COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC CONSIDERATION OF THE IMPLEMENTATION OF THE NET METERING ACT	))	CASE NO. 2019-00256

ORDER

On July 30, 2019, the Commission initiated this administrative proceeding to consider the implementation of Senate Bill 100, An Act Related to Net Metering (Net Metering Act), which takes effect on January 1, 2020.[1] The purpose of this proceeding is to invite comments from interested utilities and stakeholders, as well as the general public, in order to develop a record upon which the Commission can consider the issues of implementation of the Net Metering Act. The record of this proceeding will be incorporated by reference into all initial ratemaking proceedings initiated by retail electric utilities pursuant to the Net Metering Act.

Pursuant to a procedural schedule, the Commission received written comments into the case record from interested utilities, stakeholders, and the public. The Commission held a public comment hearing on November 13, 2019, and received comments from interested utilities, stakeholders, and the general public. In addition, Kentucky Solar Industries Association, a non-party to this proceeding, responded to a post-hearing request for information regarding the adoption rate of rooftop solar in areas served by the Tennessee Valley Authority (TVA) and municipal electric utilities compared to the

[1] The Net Metering Act was signed into law on March 26, 2019.

adoption rate in areas served by electric utilities that are subject to the Commission's jurisdiction.

BACKGROUND

The primary issue to be addressed in implementing the Net Metering Act is the ratemaking process for determining the compensation rate for net metered customers – termed eligible customer generators in the Net Metering Act – who feed electricity back to the electric grid.[2] Kentucky's Net Metering Act amended portions of KRS 278.465–.467 during the 2019 Session of the Kentucky General Assembly to give the Commission an integral role in determining the compensation rate for net metered customers. Prior to the amendment, net metered customers received a credit on their monthly bill for the kilowatt hour (kWh) difference between the electricity supplied by an electric utility to the net metered customer and electricity generated by a net metered customer that was fed back to the electric utility via the electric grid for that billing period. Electricity generated by a net metered customer that is fed back to the grid was valued at the same per-kWh retail rate as that in the utility's tariff for electricity consumed by the net metered customer. The Commission notes that these provisions will remain in effect for a period of 25 years for eligible generating facilities put into service prior to the Commission setting new net metering rates under the Net Metering Act for the utility serving such facilities.

The Net Metering Act revised the compensation rate paid to net metered customers who start new net metering service as of January 1, 2020. In lieu of being valued

[2] A net metered customer is a customer of a retail electric utility who owns and operates a solar, wind, biomass, biogas, or hydro energy generating facility located on the customer's premises for the primary purpose of supplying all or part of the customer's own electricity requirements. The electric utility serving a net metered customer must use a meter capable of registering the flow of electricity in two directions, which permits a net metered customer to take electricity from the electric grid and feed electricity back to the electric grid. KRS 278.465.

identically to the kWh retail rate in the utility's tariff for electricity for customers of that class, the compensation for production in excess of usage over a billing period, after January 1, 2020, "shall be in the form of a dollar-denominated bill credit." Additionally, the Net Metering Act provided that for net metered customers, retail electric utilities are entitled to implement rates to recover all costs necessary to serve net metered customers, including but not limited to fixed and demand-based costs. Compensation rates and the rate charged to net metered customers will be determined by the Commission using the ratemaking process under KRS Chapter 278. Similar to the previous net metering statutes, the bill credit carries forward if the amount of the bill credit exceeds the amount billed in a billing period.

COMMENTS

Kentucky Office of Energy Policy (OEP)

OEP is housed within the Kentucky Energy and Environment Cabinet. OEP's mission is to support the utilization of Kentucky's energy resources for the betterment of the Commonwealth while protecting and improving the environment. In its written comments, OEP noted that in 2018, Kentucky had approximately 1,500 distributed renewable generator interconnections, with a total generating capacity of 34 megawatts (MW). Thirty percent of the interconnections were net metering interconnections and 70 percent were non-net metering interconnections. OEP noted that areas of the state served by the Tennessee Valley Authority (TVA) have the greatest distributed renewable generation adoption due in part to compensation rates that were initially set higher than retail, but since have been set at a lower rate.[3] OEP modeling projects that distributed solar generating capacity in the service areas of jurisdictional electric utilities will be between 162 MW and 3,160 MW by 2040, as compared to utility scale power plants currently operating at approximately 20,000 MW. OEP cautions that this projection was based on a 1:1 net metering compensation rate, and thus should be viewed as the upper boundaries of projected capacity.

OEP referred the Commission to several studies, including a study conducted by the Lawrence Berkley National Laboratory in 2015 that analyzed the sensitivity of compensation rate on adoption of customer-sited distributed solar generation, which is attached to this Report and Order as Appendix B. OEP also referred the Commission to the executive summary of the 50 States of Solar Report Annual Review for 2018, published by the N.C. Clean Energy Technology Center at North Carolina State University, which highlights actions relating to solar policies, net metering, and rate design around distributed generation.[4] This report notes that compensation structures are becoming increasingly complex, with separate rates for energy imports and exports, residential demand charges for distributed solar customers, and examination of the locational value of distributed generation. OEP noted that the National Association of Regulatory Utility Commissioners (NARUC) published a Manual on Distributed Energy Resources Rate Design and Compensation in 2016[5] that emphasized the importance of

---

[3] OEP noted that TVA's value of distribution generation methodology assessment resulted in a compensation rate much lower than the residential retail rate of 9 cents per kWh charged by the TVA's Kentucky electric cooperatives.

[4] https://nccleantech.ncsu.edu/wp-content/uploads/2019/01/Q4-18-Exec-Summary-Final.pdf

[5] https://pubs.naruc.org/pub.cfm?id=19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

understanding tradeoffs in determining an appropriate compensation methodology in regard to technology adoption, particularly the impact to the market and to the utility if one technology is emphasized over another, and cost shifting, which at high levels of net metering adoption can result in significant reallocation of utility revenue to non-net metered customers.

