial and industrial customers, and though rare for residential customers, are most often paired with time-of-use rate schedules when included in residential rates. A **standby charge** is a charge applied to customers with on-site generation, and may have volumetric, demand-based, and capacity-based components. Standby charges are intended to compensate the utility for providing power when the on-site generator is not producing energy. Another type of solar charge is a **flat monthly fee**, sometimes called a **grid access charge**, which functions as a higher total fixed charge.

Table 16. Updates on Residential Demand and Solar Charges (Q4 2018)

State	Utility	Monthly Demand/Solar Charge(s)			Description	Source
		Current	Proposed	Approved		
AL	Alabama Power	$5.00 per kW DG capacity	N/A	*N/A*	In April 2018, the Southern Environmental Law Center (on behalf of two individuals and a non-profit organization) filed a formal complaint and petition for a declaratory ruling regarding the legality of Alabama Power's Capacity Reservation Charge included in Rider RGB. Both exporting and non-exporting on-site solar generation facilities are currently required to pay the Capacity Reservation Charge.	Docket No. 32767
	Alabama Power	$5.00 per kW DG capacity	$5.42 per kW DG capacity	*Pending*	In June 2018, Alabama Power proposed modifications to its Rider RGB. The modifications and charge in its current form are being challenged in Docket No. 32767.	Docket No. U-4226
AZ	Salt River Project	$13.70	$17.60	*Pending*	In December 2018, Salt River Project proposed changes to its Customer Generation tariff (E-27). Among the proposed changes is an increase in the monthly fixed charge for customer-generators from $13.70 to $17.60. Public comment sessions are scheduled for January 2019, and a presentation will be made at the board meeting on February 18, 2019.	SRP Proposed Solar Options Detailed Changes
	Salt River Project	$3.55 - $34.19 per kW, varying by season and	$3.49 - $33.59 per kW, varying by season and level of demand	*Pending*	In December 2018, Salt River Project proposed changes to its Customer Generation tariff (E-27). Among the proposed changes is a slight reduction in most of the tariff's demand charges.	SRP Proposed Solar Options Detailed Changes

		level of demand			Public comment sessions are scheduled for January 2019, and a presentation will be made at the board meeting on February 18, 2019.	
	Salt River Project	$3.55 - $34.19 per kW, varying by season and level of demand	$8.13 - $21.94 per kW, based on the average on-peak daily demand, varying by season	*Pending*	In December 2018, Salt River Project proposed two new tariff options for customer-generators. One proposed option (E-15 Customer Generation Average Demand) features demand charges based on a customer's average daily demand during on-peak hours, rather than maximum monthly on-peak demand. Public comment sessions are scheduled for January 2019, and a presentation will be made at the board meeting on February 18, 2019.	SRP Proposed Solar Options Detailed Changes
	Salt River Project	$3.55 - $34.19 per kW, varying by season and level of demand	$0.00	*Pending*	In December 2018, Salt River Project proposed two new tariff options for customer-generators. One proposed option (E-13 Customer Generation TOU Export) does not include a demand charge. Public comment sessions are scheduled for January 2019, and a presentation will be made at the board meeting on February 18, 2019.	SRP Proposed Solar Options Detailed Changes
KS	Kansas City Power & Light	$0.00	$9.00 per kW during summer months and $2.00 per kW during winter months, based on the 15-min. max demand during peak hours	$9.45 per kW during summer months and $3.15 during winter months, based on the 60-min. max demand during	In May 2018, as part of a general rate case, Kansas City Power & Light proposed the creation of a new sub-class for future DG customers, which would include a demand charge. The proposed demand charge is based on the 15-minute maximum demand during peak hours (4 to 8 PM on non-holiday weekdays). DG customers would have a lower monthly	Docket No. 18-KCPE-480-RTS

