APPENDIX

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

by

Co-Authors

Jamie Barber, Energy Efficiency and Renewable Energy Manager, Georgia PSC and Chair of NARUC Staff Subcommittee on Rate Design

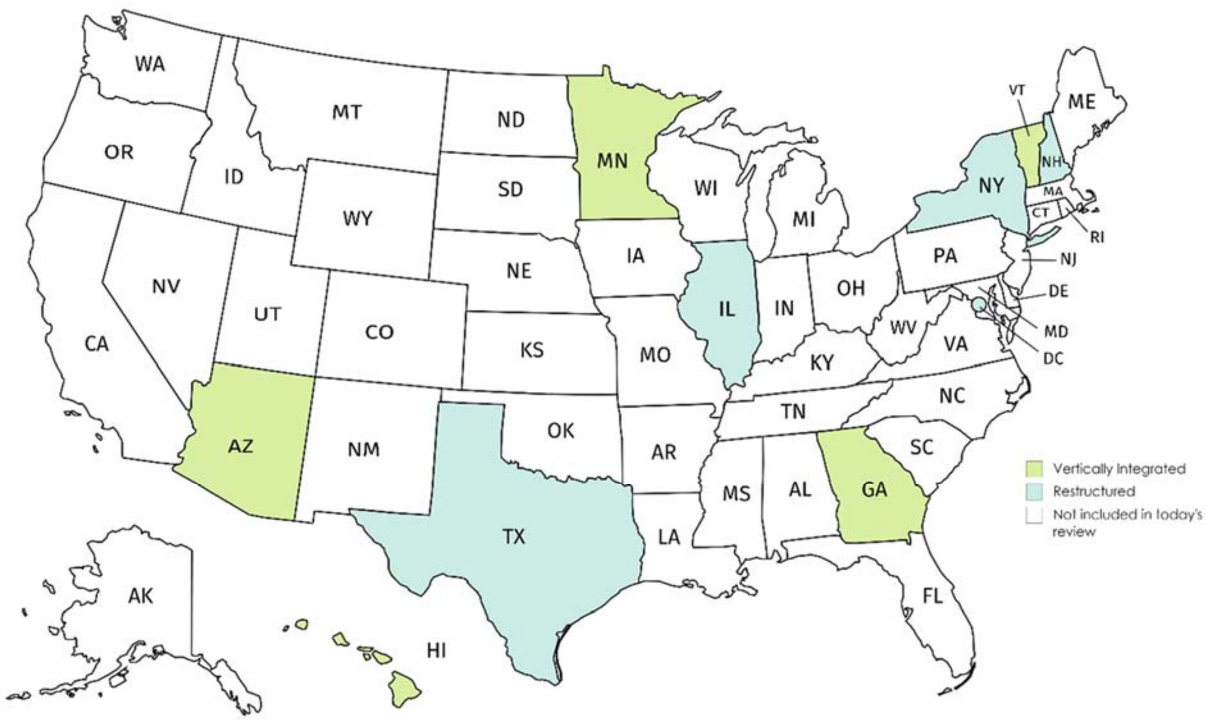
and

Tom Stanton, Principal Researcher, Energy and Environment National Regulatory Research Institute

Introduction

In completing this review of state activities regarding NEM 2.0 and NEM successor tariffs, the authors completed somewhat more detailed reviews of activities in ten states, five vertically integrated states and five restructured states. The five vertically integrated states, shaded in green in Figure A-1, include: Arizona; Georgia; Hawaii; Minnesota; and, Vermont. The five restructured states, shaded in blue in Figure A-1, include: the District of Columbia; Illinois; New Hampshire; New York; and, Texas. Those ten states were selected because they have each engaged in more than one of the actions included in the review completed for this project.[a]

Figure A-1: Map of States Included in Summary Reviews



---

[a] Readers aware of any needed corrections, additions, or deletions are invited to contact Mr. Stanton, at NRRI. Please email tstanton at nrri dot org.

Arizona (vertically integrated)

In Docket No. E-01345A-16-0036 in June 2016, Arizona Public Service (APS) requested to increase its residential fixed charge as well as implement mandatory demand rates for all residential and small commercial customers. A settlement among 30 of the approximately 40 intervening parties – including APS, Arizona Commerce Commission (ACC or Commission) Staff and solar advocates – provides an optional demand-based rate or a time-of-use (TOU) rate for all new distributed solar customers. The settlement agreement also allows those rates as options for non-solar customers.

After May 1, 2018, all non-solar and new APS customers will be required to be on some kind of time-varying rate. As part of the ACC Order, APS was required to file for approval a Customer Education and Outreach Program to provide customers adequate notice of their rate options after May l, 2018, accompanied by information on the estimated bill impact if they do switch to another rate.

The settlement agreement, approved by a 4-1 ACC vote and effective 19 August 2017, increased the average residential customer monthly bill by 4.54% or $6, but that is less than the 7.96% or $11 increase that APS originally requested.

The settlement agreement included a $15 million refund in already-collected, unspent funds, which had been earmarked for energy efficiency projects but now will be used to help offset first-year bill impacts. APS also agreed not to file a rate case until at least June 1, 2019.

Grandfathered DG customers will continue to take service under full retail rate net metering. Distributed generation (DG) customers that filed their interconnection application before 19 August 2017 were grandfathered for 20 years from the date their system is interconnected with APS.

New DG customers are eligible for four different rate schedules including all proposed TOU and demand rates. DG customers that select TOU-E will be subject to a grid access charge. The self-consumption offset rate for TOU-E will be approximately $0.120/kWh. This offset rate includes a grid access fee, and was based on the load profile and production profile of APS customers with DG during the test year. Actual customer offsets will vary based on individual usage patterns and DG system size, orientation, and production.

The new export rate for new customers, based on the settlement, is 12.9 ¢/kWh. The export rate will be reevaluated annually, based on the Resource Comparison Proxy (RCP) model ACC approved in December 2016 as part of a year-long value-of-solar proceeding Docket No. E-00000J-14-0023.

Based on that ACC decision, solar export rates are to be calculated using the RCP, or by an avoided-cost methodology based on five- year forecasting to evaluate the costs and values of energy, capacity, and other services delivered to the grid from distributed generation. RCP is to be used until the Five Year Avoided Cost methodology is finalized. The RCP is calculated using a rolling historical five-year weighted average cost of grid scale solar PV facilities that APS owns or has rights to through a PPA, plus applicable avoided transmission capacity cost, avoided distribution capacity cost, and line losses. An export rate will stay in effect for ten years from the time of the customer's interconnection. After each customer's initial 10-year period, the export rate will be based on the purchase rate in effect at that time, and will change from year to year.

In February 2017, the ACC approved a 30 percent increase, from $10.00 to $13.00, in the residential fixed charge for customers of Tucson Electric Power (TEP). TEP also received approval for a more advanced TOU rate design with a plan to make TOU rates the default for all new customers starting in 2018.

In August 2017, the Utilities Division Staff requested that the Commission open a docket starting a Rulemaking process to review and amend the current Net Metering Rules, to comport with the major changes in circumstances since their adoption. On November 17, 2017, the Commission opened Docket RE-00000A-17-0260. Prior to the drafting of revised rules, in February 2018, the Staff solicited comments from stakeholders, raising 11 specific questions. The questions include how export rates are addressed, which Phase II proceeding decisions to include in the revised rules, and if provisions for nonresidential customers and non-solar technologies should be included.

On July 17, 2018, the ACC opened docket E-01345A-16-0036. This is the nation's first state docket focused on transactive energy. ACC Commissioner Andy Tobin, who requested the hearing, expects the docket to address several transactive energy issues, including the internet of things, cybersecurity, utility accounting, tracking renewable energy credits, and the effects of applications for distributed ledger technologies, like blockchain, on the grid.

Georgia (vertically integrated)

Third-Party Ownership – In 2015, the Georgia legislature passed House Bill 57, authorizing third-party ownership, including both leasing and solar energy PPAs. The legislation took effect July 1, 2015 (http://www.legis.ga.gov/legislation/en-US/Display/20152016/HB/57). In addition, Georgia Power started providing information to its customers, through "solar energy experts," about whether solar was right for them and announced plans to offer financed distributed-solar systems through an unregulated affiliate.