OEP provided the historical context of net metering compensation mechanisms, including valuing distributed generation at the retail rate, at the wholesale rate, or the avoided cost of the utility. OEP also highlighted the distinction between net metering compensation and compensation under the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended, which was enacted to encourage cogeneration and renewable resources. Importantly, PURPA requires electric utilities to purchase energy from cogeneration and small renewable generation sources of 80 megawatts (MW) or less at a cost not to exceed avoided cost. Thus, under PURPA, energy exported to the grid is considered a sale that is valued at the avoided cost of the utility, as opposed to net metering billing mechanisms producing credits that reflect the difference between the electricity a net metered customer takes electricity off the system and the electricity that customer puts on to the system when generating power in excess of the customer's consumption. OEP encouraged the Commission to consider net metering compensation rates and methodologies as separate and distinct from PURPA tariffs, and to retain existing characteristics of simplicity, consistency, and interconnection standardization across Kentucky jurisdictional electric utilities.

In terms of rate design, OEP contended that the core issue is establishing a compensation rate for net metered customers that is not acutely out of line with the utility's costs of rendering electric service to the net metered customers. OEP urged the Commission to consider eight attributes of rate structure under traditional ratemaking principles: simplicity and feasibility of application, unambiguous interpretation, revenue stability, revenue requirements yielding a fair return, minimization of unexpected changes, fair apportionment of cost of service among difference rate classes, avoidance of undue discrimination, and discouraging of the wasteful use of resources.

OEP discussed cost-of-service ratemaking, which incorporates a cost-of-service study of energy costs, versus value-of-service ratemaking, which is the value of service to consumers as measured by their willingness to pay. OEP explained that value-of-service methodology incorporates societal benefits that can be hard to quantify and is a departure from cost-based ratemaking. OEP opined that utility rates are not the solution to addressing all societal costs or benefits related to renewable energy, and that comprehensive public policies, such as tax law, economic development incentives, and workforce training and education, along with sound cost-based ratemaking, may be the best way to minimize societal costs and maximize social benefits of promoting renewable energy.

Finally, OEP noted that net metering compensation rate design is not a one-time process. OEP emphasized that the reasonableness of net metering compensation rates depends upon ongoing processes and refinement of compensation methodologies as cost and benefits change based on penetration of distributed generation.

<u>Kentucky Association of Electric Cooperatives, Inc. (KAEC)</u>

KAEC, a statewide association representing Kentucky's 21 electric cooperatives, filed written comments and a representative of KAEC spoke at the public comment hearing. KAEC stated the Kentucky General Assembly amended the Net Metering Act to address the imbalance or inequity of the current net metering law, which results in subsidization of costs. KAEC emphasized that differences exist between the electric cooperatives and investor-owned utilities (IOU), and between the electric cooperatives themselves, and thus a flexible approach is necessary when establishing net metering compensation rates. For example, KAEC noted that cooperatives purchase their power supply and transmission functions from wholesale generation and transmission utilities (G&T), while vertically integrated IOUs provide all three functions within a single rate design. KAEC also noted that the penetration of net metering differs between urban and rural areas, which impacts the number of affected customers and the extent that net metering compensation rates affects the utility's overall financial condition.

In contrast to OEP's assertion that net metering compensation rates should be separate and distinct from PURPA tariffs, KAEC encouraged the Commission to embrace the PURPA rate scheme and use applicable qualifying facilities (QF) tariff rates already approved by Commission to establish net metering compensation rates for the cooperatives and their G&Ts, East Kentucky Power Cooperative, Inc. (EKPC) and Big Rivers Electric Corporation (Big Rivers). The cooperatives', EKPC's, and Big Rivers' QF tariffs are based on avoided cost calculations and the comparative characteristics of the QF. The existing QF tariffs approved by the Commission have rates, terms, and conditions that vary with the size of the relevant QF and whether the resources are dispatched by the utility. KAEC asserted that net metering facilities resemble small QF resources that are not dispatched by the utility, and therefore the existing QF tariff would be a reasonable and expedient net metering compensation rate.

KAEC urged the Commission to allow utilities to establish or enhance safety-related terms and conditions for eligible generating facilities that are consistent with the National Electric Safety Code or other accepted safety guidelines. KAEC explained that the growth of photovoltaic (PV) solar systems on customers' buildings presents a safety hazard to utility line workers, noting that a grid-tied PV solar system generates electricity when exposed to light and cannot be powered down, creating potential safety concerns for utility workers and others. KAEC asserted that establishing safety practices and guidelines in connection with net metering ratemaking proceedings are necessary to ensure the safe and reliable operation and maintenance of the electric grid and for the safety of utility customers and employees.

In response to a question at the public comment hearing, a representative of EKPC indicated that EKPC will work with its member-owners to develop one overarching net metering tariff to mitigate the complexity and administrative burden of separate ratemaking proceedings for each of EKPC's 16 owner-members.

Duke Energy Kentucky, Inc. (Duke Kentucky)

Duke Kentucky, an IOU, filed written comments, had a representative speak at the public comment hearing, and filed additional written information requested by the Commission at the public comment hearing. In its written comments, Duke Kentucky provided a historical overview of net metering in Kentucky, noting that, prior to the enactment of the recent amendments to net meter statutes, the 1:1 compensation rate created a subsidy for net metered customers that was paid by all other customers. Duke Kentucky stated that, while a 1:1 compensation rate may have been justified on a policy basis to promote the adoption of rooftop solar facilities when they were first introduced, the number of such facilities has grown and the cumulative cost impact of subsidizing eligible generating facilities can no longer be justified on a policy basis.

At the public comment hearing, Duke Kentucky's representative contended that the compensation rate for net metered customers should have three key features: 1) ensure that net metered customers bear their appropriate share of costs, including the cost of guaranteeing reliable, available service; 2) reflect the kWh value at the time the energy is put back onto the grid; 3) and encourage net metered customers to align eligible generation technology with their pattern of usage to incentivize energy efficiency.