			peak hours	customer charge and energy rate than non-DG customers (normal residential service would have a $15.18 customer charge vs. $14.00 for DG service; normal residential energy rates would be 9.00 to 11.66 cents per kWh vs. 6.70 to 8.68 cents per kWh for DG customers). An evidentiary hearing is scheduled for October 23rd.	
Westar Energy	$0.00	$9.45 per kW during summer months and $3.15 during winter months, based on the 60-min. max demand during peak hours	$9.00 per kW during summer months and $3.00 during winter months, based on the 60-min. max demand during peak hours *Appealed*	In February 2018, Westar Energy proposed implementing a monthly demand charge for residential customers with DG systems. Residential DG customers are currently treated as a separate customer class by Westar, but there are currently no differences in the rates between residential DG and non-DG classes. Residential customers without DG would have the option of opting into a tariff with the same demand charge. Westar also proposed an energy charge that would be higher for DG customers than non-DG customers on the optional demand tariff (7.23 cents per kWh for DG customers versus 5.62 cents per kWh for non-DG customers). The demand charge would be based on the highest 60-minute demand during the billing period, limited to the hours of 2pm to 7pm on non-holiday weekdays. In July 2018, a non-unanimous settlement agreement was filed (with several environmental and solar parties not joining the agreement), which included the charges for DG customers. In September 2018, the Commission	Docket No. 18-WSEE-328-RTS Order

					issued an order approving the agreement. A petition for reconsideration filed by the Sierra Club and Vote Solar in October 2018 was denied in November 2018; those parties filed a petition for judicial review in December 2018.	
MA	National Grid	$0.00	$4.20	*Pending*	As part of National Grid's general rate case, filed in November 2018, the utility proposed a Monthly Minimum Reliability Contribution (MMRC) for net metering customers. The MMRC is in the form of a fixed charge for all applicable rate classes. The proposed MMRCs are as follows: residential - $4.20, small general service - $9.50, general service demand - $28.00, and general service TOU - $164.00.	Docket No. 18-150
MI	DTE Electric	$0.00	$2.31 per kW installed DG capacity	*Pending*	In July 2018, as part of a general rate case, DTE Electric proposed a system access charge for new DG customers. This monthly charge would be based on the capacity of the customer's DG system. The charge would not be applied to DG customers taking service under demand-based rates. A hearing took place in December 2018.	Docket No. U-20162
	Upper Peninsula Power Company (UPPCO)	$0.00	Not Specified	*Pending*	In September 2018, as part of a general rate case, UPPCO proposed a system access contribution for new DG customers. The amount of this charge is not specified in the initial rate case filings (listed as $XX.XX per kW). The system access contribution would not apply to customers taking service	Docket No. U-20276

					under demand-based rates. Initial testimony is due by February 21, 2019, and a final order is expected by August 21, 2019.	
MT	North-Western Energy	$0.00	$8.64 per kW, based on the 60-min. max demand during the billing cycle	*Pending*	In September 2018, as part of its general rate case application, NorthWestern Energy proposed the creation of a new customer class for future residential net-metered customers. The proposed residential net metering customer rate includes a mandatory demand charge, based on the customer's non-coincident peak demand.	Docket No. D2018.2.12
NM	Southwestern Public Service Company d/b/a Xcel Energy	$0.0367 per kWh prod-uced	$0.0409 per kWh produced	$0.00 *Appealed*	In October 2017, Southwestern Public Service Company (SPS) proposed an increase in its residential DG production standby charge from approximately $0.005 to $0.006 and an increase in its residential DG transmission and distribution standby charge from approximately $0.031 to $0.035. The standby rates are based on the amount of per kWh production from the customer generation system that is either used on-site or applied as an offset to energy delivered from SPS. A recommended decision was published in late June, which would eliminate entirely the DG standby charge. In a September 2018 order, the Commission accepted the Hearing Officer's recommended decision on the standby charge, canceling the charge (Rate No. 59 and 67) and noted that it will open a rulemaking to address issues around standby	Docket No. 17-00255-UT Recomm-ended Decision Final Order

					charges for DG customers. SPS appealed the decision in September 2018, including the decision to cancel the standby charge, and the Commission denied the petition. SPS then filed an appeal with the Supreme Court of New Mexico.