Value-of-Solar – A discussion about VOS was initiated in Georgia in 2014, with a filing from the Georgia Solar Energy Industries Association (GSEIA) and Vote Solar. SEIA and Vote Solar requested that the Georgia Public Service Commission (GA-PSC or Commission) establish and calculate the value of solar energy delivered to Georgia Power Company (Georgia Power or Company) from customer-sited facilities, as well as establish a valuation methodology for all programs and initiatives. At that time, behind the meter distributed generation (DG) compensation was based on a Public Utility Regulatory Policies Act (PURPA) avoided cost rate, as determined by Commission Order, with an adder to account for distribution system benefits. Since Georgia does not provide for full retail net metering or the banking of excess generation, many parties felt that self-generators were not being appropriately compensated for their energy exports.

Prior to the 2016 IRP filing for Georgia Power, the Commission held a workshop to examine issues related to, and try to find consensus on, a methodology for determining the value of renewable and distributed energy resources. After the workshop, GA-PSC Staff finalized a report that included six recommendations for specific analyses to be submitted by the Company as part of its 2016 IRP filing.

In its 2016 IRP, Georgia Power sought approval of a proposed Renewable Cost Benefit (RCB) Framework. The proposal included methods for: (a) updating avoided cost methodologies to reflect future costs and benefits; and (b) determining the value of behind the meter DG. The Company defined 21 separate elements of system costs that could change, up or down, when a renewable resource is added to the grid. Several of the same elements had been included in the Company's previous avoided cost methodology.

In the 2016 IRP Final Order, the Commission approved a stipulation between Staff, Georgia Power, and many other parties, providing that certain components of the RCB Framework would be utilized in the upcoming utility-scale solar resource evaluation. The Order also required Staff and Georgia Power to continue discussions regarding the RCB framework and file a recommendation within four months. A Joint Recommendation filed in December 2016 was subsequently approved by the Commission. That recommendation specifically stated that a modified RCB Framework would be utilized in both the 2017 and 2018 Utility Scale Renewable Energy Development Initiative (REDI) evaluations and the upcoming REDI DG evaluation, but would not apply to behind the meter technologies. During its consideration of this issue, the Commission encouraged parties to work together to develop a RCB methodology that could apply to behind the meter technologies.

Several parties, including Staff, Georgia Power, Southface, Georgia Interfaith Power and Light and GSEIA, met over the next several months and on June 1, 2017 Georgia Power filed a request to apply the RCB Framework for behind the meter technologies. This request also included a project size increase from 100kW to 250 kW for non-residential projects to qualify for the Company's Renewable and Nonrenewable Resources (RNR) tariff. The Commission approved this request, with the new RNR tariff effective August 2017.

Community Solar – During the 2016 IRP proceeding, with the approval of a motion by Commissioner Tim Echols, a three megawatt (MW) community solar program was approved. Under that program, Georgia Power may construct these projects and include them in rate base, as long as they can produce energy at or below avoided costs.

In April 2017, Georgia Power requested approval of a Community Solar (CS) Program and related tariff CS-1. The CS program pro-vides residential customers an opportunity to support solar power in Georgia by purchasing monthly subscriptions, priced at $24.99 per average block estimated at 180 kWh per month (~13.8 ¢/kWh). With a subscription, the customer will receive a bill credit based on production from the company-owned solar facilities that support the CS program. The CS tariff was effective with the December 2017 billing month. In addition to the 3 MW approved during the 2016 IRP, GA-PSC, in January 2018, approved an additional 5 MW of community solar owned by Georgia Power.

Hawaii (vertically integrated)

In 2015, due to rapid growth in solar installations, Hawaii became one of the first states to end its net metering program and approve successor tariffs. Changes to Hawaii policies already include the net metering successor policies and a round of revisions to them, increases in residential fixed charges, and added customer options for community solar.

Net metering successor policy – In an October 2015 order, the Hawaii Public Utilities Commission (PUC or Commission) ended its net metering program and approved a net metering successor policy. On August 21, 2014, the PUC initiated Docket 2014-0192 to investigate the technical, economic, and policy issues associated with DER as they pertain to the electric operations of each of the Hawaiian Electric Companies and *Kauai Island Utility Cooperative (KIUC)*. In its decision, the Hawaii PUC grandfathered existing net metering customers.

A choice of new DG tariffs – After October 12, 2015, new self-generators must export energy under either: (1) a grid-supply option with credits based on a utility avoided cost determined by the Hawaii PUC (net billing); or, (2) a customer self-supply (CSS) option, which receives no credit for grid exports. The grid-supply option credits for exported energy ranged from $0.15 to $0.27 per kWh, depending on the utility service territory. The export credit rate was good for two years, not the five years Hawaiian Electric Company (HECO) originally requested.

The PUC also set caps for the grid supply tariff which were 25 megawatts ("MW") for HECO, 5 MW for Hawaiian Electric Light Company (HELCO) and Maui Electric Company (MECO), based on the idea that unconstrained growth in the grid-supply option would not be in the public interest, particularly if such growth would come at the expense of future opportunities to acquire even lower-cost renewable energy from other sources or prevent the HECO Companies from offering community-based renewable energy options for their customers.

Under the grid supply tariff, if a customer generates more than they consume, there is no credit for the excess generation and credits do not carry over to the next month. The self-supply tariff does not compensate customers for exporting electricity to the grid. The PUC found that a time of use (TOU) rate option could provide significant benefits to customers and to each island power system, and should be offered by the HECO Companies and KIUC. However, the Commission did not approve the proposals presented by the Parties in this docket and instructed the HECO Companies to re-file a TOU tariff option within 30 days, with three time periods each day: off-peak, mid-day, and on-peak. TOU rates with three time periods per day are unique to Hawaii at this point, driven by the high percentage of customers using distributed PV combined with Hawaii's abundant year around solar radiation (because Hawaii is relatively close to the equator). Generally that means the VOS in Hawaii is somewhat lower during the mid-day time period, as the large volumes of solar energy exports drive down total utility production costs during the day, and that is followed by the "on-peak" demand period from 5 to 10 p.m., as the sun is gradually setting and more residential consumers return home and use more electricity.

Phase 2 DER Proceedings: The caps for the grid-supply option were reached in 2016, leaving CSS as the only option open to new customer-generators. The Commission retained the ability to adjust the grid-supply tariff cap to accommodate other offerings that might become available to customers in this interim time period, and could consider adjustments to the grid-supply tariff caps in Phase 2 of this proceeding.

In a December 2016 Order No. 34206 in Docket No. 2014-0192, the Commission launched Phase 2 of its DER proceeding, to consider a variety of DG issues, including determining whether either the tariff options themselves, interconnection standards, or both should be modified to facilitate or enable proposed changes to the interim DER options.

The Phase 2 proceeding included a technical track with two issues: (1) how utility DER integration analyses can more accurately characterize grid capacity from various DERs; and, (2) how interconnection standards can be modified to promote the safe and smooth grid integration of increasing levels of DERs. At this juncture, the Commission mandated the use of advanced inverters, which are capable of achieving voltage regulation at a small fraction of the alternative cost of installing conventional voltage regulators on the distribution system.

In addition to the technical issues, there five market issues are being examined: (1) longer-term competitive market structures for DER exports and services, including 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 unable 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. A July 2017 Commission order established the procedural schedule, which consists of multiple working groups. In August 2017, parties sub-mitted stipulations addressing both technical and market issues.

Revisions to the NEM Successor Tariffs – During October 2017, the Hawaii PUC issued an Order No. 34924, revising the net metering successor tariffs, creating a new Smart Export option to encourage solar-plus-storage and a control-able grid-supply option, called the CGS+ tariff. The Smart Export and CGS+ programs complement the existing customer self-supply (CSS) program.

The Smart Export is designed for solar-plus-storage customers and will compensate participants for exports during non-daytime hours (that is, not between 9 am and 4 pm), but compensation will be below retail rates, reflecting the relative value to the grid. The Commission approved interim Smart Export program capacity limits of 25 MW for HECO, 5 MW for HELCO, and 5 MW for MECO. The HECO Companies will receive and approve applications until the capacity of approved applications reaches the interim Smart Export program cap. Once that occurs, the HECO Companies will continue to accept applications, but cannot approve them unless program space is made available because a previously approved application is withdrawn.

A “controllable grid-supply” (CGS+) option succeeded the grid-supply option. This tariff allows the utility to control output from customer-owned PV with excess generation credited below retail. The CGS+ tariff will be available to new capacity (the grid-supply tariff reached its cap in 2016). Although in its Order, the Commission reduced the export credit rates, the rates are fixed for five years. The Commission approved program caps for the CGS+ program is 35 MW for HECO, and 7 MW for HELCO and MECO. The PUC required the HECO Companies to provide notice when 50%, 75%, and 90% of their respective CGS+ program caps have been reached. Upon receiving notice from any of the HECO Companies that 75% of its CGS+ program capacity has been reached, the commission intends to issue a notice to the Parties, setting a date and time for a technical conference to discuss the program cap. Smart Export and CGS+ customers will be required to enable advanced inverter functions to help mitigate any impacts the DER systems will have on grid reliability.

