Valuing Distributed Energy Resources: A Comparative Analysis

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June 4, 2018

The total capacity of installed solar in the United States continues to increase at a rapid pace.[1] To date, this growth has been primarily driven by policy choices at both the state and federal level, including: state renewable portfolio standards; state and federal tax incentives for renewable energy investments; net metering; and requirements that electric utilities purchase electricity from renewable energy facilities pursuant to the Public Utilities Regulatory Policy Act (PURPA).[2] While much of the growth in solar capacity – especially outside states with aggressive renewable energy goals (e.g., California) – has

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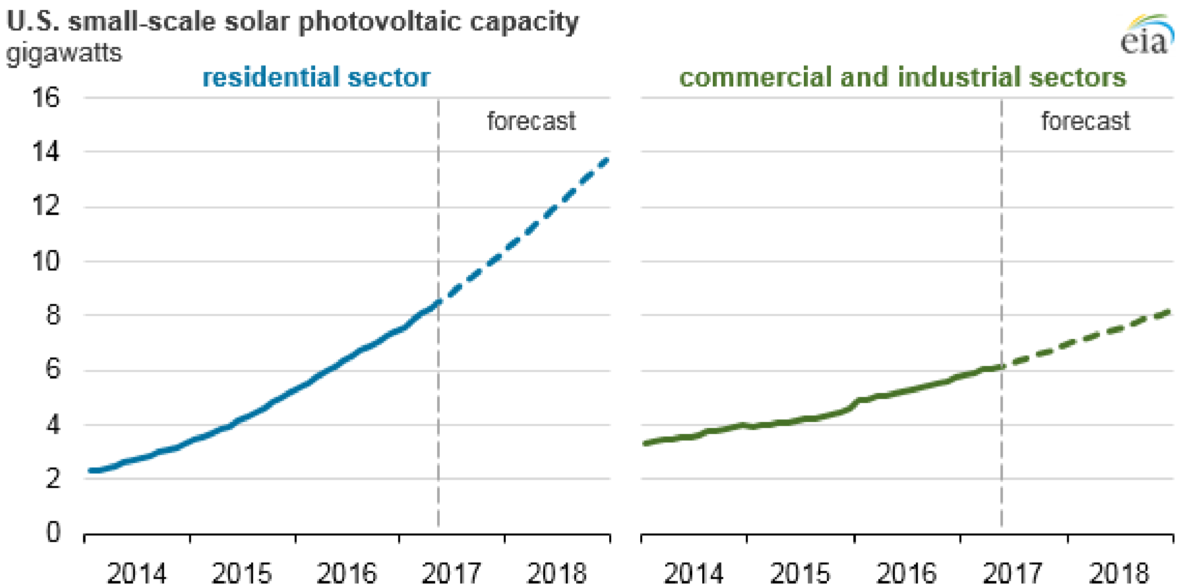
[1] For example, solar energy capacity in the Southeast increased from 200 MW in 2012 to 6 GW in 2017. Julia Pyper, *The Rise of Solar in the Southeast*, GREENTECH MEDIA (Mar. 9, 2018), https://www.greentechmedia.com/squared/read/the-rise-of-solar-in-the-southeast?utm_source=newsletter03.10&utm_medium=email&utm_campaign=gtm2#gs.wVovaEA. A cumulative 10.6 GW of solar PV was installed in the United States in 2017. Julia Pyper, *US Residential and Utility-Scale Solar Markets See Installations Fall for the First Time*, GREENTECH MEDIA (Mar. 15, 2018), https://www.greentechmedia.com/articles/read/us-residential-and-utility-scale-solar-see-installations-fall-first-time?utm_source=Daily&utm_medium=email&utm_campaign=GTMDaily#gs.4hx=F70.

[2] The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601-2645 (2016), was meant to promote energy conservation and greater use of domestic and renewable energy. It established a new class of generating facilities, known as "qualifying facilities," which are either small power production facilities (generally under 20 MW in RTO territories and under 80 MW elsewhere) that has a renewable fuel as a primary source or cogeneration facilities. FED. ENERGY REG. COM'N, WHAT IS A QUALIFYING FACILITY (2017), https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp These QFs have the right to sell energy and capacity to a utility at the utility's avoided cost; the utility must accept the generation. Avoided cost is "the incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source." FED. ENERGY REG. COM'N, WHAT ARE THE BENEFITS OF QF STATUS? (2017), https://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp.

been large, utility-scale projects,[3] distributed solar capacity is also increasing due to falling prices, increased consumer interest, and favorable state policies.[4] The Energy Information Administration projects that renewable energy capacity, including small-scale solar, will continue to increase despite changes to federal and state policies.[5] This is true even with the imposition of the §201 tariffs in early 2018.[6]



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook Supplement: Expanded Forecasts for Renewable Energy Capacity and Generation*, July 2017.

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[3] Larger projects allow for legal and other transactional costs to be spread over a larger base of energy output.
[4] About an eighth of installed solar in the Southeast is distributed. Herman K. Trabish, *In the New South, Customer Demand is Showing Utilities the Dollars and Sense in Solar*, UTILITY DIVE (Mar. 15, 2018), https://www.utilitydive.com/news/in-the-new-south-customer-demand-is-showing-utilities-the-dollars-and-sens/518857/?mc_cid=49b8c4dbed&mc_eid=7c8d730a3c; Julia Pyper, *The Rise of Solar in the Southeast*, GREENTECH MEDIA (Mar. 9, 2018), https://www.greentechmedia.com/squared/read/the-rise-of-solar-in-the-southeast?utm_source=newsletter03.10&utm_medium=email&utm_campaign=gtm2#gs.wVovaEA.
[5] U.S. Energy Information Admin., Annual Energy Outlook 2018, 13-14 (Feb. 6, 2018), https://www.eia.gov/outlooks/aeo/.
[6] Projected reductions are expected over the next five years of 7.6 GW from the tariffs, Lacey Johnson, *Forecast Shows How Trump Tariffs Will Hurt Solar Growth, State by State*, GREENTECH MEDIA (Feb. 1, 2018), https://www.greentechmedia.com/articles/read/forecast-shows-how-tariffs-will-hurt-solar-growth-state-by-state?utm_source=Daily&utm_medium=email&utm_campaign=GTMDaily#gs.JUW9ne8, or a reduction of around 11% from what was expected mostly coming from utility-scale installations, Julia Pyper, *New Tariffs to Curb US Solar Installations by 11% Through 2022*, GREENTECH MEDIA (Jan. 23, 2018), https://www.greentechmedia.com/articles/read/tariffs-to-curb-solar-installations-by-11-through-2022?utm_source=Daily&utm_medium=email&utm_campaign=section201#gs.JcS4rKg; "Total solar installations across the U.S. fell from 15 GW in 2016 to 10.6 GW in 2017, driven partly by uncertainty over tariffs on solar cells and modules that were eventually imposed in January by the Trump Administration." Trabish, *supra* note 4. The price increases could hurt solar expansion in the Southeast the hardest. Zack Coleman, *Traffic Could Fall Heaviest on Southeastern States*, CLIMATEWIRE (Jan. 18, 2018), https://www.eenews.net/climatewire/2018/01/18/stories/1060071271, although the Southeast is leading in new installations for 2018. E & E News, *South to Lead Solar Development in 2018*, ENERGYWIRE (Jan. 22, 2018), https://www.eenews.net/energywire/2018/01/22/stories/1060071481.