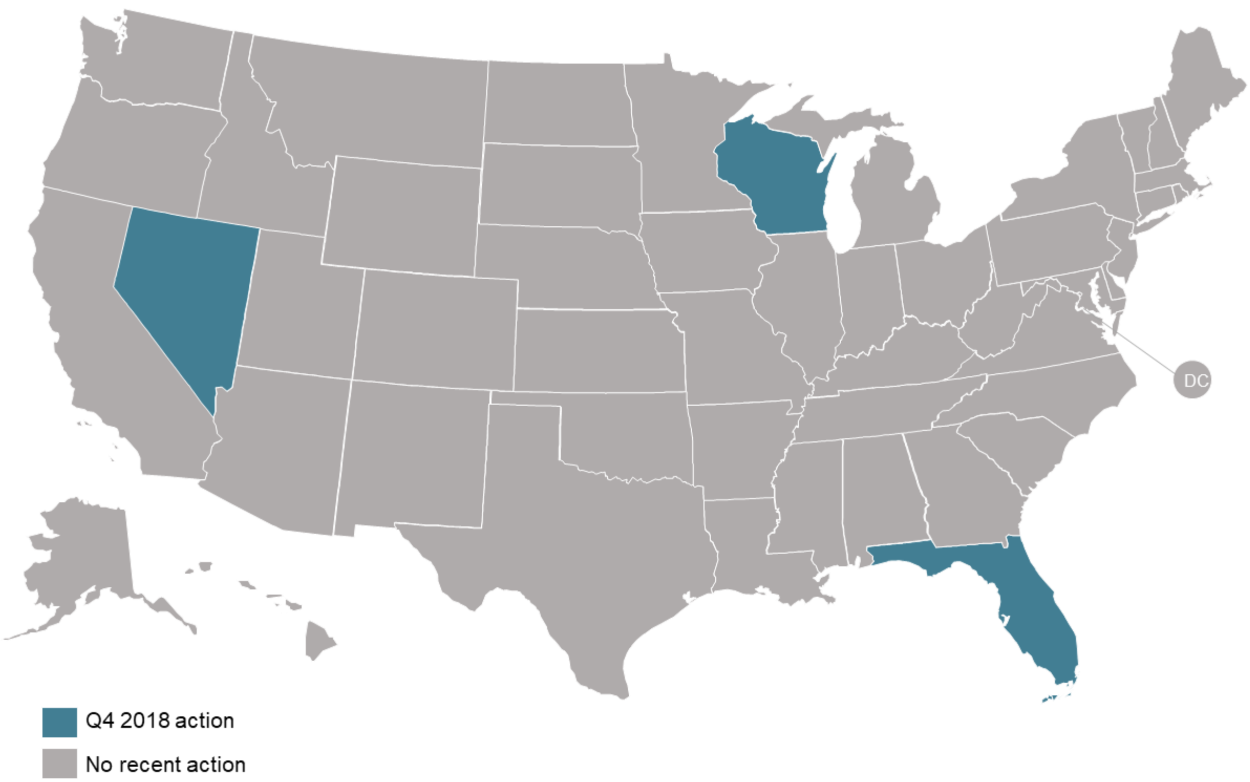
THIRD-PARTY SOLAR OWNERSHIP

Key Takeaways:

- In Q4 2018, three states took action regarding the legality of third-party solar ownership options.
- Solar companies filed petitions for declaratory rulings in two states – Florida and Wisconsin – regarding the legality of their residential solar equipment leases.
- The Public Utilities Commission of Nevada denied a petition for an advisory opinion that the sale of output from DG facilities on multi-family buildings does not classify the facilities as jurisdictional public utilities.

Regulators in three states – Florida, Nevada, and Wisconsin – considered the legality of specific third-party solar ownership options in Q4 2018. In both Florida and Wisconsin, rooftop solar companies filed petitions for declaratory rulings that their residential solar equipment leases are legal. Sunrun's new petition in Wisconsin and Tesla's petition in Florida follow approval of Sunruns' residential solar equipment lease in Florida earlier in 2018.

Figure 38. Action on Solar Third-Party Ownership (Q4 2018)



In Nevada, regulators denied a petition from a property management company that would have opened the door to allowing the sale of energy from solar facilities on multi-family buildings to building tenants.