The HECO companies filed new tariffs in December 2017, and the Commission accepted comments. In a March 2018 order, the Commission required the HECO companies to make changes to both tariffs in regards to control equipment. In 2018, HECO resubmit-ted its new tariffs and its policy and procedure for allowing net metering customers to add non-exporting energy storage systems. The PUC issued a June 2018 Order No. 35563 in Docket No. 2014-0192. Through that order, the PUC approved HECO's smart export tariff and net metering policy proposal, and invited comments on the CGS+ tariff.

Residential Fixed Charges – In 2015, three of Hawaii's utilities, Maui Electric Co., Hawaiian Electric Co., and Hawaiian Electric Light Company, increased residential fixed charges. In December 2016, Hawaiian Electric Company (HECO) proposed an increase in its residential monthly fixed charge from $9.00 to $14.00 ($11.50 was approved) and an increase in its residential monthly minimum bill from $17.00 to $25.00 ($25.00 was approved). At HECO rates, this minimum bill covers only $16 of electricity, or about 50 kWh per month; any customers with a refrigerator, coffee pot, and a few lamps will exceed this minimum. Thus, the minimum bill mainly affects customers with second-homes, that net-meter to zero usage when the homes are not occupied. The minimum bill was carefully crafted to have essentially no effect on full-time residents with properly-sized PV systems. The PUC issued an interim decision and order in December 2017, approving in part and denying in part, a November 2017 settlement filed by HECO and the Consumer Advocate. Among the disputed aspects of the settlement was the PUC's request that the interim revenue increase be scaled back by $5 million. In the coming months the PUC will examine other issues related to the rate case.

In September 2016, Hawaiian Electric Light Company (HELCO) proposed an increase in its residential monthly fixed charge from $10.50 to $14.50 ($11.50 was approved) and its monthly residential minimum bill from $20.50 to $25.00 ($25.00 was approved). HELCO and the Consumer Advocate filed a stipulated settlement letter in July 2017, which included an interim increase in revenues and the full increase requested for the residential minimum bill. The Commission issued an interim decision and order in August 2017, granting an interim rate increase, but left some issues unresolved.

In March 2018, HELCO filed a Motion to Adjust the Interim Rate Increase, to reflect the effects of the corporate tax cut enacted by Congress. A June 2018 order from the PUC approved the settlement, increasing the minimum bill to $25.00.

In October 2017, Maui Electric Co. (MECO) applied to increase its minimum bill to $25.00, as well as increase the residential monthly fixed charge from $8.50 to $13.50. 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, plus the requested minimum bill increase to $25.00.

Community Solar – S.B. 2010, which was enacted in May 2015, allows any person or entity to "own or operate an eligible community-based renewable energy project." The legislation required utilities to file community renewable energy tariffs with the Hawaii PUC by October 1, 2015. In Docket 2015-0382, all of Hawaii's major utilities proposed new community-based renewable energy tariffs.

In June 2016, the PUC filed a draft proposal which identified the core elements and parameters of a community-based renewable energy program that would credit customers at time-varying rates. In Docket No. 2015-0389, the Hawaii PUC issued a December 2017 order, establishing final rules for the state's community solar program.

The program will take a phased approach, using flat credit rates for participants in Phase I (based on mid-day rates) and moving to time-varying rates in Phase II. Phase II will also offer special credit rates to facilities delivering at least 85% of their output during peak periods, and allow utilities to develop, own, and/or operate projects as long as at least 50% of subscribers are from low to moderate income households.

Minnesota (vertically integrated)

Value of Solar– The State of Minnesota passed legislation in 2013 that required the MN Department of Commerce (MN-DOC) to establish a calculation methodology to quantify the value of distributed photovoltaics (Value of solar). Value components required for inclusion in the calculation were: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. Following a workshop process that included over 50 sets of comments, the MN-DOC submitted the draft methodology to the Minnesota Public Utilities Commission (PUC or Commission) in January 2014 and the PUC approved it in an April 2014 Order.

Residential Fixed Charges – In 2015, the Minnesota legislature amended the state's net metering statute, allowing cooperative and municipal utilities to charge fees to recover fixed costs from net metering customers.

In November 2015, Xcel Energy requested an increase in its residential monthly fixed charge from $8 to $10. In a May 2017 Order, the Commission rejected Xcel's request to increase the fixed monthly service charge.

In February 2016, Otter Tail Power Company requested an increase in its residential monthly fixed charge from $8.50 $13.30. And, in Docket No. 16-664, November 2016, Minnesota Power requested an increase from $8 to $9. In March 2018, the PUC denied Minnesota Power's request. Minnesota Power filed a petition for reconsideration in April 2018, which raised several questions, but did not contest the Commission's determination on the fixed charge

In June 2016, following challenges filed in response to the first of these proposals, the Commission opened a generic hearing about methodologies for determining these types of fees for electric cooperatives. As directed by the Commission, all cooperatives currently charging or considering fees of this type submitted their methodologies in July 2017.

The MN-PUC accepted comments and issued an order in December 2017, ruling that the existing fees were not compliant with state law and offering solutions for bringing them into compliance. The MN-PUC also ruled that to prevent double recovery of fixed costs, a cooperative must not assess to DG customers both a per-kW fee and a minimum monthly charge. Further, for cooperatives assessing a kWh fee and a minimum charge to DG customers, the kWh fee must apply only to the DG customers' excess energy production.

In response to this, in 2017 Gov. Mark Dayton signed an omnibus jobs and energy bill, removing both: (1) the previous provision for MN-PUC review of cases involving fixed charges administered by cooperative and municipal electric utilities; and (2) a previous requirement that munis and coops participate in a state-mandated conservation program. In Minnesota, cooperative (member-owned) utilities serve between 20–25% of ratepayers.

Community Solar – In 2013, Minnesota passed legislation (§216B.1641) establishing the framework for a "community solar garden (CSG)" program. The law requires the rate paid for energy from solar gardens must be either the retail rate or the VOS alternative.

On September 30, 2013, Northern States Power (dba Xcel Energy) made a filing proposing to use an NEB Service tariff as the basis for the bill credits for its CSG program. Under that tariff, net energy is purchased at a blended retail rate that differs by demand/ non-demand class, and by season. Xcel stated that it would begin operating its community solar gardens program within 90 days of a Commission order approving the plan.

In an April 2014 Order, the MPUC rejected Xcel's solar-garden tariff filing and required that Xcel file a revised plan, along with an amended tariff and standard contract, that considers: the following items into consideration: crediting solar-garden subscribers' bills at the full retail rate for their portion of the garden's production; rolling surplus credits over from month to month, and purchasing any remaining credits at the end of each February; the purchase of unsubscribed energy from the solar-garden operator at Xcel's avoided-cost rate for solar gardens 40 kilowatts or larger and at Xcel's average retail utility energy rate for solar gardens smaller than 40 kilowatts; and, allowing a solar-garden operator, at its option, to retain RECs or sell them to Xcel at a Commission-determined rate.

Per the legislation, a CSG may have a nameplate capacity of no more than 1MW and each subscription may supply no more than 120 percent of the subscriber's average annual consumption when combined with any other DG resources serving the subscriber's premises. CSG subscribers must reside in the county where the garden is located or in a contiguous county.

In addition to compensation from Xcel for the energy they produce, solar gardens are also eligible for production-based incentives under Minnesota's Solar*Rewards and Made in Minnesota incentive programs. Under the Solar*Rewards program, Xcel provides a per-kWh payment to customers who own a solar energy system with a capacity of 20 kW or less and receives the RECs. Under the Made in Minnesota program, the Commissioner of Commerce provides a per-kWh payment to owners of certified Minnesota-made solar photovoltaic modules with a capacity of 40 kW or less. RECs associated with energy provided to a public utility under this program belong to the utility.

Also in the April 2014 Order, the Commission decided that solar-garden capacity should be defined in alternating current (AC) and required Xcel to credit each subscriber's portion of the solar-garden production at the full retail rate, including the energy charge, demand charge, customer charge, and applicable riders for the subscriber's customer class. This retail rate was used because there was not an approved VOS rate at the time. The Commission also allowed the solar garden operator or developer to transfer the solar RECs to Xcel at a compensation rate of $0.02 per kWh for solar gardens with a capacity greater than 250 kW and $0.03 for solar gardens with a capacity of 250 kW or less.