Duke Kentucky asserted that the assumption that a kWh of energy produced and distributed by a utility is equivalent to a kWh of energy fed back to the grid by a net metered customer is a false equivalence. Duke Kentucky contended that a compensation rate that is equal to the full retail tariff rate ignores costs incurred by a utility to maintain transmission and distribution at adequate capacity and required reliability guaranteed to be available to serve net metered customers 24/7, irrespective of whether net metered customers fully meet their energy needs at certain times. Duke Kentucky further contended that a compensation rate equal to a full retail tariff rate fails to account for limitations of customer-generated energy. Duke Kentucky explained that renewable energy resources cannot relieve a utility of any portion of the costs incurred to meet load and reliability requirements. Unlike energy produced by a utility, energy produced by net metered customers is not dispatchable, and is not reliably or predictably available, and thus reduces the value to the utility of the customer-generated energy to an amount that is significantly less than retail tariff rates. Duke Kentucky asserted that compensation rates must be designed to ensure that net metered customers bear their share of the costs of generation capacity, transmission, and distribution that such customers rely upon when self-generation is unavailable or insufficient.

Duke Kentucky maintained that compensation rates should be valued at the incremental value of a single additional kWh. For utilities like Duke Kentucky that are members of PJM Interconnection, LLC (PJM), a regional transmission organization (RTO), the RTO wholesale market determines the value a utility can derive from a kWh hour sent back to the grid by a net metered customer. Under Duke Kentucky's proposal, the compensation rate would reflect the kWh value at the time the kWh is put back on the grid in the RTO wholesale market.

In response to a question from the Commission at the public comment hearing, Duke Kentucky filed supplemental comments regarding whether and to what extent Duke Kentucky relies on solar resources to meet its capacity requirements as a member of PJM. Due to the intermittent nature of the energy, Duke Kentucky does not utilize any solar facilities as direct capacity resources in its service area in PJM. However, Duke Kentucky explained the benefits and risks of utilizing renewable resources to meet PJM capacity requirements. To the degree that eligible customer generation facilities offset the load at the times of PJM's coincident peak, there is a benefit to Duke Kentucky because its capacity obligation is calculated based on a reduced load, and thus indirectly reduces the magnitude of Duke Kentucky's capacity obligation. However, there is a risk associated with counting solar transmission-connected facilities towards the capacity requirement because, even though solar generation facility capacity is heavily discounted, solar energy is never guaranteed to be available and cannot be relied upon to meet capacity requirements. If Duke Kentucky relied upon solar facilities to meet its capacity obligation, it would risk under-performance of its capacity obligation and be assessed significant financial penalties. The level of risk exposure from including solar facilities in its capacity obligation makes it unacceptable.

Kentucky Industrial Utility Customers, Inc. (KIUC)

KIUC provided written comments and a representative spoke at the public comment hearing. KIUC cautioned the Commission against overcompensating net metered customers by setting a compensation rate at a level greater than the value of the service they provide to the system. KIUC asserted net metered customers provide energy to the grid only when and if they wish to do so. As a result, net metered customers credited at the full retail rate receive payments for capacity, transmission, and distribution services they did not provide, which results in other customers subsidizing net metered customers.

KIUC stated that, to avoid overcompensation, net metered customers should receive only the value of the energy they provide to the grid. KIUC maintained that the plain language of the amended net metering statutes and the legislative intent regarding the term "dollar value" in regard to compensation rate specifically referred to energy-only costs. KIUC asserted that electricity is a commodity that does not include externalities, such as public health or environmental costs or benefits, and that the Kentucky legislature did not intend for externalities to be factored into the compensation rate.

KIUC noted that, ideally, the compensation rate would be set at the real-time energy price effective at the time of the energy delivery. For net metered customers with smart meters, the meters can assess the customer's hourly load, with the compensation rate set as the real-time energy price effective at the time of energy delivery. For net metered customers without smart meters, KIUC proposed several options for providing an energy-only credit to net metered customers. First, the Commission could require retail electric suppliers to compensate net metered customers at the current energy rates set forth in the suppliers' tariff. In the alternative, the Commission could establish compensation rates based upon the energy costs in each supplier's' most recently filed cost-of-service study. Finally, the Commission could require all retail electric suppliers to conduct a new cost-of-service study to determine more precisely the current level of energy costs and use those findings to establish each supplier's net metering compensation rate.

In response to a question from the Commission at the public comment hearing regarding a response to those who advocate for delaying implementing the Net Metering Act KIUC said that the Commission would not be doing its job if it did not comply with the amended statutes because, as of January 1, 2020, utilities have the legal right to file rate cases to establish new net metering compensation rates. KIUC argued that there is enough data to enforce the statute.

Attorney General of the Commonwealth of Kentucky

The Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General), filed written comments and spoke at the public comment hearing. The Attorney General encouraged the Commission to afford intervenors and the utility applicant in a net metering case the opportunity to present any relevant data, information, or arguments they wish to present. In that vein, the Attorney General urged the Commission to adopt a broad and generous approach to considering data and arguments and to continue the Commission's policy of a liberal discovery process and full procedural schedule ordinarily used in rate proceedings.

Because the Net Metering Act does not state with specificity the costs that should be considered in developing the compensation rate, the Attorney General asked the Commission to consider costs and benefits that affect utility rates or service under existing or reasonably foreseeable regulatory requirements. The Attorney General argued that the types of costs and benefits that electric utilities consider in their Integrated Resource Plan (IRP) may be appropriately considered in determining a net metering compensation rate. The Attorney General cited specific IRP costs and benefits that may be considered in determining the compensation rate for net metering customers, such as carbon dioxide prices, fuel prices, generating unit operating lives, reserve margin reliability costs, environmental regulations, capacity constraints, transmission constraints, and transmission and distribution line losses.

Finally, the Attorney General urged the Commission to adopt a flexible framework or methodology for the compensation rate with an expansive consideration of costs For example, the Attorney General noted that the difference between generation-only costs and benefits incurred by G&Ts, distribution-only costs incurred by electric distribution cooperatives, and IOUs that incur both generation and distribution costs precludes a one-size-fits-all ratemaking process regarding costs and benefits upon which the compensation rate is calculated.

In response to a question from the Commission at the public comment hearing, the Attorney General explained that factors considered in an IRP should be the floor for factors to be considered in establishing a net metered compensation rate.

Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E)

KU/LG&E, IOUs with combined generation and transmission functions, but which are legally separate entities, filed written comments; a representative spoke at the public comment hearing. As an initial matter, KU/LG&E observed that, no matter the fuel source, all economic generation choices must be based on objective costs and data, and must deliver reliable energy to all customers at all times. KU/LG&E further observed that the Commission's well-established standard that a generation resource must be a reasonable, least-cost resource does not provide an exception based on the generation source.

KU/LG&E provided an overview of the history of Kentucky net metering laws and the Net Metering Act. KU/LG&E stated that, under the Net Metering Act, retail electric suppliers have the legal right to recover from net metered customers the costs incurred to serve those customers. To that end, KU/LG&E explained that compensation rates should be based on objective costs and data to avoid creating subsidies for and false price signals to net metered customers. KU/LG&E stated that the Commission does not consider externalities in evaluating the cost-effectiveness of demand-side management programs and, in the past with regard to demand-side management programs, the Commission has stated that it does not have jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or services. KU/LG&E urged the Commission to follow those same tenets in establishing the net metering compensation rate.

KU/LG&E advocated that the Commission consider the same methodology it approved for KU/LG&E's solar share program (SSP).[6] KU/LG&E utilize a net billing compensation mechanism to calculate a monthly SSP energy credit. KU/LG&E compares a SSP customer's share of energy generated from SSP facilities to the customer's energy usage in 15-minute intervals. If the SSP customer's energy consumption is less than the solar energy generated in the same 15-minute interval,[7] then the SSP customer receives a bill credit per kWh that is equal to the non-time differentiated rate approved by the Commission. The non-time differentiate rate is based on KU/LG&E's estimated avoided cost for generation. KU/LG&E asserted that applying this methodology to net metered customers would create a level playing field for net metered customers who put energy back onto the grid and SSP customers.

Should the Commission use another methodology to develop cost-based compensation rates, KU/LG&E requested that the Commission consider the characteristics of solar energy that lessen its value. KU/LG&E observed that energy put back onto the grid from net metered customers is not dispatchable and, because it is not under the control of the utility, is not a reliable capacity resource. Additionally, because solar energy cannot be controlled and results in intermittent power flows, solar energy offers less value than other generation sources that consistently provide power upon demand. KU/LG&E also asked the Commission to consider costs utilities must incur to serve net metered customers, such as costs to bolster telemetry and frequency response

---

[6] Customers who subscribe to the SSP receive solar energy credits generated from a community solar facility in exchange for paying a monthly fee that covers the cost of constructing and maintaining the solar share facilities.

[7] Because one of the requirements to participate in SSP is that participants must have an advanced meter, KU/LG&E is able to monitor participants' energy consumption in 15-minute increments.

tools to accommodate intermittent output of net-metered facilities. KU/LG&E explained that when the penetration levels of net metered customers increase, they will have to invest in their distribution systems to avoid overloading circuits from this intermittent output, which impacts KU/LG&E's ability to provide safe, adequate, and reliable service to customers and jeopardizes the safety of utility employees.

Similar to other utilities, KU/LG&E also stated that the Commission should update interconnection guidelines to reflect new technologies. KU/LG&E explained that interconnected eligible customer generation transforms the distribution system from a one-way delivery mode into a complex bi-directional network through which electricity flows and has to be carefully monitored and balanced. Thus, according to KU/LG&E, interconnection guidelines must be updated to address safety and operational concerns.

In response to questions from the Commission at the public comment hearing, KU/LG&E countered the argument from solar advocates that solar energy flows to the nearest neighbor, and thus uses few grid resources, by pointing out that electrons are part of an integrated system and flow where they flow, whether down the street or across the city. In response to a question about distribution system upgrades for safety reasons, KU/LG&E agreed that is a circuit-by-circuit determination that examines how dense the generation is and how it affects the circuit.

<u>Kentucky Power Company (Kentucky Power)</u>

Kentucky Power, an IOU, filed written comments, had a representative speak at the public comment hearing, and filed supplemental comments. Kentucky Power noted that the Net Metering Act provides that retail electric suppliers can recover <u>all</u> costs necessary to service net metered customers, including, but not limited to, fixed and demand-based costs. Kentucky Power further noted that its current net metering tariff falls short of these requirements because net metered customers do not pay all costs required to serve them.

Kentucky Power identified two types of costs that it directly incurs to accommodate net metered customers. The first are capacity costs, or fixed costs, incurred for generation, transmission, and distribution infrastructure needed to provide service to net metered customers. Kentucky Power explained that, because net metered customers rely on energy provided by Kentucky Power multiple times each day when the customer-generated energy is insufficient to meet the customer's demand, these costs are necessary to guarantee reliable, available service to all of its customers. The second type are costs required to interconnect customer generation facilities to Kentucky Power's system (Net Metering Interconnection Costs), which include, among other things, administrative, planning, and analytical costs. Depending upon the size of the customer generation facility, Net Metering Interconnection Costs can range from $600 to $7,500 per net metered customer.

Kentucky Power stated that rates that recover costs of providing service through volumetric-based charges result in intra- and inter-class subsidies and cost shifting. In support of this, Kentucky Power explained that net metered customers can reduce the volumetric portion of their electric bill by offsetting energy consumed with energy generated, thereby avoiding paying the full costs of providing service to net metered customers. Kentucky Power further explained that, because net metered customers avoid costs that are not avoided by the utility, this results in the allocation or reallocation of fixed costs to the non-net metered customers.

Kentucky Power stated that, under its current rate design, it recovers its fixed cost of service primarily through a variable energy charge (dollar per kWh or $/kWh) and a small fixed monthly charge of between $14.00 and $17.50 that is significantly below the actual cost of providing residential service, which is approximately $39.00 per month. Kentucky Power explained that the variable energy charge is a means of encouraging conservation by its customers, who the Commission notes are among the most economically challenged Kentuckians due to the significant downturn in business activity in its service territory, including the loss of coal-related jobs.