Growth in solar energy capacity is leading some states to reevaluate compensation for distributed energy resources. This is driven by a variety of factors, including increased distributed generation adoption, questions about how that may be impacting other electricity customers, and what benefits, such as decreased air pollution or resiliency, should be taken into account when looking at the value assigned to distributed energy resources. These valuation processes primarily focus on solar energy, but the choices may inform compensation for other distributed energy resources. In some states, this process is part of broader rate reform efforts.[7] In others, the focus on valuing solar energy arises specifically in the context of rooftop net metering and compensation provided to renewable energy facilities pursuant to PURPA. By one tally, more than 249 policy or rate design changes around solar policy occurred at the state level in 2017.[8] Despite the increasing focus on the role of renewable energy in the electricity system, there is no consensus regarding which factors states consider or the valuation methodologies states utilize.[9]

This paper compares recent solar valuation approaches in nine states that have explicitly engaged in actions to determine compensation for distributed energy resources, including distributed solar. The selected states represent a variety of political environments, regulatory structures, climate policies, sizes, and starting places for current compensation. The paper examines key factors that influence these states' solar valuation processes and, where possible based on the administrative record, factors that state policymakers explicitly declined to consider.

Starting with a general discussion of the current status of net metering, the paper then highlights seven key areas: how states started their DER valuation process, grandfathering, methods utilized to determine valuation of distributed resources, impacts on the distribution system, environmental consideration, resiliency, risk hedging, and each state's plan to revisit their valuation. The appendix summarizes key factors that each state considered as part of the valuation process.

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[7] Autumn Proudlove et al., N.C. CLEAN ENERGY TECH. CENTER, THE FIFTY STATES OF SOLAR: 2017 POLICY REVIEW AND Q4 2017 QUARTERLY REPORT (2018), https://nccleantech.ncsu.edu/wp-content/uploads/Q4-17_SolarExecSummary_Final.pdf ; Herman K. Trabish, *As Solar Matures, Rate Design and Incentive Debates Grow Ever More Complex*, UTILITY DIVE (May 23, 2017), https://www.utilitydive.com/news/as-solar-matures-rate-design-and-incentive-debates-grow-ever-more-complex/443185/?mc_cid=0b768eb51f&mc_eid=7c8d730a3c ; Herman K. Trabish, *In New Trend, Utilities Propose Separate Rate Classes for Solar Customers Without Rate Increase*, UTILITY DIVE (Nov. 2, 2017), https://www.utilitydive.com/news/in-new-trend-utilities-propose-separate-rate-classes-for-solar-customers-w/508393/.

[8] Proudlove, *supra* note 7.

[9] "While there is growing convergence toward the net billing framework, states are taking diverse approaches to credit rates for excess generation. The most common of these have been avoided cost and value-based crediting, although there are is a wide variety of methodologies in use or under consideration for calculating avoided cost and the value of distributed generation." Proudlove, *supra* note 7.

Status of Net Metering

Net metering currently exists in 38 states plus the District of Columbia.[10] The traditional concept of net metering is that a customer's electricity meter runs backwards – providing a direct offset between electricity used from the grid and electricity put back onto the grid.[11] While PURPA encourages states to adopt net metering, there are significant differences between how states have implemented net metering.

States have considered six main choices when implementing net metering and other valuation schemes which have led to differences in implementation.[12] The first is whether all electric utilities in the state must offer net metering, or if municipal utilities or electric cooperatives are exempt. In Arizona, for example, the Salt River Project and municipal utilities are exempt from the mandate to provide net metering. California specifically exempts Los Angeles Department of Water and Power (publicly-owned electric utilities with more than 750,000 customers who also provide water are exempt, and LADWP is the only entity which meets that criteria). Which sources can use net metering has also developed differently on a state-by-state basis. Solar PV and wind are the most commonly qualified sources, with biomass and hydroelectric also able to be net metered in a majority of states with net metering programs. Combined heat and power/co-generation systems can also be net metered in a variety of states, including Arizona, Minnesota, New York and South Carolina.

The size of systems allowed varies between 10kW and 80MW, depending on the technology and the state. While highly variable, a common size constraint is that the maximum size of the installation is tied to the monthly or annual average usage of the site with the generation. For example, in Arizona, the cap is 125% of a customer's total connected load. Other states set the limit at 100% of annual usage, including South Carolina.

The amount of net metering allowed in the state can also be capped based on utility average or peak load, with states setting caps between 0.2% and 20% of utility load. California, Hawaii, New York, and South Carolina all have caps based either on utility peak demand or annual average demand. The owner of the renewable energy credits (RECs) awarded for the net-metered power generation is also a point of difference. A number of states, including Minnesota, have decided that the customer owns the RECs. Other states, including California, fall into a hybrid system, where RECs are transferred under specific conditions but are kept with the customer under other scenarios.

One of the most contentious issues more recently is whether net metering customers are considered a separate rate class, which could lead to different fixed rates or the imposition

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[10] DSIRE, NET METERING (Nov. 2017), http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/11/DSIRE_Net_Metering_November2017.pdf. However, the number of states offering net metering has been declining over the last few years.

[11] *See* Richard L. Revesz and Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 41 Harv. Envtl. L. Rev. 43 (2017).

[12] Heather Payne, *A Tale of Two Solar Installations: How Electricity Regulations Impact Distributed Generation*, 38 U. Haw. L.R. 135 (2016).

of demand charges. Arizona and Hawaii have sorted customers with distributed energy generation into separate classes. In contrast, Nevada enacted a statute which specifically forbade classifying distributed energy generators as a separate rate class.

These considerations are independent of the primary question regarding direct compensation for electricity generated by the distributed energy resource but can have an impact on both valuation and adoption. Additionally, states continue to call some rate designs net metering when they actually provide valuations other than a one-for-one offset.

Origin and Oversight of the DER Valuation Processes

Some state legislatures have initiated inquiries into the value of distributed energy resources following the enactment of a statute requiring the action. In other states, the PUCs opened dockets on DER valuation on their own initiative. Of the states included in this study, legislatures in California, Massachusetts, Minnesota, New Hampshire, and South Carolina adopted statutes with varying degrees of specificity, while PUCs in Arizona, Hawaii, Mississippi, and New York initiated the valuation of distributed energy resources on their own. The legal circumstances underlying a state's decision to evaluate the value of distributed energy resources can influence the outcomes, as legislation may be more prescriptive regarding the factors to consider while PUC-initiated efforts may allow commissioners broader latitude regarding the factors to consider and the relative weight assigned to each. New legislation may also identify a broader range of societal interests to consider when assessing the value of distributed energy resources than may otherwise fall under the PUC.

For example, New Hampshire's legislature identified the following factors for the PUC to take into account when determining valuation: costs and benefits of customer generator facilities; avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time-based tariffs; whether there should be a limitation on the amount of generating capacity eligible for alternative net metering tariffs; the size of facilities eligible to receive net metering tariffs; timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms; continuance of reasonable opportunities for electric customers to invest in and interconnect customer generator facilities and receive fair compensation for such locally-produced power while ensuring costs and benefits are fairly and transparently allocated among all customers; and the promotion of a balanced energy policy that supports economic growth and energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits and a modern and flexible grid.