No solar REC value will be paid if the solar garden has received or intends to accept a Made in Minnesota or Solar*Rewards benefit, since these incentive programs require that the RECs be transferred to Xcel. The Commission acknowledged that these rates are not market rates and the rates are to be reviewed annually. Depending on subscriber class and garden size, the total effective compensation rate ranges from approximately 10 to 16 cents per kWh.

The Commission required Xcel to carry all bill credits forward for at least a 12-month cycle, to purchase all outstanding credits reflected on the statement for the billing period that includes the last day of February and to restart the bill-credit cycle in the next billing period with a zero balance. The Commission required Xcel to purchase unsubscribed energy from CSG operators at Xcel's avoided-cost rate for solar gardens larger than 40 kW capacity and at Xcel's average retail energy rate for solar gardens smaller than 40 kW. Also the Commission decided that the standard contract term between Xcel and CSG operators should be 25-years instead of 20 as Xcel requested.

On April 1, 2014, the Commission issued an order approving the Minnesota Department of Commerce's (Department) value-of-solar methodology, as modified by the Commission. Xcel was then required to calculate a VOS rate for its system using the Department's methodology and file a VOS tariff for the Commission's review.

On May 1, 2014, Xcel filed a motion to show cause which included its calculation of a CSG VOS rate and why the rate should not be implemented for CSG. On May 7, 2014, Xcel filed a revised proposal incorporating changes ordered by the Commission.

In a September 17, 2014 Order, the Commission approved Xcel's CSG plan, as revised in its June 19, 2014 reply comments and as modified by the MPUC's Order. The Commission decided that was not in the public interest to approve a VOS rate for CSGs at this time, and that Xcel should continue to use the applicable retail rate, with an optional REC sale, as decided in the Commission's April 7, 2014 order. Several proposed modifications to the program were approved by the Commission, including Xcel's request to name the program, "Solar*Rewards Community." Xcel began its CSG program in late 2014.

A settlement agreement between Xcel and several CSG developers filed on June 22, 2015 recommended a 5 MW co-location cap on CSG applications in the interconnection queue as of the effective date of the agreement, as well as for applications submitted after the effective date but before September 25, 2015. For applications submitted between September 25, 2015 and September 15, 2016, no more than 1 MW of co-located CSG would be allowed at any given site. In an August 5, 2015 Order, the Commission approved the request to limit to a 5 MW co-location cap and required Xcel to purchase the RECs associated with unsubscribed energy at a rate of $0.01 per kWh for unsubscribed energy, regardless of garden size. This rate had previously not been deter-mined by the Commission. On December 18, 2015, Xcel Energy filed revised CSG tariffs which reflected the program changes required by the MPUC. At the end of 2015, Xcel Energy's website indicated that solar developers had submitted applications for more than 1,400 MW at more than 1,500 CSGs across its service territory. Until then only one CSG had been built, but it now appears that Minnesota's program has the potential to be the largest in country.

On February 26, 2016, the MPUC requested comments, due on April 1, 2016, on whether the bill credit (retail rate) should be replaced with the VOS rate and what actions, if any, should be taken to encourage residential, low-income, and minority participation in the CSG program. On September 6, 2016, the MPUC modified the bill credit such that subscribers to CSGs with applications filed after December 31, 2016 would be compensated at the VOS rate rather than at the retail rate. The Commission clarified that the VOS rate that is in place at the time a CSG application is deemed complete will be the bill-credit rate for the term of that CSG and required Xcel to file by October 1 each year its VOS rate for the upcoming year, so that the Department can review it for compliance with statute and Commission order.

In September 2015, Minnesota Power, in Docket No. 15-825, filed for approval of a CSG Pilot Program. In July 2016, the MPUC approved the program as amended. Under the Pilot Program, Minnesota Power will own a 1MW system and sell subscriptions to its customers. The PUC order approving the Pilot Program also requires Minnesota Power to release three requests for proposal (RFPs) for additional CSGs up to 1MW each, which will not be owned by the utility.

On August 25, 2016, Minnesota Power issued an RFP for solar RECs (SRECs) eligible for Minnesota's Solar Energy Standard and certifiable in the Midwest Renewable Energy Tracking System (MRETS). The RFP requested pricing for up to 1,500 SRECs per year for up to 25 years, with proposals due no later than September 15, 2016. No proposals were submitted in response to the RFP. The Company filed updated tariff sheets and a subscriber contract on August 29, 2016. Due to the lack of response to its RFP, the Company proposed to launch the pilot program using its originally proposed pricing and SREC discount. The three options approved in the Commission's July 27, 2016 Order included: (1) an upfront payment of $2,132.15 for each 1 kW block of capacity; (2) a fixed monthly subscription fee of $15.62/month for each 1 kW block of capacity; or, (3) a fixed $0.1115/kWh energy charge. The Commission in an April 21, 2017 Order approved Minnesota Power's tariff sheets with SREC compensation prices ($0.002/kWh) and a customer contract. The Commission also allowed Minnesota Power to use its SREC discount price of $0.002/kWh and directed the Company to update its price for future programs.

Low- and Moderate-Income Participation – The Commission also required Xcel to develop a CSG proposal or proposals specifically for low-income customers, applying federal low-income heating energy assistance program (LIHEAP) eligibility standards. The Commission also accepted proposals by other parties to enhance access to CSGs for low-income customers. Xcel's proposal(s) and any others were to be filed by March 1, 2017. Starting with its 2018 VOS rate filing Xcel was required to use location-specific avoided costs in its calculation of avoided distribution capacity. Xcel filed for reconsideration regarding the rate to be credited, but the Commission denied Xcel's request.

Also in its September 6, 2016 Order, the Commission called on the Department 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 filed its recommendations in March 2017 recommending that only residential subscribers receive an adder to make community solar more attractive. The Commission heard comments and reply comments on the Department's proposal, and in December 2017 issued an order related to the proposal. In the Order, the Commission did not approve or deny the Department's proposal, stating that there was not sufficient information to act on the recommendations at the time. The PUC stated that maintaining CSG accessibility for residential customers is important, but there is some doubt that the benefit of an adder would be worth the cost to ratepayers. Instead, the Commission required that Xcel Energy conduct an analysis of the potential rate impact of the Department's proposal, and how a solar carve-out for CSGs would be implemented and enforced.

Xcel Energy provided its analysis in February 2018, and the Commission established a comment period on the analysis with initial comments due in early April, and reply comments due May 11th.

Vermont (vertically integrated)

Net Metering – In 2014, the Vermont Legislature passed Act 99, which raised the net metering cap for each utility in Vermont from 4% to 15% of the utility's peak load from 1996 or the peak demand during the most recent full calendar year, whichever is greater, and required the Vermont Public Service Board (Board) to establish a revised net-metering program pursuant to criteria and standards set forth in 30 V.S.A § 8010. During 2014-15, the Board conducted eight workshops and solicited three rounds of written comments, seeking input on designing a revised net-metering program.

By November 2015, Green Mountain Power (GMP) had received interconnection requests that exceeded its cap. GMP requested approval from the Board to offer net metering above this cap, but GMP notified the Board that it would reject applications above 15kW until a decision was made. The Board issued an order suspending review of applications above 15kW in GMP service territory until a decision is reached.

In December 2015, the Board released new draft net metering rules. The proposed rules would provide siting incentive credits of $0.02/kWh for excess generation produced by systems on structures with a primary purpose other than generating electricity, on brown-fields, landfills, over parking lots, or in the disturbed portion of gravel pits.

In compliance with H.B. 40, passed in June 2015, RECs are transferred to the utility unless the customer elects to keep them. If the utility owns a customer's RECs, the customer will receive an additional credit of 3¢/kWh of excess generation; if the customer retains ownership of RECs, excess generation will be credited at the retail rate. The rules also left aggregate caps unspecified and gave utilities the authority to require a customer charge to cover fixed costs. The utility has the option whether to allow a customer's bill credits to apply toward this charge.

The Board received a significant amount of feedback regarding the draft rule. As a result, the Board released for comment an additional draft of the rule on February 19, 2016. This second draft also received significant feedback from the public, which resulted in further revisions. On March 27, 2016, the Board filed a proposed net-metering rule with the Vermont Secretary of State. The Board then conducted two public hearings in May 2016.