Kentucky Power discussed how net metered customers' load shape differs from non-net metered customers. For example, a net metered customer's peak loads in the winter occur in the early morning hours when the sun has not yet risen or is very low in the sky, then fall nearly to zero between the hours of 11:00 a.m. and 3:00 p.m. Because customer-generated energy typically occurs between the hours of 11:00 a.m. and 3:00 p.m., net metered customers do not generate energy during times of peak demand. As a result, when a net metered customer produces energy in excess of consumption, Kentucky Power purchases the excess energy at about 10 cents/kWh, which is significantly more than market-priced energy that Kentucky Power would have purchased or generated at a cost of about 4 cents/kWh. As a result, Kentucky Power and its ratepayers pay more than double the market price for energy generated by net metered customers.

Kentucky Power proposed two options for establishing fair and reasonable compensation rates that do not result in intra- or inter-class subsidies. Under the first option, net metered customers would be in their own rate class that, along with the existing monthly customer charge and energy charge, would include a demand charge that would recover demand-based costs and fixed costs incurred to serve net metered customers. Kentucky Power explained that this rate design is used for larger commercial and industrial customers, and aligns the cost collection mechanism with the nature of the costs. Under the second option, net metered customers would sell all of the energy they produce at a market-based rate and then purchase all of the power they use under an existing tariff rate. Net metered customer would be responsible for any facility modifications directly related to serving net metered customers, including metering changes, circuit impact studies, and telemetry.

At the public comment hearing and in supplemental comments, Kentucky Power illustrated that residential net metered customers with net zero usage receive a subsidy of $56 per customer per month or $672 per customer per year for the distribution and transmission portion of a residential bill. In response to a question from the Commission regarding how Kentucky Power would value externalities in net metering compensation rates, Kentucky Power responded that its ratemaking is cost based and not value based. As an example, Kentucky Power stated that the value of a safety team at a nuclear facility is not factored into rates, although there is substantial indirect benefit.

Kentucky Solar Industries Association (KYSEIA)

KYSEIA, a trade association representing the solar industry, filed multiple written comments, appeared at the public comment hearing, and filed a written response to a post-hearing request for information. KYSEIA stated that 1,410 people were employed in the solar industry in Kentucky at the end of 2018, a 40 percent increase in solar jobs since 2015. KYSEIA asserted that the 1:1 net metering compensation rate has been essential for promoting the growth of solar energy in Kentucky, and that the Commission should maintain the 1:1 compensation rate. KYSEIA encouraged the Commission to delay changing the current compensation rate, arguing that statutory restrictions limiting the size and total capacity of net metering in Kentucky are safeguards that prevent or constrain the subsidization of net metered customers by other customers. Further, KYSEIA asserted that the utilities had not provided evidence of subsidization of costs.

KYSEIA made several procedural recommendations regarding revisions to net metering tariffs, net metering applications, and interconnection guidelines to comply with revised provisions of net metering statutes, as well as recommendations regarding filing procedures and the methodology for calculating the 1 percent cap on net metered customers. KYSEIA recommended that the Commission require electric utilities to file progress reports regarding remaining capacity for net metered customers based upon the 1 percent cap, and that weekly reports be required once a utility reaches 90 percent of the available net metering capacity. KYSEIA requested that the Commission initiate a proceeding to revise and modernize the interconnection guidelines previously approved by the Commission. As one example of a potential change, KYSEIA asserted that the requirement that customers install an external disconnect switch (EDS) is unnecessary and duplicative because other standards already provide adequate safety requirements.

KYSEIA advocated that the Commission include all components of an electric rate, including demand-related costs, in establishing the compensation rate and not confine compensation to energy-only costs. In considering the costs incurred to serve net metered customers, KYSEIA asserted that all costs and benefits should be valued. KYSEIA argued that a *de minimis* difference in net costs to serve net metered customers is not sufficient evidence to support discrete rates for net metered customers. KYSEIA further asserted that, if a utility failed to conduct a robust examination of net metering impacts, the Commission should consider the omission to be *prima facie* evidence that the impacts are too minimal to merit a substantive change to the compensation rate.

KYSEIA urged the Commission to conduct a thorough investigation into net metering and determine a methodology for establishing the dollar value pursuant to the Net Metering Act and that utilities should make proposals on implementing the Net Metering Act in their next base rate case filed on or after January 1, 2020. Finally, KYSEIA asked that the Commission evaluate utility proposals and stakeholder counterproposals taking into full consideration benefits that customer-generated energy provides to the grid, other customers, and the general public, such as avoided line losses and deferred need to invest in generation and transmission systems. KYSEIA explained that the Commission should have an independent study conducted on the benefits and costs of net metering and that the Commission might be eligible to receive free technical assistance from nationally recognized experts, such as the Lawrence Berkeley National Laboratory or the Pacific Northwest national Laboratory.

KYSEIA argued that the Commission should consider certain ratemaking principles in implementing the Net Metering Act, including cost causation, which would include a holistic examination of the customer class's usage; gradualism, such as using caution when factoring in demand rates and fixed charges, which are unfamiliar concepts for residential customers; ease of understanding for customers; and efficient use of service, with rates designed to provide price signals to promote beneficial behaviors, including encouraging energy efficiency.

In supplemental comments, KYSEIA argued that, under the provision in the amended Net Metering Act that retains the 1:1 compensation rate for current net metered customers, the 25-year period in which current net metered customers are grandfathered begins to run not on January 1, 2020, but as of the effective date of any new net metered rates approved by the Commission. KYSEIA further argued that utilities cannot defer service to new net metered customers and must offer said service as of January 1, 2020, and that the intent of the Kentucky legislature was not to "chill" the installation of new customer generation facilities. KYSEIA further recommended that the Commission convey that utilities must timely process applications for net metering and interconnection and recommended procedures and policies that utilities should implement regarding net metering applications.