Similarly, South Carolina's statute required the Public Service Commission to consider a number of factors when determining the value of distributed energy resources, including: avoided energy; energy losses/line losses (at generation, transmission and distribution); avoided capacity; ancillary services; transmission and distribution capacity; avoided criteria pollutants; avoided carbon dioxide emission cost; fuel hedge; utility integration and interconnection costs; utility administration costs; environmental costs; and other categories which cannot currently be quantified but which will be continuously updated. However, the statute also specified that the avoided carbon dioxide emission cost was to be set at zero monetary value until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions, and environmental costs had to be quantifiable and not based on estimates.

Who conducts the valuation analysis also varies by jurisdiction. PUC staff conducted the analyses in Arizona, New Hampshire, and New York. South Carolina's valuation is currently pending, with the state's Office of Regulatory Staff conducting the analysis. Minnesota took a slightly different approach; rather than the analysis being performed by PUC staff, public staff of the Minnesota Department of Commerce undertook the analysis.

California based its decision on information presented by utilities and intervenors, rather than tasking regulatory staff with conducing an independent inquiry. While not of primary importance to final outcomes, both New Hampshire and New York also took into account valuation analyses presented by third parties in addition to having public staff provide an analysis to the PUC.

Massachusetts and Mississippi did not perform any specific valuation determinations in the dockets studied as part of this analysis. As states look to determine how to change distributed energy valuation, one of the first questions is how to handle existing net metering customers.

Treatment of Existing Net Metering Customers

Justifications for grandfathering in the net metering context are similar to other circumstances when policy changes impact the value of past infrastructure investments. Although the level of investment for a single rooftop solar installation pales in comparison to the costs of large-scale generation such as natural gas-fired power plants, the upfront costs of a rooftop solar installation may represent a significant investment for a homeowner or business owner. Changing compensation methodologies after the initial investments could impact the value of the rooftop system and thus the economic impacts for the owner, especially in light of payback periods of 10 years or more in certain jurisdictions. Some states have addressed this concern by exempting existing rooftop solar installations from any changes to net metering rates for a length of time deemed sufficient to recoup the initial capital investment.

Arizona and California both grandfathered existing customers for 20 years. New Hampshire grandfathered customers until 2040. New York adopted a slightly more complicated standard; the period is either 20 or 25 years, depending on the time of interconnection. However, developers can request a period longer than 20 years based on existing financial or contractual conditions.

While Nevada was not among the nine states included in this analysis, the state's experience in dramatically altering the value proposition for existing net metering customers may prove instructive. In December 2015, the Nevada PUC eliminated net metering for both new and existing customers, ramping down the valuation paid to existing net-metered customers over a short time span. With broad public support, the legislature passed new legislation in 2017 that reversed the net metering order and, additionally, prohibits customers with net metering from ever being considered in a separate rate class.[13] While not retaining full retail-rate net metering, the valuation currently will be 95% of the retail rate, slowly trending down as more solar is added to the grid. The minimum price will be 75% of the retail rate. The commissioners who made the original decision to reduce net metering were also replaced, and, for the first time in 30 years, an investor-owned utility in the state was forced to decrease rates as part of a general rate case (both fixed and volumetric rates went down).[14] While it was an uncertain situation for distributed energy valuation in Nevada for two years, the situation has now stabilized, with different commissioners, new legislation including a statutorily guaranteed right to self-generate electricity, and more consumer protections for those who adopt distributed generation.[15] The public outcry from the policy change being applied retrospectively is widely considered to have brought these changes about.[16]

Methods Utilized to Determine DER Compensation

The methods used to determine the value of distributed energy resources vary greatly. An initial decision for many states is whether to value distributed energy resources at retail electricity rates, or to determine another valuation, most often starting with the wholesale electricity rate. California, New York, and South Carolina currently have retail-rate net metering for at least residential distributed generation customers, although California requires the payment of non-bypassable charges. New York, additionally, has chosen a different path for non-residential customers, based on the "value stack" approach. The value stack attempts to value distributed resources based on the locational marginal value of the energy plus value to the distribution system and environmental benefits to maximize the system as a whole.[17] With this formula, New York takes into account energy value (day ahead hourly zonal locational-based marginal price, inclusive of transmission losses); capacity value (different methodologies for intermittent and dispatchable technologies); environmental value (based on latest Tier 1 REC published by NYSERDA or Social Cost of Carbon, whichever is higher); demand reduction value and locational system relief value

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[13] Julia Pyper, *Nevada PUC Approves Net Metering Rules Expected to Reboot the State's Rooftop Solar Industry*, GREENTECH MEDIA (Sept. 5, 2017), https://www.greentechmedia.com/articles/read/nevada-puc-approves-net-metering-rules-expected-to-reboot-the-rooftop-solar#gs.tFEYAQE.

[14] Julia Pyper, *Regulators Deny NV Energy's Rate Increase, Garnering Cheers from Solar Advocates*, GREENTECH MEDIA (Jan. 4, 2017), https://www.greentechmedia.com/articles/read/regulators-deny-nv-energy-rate-increase-rooftop-solar#gs.YGSovVc.

[15] *Id.*; *see also* Julia Pyper, Nevada's New Solar Law Is About Much More Than Net Metering, GREENTECH MEDIA (Jun. 16, 2017), https://www.greentechmedia.com/articles/read/nevadas-new-solar-law-is-about-much-more-than-net-metering#gs.XQ91DIo.

[16] Pyper, *supra* note 15.

[17] Michael Kuser & Rich Heidorn Jr., *NYPSC Adopts 'Value Stack' Rate Structure for DER*, RTO INSIDER (Mar. 9, 2017), https://www.rtoinsider.com/nypsc-value-stack-rate-structure-der-39880/.

(determined every three years; projects that qualify for LSRV will receive that compensation for ten years, whereas DRV shall not be fixed but instead changes as updated by the utility on a three-year basis).

Other states start with the avoided cost and then determine what other values to include in the value associated with distributed energy resources. Arizona, for example, added a number of additional considerations: avoided generation (energy and capacity),[18] transmission and distribution capacity with line losses adjusted for geographic location; grid support services; financial risk, including fuel price hedging and market price responses; security risks; and environmental considerations. In addition to the changes in valuation, Arizona has implemented export credits based on short-term valuation methods, specifically basing value on a five-year average of utility-scale solar PPA pricing.[19]

Minnesota, similarly, started with avoided cost[20] and then added avoided fixed plant operations and maintenance (O&M) costs, avoided variable plant O&M, avoided generation capacity cost (based on natural gas facilities), avoided reserve capacity cost, avoided transmission capacity cost, avoided distribution capacity cost (based on location), and avoided environmental cost. New Hampshire (pending a more detailed valuation study to be developed) values distributed resources at the wholesale energy cost plus 100% of the transmission charges and 25% of the distribution charges, but still requires distributed energy generators to pay per kWh non-bypassable charges. Hawaii, on the other hand, set the value for exported generation at just the energy avoided cost.[21]