On June 30, 2016, the Vermont Public Service Board issued an order establishing a revised net-metering program to be effective January 1, 2017 (Case ND-0047). This version removed the aggregate cap on net metered procurements. The rules also allowed existing net metering customers to continue to offset nonbypassable charges (that is, the customer charge, energy efficiency charge, energy assistance program charge, and any on-bill financing payments or equipment rental charges) with net metering credits, through a 10-year grandfathering period. Grandfathered systems would not be subject to any REC or system size/siting credit adjustors. The utility would own all RECs unless the customer elected to retain ownership. Customers that allowed the utility to retain the RECs would receive a 3¢/kWh credit on all system production for 10 years. Customers that elect to retain ownership of their RECs receive a negative 3¢/kWh credit adjustor in perpetuity. Any customer net excess generation would be credited at the blended residential rate and carried over to the customer's next bill. Any excess generation must be used within twelve months of the month earned, or it is granted to the utility.

In an August 29, 2016 Order, the Board, modified the previous rules and approved revised NEM rules. During this decision, the Board removed the annual 4% cap on the capacity of proposed NEM systems and altered the provisions that would have prohibited pre-existing customers from applying accrued NEG credits to bill charges that would otherwise be nonbypassable. In an October 10, 2016 Order, the Board approved a request filed by the Vermont Department of Public Service to determine the "weighted statewide average of all electric company blended residential retail rates" at $0.1491 per kWh. That rate was effective January 1, 2017. Final Net Metering Rules approved on June 8, 2017 took effect July 1, 2017.

Also effective July 1, the Vermont Public Service Board was renamed the Public Utility Commission (PUC). The new name "more clearly reflects… existing statutory responsibilities and clarifies the difference between [the PUC] and the separate state agency known as the Public Service Department" (PUC 2017).

In December 2017, the Vermont Department of Public Service, Natural Resources Board, and Agency of Natural Resources requested that the PUC hold a workshop related to defining the term "preferred site" in the state's NEM rules.

In January 2018, the PUC opened a biennial update proceeding to review the current NEM program. Updates to REC adjustors, siting adjustors, the statewide blended residential rate, and the eligibility criteria for different system categories were considered in this proceeding. Four size categories are identified for DG interconnections:

I. not hydroelectric and capacity less than 15kW;
II. not hydroelectric and capacity more than 15kW and less than or equal to 150kW, sited on a preferred site;
III. not hydroelectric and has a capacity of greater than 150kW and less than or equal to 500kW, sited on a preferred site.; and,
IV. not hydroelectric and has a capacity of greater than 15kW and less than or equal to 150kW, and is not located on a preferred site. (Vermont PUC, Rule 5.103)

The Department of Public Service (Department) recommended reducing the REC adjustor from $0.03/kWh to $0.025./kWh, but did not recommend making significant changes to siting adjustors. The Department also recommended increasing the blended residential rate to $0.15417/kWh, and did not recommend significant changes to preferred site eligibility. The

Agency of Natural Resources did not propose any changes to credit adjustors, but did recommend changes to some definitions of preferred sites.

The PUC issued an order May 4, 2018, which reduced the REC adjustor for customers transferring RECs to the utility to $0.02 per kWh for July 2018 - June 2019 and $0.01 per kWh beginning July 2019. The PUC did not change the REC adjustor for customers electing to retain REC ownership. The PUC also changed the siting adjustor for Category III systems from negative $0.01 per kWh to negative $0.02 per kWh, beginning July 2018. The PUC did not make any changes to eligibility criteria for Category I, II, III, or IV net metering systems. Green Mountain Power filed its new net metering tariff on May 14, 2018, which the Commission approved in June 2018 with an effective date of July 1, 2018.

District of Columbia (restructured)

Net Metering – In June 2015, the Public Service Commission of the District of Columbia (Commission or PSC) initiated Proceeding FC 1130 to identify technologies and policies to modernize and increase the sustainability, reliability, and efficiency of the electric grid. Initial comments were due by August 31, 2015 and the PSC held a Kickoff Workshop on September 22, 2015.

The Order also established a series of three workshops to be held in the proceeding. In an Order dated March 17, 2016, the PSC announced that the third workshop would be held on April 27, 2016 which was to focus on the legal and regulatory framework necessary to facilitate and support a modern energy delivery system that includes DER. DER includes clean and renewable DG systems (such as high efficiency combined heat and power and solar PV systems), distributed storage, demand response and energy efficiency.

At the conclusion of the third workshop, the PSC announced that its staff would prepare a Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS) Report that would address the comments and make recommendations on next steps. The staff prepared the report and, on January 25, 2017, the PSC issued the report for public comment.

The report identified barriers to different aspects of grid modernization, including those related to DERs, and potential solutions to remove these barriers. Specifically, in the report, Staff recommended that the Commission adopt and amend pertinent DER related definitions in its regulations in order to establish a consistent language for addressing the complex issues related to modernizing the District's energy systems, especially as it relates to DER deployment, going forward. In October 2017, the PSC invited public comment, until the end of December, on Staff's proposed vision statement for the MEDSIS initiative, whether a full assessment of the current capabilities of the energy delivery system is warranted, and whether an external consultant would be useful to move MEDSIS forward more expeditiously.

The PSC adopted the MEDSIS vision statement in February 2018 and issued a Request for Proposals in March 2018 for a Technical Consultant to assist the PSC. During the second quarter of 2018, a number of parties filed Statements of Interest in participating in the stakeholder engagement process to be facilitated by the Technical Consultant.

In November 2017, the DC PSC published a Notice of Proposed Rulemaking adding new definitions for customer generator, battery, back up generation, energy storage, microgrid, smart inverter, and others to its Small Generator Interconnection and NEM rules. The proposed amendments explicitly state that owners of behind-the-meter generators are exempt from classification as an electric utility, electricity supply, or competitive electricity supplier.

The amendments took effect 60 days after the rules publication in the DC Register, which occurred on November 3, 2017. Comments on the amendments were filed in January 2018. The

Commission made revisions based on the comments it received, and in May 2018, issued its Notice of Second Proposed Rulemaking. The revisions include removing the terms “battery” and “smart inverter,” replacing “electric storage” with “energy storage,” and revising the definitions for “cogeneration facility,” “combined heat and power facility,” “demand response,” and “distributed energy resource.” The notice affirms the earlier definition of an electric company, which excludes owners of behind-the-meter generators from the definition. The Commission accepted comments for 30 days.

Value of Solar – On May 19, 2017, the DC Office of the People's Counsel (OPC) filed a value of solar study. The study which was conducted by Synapse Energy Economics estimated that the utility system total value of solar for 2017-2040 is $0.13266/kWh, while the societal total value is $0.1944/kWh. In June, the PSC approved PEPCO's request to initiate a comment period on the OPC value of solar study. Comments were accepted through mid-July 2017.

The PSC noted in an October 19, 2017 Order that Staff had reviewed the comments submitted on OPC’s Value of Solar Report, and that the PSC will give the Report and its conclusions appropriate consideration in future solar-related matters before the PSC.

Fixed Charges – On June 30, 2016, Potomac Electric Power Company (“PEPCO”) requested an increase in its residential monthly fixed charge from $13.00 to $16.75. In a July 25, 2017 Order, the Commission stated that Pepco will collect the entire increase in revenues for the Residential class through an increase in the customer charges and that this decision continues the Commission’s policy of moving the design of residential distribution rates away from volumetric (kWh) rates, and towards rates that are based more on customer and demand charges. The residential monthly fixed charge was increased to $15.00.

Illinois (restructured)

Net Metering – In April 2015, Docket 15-02373, the Illinois Commerce Commission (ICC) initiated a rulemaking on net metering rules. The proposed rule adds new, clarifying definitions, enables web-based electronic application procedures, and requires a case-by-case consideration of meter aggregation by the utility and an explanation by the utility to the ICC if a request for meter aggregation is denied. The proposed rules align net metering rules with previously enacted legislation.

In November 2015, the ICC submitted its Second Notice on the rulemaking to the Joint Committee on Administrative Rules (JCAR), after which the rule can be adopted if JCAR does not issue an objection. In April 2016, the final rules were approved by the ICC, which allow an electricity provider to establish an enrollment cap of 5% of peak demand, with a waiting list created to fill an available space.

In December 2016, Illinois passed S.B. 2814, the *Future Energy Jobs Act*, which made numerous changes to the state's renewable portfolio standard (RPS) and other renewable energy policy while leaving net metering policy unaffected. This legislation requires utilities to allow meter aggregation for properties owned or leased by multiple customers, individual units within single buildings that are owned or leased by multiple customers (e.g., apartments or offices), and community renewables projects. Utilities were previously only required to consider whether to allow meter aggregation. The legislation also creates a set-aside within the solar portion of the state's RPS, requiring 50% of the solar standard to be met using distributed solar, community solar, and brownfield-redevelopment projects, and for utilities to serve customers subscribing to community solar projects.