KYSEIA rebutted comments filed by utilities, arguing that the PURPA avoided-cost model is inappropriate to apply to small distributed generation and thus should not serve as a basis for establishing a compensation rate for net metering. KYSEIA requested that the Commission adhere to monthly netting to avoid complexity, arguing that netting over 15-minute or one-hour intervals would require net metered customers to install new metering equipment and would add unwarranted complexity and cost. KYSEIA asserted that recovering fixed costs and demand-related costs through demand charges is not consistent with principles of rate design and is inappropriate for residential customers, who have low load factors. KYSEIA recommended that interconnection costs are more typically \$50 to \$100, and not the \$600 to \$7,500 range suggested by Kentucky Power. KYSEIA argued that interconnection costs should be limited to the costs of administratively processing a net metering application.

In response to a post-hearing request for information regarding the adoption rate of net metering facilities, KYSEIA first noted that the information is not maintained in the normal course of business and that KYSEIA's membership does not include all solar installer companies in Kentucky. With that caveat, KYSEIA collected information for 403 solar projects that was compiled in four schedules including year-by-year summaries of installations in the service territories of jurisdictional utilities, TVA cooperatives, and municipal utilities. KYSEIA filed the information in Excel spreadsheet format, which Commission Staff will utilize in future utility-specific net metering ratemaking proceedings.

Kentucky Resources Council, Inc. (Kentucky Resources Council)

Kentucky Resources Council, a nonprofit organization that provides policy and legal advocacy related to Kentucky's natural resources, indicated that the rates should be fair, just, and reasonable to all participants and requested reasonable fact-based policies that are fair to all stakeholders. Kentucky Resources Council emphasized that the Commission should conduct a thorough and transparent analysis that includes the full range of costs and benefits specific to each utility. Kentucky Resources Council urged the Commission to grant intervention in all net metering ratemaking proceedings for all unique interests in order to ensure full understanding of the issues. Kentucky Resources Council asserted that inviting public comments is not a substitute for the input that can be gained with full intervention.

Kentucky Resources Council cautioned the Commission not to base the compensation rate solely on avoided costs because that would ignore the fact that, unlike utilities, net metered customer-generators incur little-to-no distribution costs, avoid line losses, and receive the benefit of reduced financial risk, reduced costs of environmental compliance, and avoided greenhouse gas emissions. The Council contended that, while net metering provides benefits to the utility, other customers, and the grid itself, there is no clear consensus on the methodology for determining the appropriate rate. Kentucky Resources Council pointed to a U.S. Department of Energy report that stated that the value of solar in any analysis depends on the data and assumptions made, which can vary by geography, penetration, inputs such as marginal unit displacement and discount rates, and the inclusion or exclusion of externalities.

Kentucky Resources Council provided two published guides for use in assessing cost and benefits of distributed renewable energy. The first, provided by the Interstate Renewable Energy Council, concluded that: (1) avoided energy costs should be priced at the cost of combined-cycle natural gas facilities that would not be needed due to the growth of distributed solar generation; (2) distributed solar generation should be credited as a capacity value upon interconnection, as the installations are predictable; and (3) societal benefits such as job growth, and health and environmental benefits, should be included in the valuation. The second, from the National Renewable Energy Laboratory, was utility focused and recommended methods for calculating costs and benefits of displaced energy and capital investments, environmental factors, transmission and distribution losses and capacity value reduction, ancillary services, as well as external issues such as fuel price hedging/diversity and market-price suppression. Kentucky Resources Council stressed that the mitigation of climate change and greenhouse gas emissions should be considered as a quantifiable benefit, noting that, in previous proceedings to authorize utility-installed solar arrays, utilities have included the impact on greenhouse gas emissions in their cost/benefit analysis in support of such facilities.

Kentucky Resources Council argued that a number of studies indicate that the value of customer-generated distributed generation is higher than the retail rate and, due to the level of distributed energy penetration, there is very little intra-class cross subsidization. Kentucky Resources Council asserted that utilities should produce substantiated evidence that net metered customers not only cost more to serve, but that the alleged cross subsidization is material. Kentucky Resources Council further asserted that net metered customers pay a utility's customer charge and thus are already paying their fixed costs. Kentucky Resources Council contended that if the customer charge does not fully recover fixed costs, it is a ratemaking issue, not a net metering issue.

Kentucky Resources Council maintained that not offering a retail rate for net metering takes away one of the few options available in the monopolistic utility market for a customer to control their energy use and reduce their bills. Kentucky Resources Council opposed the proposal to place net metered customers in a separate class, stating that would be contrary to the requirement that rates be fair, just, and reasonable. In addition, if rates do change substantially, Kentucky Resources Council cautioned the Commission to apply the rate-setting principle of gradualism so as not to dramatically slow the adoption of renewable-sourced distributed generation. Kentucky Resources Council encouraged the Commission to establish a rate that allows the customer-generator to easily calculate a rate of return on their investment based on usage and to be mindful of economic development impacts of the fast-growing solar industry.

Finally, Kentucky Resources Council requested that the Commission keep in mind that the purpose of utility regulation is to protect the health, safety, morals, and general welfare of its citizens.

In supplemental comments, Kentucky Resources Council reiterated that any rate changes should be analyzed on a utility-specific basis and that the methodology should be robust and include all costs and benefits. Kentucky Resources Council emphasized that allowing all possible stakeholders to intervene in future net metering ratemaking cases will assure that the results are fair, just, and reasonable.

Kentucky Resources Council opposed the proposals that would value energy in 15-minute or one-hour intervals. Kentucky Resources Council explained that the intention of the Net Metering Act is that net metering represents the excess energy placed onto the grid at any time, rather than valuing the electricity fed into the grid in certain 15-minute or one-hour intervals. Kentucky Resources Council claimed that it was not the intention of the General Assembly to alter the current practice under existing law and reading the statues otherwise would be inconsistent. Additionally, Kentucky Resources Council stated that it was not the General Assembly's intent to require regulated utilities to have metering equipment beyond the standard bi-direction meters to capture the amount of electricity fed into the grid on an instantaneous basis.

Expanding upon its previous comments, Kentucky Resources Council argued that basing the compensation on a utility's avoided cost fails to recognize that net metered customers have different fundamental characteristics than the traditional independent power producer, receive compensation in the form of a bill credit rather than cash, and have varying benefits, including locational benefits. Kentucky Resources Council asserted that, just as environmental costs of coal-fired generation are incorporated into rates paid by consumers, the Commission should recognize environmental benefits in the calculation of the net cost of net metering.