Mississippi adopted a "buy all, sell all" approach for compensating owners of distributed energy systems. In a "buy all, sell all" approach, a customer has two meters – one for electricity coming onto the site, and one for electricity leaving it. All electricity coming onto the site is purchased by the customer, and all electricity leaving the site is purchased by the utility. This allows PUCs to assign different values to the electricity depending on whether it is being purchased from the utility or sold back to it. With this change, usage from the

[18] The Arizona Corporation Commission adopted the Staff's proposed definition of avoided cost. Decision 75859, page 147-150. Staff defined avoided cost as the "costs of energy that would have been produced or purchased but for the existence of the DG." Decision 75859, page 103 FN 727, http://images.edocket.azcc.gov/docketpdf/0000176114.pdf. This is not limited to only renewable resources or distributed energy resources, as renewable resources or distributed generation would not be the only sources which could see to the utility to meet this need. For a discussion of where states can limit avoided cost to comparable resources, *see generally* Felix Mormann, *Regulatory Opportunities for State Climate Policy*, 41 Harv. Envtl. L. Rev. 189 (2017).

[19] Julia Pyper, *Arizona Vote Puts an End to Net Metering for Solar Customers*, GREENTECH MEDIA (Dec. 21, 2016), https://www.greentechmedia.com/articles/read/Arizona-Vote-Puts-an-End-to-Net-Metering-for-Solar-Customers?utm_source=Daily&utm_medium=Newsletter&utm_campaign=GTMDaily#gs.uR4WwT0.

[20] Minnesota similarly defined the avoided fuel cost based on energy market costs, which are not limited to a particular form of generation or are necessarily distributed. Benjamin L. Norris et al., Clean Power Res., Minnesota Value of Solar: Methodology (Jan. 30, 2014), https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

[21] Hawaii continues to see solar adoption with this valuation, likely due to high electricity prices from the state's dependence on imported oil to generate electricity.

grid is billed at the retail rate and excess electricity exported back to the grid is paid at the avoided cost rate (energy only, not capacity) plus 2.5 cents/kWh for currently unquantifiable benefits. Michigan also recently decided to change how they approach net metering and changed to a "buy all, sell all" approach. Per Michigan's new rules, all electricity purchased by the customer will be paid for at retail rate, but the utility will only pay avoided cost for the electricity generated and put back onto the grid.[22]

Impacts on the Distribution System

One of the considerations when determining the value of solar is how distributed energy resources will impact the distribution grid. Many are in agreement that, at this point in time, distributed resources, especially rooftop solar, do not impact the transmission system. (California and Hawaii may be the exceptions, given the large penetration of rooftop systems in those states.) Therefore, it is generally agreed that distributed resources should be credited for the full amount of any avoided transmission charges. The calculation around the distribution system, however, is more nuanced and complicated.[23] At this point in time, no state has finalized a specific value, but some states are working on determining the methodology that they will use.

The distribution system was originally designed for one-way flows of electricity (i.e., from a power plant to a home). With two-way flows, several scenarios are possible. With certain scenarios, distributed generation can lead to decreased distribution spending (by avoiding the need for infrastructure upgrades, for example); with others, adding distributed generation on the system may lead to additional cost (where equipment needs to be updated to handle the additional generation coming into the system). The conditions will depend on circuit-level circumstances, potentially leading to difficulties in valuation. Other factors that could influence valuation include increases in the amount of distributed generation on a particular circuit, the amount of distributed generation consumed on-site, the location of the distributed generation on the circuit (in relation to the transformer), and changes to the timing of peak use on that distribution circuit.

Acknowledging that distributed energy resources, especially larger facilities, could have an impact on the distribution system, California ruled that systems larger than 1 MW can participate in net metering provided they have "no significant impact" on the distribution grid. Minnesota has not currently calculated a specific value, but has a placeholder for solar integration cost pending the ability for that value to be measurable in the future.

Other states have sought to specifically address the impact of distributed energy resources on the distribution grid. New York, for example, has opened a separate proceeding on the value of distributed generation to the distribution system (the "Value of D"), which is ongoing. New York's value stack for distributed energy resources provides compensation

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[22] Robert Walton, *Michigan Nixes Net Metering*, UTILITY DIVE (Apr. 19, 2018), https://www.utilitydive.com/news/michigan-nixes-net-metering/521755/.
[23] *See generally* Joel B. Eisen and Felix Mormann, *Free Trade in Electric Power*, 2018 Utah L. Rev. 48, https://dc.law.utah.edu/ulr/vol2018/iss1/2/.

for avoided distribution-level infrastructure costs (as mentioned above) through the demand reduction value (DRV) and locational system relief value (LSRV). "The DRV applies to all projects in a utility's territory and is based on the utility's average cost of service. The LSRV is specific to projects that, based on their location and characteristics, contribute to meeting a particular utility need and therefore provide a specific, higher value to the distribution system."[24] However, these are based on the utility's marginal cost of service, which ranges from a low of $15/kW to a high of $226/kW in New York based on utility methodologies and inputs.[25] This has led to uncertainty around what the value would be for any particular distributed project. New York has plans to further standardize and improve these calculations during the next phase of the value-stack proceeding.[26] Similarly, Arizona also tied the value provided to the distribution system to location, including distribution capacity with line losses adjusted for geographic location in the valuation calculation, as did Minnesota, including avoided distribution capacity cost based on location.

New Hampshire took a different approach. Given that, as a restructured state, transmission and distribution charges were already calculated separately, distributed generation received the full value for transmission costs, but only 25% of distribution costs.[27] This was to acknowledge that distributed generation would create some costs for the distribution network, but that there were also cases where it would be beneficial. Rather than attempt to calculate it specifically on a circuit-by-circuit and project-by-project basis, New Hampshire opted to use the 25% average until better data are available.[28] South Carolina was less specific, requiring energy, line losses, and capacity from the distribution system to be factored into the value of distributed resources.

Environmental Benefits

Based on 2017 data from the U.S. Energy Information Administration, about 63% of total U.S. electricity production was from fossil fuel sources, including coal, natural gas, and

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[24] Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matter at 5, 10, In the Matter of the Value of Distributed Energy Resources, No. 15-E-0751, and Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program, No. 15-E-0082 (N.Y. Pub. Serv. Comm'n Sept. 14, 2017) [hereinafter Order on Phase One Value].

[25] Jeff St. John, *Why Solar Advocates Are Crying Foul Over New York's Latest REV Order*, GREENTECH MEDIA (Sept. 19, 2017), https://www.greentechmedia.com/articles/read/why-solar-advocates-are-crying-foul-over-new-yorks-latest-rev-order#gs.6rMsPnA.

[26] Order on Phase One Value, *supra* note 24, at 8, 12.

[27] The 25% value was part of a negotiated settlement; some parties to the proceeding wanted 0%, and some 100%.