Table 17. Solar Third-Party Ownership Updates (Q4 2018)

State	Description	Eligible Sector(s)	Source
FL	In December 2018, Tesla filed a petition for a declaratory statement that its residential solar equipment lease does not constitute a sale of electricity, does not deem the company a public utility, and does not subject the company or its customer-lessees to Commission regulation. The petition follows similar petitions from Sunrun and Vivint, which were approved.	Residential	Docket No. 20180221
NV	In October 2018, Ovation MM, Inc. (a property management company) filed a petition for advisory opinion from the Public Utilities Commission of Nevada that the DG facilities installed on multi-family buildings and the sale of output from these facilities are not jurisdictional public utilities. Parties filed comments in mid-November 2018, with some in support of the petition and others opposed. The Commission's General Counsel filed a briefing memo in November 2018, recommending that the Commission deny the petition. The Commission issued an order denying the petition in December 2018.	Multi-Family Buildings	Docket No. 18-10008
WI	In early December 2018, Sunrun filed a petition for a declaratory ruling that its residential solar equipment lease will not cause the company to be deemed a public utility under Wisconsin law. Several parties filed comments regarding the petition in late December 2018; the Environmental Law and Policy Center supported the petition while Fair Rates for Wisconsin's Dairyland and the Wisconsin Utilities Association opposed the petition.	Residential	Docket No. 9300-DR-103

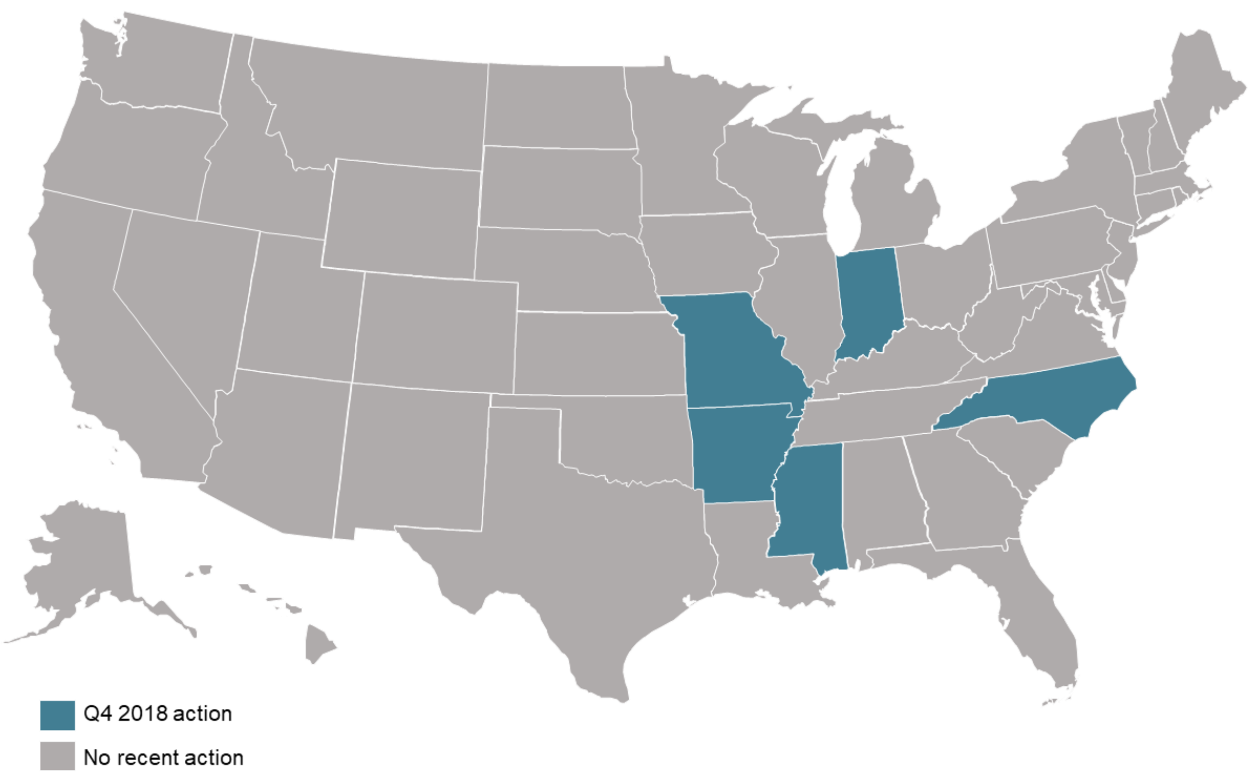
UTILITY-LED ROOFTOP SOLAR PROGRAMS

Key Takeaways:

- Five states took action related to utility-led rooftop solar programs during Q4 2018.
- Duke Energy received approval to offer solar leases to commercial customers in North Carolina through its subsidiary, Duke Clean Energy Resources, LLC.
- Duke Energy requested approval to offer solar leases to its non-residential customers in Indiana.