At the public comment hearing, Kentucky Resources Council asserted that the General Assembly expressly rejected using avoided costs similar to PURPA, despite the utilities' lobbying efforts for such a compensation scheme. Kentucky Resources Council stated that is was disingenuous for utilities to suggest that public health mandates should not be part of the compensation rate given that the costs of pollution controls required for coal-fired generating facilities are recovered in environmental surcharges. In response to a question from the Commission, Kentucky Resources Council agreed that if a higher percentage of fixed costs are in a customer charge, the opportunity for cost shifting is reduced, but also noted that the effect would differ for each utility depending upon how fixed costs are embedded in rates.

Kentuckians for the Commonwealth (KFTC) and Mountain Association for Community Economic Development (MACED)

KFTC and MACED, both nonprofit organizations, filed written comments and appeared at the public comment hearing. As an initial matter, KFTC/MACED encouraged the Commission to grant intervention in future utility-specific net metering ratemaking proceedings to all interested parties without limitation because every Kentuckian has a stake in such proceedings and therefore should be full participants in the process.

KFTC/MACED urged the Commission to retain the full retail rate credit for net metered customers and prohibit utilities from discriminating against net metered customers through unfair, unjust, and unreasonable compensation rates. KFTC/MACED maintained that utilities should be required to use a comprehensive cost-benefit analysis with a fair cost-of-service based methodology or value of solar methodology for all net metering ratemaking proceedings. KFTC/MACED counseled the Commission to be skeptical of utility claims about cross-subsidization, asserting that there is no data to support such arguments. KFTC/MACED argued that net metered customers do not create costs when they generate their own energy because customers that use less, cost less.

KFTC/MACED rebutted comments filed in this proceeding, arguing that there is no basis for the assertion that net metered customers are subsidized. KFTC/MACED argued that evidence in other states strongly suggests that the benefits of net metering outweigh the costs, and that Kentucky-specific data is insufficient to support reliable conclusions. KFTC/MACED opposed establishing a rate class for net metered customers as inconsistent with ratemaking principles, explaining that the number of net metered customers is not sufficient to support a stand-alone rate class and that there is no cost-of-service evidence to support a stand-alone rate class for net metered customers. KFTC/MACED claimed that there is no evidence to support a conclusion that the costs to serve net metered customers are different from the costs to serve non-net metered customers. KFTC/MACED rejected proposals to net bill credits on 15-minute or one-hour intervals because it would add complexity to ordinary customers' understanding of their bills. KFTC/MACED also rejected a proposal to base the net metering compensation rate on QF rates set under PURPA, arguing that QF rates are design to address only wholesale market impacts, while customer-generated energy serves the nearest unserved load and earns the utility the full retail rate.

<u>Public Comments</u>

The Commission received a significant number of written comments from the general public, almost all of which addressed net metering in the context of rooftop solar generating facilities. The public comments can be viewed on the PSC website at:

https://psc.ky.gov/PSC_WebNet/ViewCaseFilings.aspx?Case=256. The Commission also received comments from the general public at a public comment hearing on November 13, 2019. A summary of those comments is attached as Appendix A to this Order.

Many public comments encouraged the Commission to consider and quantify a full range of benefits of solar energy into the net metering rate design. In these comments, members of the public asserted that rooftop solar provided benefits to electric utilities, other ratepayers, and society in general including: avoided costs, such as fuel costs and reduced need for new generation or infrastructure; reduced line losses; grid resiliency; environmental and public health benefits from reduced pollution and emissions; and job creation and economic development. Those commenters maintained that the benefits of distributed solar energy outweighed costs to the utility.

Some public comments supported a net metering credit at a level equal to or greater than retail rates. Many commenters asserted that customers with rooftop solar should receive the full retail price because deployment of distributed solar generation reduces energy consumption, and thus is akin to installing energy efficient appliances that reduce that customer's energy consumption, which reduces their energy bill by the same amount as the energy they do not consume. Others conceded that net metered customers are subsidized by non-participating customers, but maintained that net metered customers should receive a credit for the full retail rate because the amount of subsidization was *de minimus* when spread over all customers and was offset by environmental and health benefits.

Other public comments requested that the Commission avoid creating barriers to solar adoption through net metering rate design that disincentivizes deployment of rooftop solar facilities. Many of these commenters addressed the impact of compensation rates on the pay-back period, which is the amount of time it takes for cumulative electric bill savings to equal the cost of rooftop solar facilities. These commenters explained that compensation rates below the tariffed retail rate for consuming electricity discourage customers from purchasing solar rooftop facilities because the payback period is too lengthy to justify the investment. These commenters further explained that slowing or decreased sales had an adverse economic impact on solar energy jobs, which could result in an adverse economic impact on the economy as a whole.

Some public comments addressed the overall solar incentive structure, which includes net metering rate design, asserting that net metered customers receive above-market benefits while non-solar customers bear increased costs as a result. As an example, these commenters noted that a utility that buys power from a net metered customer at the retail rate is often unable to recover fixed costs of grid maintenance attributed to net metered customers. As a result, non-solar customers must cover the portion of grid maintenance costs not recovered from net metered customers.

DISCUSSION

As we noted in the Order opening this proceeding, the purpose of this proceeding is to develop a record by compiling comments from utilities, stakeholders, and the general public that the Commission can draw upon when implementing the Net Metering Act in ratemaking proceedings initiated by retail electric utilities. Methodologies for assessing costs in the course of establishing a fair, just, and reasonable utility-specific compensation rate for the dollar-denominated bill credit for net metered customers are a significant component in the implementation of the Net Metering Act. The Commission's goal is to ensure fair, just, and reasonable rates for net metered and non-net metered customers alike.