[28] On April 30, 2018, the Commission directed parties to this proceeding to conduct a distribution-level locational DG valuation study to evaluate alternative study designs and methodologies to address the potential locational value of DG on the utility distribution system. Docket Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms And Tariffs For Customer-Generators, Order No. 26,124 Addressing Non-Wires Alternatives Pilot Program, 30 April 2018.

petroleum.[29] Emissions from coal plants include varying amounts of carbon dioxide, carbon monoxide, sulfur dioxide, nitrogen oxides, particulate matter, and heavy metals such as mercury, whereas emissions considerations for natural gas focus mostly on carbon dioxide.[30] The degree to which these are released per unit of electricity produced depends on the source.[31] The emissions from fossil fuel plants can contribute to climate change, acid rain, respiratory problems, heart disease, asthma and bronchitis, or other health problems.[32] Which of these sources produce more electricity for a given area – or whether cleaner sources like hydropower, wind and solar supply more of the local electricity – will have an impact on what environmental benefits might be achieved through the adoption of distributed energy resources.

As with many of the attributes associated with distributed resources, state approaches to evaluating the potential environmental benefits vary greatly. In Arizona, for example, environmental benefits including carbon emissions, criteria pollutants, and water and land impacts can be factored into the valuation, but only if these are not already considered in operating costs. Minnesota was also specific, including the value of avoided environmental costs based on the federal government's metric for the social cost of carbon and Minnesota-specific externality costs within a specific utility service territory. Currently, Minnesota anticipates the likely cost of carbon regulations to be in the range of $5 to $25 per ton of CO_2.[33] New York included an environmental value in the value stack provided to distributed energy resources, based on the latest Tier 1 REC published by NYSERDA (which for 2017 was $21.71[34]), or the social cost of carbon (which was around $36 in 2016 with a suggested value of $42 from the Interagency Working Group in 2017[35]), whichever is higher. New Hampshire's legislature included a mandate for the commission that the value was to factor in environmental benefits but was not more specific than that. South Carolina's legislative mandate also stated that environmental costs should be taken into account but mandated that those values must be quantifiable and not based on estimates.

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[29] U.S. ENERGY INFO. ADMIN., WHAT IS U.S. ELECTRICITY GENERATION BY ENERGY SOURCE? (2017), https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

[30] U.S. ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED: ELECTRICITY AND THE ENVIRONMENT (2017), https://www.eia.gov/energyexplained/index.cfm?page=electricity_environment. *See also* U.S. Energy Info. Admin., Frequently Asked Questions: What are the greenhouse gas and air pollutant emissions factors for fuels and electricity?, https://www.eia.gov/tools/faqs/faq.php?id=76&t=11.

[31] U.S. Energy Info. Admin., Carbon Dioxide Emissions Coefficients (Feb. 2, 2016), https://www.eia.gov/environment/emissions/co2_vol_mass.php.

[32] U.S. ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED: ELECTRICITY AND THE ENVIRONMENT (2017), https://www.eia.gov/energyexplained/index.cfm?page=electricity_environment.

[33] Jeffrey Tomich, *Minn. Tackles Timing, Cost of Carbon Regulations*, ENERGYWIRE (Apr. 23, 2018), https://www.eenews.net/energywire/2018/04/23/stories/1060079769.

[34] CLEAN ENERGY STANDARD, N.Y. STATE ENERGY RESEARCH & DEV. AUTHORITY, 2017 SOLICITATION (2017), https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts/2017-Solicitation.

[35] NAT'L ACADS. OF SCI., ENG'G, & MED., VALUING CLIMATE DAMAGES: UPDATD ESTIMATION OF THE SOCIAL COST OF CARBON DIOXIDE 2 (2017), https://www.nap.edu/read/24651/chapter/2#2.

Resiliency Attributes

Grid resiliency – generally thought of as the ability of the grid to recover after disasters or other life-threatening emergencies, and different from grid reliability – is difficult to define and to qualify. While more utilities and PUCs are starting to consider grid resilience, few have attempted to quantify the benefits that distributed energy resources may have in relation to grid resilience, or even define exactly what they mean when they use the term grid resilience. Arizona included security risks (both resilience and reliability) in the state's valuation, although these were not quantified, but instead simply included in the list of criteria to be considered. While New Hampshire adopted a long list of state DER goals, including promoting independence and reliability, resiliency was not included among them. However, the state requires customers using net metering to pay non-bypassable charges that include a storm recovery surcharge—a cost that is otherwise incorporated into customers' regular billing, and arguably adds to the state's resiliency through ensuring sufficient funds for restoration.

Risk-Hedging Attributes

Renewable energy resources can help hedge against the financial and regulatory risks facing the electricity sector. For example, solar and wind generation do not require fuel purchases and thus avoid the risk of fuel price volatility that has historically affected natural gas-fired generation. Solar energy also has predictable construction costs and relatively short construction time frames compared to other electricity generation options. Because most distributed energy generation does not emit air pollutants or utilize water, the facilities can also help electric power generators manage regulatory uncertainty regarding climate policy and other environmental regulations.

Despite the risk-hedging attributes associated with renewable energy, few states explicitly consider this factor in their DER valuation processes. Arizona considers valuations for financial risk, including fuel price hedging, in its calculations. The South Carolina legislature also identified fuel hedging as a factor for regulators to consider when valuing distributed energy resources. To date, neither state has quantified the risk-hedging benefits of DER.

Plans to Revisit DER Valuation

A number of states have specifically noted that either more information is needed or that the solution being implemented at this point in time is an interim one. Arizona will determine in future rate cases if they are going to retain valuation based on the five-year average of utility-scale solar PPA pricing or move to an avoided-cost methodology that "uses five-year forecasting to evaluate the costs and values of energy, capacity and other services delivered to the grid from distributed generation."[36] California plans to revisit retail-rate net metering (with non-bypassable charges) in 2020. Minnesota's valuation methodology includes two placeholder values, pending available data in the future. Mississippi is conducting an independent consultant study to determine if the 2.5 cent/kWh adder is the right value, or if it should be changed, and what values should be

[36] Pyper, *supra* note 19.

included in that decision. New Hampshire will revisit after a working group determines the details of data collection for a distributed energy resources valuation study and that study is performed. New York, while adopting the value stack approach for distributed energy resources,[37] continues to evaluate the appropriate valuation overall for distributed resources within the "Value of D" proceeding.

Conclusion

The nine states analyzed for this project have each taken a different path to valuation of distributed energy resources, and that is likely to continue into the future. State-level policy choices will continue to impact the valuation determinations made. While outside of the specific categories looked at in this paper, states continue to make other policy choices which impact their valuation decisions. Arizona, for example, specifically decided not to include any social impacts, including economic development opportunities, as being too speculative. California is moving all customers to default time-of-use (TOU) rates with an opt-out, but net-metered customers will not be able to choose to move back out of a TOU rate. Massachusetts most specifically dealt with land use concerns, grouping projects into those where the land hosting the project is agricultural or non-agricultural, and allowing the base compensation rate to have the potential for both adders (for specific locations like brownfield and landfills or as solar canopies; for shared community solar, low income properties, or public entities; and for storage and solar trackers) and subtractors (for greenfield development). Mississippi has also made low-income customer adoption a priority by providing a specific 2 cents/kWh adder for low income customers. As distributed generation penetration increases, states will continue to make choices based on state policies and goals that impact distributed generation valuation and customer choice.

Summary Table

This table summarizes the above material, and only includes what was found in the particular orders or statutes described in the Appendix. It does not reflect other aspects of state policy, but rather is limited to the material directly researched for this paper.