Rate Changes – In a 2015 filing, Springfield Water Power and Light Company proposed an increase to its residential monthly fixed charge from \$5.76 to \$8.76 in 2016, \$8.94 in 2017, \$9.12 in 2018, and \$12.87 in 2019. The utility's proposal was not approved as proposed: The residential monthly fixed charge approved in March 2017 is \$8.82.

Community Solar – S.B. 2814 also created the Illinois Solar for All Program, which includes incentives for low-income community solar projects. The incentives will be offered directly to customers to increase participation of low-income subscribers, as well as to projects that are 100% low-income subscriber owned, which can include low-income households, non-profits, and affordable housing owners. Community solar pilot projects may be proposed under this program. Projects are permitted to exceed 2 MW, but not \$20 million. The Illinois Solar for All Program will be funded through the Illinois Power Agency Renewable Energy Resources Fund. The legislation created four sub-programs under the Illinois Solar for All banner. They are: (1) low-income distributed generation for on-site solar projects; (2) low-income community Solar for off-site solar projects; (3) on-site project incentives for non-profits and public facilities; and, (4) low-income Community Solar Pilot Projects.

On December 4, 2017, the Illinois Power Agency published its Long-Term Renewable Resources Procurement Plan which provides details for the community solar program. That agency procures renewable energy for all suppliers in the state. Community solar projects are included in the adjustable block purchasing program for renewable resources, and community solar subscribers are eligible for net metering, with investor owned utilities being required to submit community solar net metering tariffs by September 27, 2017. The draft plan also describes low-income community solar incentives that provides extra funding of $69.23 to $129.56 per REC (that is, per MWh), depending on the utility and the project capacity, for community solar projects subscribed to by low-income customers. The draft plan also includes a competitive-bidding process for low-income community solar pilot projects, separate from the incentive program. A final plan filed in December 2017 was approved on April 3, 2018.

Solar Valuation Study – In March 2017, Docket No. 17-0142, the Illinois Commerce Commission approved a resolution to begin a proceeding to investigate grid modernization and the creation of a 21st century regulatory model. The Illinois NextGrid proceeding is being conducted as a facilitated stakeholder process, managed by the Commission with assistance from an expert independent third party facilitator, the University of Illinois.

A conference and launch event for NextGrid took place in late September 2017. 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) rate-making. NextGrid also includes a Stakeholder Advisory Committee, which meets quarterly to provide input on project process and deliverables, and a Technical Advisory Group, which meets monthly to advise whether all relevant technical issues have been identified and addressed. Based on the current schedule, the working group for DER cost-benefit analysis is expected to meet in early 2019 and the final report will be completed in mid-2019.

The Illinois Commerce Commission initiated its investigation into DG valuation and compensation in February 2018, publishing a white paper summarizing issues in DG valuation and the approaches taken by other states. The report was prepared by staff from the Pacific Northwest National Laboratory (PNNL). Stakeholder workshops were held on March 1 and June 28, 2018, at which participants discussed a second version of the PNNL white paper. Comments on the second version were due July 28, 2018 and a final report will be published in Fall 2018.

Reports from each Illinois NextGrid work group are being published, first in draft and then final form, on the NextGrid web page. Three workgroups in particular are focused partly on

DER topics: Workgroup 1 is addressing VDER, DER grid integration, and distribution system planning; Workgroup 6 is reviewing environmental impacts of DER; and, Workgroup 7 is focusing on Ratemaking, including the topics of time-varying rates, and VDER.

New Hampshire (restructured)

Net Metering – In July 2015, in Docket No. 15-271, the New Hampshire Public Utilities Commission (NHPUC) began an investigation into the queue process for net-metered customer-generators. This was following a recommendation from the staff of the Sustainable Energy Division of the PUC. The key issues were the interpretation of "first-come, first-served" due to a 50 megawatt (MW) cap on net metering participation, investigating utility interconnection requirements, and opening a forum for utility and public input for net metering policies. In December 2015, NHPUC staff recommended that the NHPUC schedule a public hearing to receive comments on the proposed Net Metering Program Capacity Allocation Procedures (Procedures) from parties in the docket and other interested stakeholders. An updated version of the Procedures was released, incorporating modifications directed by the NHPUC in its Order of March 22, 2016. New Hampshire's three regulated electric distribution utilities were directed to adopt and implement the new Procedures.

On May 2, 2016, two legislative enactments (HB 1116 and SB 378) became effective that could affect certain provisions of the Procedures. Staff recommended that the NHPUC clarify how the Procedures should be administered in light of the recent legislative changes. Staff further recommended that all projects on all waiting lists be approved and that no proposed group net metering project would be granted capacity allocation without first receiving project-specific approvals. HB 1116 and SB 378 modified the cap of available distributed generation to 100 MW, which was then allocated to the different distribution utilities and apportioned to different size systems. The legislation directed the NHPUC to initiate a proceeding to develop new alternative net metering tariffs, accounting for costs and benefits, cost shifting concerns, rate effects for all customers, rate structures, eligible facility size, and potential limitations on the amount of eligible generation in the total program.

In a May 19, 2016 Order in Docket DE 16-576, the NHPUC initiated development of new alternative net metering tariffs. Diverse proposals were received from many stake-holders, including various provisions for real-time pricing or time-of-use based crediting, a fixed solar credit rate, credits at the default energy rate, and residential demand charges. In December 2016, the PUC approved an alternative net metering tariff for an interim period, effective from March 2, 2017, until a further decision is made.

On June 23, 2017, the PUC issued a final order approving an alternative net metering tariff based on common elements in two settlement proposals and also resolving differences between the two settlements. The new tariff is to be in effect for a period of years, while further data is collected and analyzed, pilot programs are implemented, and a distributed energy resource (DER) valuation study is conducted.

Small customer-generators (those with renewable energy systems of 100 kW or less) will net meter their distributed generation resources with monthly netting. Those customer-generators will receive monthly excess export credits equal to the value of kWh charges for energy service and transmission service at 100 percent and distribution service at 25 percent. On the full amount of their electricity inputs from the grid, the customer-generators will pay all non-bypass-able charges, such as the system benefits charge, stranded cost recovery charge, other similar surcharges, and the state electricity consumption tax. Systems that are installed or queued during that period of years will have their net metering rate grandfathered until December 31, 2040. Following completion of the DER valuation study, the NHPUC will open a new proceeding to determine whether and when further changes should be made to the net metering tariff structure.

Value-of-DER Study –Docket DE 16-576 calls for a long-term avoided cost study using marginal cost concepts and incorporating both the Total Resource Cost and Rate Impact Measure test criteria, as well as consideration of demonstrable and quantifiable net benefits associated with relevant externalities. The study period will be 10-15 years (a compromise between the 3 to 5 years proposed by a coalition of utility and consumer parties and 25 years proposed by a coalition of solar and sustainable energy interests) and the focus will be on PV and hydroelectric facilities. The PUC held an initial stakeholder meeting on August 16, 2017, focusing on the organization and membership of the working groups.

The NHPUC staff submitted a working group status report in late December 2017. The value of DER study working group met multiple times during 2017 and 2018 to determine the scope of the study, and filed its proposed scope in May 2018. New Hampshire will use a study period of 15 years and will examine a wide array of DER costs and benefits. The proposed study will include an hourly avoided cost calculation, as well as a distribution-level, locational-value study. The avoided cost calculation will include close to 20 factors. While stakeholders agreed on study methodologies for several factors, a consensus was not reached on every one. An independent consultant will conduct the study, which is slated for completion in 2020.

Also in the June 23, 2017 order, the NHPUC approved several pilot programs. First, a Time-Of-Use (TOU) pilot for both residential and small commercial customers for both DG and non-DG customers will explore on-peak and off-peak differentials. Second, a pilot offering monetary bill credits will extend the benefits of solar DG system ownership to low and moderate income customers who other-wise would not be able to participate in net-metered renewable energy projects. Third, a Real-Time-Pricing pilot program proposed by the City of Lebanon will use municipal aggregation to study customer behavior and utility rate impacts. Finally, a non-wires alternative pilot program was approved, which will demonstrate the effects of DG on potentially-stressed utility distribution system components at specific locations.

Docket DE 16-576 remains open, including four working groups that meet quarterly to explore further: (1) a Low and Moderate In-come Program; (2) a Time-of-Use Rate Pilot Program; (3) a Non-Wires Alternative Pilot Program; and, (4) the Value of DER Study Scope. In a December 28, 2017 memo, NHPUC Staff reports that the consensus of working group participants is for participation in the working group process to remain open and unrestricted at this time.