Utility-led rooftop solar programs remain an emerging area of interest, with the majority of action taking place in the U.S. Southeast and Midwest. The North Carolina Utilities Commission approved a request from Duke Energy to offer commercial solar leases through its subsidiary, Duke Clean Energy Resources, LLC. H.B. 589, enacted in North Carolina in 2017, established solar leasing rules, which included allowing utilities to become solar lessors.

Figure 39. Utility-Led Rooftop Solar Program Updates (Q4 2018)



Meanwhile, the Arkansas Public Service Commission is preparing to address utility-led rooftop solar as part of a broader proceeding, and the Mississippi Public Service Commission is considering a proposal from Entergy Mississippi to offer various customer-oriented technologies and services, including distributed solar, directly to residential customers.

Table 18. Updates on Utility-Led Rooftop Solar Programs and Policies (Q4 2018)

State	Utility	Description	Source
AR	All Utilities	In April 2016, the Public Service Commission (PSC) opened a general proceeding regarding DERs. In November 2017, the PSC issued an order outlining specific topics and questions to address during this proceeding, including many related to advanced metering infrastructure (AMI) deployment, pursuant to the final order in Entergy Arkansas' AMI deployment proceeding. These issues include identification of non-quantifiable functionalities and DERs that can be enabled or enhanced by AMI, and which of these are better offered by utilities or third parties. As part of this, parties are to consider competitive concerns related to utility offerings and potential remedies. The PSC issued an order in July 2018 with an initial list of issues to be considered during the proceeding. These issues include the appropriate roles for distribution utilities, third-party DER providers, and customers; tariff-based DER programs; net metering and rate design; and DER compensation and program design for low-income participation among many other specific DER and grid modernization issues. Comments on the proposed issues were accepted until late September, and the Commission intends to schedule an initial educational workshop on procedural issues.	Docket No. 16-028-U Order No. 10
IN	Duke Energy Indiana	In September 2018, Duke Energy Indiana filed a petition for approval of a new solar services program tariff, which would provide an alternative means for financing solar installations located on a non-residential customer's property. Customers would pay a monthly fee to cover the cost of construction, operation, and maintenance of the solar installation. The total capacity to be installed under this program would not exceed 12 MW. Customers would receive all electricity generated by the installations and would be credited through net metering; however, capacity installed under this program would not count towards the aggregate net metering capacity limit for Duke Energy Indiana. An evidentiary hearing was held in late January 2019.	Docket No. 45145
MO	Ameren	In December 2016, the Missouri Public Service Commission issued an order approving a solar partnership pilot program proposed by Ameren Missouri, which would have consisted of up to $10 million in investment in solar facilities by Ameren Missouri, with the facilities to be located on the property of Ameren customers. The Office of the Public Counsel appealed the order, and the appeal was resolved with an agreement on a smaller pilot program, with up to $4 million in investment and only one facility. In November 2018, Ameren submitted its proposed site for the facility: a parking garage owned by BJC Healthcare and Washington University in St. Louis. The Commission Staff submitted a report finding the site met all requirements of the agreement in January 2019.	Docket No. 2016-0208

MS	Entergy Mississippi	In July 2018, Entergy Mississippi proposed a new Smart Energy Services program. Smart Energy Services is intended to broadly encompass energy efficiency and demand response, distributed solar, community solar, battery storage, distributed back-up generation, home energy services, and new billing options. Under the proposed program, Entergy would offer these various services to customers and recover costs in the manner it recovers supply-side resource investments. Entergy notes that one of the major drivers behind its proposed program is to expand access to these types of services to low-income customers. Entergy filed supplemental testimony in November 2018.	Docket No. 2018-UN-133
NC	Duke Energy	In October 2018, Duke Energy filed an application to become a certified solar lessor under a separate subsidiary company, Duke Clean Energy Resources, LLC. Duke Energy plans to offer solar leases primarily to non-residential customers, including commercial and industrial customers, schools, and the military. The Commission approved Duke Energy's request in December 2018.by the parties, but not addressed by the rules. One major issue unaddressed in the rules is the extent to which the utilities can use their access to non-publicly available data in their business operations as potential lessors. These issues will presumably be addressed if/when a utility applies for a certificate.	Docket No. AR 603