	Initiated by	Grandfathering	Distribution Impacts	Environmental Benefits	Risk Hedging	Plans to Revisit
Arizona	PUC	Yes	Yes	Yes	Yes	Yes
California	Legislature	Yes	Yes			Yes
Hawaii	PUC					
Massachusetts	Legislature					
Minnesota	Legislature		Yes	Yes		Yes
Mississippi	PUC					Yes
New Hampshire	Legislature	Yes	Yes	Yes		Yes
New York	PUC	Yes	Yes	Yes		Yes
South Carolina	Legislature		Yes	Yes	Yes	

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[37] *Briefing Notes: Value of DER— Phase I Order*, E9 INSIGHTS (Mar. 2017), https://gallery.mailchimp.com/3dcda9a0dee5aecdf43892999/files/47f317c5-0ce8-4d4b-9132-4ff26bb0e401/Briefing_Notes_Value_of_DER_Phase_I_Order.01.pdf.

ARIZONA[38]	
Factors chosen	**Factors identified but not adopted**
• 5- year timeframe • Avoided energy costs, including energy and system losses • Avoided generation, transmission and distribution capacity with line losses adjusted for geographic location • Grid support services • Financial risk, including fuel price hedging and market price responses • Security risks (reliability and resilience) • Environmental considerations, including carbon emissions, criteria pollutants, water and land impacts; but will not duplicate if these are already considered in operating costs • Existing net metered customers grandfathered for 20 years • Analysis on valuation performed by ACC staff, voluntarily undertaken as part of the ACC Renewables Initiatives[39]	• Longer timeframe (20 to 30 years) • Social impacts, including economic development opportunities

[38] In the Matter of the Commission's Investigation of Value & Cost of Distributed Generation., 334 P.U.R.4th 29, Decision No. 75859 (Jan. 3, 2017), at 106, 114, 134, 148, 150, 152– 54, 156, 157, http://images.edocket.azcc.gov/docketpdf/0000176114.pdf.

[39] In the Matter of the Commission's Investigation of Value & Cost of Distributed Generation., 334 P.U.R.4th 29, Decision No. 75859 (Jan. 3, 2017), at 5, http://images.edocket.azcc.gov/docketpdf/0000176114.pdf.

CALIFORNIA[40]	
Factors chosen	**Factors identified but not adopted**
• Continue basic net metering structure, including retail rate compensation • Adopt default time of use (TOU) rates for all residential customers; all new net metering customers have no option to opt out of a time-differentiated rate • Customers who opt into a TOU rate prior to default residential TOU rates going into effect can stay on that TOU rate for a period of five years • New net metering customers pay interconnection costs of $75-$150 (waived for low income households) • Net metering customers must pay non-bypassable charges on each kWh of electricity they consume from the grid, including the Public Purpose Program Charge, the Nuclear Decommissioning Charge, the Competition Transition Charge, and the Department of Water Resources Bond Charges • No change to standby charges • Systems larger than 1 MW can participate in net metering provided they have “no significant impact” on the distribution grid and pay all interconnection costs • Customers under current net metering standard grandfathered for 20 years from the date of the customer’s interconnection • Customers under this current net metering order also grandfathered for 20 years • Customers may not restart the 20- year grandfathering period by switching to the new metering tariff, but they can elect to transfer if they choose • Valuation analyses performed by intervenors • Action required by state statute[41]	• Customers continue not to pay non-bypassable charges, or only pay for the Public Purpose Program Charge after the market recovers from the projected loss of the federal investment tax credit or another transition period • Allow systems larger than 1 MW to be exempt from interconnection fees, grid charges, standby charges and non-bypassable charges • Add demand charges, grid access charges, additional fixed charges, grid use charge, standby charges, or installed capacity charges, including for residential customers • Require systems larger than 1 MW to pass the Rule 21 Fast Track process to be eligible for net metering • Interconnection fees for residential up to $280, and higher for systems above 30kW • Compensate at less than full retail rate (energy generation rate, levelized avoided cost, levelized avoided cost plus renewable energy credit adder), retail system average commodity rate, or wholesale rate • Cap total eligible system size at 3 MW • Customers purchase all energy consumed and are credited on their bills at the utility’s avoided cost for all energy they generate • Eliminate annual true up • Grandfather a specific rate for 10 years, based on levelized 10 year forecast of avoided cost, plus a distributed generation adder

[40] Order Instituting Rulemaking to Develop A Successor to Existing Net Energy Metering Tariffs Pursuant to Pub. Utilities Code Section 2827.1, & to Address Other Issues Related to Net Energy Metering., 327 P.U.R.4th 75, Decision 16-01-044 (Jan. 28, 2016), at 2–5, 23–36 86–89, 91– 96, 99–101, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.

[41] Cal. Pub. Util. Code § 2827.1 (West); *see* PUBLIC UTILITIES—ENERGY—RATES AND CHARGES, 2013 Cal. Legis. Serv. Ch. 611 (A.B. 327) (West).

HAWAII[42]	
Factors chosen	**Factors identified but not adopted**
• Caps net metering program at existing levels, indicating that net metering is fully subscribed and closed to new participants • Customers who applied for interconnection up to the date of the order shall continue to be eligible for interconnection under the net metering program • Customers going forward can choose a self-supply tariff or a grid-supply tariff • All future interconnection applications will be treated as an application under the grid-supply tariff unless otherwise indicated by the customer • The self-supply tariff is a limited, non-export solution that requires customers to use their generation to meet their own energy needs; allows only a limited amount of inadvertent export to the grid, with no compensation provided for any exported energy • The grid-supply tariff provides customers with the option of exporting excess generation, compensated at the energy credit rate, calculated at 12-month average on-peak avoided cost ending June 2015 for each island grid, guaranteed for 2 years; but this is seen as a transitional option, and initially set a cap at 24 MW for HECO and 5 MW each for HELCO and MECO for this option; no carry-over of energy credits month to month • Minimum bill of $25 for residential customers and $50 for small commercial customers under either option • TOU rate available to any eligible customer, with three time periods: overall system peak period, mid-day period, and off-peak period • Valuation is pending as part of the Phase 2 analysis [43] • Adopted on HPUC's own initiative	• No minimum bill charges or minimum bill for all customers • Mandate a minimum interconnection fee • Grid-supply tariff rate should be fixed for a period of five years • Compensation rate for grid-supply option should use wholesale value of renewable energy provided to the grid rather than wholesale rate • Limit TOU options to pilot areas • Two-period TOU design (only on-peak and off-peak) • No TOU at this time, need further study

[42] In the Matter of Pub. Utilities, Comm'n, 325 P.U.R.4th 339, Order No. 33258, (Oct. 12, 2015), at 118–123, 126–34, 139–42, 146–52, 196–97, https://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15J13B15422F9046418+A15J13B31859H489831+14+1960.
[43] *Id.* at 62.