Third Party Solar Leasing – In August 2015, Docket DE 15-303, Vivant Solar filed a petition with the NHPUC for a declaratory ruling to clarify whether or not the company would be regulated as a utility, competitive electric power supplier, or limited producer of electrical energy when offering third-party PPAs and solar leases. Vivant argued it should not be regulated as any of these. In a January 15, 2016 Order, the NHPUC granted the petition.

Fixed Customer Charges – In April 2016, Docket No. DE 16-383, Liberty Utilities requested an increase in the residential fixed charge from $11.79 to $14.50. On March 15, 2017, a stipulation and settlement agreement was reached between Liberty Utilities, the Office of Consumer Advocate, the City of Lebanon, and the NH PUC Staff. The increase to $14.50 was approved by the NHPUC in an April 12, 2017 Order.

In April 2016, in Docket DE 16-384, Unitil requested an increase in the residential fixed charge from $10.27 to $15.00. A settlement agreement was reached between Unitil, Staff, and the Office of the Consumer Advocate. In an April 20, 2017 Order, the NHPUC increased the residential customer charge to $15.00 per month.

Residential Demand Charges – On April 29, 2016, Unitil filed for a new tariff, Domestic Distributed Energy Resources (Schedule DDER). Schedule DDER sets forth rates to be charged to certain residential customers with renewable distributed generation systems installed behind the retail meter. In a June 9, 2016 Order No. 25,906, the NHPUC suspended this proceeding until the completion of the Value of DER Docket, No. DE 16-576.

Community Solar – In July 2017, S.B. 129 became law without the Governor's signature. This legislation requires at least 15% of funds from the state's Renewable Energy Fund to be used to benefit low to moderate income residential customers, including the financing of low to moderate income community solar projects in manufactured housing communities or in multi-family rental housing. The NHPUC is to report on the costs and benefits of these projects by December 31, 2019. The bill also allows members of group net-metered low to moderate income community solar projects to receive credits on their electric bills, provided that only one new project of this type will be available in each utility's service territory by December 31, 2019.

The NHPUC opened Docket DE 17-172 to develop, review and approve programs and procedures designed to meet the requirements of S.B. 129. A stakeholder technical session was scheduled for November 15, 2017 and to date two stakeholder meetings have been held. In the first quarter 2018, the NHPUC approved a proposal to issue RFPs for programs designed to benefit low and moderate income customers, including community solar projects.

Grid Modernization Study – In July 2015, H.B. 614 implemented the goals of the state 10-year energy strategy developed by the NH Office of Energy and planning. This bill included a provision for the PUC to open a docket on electric grid modernization with a final report to be delivered in March 2017. The report sets out to study: (1) improved reliability, resiliency and operation efficiency of the grid; (2) reducing generation, transmission and distribution costs; (3) empowering customers to use electricity more efficiently and to lower their electricity bills; and, (4) facilitating the integration of DERs. Eighteen stakeholder groups participated in the Working Group. The final report, dated March 20, 2017, offered several recommendations for rate setting and planning strategies and noted that due to the on-going study in Docket DE 16-576, the recommendations are intertwined with that process.

New York (restructured)

New York continues its large-scale effort, Reforming the Energy Vision (REV). REV is a set of multi-year regulatory proceedings and policy initiatives, launched in 2014, to address financial costs, environmental costs, and resiliency of the New York state grid.

Net Metering – Since New York is looking at comprehensive reforms as part of its REV, New York lifted its aggregate net metering cap, until the issue of net metering and distributed resource valuation is addressed.

In September 2015, Case 15-E-0572, several stakeholders petitioned the New York State Public Service Commission (NYPSC) to change the way the true-up date for net excess generation credits was assigned to residential net-metered PV customers. At that time, net-metered customers only had a one-time option to select the date on which their excess credits are cashed out each year at the wholesale rate. In a January 16, 2017 Order, the NYPSC decided that Petitioners had not justified a revision to the method for assigning an anniversary date for residential net metered PV customers because the current methodology was flexible and customers themselves are best positioned to take responsibility for cost-effective operation of their PV systems. However, the Commission decided that additional outreach and education was appropriate to ensure that customers made informed decisions. While conducting the inquiry into the cash out process, it was discovered that Orange and Rockland Utilities (ORU), Inc. used the average locational-based marginal price (LBMP) from only the anniversary month, standing alone, as its avoided cost for calculating annual cash out payments. In contrast, the other utilities used the average LBMP avoided cost. NYPSC required ORU to either revise its tariff language to calculate cash out payments at the cumulative avoided cost or justify its current methodology. ORU filed a revised tariff on April 15, 2016.

In an October 16, 2015 Order, Case 15-E-0407, the PSC denied Orange and Rockland Utility's petition to cease offering net metering once the 6% net metering aggregate cap was met which had been filed on July 14, 2015. Within this petition, multiple utilities proposed to offer alternatives to net metering, preferring a "buy-all sell-all" arrangement. The PSC ordered all New York utilities to continue accepting applications regardless of the cap until the issue of net metering was addressed in the REV process.

In November 2015, the six IOUs in New York state petitioned the PSC for rehearing of the Order. The utilities argued that the statute provided the PSC only limited authority to increase the net metering cap, not eliminate it altogether. The PSC subsequently filed a Notice of Proposed Rulemaking with comments due January 25, 2016. This proceeding was on hold during 2016 as discussion of creating a successor to net metering was being considered in a separate proceeding (Case 15-E-0751).

Value of Distributed Energy Resources – On December 23, 2015, Case 15-E-0751, the NYPSC requested comments from parties regarding the value of distributed generation. The Commission directed the public staff to develop recommendations on the value of DERs that could potentially lead to an alternative to net metering. On October 27, 2016, the Staff released its report, including recommendations for the interim methodology for valuation and compensation of DERs. This report included the use of Locational Based Marginal Pricing (LBMP). The PSC requested and accepted comments on the report until December 5, 2016.

On March 9, 2017, Case # 15-E-0751, the PSC issued a net metering transition order, addressing Phase I of the Value of Distributed Energy Resources (VDER) proceeding and outlining a Phase II. Beginning March 9, 2017, community solar, remote net-metered projects, and large distributed energy projects will be compensated through the Phase I "Value Stack" VDER tariff that includes energy (based on LMP), capacity, environ-mental, and demand reduction credits. Mass market DER projects will be 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 will be able to continue with traditional net metering. The utilities filed VDER implementation plans in May 2017.

The March 2017 net metering transition order also addressed the calculation of market transition credits (MTC). In April 2017, a New York resident filed a petition for the PSC to modify its VDER order in order to allow MTC compensation for small customer tenants in master-metered buildings and to clarify that sub-metered residential and small commercial customers are eligible for the MTC.

In May 2017, the PSC organized a conference, creating working groups and protocols for Phase II of the proceeding. Three working groups were established, focusing on: (1) the value stack; (2) rate design; and, (3) low and moderate income issues. The working groups will support the public staff in developing recommendations. On September 14, 2017, the PSC issued an order finalizing Phase I implementation.

In December 2017, the PSC initiated Phase II of the VDER value stack and rate design working group process. The process includes two parallel working groups, value stack and rate design. The PSC published a schedule for 2018, which will culminate with a white paper from the PSC staff.

Remote Net Metering – In an April 17, 2015 Order, the PSC approved a transition plan to move from monetary to volumetric crediting for remote net metering customers. The previous rate design allowed a farm or a non-residential customer with remote net metering at a site where a non-demand rate was in effect to obtain monetary credits that applied to its satellite sites. Previously, on-site net metering credits were offered at volumetric rates, which were generally lower than the monetary rates offered for remote net metering, thus providing an advantage for remote net metering.

On October 16, 2015, in Case #15-E-0267, the PSC issued an order addressing two remote net metering issues. Under "one host limitation," the utilities do not allow customers to assign multiple host accounts (sites of generation) to one satellite account (remote site), and under "net metering limitation" utilities prohibit interconnection of net metering generation at sites designated as satellite accounts. The Commission ordered the utilities to allow customers to assign credits from multiple host accounts to one satellite account such that the sum of the credits do not exceed 2 MW per satellite account and permit the satellite accounts with less than 2 MW in host account credits to interconnect on-site generation.

In September 2016, Case 14-E-0422, a number of solar advocates petitioned the PSC to amend the Transition Plan order to relieve grandfathered projects from milestones that required the projects to enter into service by the end of 2017. The petitioners instead requested that the PSC adopt a four-part test that would allow qualifying projects to preserve their grandfathered status. On December 16, 2016, the PSC approved the request without any modifications.