Q1 2019 OUTLOOK

Most state legislatures are beginning their 2019 sessions in the first quarter of the year. Several bills relating to community solar, net metering, and third-party ownership have already been introduced.

Lawmakers in **Colorado**, **Maine**, **Minnesota**, **New Mexico**, **New York**, **South Carolina**, and **Washington** are considering new bills related to community solar. Meanwhile, bills expanding third-party ownership options are under consideration in **Arkansas**, **Florida**, **Kentucky**, **Oklahoma**, and **Virginia**.

In **Maine**, multiple bills have been introduced prohibiting the current gross metering policy for DG compensation. In **South Carolina**, a recently introduced bill prevents utilities from adopting certain fees on customer-generators and initiates the creation of a net metering successor tariff.

In **Arizona**, Tucson Electric Power and UNS Electric filed their pilot time-of-generation tariffs, with provide customer-generators with credits based on when they are producing energy. New rate options for customer-generators have also been proposed by **Arizona**'s Salt River Project.

In January 2019, the **Louisiana** Public Service Commission Staff filed final proposed net metering rules, which retain most of the same provisions as the Staff's previous version of proposed rules. Net metering rule changes remain under consideration in **Arkansas** as well.

The **New Jersey** Board of Public Utilities approved community solar pilot program rules for the state in January 2019. Community solar rules remain under consideration in New Orleans, **Louisiana**, where the City Council's Utilities Committee approved the proposed rules in December.

Comments are currently being accepted on draft studies in **Illinois** and **Mississippi**, and the **New Hampshire** Public Utilities Commission is scheduled to begin its distribution-level locational value study this quarter. Studies of the costs and benefits of on-site generation and fixed costs of serving customers are set to begin in **Idaho**.

Petitions for declaratory rulings related to the legality of residential solar equipment leasing are pending in **Florida** and **Wisconsin**. It is possible that companies will file similar requests in additional states where solar leasing legality is unclear in 2019.

Pepco filed a general rate case in **Maryland** in early January 2019, including only a slight increase in the residential fixed charge (2.69%), and Interstate Power & Light in **Iowa** is planning to file a rate case application by March 2019. Twenty-eight requests to increase residential fixed charges or minimum bills were pending at the end of 2018.

ENDNOTES

[1] Austin Perea, Colin Smith, Michelle Davis, Allison Mond, Benjamin Gallagher, Cory Honeyman, Shawn Rumery, Aaron Holm, Rachel Goldstein, & Justin Baca, *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

[2] Perea, et al., *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

[3] Perea, et al., *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

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[5] Daisy Chung, Brenda Chew, Medha Surampudy, & Maclean Keller, *2018 Solar Market Snapshot*, Smart Electric Power Alliance, July 2018, https://sepapower.org/resource/2018-utility-solar-market-snapshot/.

[6] Chung, et al., *2018 Solar Market Snapshot*, Smart Electric Power Alliance, July 2018, https://sepapower.org/resource/2018-utility-solar-market-snapshot/.

[7] Chung, et al., *2018 Solar Market Snapshot*, Smart Electric Power Alliance, July 2018, https://sepapower.org/resource/2018-utility-solar-market-snapshot/.

[8] Brenda Chew and Nick Esch, *2017 Solar Market Snapshot*, Smart Electric Power Alliance, July 2017, https://sepapower.org/resource/2017-solar-market-snapshot/.

[9] J. Coughlin, J. Grove, L. Irvine, J. F. Jacobs, S. J. Phillips, L. Moynihan, and J. Wiedman, *A Guide to Community Solar: Utility, Private, and Non-Profit Project Development*, National Renewable Energy Laboratory, 2010, http://www.nrel.gov/docs/fy11osti/49930.pdf.