MASSACHUSETTS[44]	
Factors chosen	**Factors identified but not adopted**
• Successor tariff to net metering as net metering has hit its full capacity of 15% of peak load; uses wholesale transactions as a base compensation rate • Developed specific land use, siting, and development criteria, including whether the land hosting the distributed generation is agricultural or non-agricultural and the size of the system • Systems are grouped into Class I, Class II, or Class III based on size (up to 60 kW, 60 kW – 1 MW, and 1 MW – 2 MW, respectively) • Systems under 10 kW on a single-phase circuit and systems under 25 kW and under on a three-phase circuit are exempt from capacity limits • All systems subject to capacity limits receive market net metering credits for excess generation • The base compensation rate will decrease with increasing solar generation, with the potential for both adders (for specific locations like brownfield and landfills or as solar canopies; for shared community solar, low income properties, or public entities; and for storage and solar trackers) and subtractors (for greenfield development) • There are limits as to which adders can be combined with different class facilities and size of generating unit • Compensation rates are in effect for 20 years for systems over 25kW and 10 years for systems under 25kW • No specific valuation yet accomplished; but changes were required by session law Chapter 75 Act of 2016[45]	• Information not available

[44] 225 Mass. Code Regs. 20.00, Solar Mass. Renewable Target (SMART) Program, https://www.mass.gov/files/documents/2017/11/14/225-cmr-20-00-draft.pdf, at *8–12, 15–24.
[45] Chapter 75 of the Acts of 2016, "An Act Relative to Solar Energy."

MINNESOTA[46]	
Factors chosen	**Factors identified but not adopted**
• Assumed 25-year lifespan for solar PV installations • New value for solar compensation based on: avoided fuel cost (based on energy market cost including the cost of long-term price risk), avoided fixed plant O&M, avoided variable plant O&M, avoided generation capacity cost (based on natural gas facilities), avoided reserve capacity cost, avoided transmission capacity cost, avoided distribution capacity cost (based on location), avoided environmental cost (based on the federal government's social cost of carbon and Minnesota-specific externality costs within a specific service territory) • Two other values are included but are currently placeholders pending the ability to be measurable in the future: avoided voltage control cost and solar integration cost • Formula looks at these components plus the load match factor, loss savings factors, discount/escalation factors, and solar penetration • Valuation calculations made by the Minnesota Department of Commerce • Changes required by statute[47]	• Component corresponding to the compliance value of solar renewable energy credits • Component representing the value of increased economic development • Any factor not based on known or measurable evidence • An assumption of a 20-year lifespan for solar PV installations • Other environmental externality values, including regulatory planning values • Other values than the social cost of carbon for CO2 emissions values • Utility-specific, substitute, or more complex avoided fuel costs • Corresponding avoided generation capacity cost to utility's next planned generation facility • Requested credit to be given for local manufacturing or assembly • Market price reduction • Adder for disaster recovery • Separate treatment of solar renewable energy credits

[46] In the Matter of Establishing A Distributed Solar Value Methodology Under Minn. Stat. S 216b.164, Subd. 10 (e) & (f), E-999/M-14-65, 2014 WL 1347985, at *4, 7–8, 10–14, 18, (Apr. 1, 2014).
[47] Minn. Stat. § 216B.164, subd. 10(e) (2017).

MISSISSIPPI[48]	
Factors chosen	**Factors proposed but not adopted**
• Excess generation sold to the utility at avoided cost plus a distributed generation benefits adder of 2.5 cents/kWh • Carryover of excess energy indefinitely but valued each month • All usage from grid billed at retail rate • Electricity exported to the grid will not offset customers' monthly electricity use • 2.5 cents/kWh is for presently non-quantifiable benefits; will be replaced with calculation of actual benefits based on independent consultant study • Credits for excess energy exported shall not reduce any fixed monthly charges or minimum bill provisions • First 1000 low-income customers receive an additional 2 cents/kWh adder for the first 15 years • Renewable energy credits transfer to utility for any excess generation sent back to the grid where 2.5 cent/kWh adder is paid • Avoided cost calculation includes the cost of fuel needed to produce that electricity and corresponding portion of plant's operation and maintenance costs; average line loss adjustment; no capacity credit. If within an RTO, is the locational marginal price for that load zone and may be adjusted to reflect daytime energy production of solar PV systems • No valuation specifically conducted • Action not required but specifically authorized by the Miss. Code Ann. § 77-3-45 and Mississippi Administrative Procedures Act, Miss. Code Ann §§ 25-43-1.101	• Carryover of energy credits in kWh for indefinite period • All usage billed at retail rate and all generated energy valued at avoided cost rate • Retail rate for excess generation • Separate determination of avoided cost for distributed generation assets • All renewable energy credits stay with the customer, regardless of whether that energy is supplied to the grid or used instantaneously by the customer • All renewable energy credits come to the utility, which monetizes them for the benefit of the entire customer base

[48] Mississippi Public Service Commission, *Order Adopting Net Metering Rule*, Docket No. 2011-AD-2, http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=362179, at 9–12, 14–20, A1–A7, B1, B6, B7–17, B20.

NEW HAMPSHIRE[49]	
Factors chosen	**Factors identified but not adopted**
• Alternative net metering tariff in effect while further data is collected, pilot programs are implemented, and a DER valuation study is conducted (details of data collection for DER study to be determined through a working group) • Systems of 100 kW or less will net meter with monthly monetary credits (rather than kWh credits) equal to the value of the kWh charges for energy service transmission at 100% and distribution service at 25%, pay non-bypassable charges (system benefits charge, stranded cost recovery charge, storm recovery surcharges, other surcharges, electricity consumption tax) on full amount of electricity imported from the grid without netting exports • Accumulated excess credits will receive a cash payment when customers move/discontinue service or on an annual basis if credit balance is above $100 • Net metering grandfathered until 2040 while the alternative tariff in place • Net metering customers will have bi-directional meters installed to record separately the quantities of electric imports from the grid and exports to the grid • Large customer generators receive export credits based on utility default service energy charge, also with monetary crediting instead of kWh banking; systems of between 100 kW and 1 MW are only eligible for new tariff if they consume greater than 20% of actual or estimated distributed generation system electric production behind the meter • Utilities have the opportunity to recover lost revenues attributable to customer net metering; approve utilities to install production meters behind the meter at no cost to those customers if the customer opts in to a production meter • Utilities permitted to recover prudently-incurred costs of required metering upgrades, study expenses, and pilot program • Approve utilities to facilitate REC program; utilities not obligated to purchase RECs, but may at reasonable market prices	• Separate rate classes for those with distributed generation • Mandatory demand charges for those with distributed generation • Mandatory time of use rates • Customers should pay 100% of distribution as well as 100% of transmission charges • Excess credited at energy service rate rather than retail rate • Excess credits at end of billing cycle paid at avoided cost rate • Install production meters so utilities could measure lost revenue from customer consumption of self-generated electricity behind the meter • Use of comprehensive list of benefits and costs to determine value of excess energy (to include avoided energy cost, avoided generation capacity, avoided line losses, avoided ancillary services, avoided transmission and distribution capacity, avoided environmental costs, avoided carbon emissions, avoided fuel hedging/fuel price uncertainty, market price mitigation, avoided renewables, and societal benefits) • If uncertainty in benefit value, consider range rather than saying it is unquantifiable and therefore assigning a zero cost • Increase system size available for net metering to 250 kW • Allow residential customers to monetize RECs by optionally selling RECs to an aggregator for a specific adder to their net metering credit • Approve specific adders for larger commercial systems (greater than 100 kW) including location benefits adder, directional benefits adder, environmental benefits adder, municipal or other public benefits adder, peak demand time of use adder, development adder, adder for storage or other ancillary services • 25-year grandfathering of rates • No cap on distributed generation

[49] Dev. of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms & Tariffs for Customer-Generators, 25,972, 2016 WL 7433293, at *1–2, 6–13, 15–20, 48–51 (Dec. 21, 2016), http://www.puc.state.nh.us/Regulatory/Orders/2017orders/26029e.pdf.