Community Solar – On July 17, 2015, in Case 15-E-0082, the New York State Public Service Commission issued an order establishing community net metering. The purpose of the Community DG Program was to expand options for customers to access clean DG. Implementation of the Community DG program was divided into two phases. The first phase began on October 19, 2015 and lasted until April 30, 2016. During this phase, projects were limited to: (a) siting in areas providing the most locational benefits to the larger grid; and, (b) promoting low-income customer participation.

A second phase began in May 2016, the community net metering projects would be fully implemented throughout utility service territories. The proceeding continued with the utilities proposing tariffs and other recommendations for implementing the program. In an October 16, 2015 Order, the PSC issued conditions for community net metering programs throughout the state.

In August 2016, Case 15-E-0082, the PSC Staff issued a report on means of encouraging low-income customer participation in community distributed energy programs. The Public Staff developed a white paper about community DG for low-income customers and sought comments on: (a) the development of a standardized customer disclosure statement; (b) application of certain Home Energy Fair Practices Act provisions; and, (c) the role of utility-sponsored community DG projects. Comments were due by January 20, 2017.

Beginning March 9, 2017, community solar, remote net-metered projects, and large distributed energy projects were compensated through the Phase I Value Stack VDER tariff that included energy (based on LMP), capacity, environmental, and demand reduction credits. All projects that interconnected prior to March 9, 2017 may continue with traditional net metering.

In December 2017, the Public Staff published a report on the low income com-munity DG proposal, which includes the positions of the intervenors and the staff's analysis on: (a) the interzonal credit, which would provide benefits to low-income customers from projects interconnected in other load zones; (b) the bill discount pledge program, providing a direct incentive to subsidize subscription prices through utility low-income funds; (c) the role of NYSERDA programs; (d) the loss reserve; and (e) environmental justice location incentives.

In January 2018, the PSC expanded the community solar program by adding a fourth tranche. Orange and Rockland customers in Tranche 4 will receive a 7.31 cent per kWh Market Transition Credit (MTC). The MTC for other utilities has yet to be determined. Tranche 4 is capped at 15 MW for Orange and Rockland, 20 MW for Central Hudson, and 80 MW for New York State Electric and Gas. In May 2018, the PSC Staff proposed to reduce the subscription size for Community Distributed Generation from 1,000 to 500 kWh per month. Comments on this proposal are due by August 6th.

Utility Led Rooftop Solar Programs – The New York REV proceeding required IOUs to file demonstration projects.

Consolidated Edison partnered with SunPower and Sunverge on a proposed Clean Virtual Power Plant demonstration project. The proposal would allow Con Edison to operate a fleet of residential combined solar and storage units to provide grid services. Under the proposal, Con Edison would offer the package to customers at a competitive rate and own the storage asset. In December 2015, Con Edison submitted a Notice of Temporary Suspension of the Clean Virtual Power Plant Project. Approvals for installation of the Sunverge Solar Integration System from the New York City Department of Buildings (DOB) and Fire Department (FDNY) took longer than anticipated. While Con Edison, SunPower, and Sunverge had many productive discussions with the DOB and FDNY, they did not come to an agreement that would allow the System to be installed in a manner consistent with its original design, nor without making changes that would impact the timing of program goals as envisioned under the original contract with SunPower. Therefore, the contract was terminated and the project is on hold until further notice.

In 2016, National Grid and Sunrun announced a strategic partnership in which the two companies will own 200 MW of rooftop solar projects, initially targeting National Grid's downstate New York service territory. National Grid committed to invest $100 million in this effort, and the program is expected to reach approximately 100,000 single-family homes.

Residential Fixed Charges – In 2015, PSEG Long Island, in Docket No. 15-00262, requested an increase in residential fixed charges from $10.80 to $19.80. The LIPA board approved new rates in December 2015, with no increase in fixed charges for 2016.

In May 2015, New York State Electric & Gas, Docket 15-01092, requested an increase in residential fixed charges from $15.11 to $18.89. In 2016, the residential fixed charge was not increased.

In November 2017, in Docket No. 17-02427/17-E-0685, Pennsylvania Electric Company requested an increase in its monthly fixed charge for New York residential customers to $7.50. The proposed Tariff will increase the total monthly bill of a residential customer using 1000 kilowatt hours from $100.05 to $106.38, or 6.33%. In May 2018, the Public Service Commission issued an order granting the proposed rate changes.

In 2018, the New York Public Service Commission approved a settlement agreement including a fixed charge decrease in Central Hudson Gas & Electric's recent rate case from $24.00 to $21.00 in 2019, $20.00 in 2020, and $19.50 in 2021.

Texas (restructured)

Rate Changes – In 2015, two Texas utilities proposed increases to fixed charges for residential customers. In Docket No. 43695, Southwestern Public Service Co (SPS) proposed an increase from $7.60 to $9.50 per month, which was approved by the Public Utility Commission of Texas in a 12/18/2015 Order. In Docket No.44941, on August 10, 2015, El Paso Electric (EPE) proposed an increase from $5 to $10 per month; in that case the approved charge was $6.50.

In Docket No. 45524, SPS proposed in February 2016 an increase to residential fixed charge from $9.50 to $10.50. A settlement agreement and stipulation between all of the parties including PUC Staff and SPS set the residential fixed charge at $10.00. This request was approved by the Public Utility Commission of Texas in January 2017.

In a December 16, 2016 filing in Docket No. 46449, Southwestern Electric Power Company (SWEPCO) proposed that all customers eligible for the distributed renewable generation (DRG) tariff pay an additional $8 per month administrative fee, for metering and billing. SWEPCO also proposed billing the customer for energy used at the retail rate and then compensating the energy exported to the grid at an avoided cost of energy rate. In order to mitigate the impacts for customer with distributed generation systems below 2MW, SWEPCO proposed to indefinitely "grandfather" the current 47 DRG customers so that the already existing customers would continue to take service under the previous DRG tariff. In a January 2018 Order, the Texas PUC denied SWEPCO's request to grandfather the current DRG customers, since customers with DG of 100 kW or less can request service under a qualified-facility tariff and can opt for net metering. The Texas PUC did approve the change from retail rate to avoided cost of energy.

In Docket No. 46831, EPE proposed an increase to the residential fixed charge from $6.90 to $10.85, with an increase to $8.25 approved by the Texas PUC. In this case, EPE, the PUC Staff, Energy Freedom Coalition of America, Solar Energy Industries Association and the County of El Paso reached a stipulation and agreement that kept Distributed Generation (DG) customers part of the Residential Service or Small General Service rate classes as applicable, for cost allocation, revenue distribution, and rate design purposes. EPE customers not subject to grandfathering under the previous DG tariff would be subject to a monthly minimum bill of $30.00. The customer's base rate monthly bill will consist of the greater of the total of base rate charges, including the monthly customer charge or the customer's Monthly Minimum Bill.

Non-grandfathered residential DG customers may otherwise elect to take service under the Alternate Time-of-Use Monthly Rate (minimum bill $26.50) or Experimental Demand Charge Monthly Rate, in which the customer's base rate monthly bill will consist of the applicable monthly customer charge, a monthly demand charge of $3.16 per kW applicable to monthly peak metered demand, TOU energy charges, and applicable riders. No changes were proposed or made to either the process of NEM for billing purposes or for crediting net energy exports. EPE also agreed for a three-year period not to initiate further rate changes or rate increases to any DG customer that would be different than the rate increase applicable to all other customers in their current class. For the same three-years, EPE also agreed not to propose any change in rate classes that would separate a DG customer from their current rate class, unless all members of its current class would be affected in the same manner. The Texas PUC issued a December 18, 2017 Order approving the agreement.

Utility led Rooftop Solar Program – In May 2015, CPS Energy, the municipal utility serving San Antonio, Texas, announced plans to operate a utility-led solar program. Formal implementation began by year-end 2015. At the time, this was the only utility-led rooftop program being implemented by a municipal utility. The first pilot program was a 1 MW community solar program, called Roofless Solar, aimed at customers whose own roofs would not be suitable for solar.

In another 10MW pilot program launched by SolarHostSA, CPS Energy will own panels to be installed on customer roofs, with no upfront costs for the customer. Participating customers will receive credits of $0.03/kWh for all of the solar energy produced on their roof, which is an estimated utility bill savings of 20 to 30%. The contract term is 20-years, and the program will provide all costs for installation and maintenance.