• After completion of the DER study, commission will open a new proceeding to determine if changes are needed • Factors required by the legislature for the commission to take into account: costs and benefits of customer generator facilities; avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time-based tariffs; whether there should be a limitation on the amount of generating capacity eligible for alternative net metering tariffs; the size of facilities eligible to receive net metering tariffs; timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms; and continuance of reasonable opportunities for electric customers to invest in and interconnect customer generator facilities and receive fair compensation for such locally-produced power while ensuring costs and benefits are fairly and transparently allocated among all customers, and the promotion of a balanced energy policy that supports economic growth and energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits and a modern and flexible grid • Valuations provided by both staff and 3rd parties • Action was required by statute[50]	• Set standard reviews of policy at specific percentages of utility peak load • Office of Consumer Advocate indicated benefits of solar range between 13 and 15 cents/kWh, not including different societal benefits which are hard to quantify • Larger systems use competitive bid/auction mechanism • Real time pricing on an opt-in basis, with credit based on load zone real-time locational marginal price with generation related ancillary services adjusted for avoided line losses and credited for capacity market prices for exported energy • Transmission charges charged or credited depending on customer's load during monthly coincident peak

[50] 2015 New Hampshire House Bill No. 1116.

NEW YORK[51]	
Factors chosen	**Factors identified but not adopted**
• Residential customers retain retail-rate net metering for 25 years after in-service date for projects under the transition plan and 20 years for projects developed under the Phase One NEM order • Grandfathering includes option for developers or customers able to file for a term longer than 20 years based on pre-existing financial or other contractual arrangements • Community Distributed Generation, Remote Net Metering, and large on-site projects compensated based on limited net metering or DER value stack depending on contractual obligations (systems with storage must use value stack) • For projects compensated under the value stack, the compensation term is 25 years from the in-service date • Value stack based on: energy value (day ahead hourly zonal locational-based marginal price, inclusive of losses); capacity value (different methodologies for intermittent and dispatchable technologies); environmental value (based on latest Tier 1 REC published by NYSERDA or Social Cost of Carbon, whichever is higher); demand reduction value and locational system relief value (adopted to maximize benefits to the system as a whole; determined every three years; projects that qualify for LSRV will receive that compensation for ten years, whereas DRV shall not be fixed by instead changes as updated by the utility on a three-year basis) • This value stack means the value of a kWh can vary greatly depending on where and when it is injected into or consumed from the grid • The costs associated with compensation under the value of DER will be collected proportionately from the same group of customers who benefit from the savings associated with the compensated DER • Valuations primarily made by PSC staff • Action taken voluntarily at PSC's initiative	• Grandfathering should be for 25 years after the in-service date for all projects • Grandfathering should be for 15 years to reduce long-term risks to non-participants • For energy value in value stack, should have additional study to understand how avoided losses are impacted with the increased use of distributed generation • For energy value in value stack, other components should be included, such as congestion and losses • For capacity value in value stack, value based on a single peak hour during the year presents too much uncertainty and variability, has the potential to unfairly favor solar over hydro, and another value should be chosen • CHP plants using non-renewable fuels should not be eligible for environmental value part of the value stack • There should be no compensation for environmental values in the value stack • The values for DRV and LSRV raises uncertainties about financing; need a long-term fixed rate for compensation for predictability • Values not taken into effect in the value stack include: distribution system values not reflected by the locational demand reduction value; reduced sulfur dioxide and nitrous oxide emissions; reductions in carbon dioxide emissions; land and water impacts; environmental justice impacts; wholesale price suppression; particulate reduction; reduced energy burden for low-income customers; local job creation; increased resiliency; and ensuring geographical equity.

[51] Case 15-E-0751 In the Matter of the Value of Distributed Energy Res, Case 15-E-0082 Proceeding on Motion of the Comm'n As to the Policies, Requirements & Conditions for Implementing A Cmty. Net Metering Program., 335 P.U.R.4th 178 (Mar. 9, 2017)), at *15–17, 46–49, 50, 52–56, 82, 86–88, 90, 93, 96, 97–100, 102–104, 106–109, 111, 119–121.

SOUTH CAROLINA[52]	
Factors chosen	**Factors identified but not adopted**
• Factors to be used to determine the value of net metered distributed energy resources: avoided energy; energy losses/line losses (at generation, transmission and distribution); avoided capacity; ancillary services; transmission and distribution capacity; avoided criteria pollutants; avoided carbon dioxide emission cost (zero monetary value until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions); fuel hedge; utility integration and interconnection costs; utility administration costs; environmental costs (must be quantifiable and not based on estimates); and other categories which cannot currently be quantified but which will be continuously updated • Utilities allowed to recover costs related to DER programs to extent that costs are reasonably and prudently incurred to implement approved programs; will be recovered during annual fuel proceeding • Any difference between value of DER generation and retail rate paid to customer generators shall be treated as a DER program expense and collected through fuel clause; not recovered through base rates • Avoided costs calculated using less of rates negotiated pursuant to PURPA or electric utility's most recently approved/established avoided cost rates • Requires development by 1/1/2021 of renewable energy facilities equal to at least 2% of previous five-year retail peak demand for each utility, with at least 0.25% of that from small scale facilities (20 kW or less) • Net metering available for all 2% required under the program • Energy generated that exceeds energy supplied by the utility during the billing period not used to offset non-volumetric electricity charges • Any excess rolled over to future billing periods; but annually utility pays for any accrued excess at avoided cost • Utility to calculate whether it has under-recovered or over-recovered revenue from net metering customers	• Environmental benefits insufficiently calculated • Rate for excess energy should be based on net cost to serve customer generators, retail rate provides a subsidy to DER customers

[52] Distributed Energy Resource and Net Metering Implementation, SOUTH CAROLINA OFFICE OF REGULATORY STAFF, (July 21, 2016), https://www.scstatehouse.gov/CommitteeInfo/PublicUtilitiesReviewComm/Act236Reports/DER%20and%20Net%20Metering.ORS.2016.pdf, at 3–4, 8–10.

by: computing bill without consideration of DER production; subtracting actual bill with consideration of DER; subtracting amount net benefits delivered by DER; if final number positive, then under recovered, if negative, then over recovered from net metering customer. • Customer generator treated same as others in rate class for all other purposes (type of meter, rate) • Cap of adder to bills to pay for incremental utility costs to implement DER under the program ($12/year for residential customers; $120/year for commercial; $1200/year for industrial) • Valuation is pending in the office of regulatory staff • Actions were required by statute[53]	

[53] South Carolina Distributed Energy Resource Act, S.C. Code Ann. § 58-39-110.