We first address the timing of implementing the Net Metering Act. Some members of the general public requested that the Commission delay implementing the Net Metering Act until the cumulative generating capacity of net metering systems reach 1 percent of the supplier's single-hour peak load during a calendar year. While we acknowledge adoption of net metering is not at a critical mass, as a creature of statute, the Commission does not have the authority to ignore a statute that was lawfully enacted. The Legislature sets forth broad statutory guidance to an administrative agency, such as the Commission, and delegates authority to the agency to carry out the purpose of statute. The Net Metering Act has a statutorily defined effective date of January 1, 2020. The scope of the Commission's authority does not include authority to override the implementation date for a lawful statute. Thus, the Commission, on January 1, 2020, must be prepared to accept rate applications under the amended Net Metering Act.

Additionally, although we do not make a finding on this point, the Commission agrees with certain commenters and stakeholders that proceedings under the Net Metering Act should be thorough and transparent. The Commission will carry out proceedings under the Net Metering Act in an organized and fair process, similar to the procedures employed in regular rate and tariff filings, which will include the opportunity for discovery and intervenor testimony, if necessary. Further, the Commission will follow the law as to the participation of intervenors. As always, any person is free to provide as many comments as they would like to tender to the Commission in any case before it. Nevertheless, the Commission must follow its legal requirements for intervention of parties in pending matters. As such, parties seeking intervention in proceedings under the Net Metering Act must tender a motion to intervene showing that they satisfy the legal requirements for intervention.

Unlike other proceedings, the Commission will not in this proceeding reach findings of fact or law regarding the implementation of the Net Metering Act. However, as a result of the comments received, we have determined two actions that we will undertake immediately in conjunction with implementing the Net Metering Act.

First, the Net Metering Act provides that the net metering ratemaking processes consider utility-specific costs, and not a uniform rate for all electric utilities. In the comments received in this matter, a variety of approaches were recommended, including consideration of avoided cost, the value of energy supplied to the grid, market-based rates, and quantification of externalities. Additionally, in surveying other states, there are three general approaches to establishing compensation rates. One approach bases compensation rates on the fixed costs for maintaining electric infrastructure and the electric grid. This approach is predicated on the contention that compensation rates that do not consider fixed costs for maintaining electric infrastructure and the electric grid inadvertently allow net metered customers to avoid those costs because net metered customers may incur very low or zero-balance electricity bills. For similar reasons, the second approach bases the compensation rate for net metered customers on avoided costs, which are the costs that a utility would otherwise incur to purchase or generate incremental electricity; or the market wholesale rate. The third approach quantifies economic and social benefits and costs. This approach is based on the position that net metered customers provide economic and social benefits that should be valued, including a reduction in the need for transmission upgrades or new generation, feeding electricity back to the electric grid at peak times when producing and acquiring electricity is costly, and a reduction in emissions and pollution, which improves public health and the environment.

The Commission must develop a process that identifies known or reasonably expected measurable costs and benefits that can be factored into the ratemaking process, along with next best alternatives, based on the principle of most reasonable least-cost alternative, and opportunity costs. As noted by a number of commenters, the totality of this proceeding is novel to the Commission. Although the Commission Staff is well prepared to facilitate the disposition of ordinary rate cases, the initial proceedings under the amended Net Metering Act are not ordinary matters. Based solely on the record before the Commission in this proceeding, it is obvious that other states and stakeholders have dealt with issues similar to those the Commission expects to be adjudicated in ratemaking proceedings under the Net Metering Act. To that end, the Commission will award a contract for a consultant to assist us in reviewing, analyzing, and evaluating new net metering tariffs, alternative rate designs, and net metering rate applications, for the purpose of establishing utility-specific compensation rates for net metered customers. The Commission believes that the engagement of an outside, independent, consultant to help review and analyze the filings in proceedings under the Net Metering Act will bring to bear expertise and experience from other states and proceedings that Commission staff itself does not possess.

Second, the Commission concurs with comments from jurisdictional electric utilities and KYSEIA that the existing interconnection guidelines for distributed generation established in Case No. 2008-00169[8] must be updated. In Case No. 2008-00169, the Commission worked with stakeholders in a cooperative process that resulted in the development of interconnection and net metering guidelines adopted by the Commission that are applicable to all jurisdictional electric utilities. The guidelines incorporated all applicable safety and power quality standards established by the National Electric Code, Institute of Electrical and Electronics Engineers, and accredited testing laboratories such as Underwriters Laboratories. The Commission will initiate a separate proceeding using the same collaborative process utilized in Case No. 2008-00169 to update the interconnection guidelines to reflect new technology and technical interconnection requirements, and upon initiating the matter, the Commission will make all jurisdictional electric utilities as parties.

Finally, several commenters referred to studies that provide additional relevant information. While we incorporate said studies by reference, two studies are attached as appendices to this Order. As noted previously, Appendix B is a study from the Lawrence Berkeley National Laboratory regarding price sensitivity of net metering rates. Appendix C is an assessment of residential net metering subsidies published in the Electricity Journal and whose authors are Sanem Sergici, Yingxia Yang, Maria Castaner, and Ahmad Faruqui.

---

[8] Case No. 2008-00169, *Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity up to Thirty Kilowatts* (Ky. PSC Jan. 8, 2009).

IT IS THEREFORE ORDERED that:

1. The record of this proceeding shall be incorporated by reference into the initial net metering rate case filed by the respective jurisdictional electric utilities.

2. This case is closed and removed from the Commission's docket.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

By the Commission

ENTERED

DEC 18 2019

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

For Executive Director

Case No. 2019-00256

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2019-00256 DATED DEC 18 2019

Summary of Public Comments
Public Hearing Held November 13, 2019

Kate Shanks
9:09:36
She is Vice President of Public Affairs for the Kentucky Chamber of Commerce (Chamber). The Chamber only takes positions on issues when its members ask it to do so. The Chamber filed joint written comments with Greater Louisville Inc., Commerce Lexington Inc., and the Northern Kentucky Chamber of Commerce. The Chamber believes the Commission is the right agency to study the issue of how utilities value excess energy produced by solar energy producers. Ms. Shanks states that solar is now more affordable. She further states that Kentucky is a manufacturing state, is competitive when it comes to energy costs, and cannot afford to lose this advantage due to policies that increase the cost of electricity. The Chamber is not opposed to solar energy, just to utilities subsidizing it.

Bill Karrer
9:14:53
He lives in Sadieville, Kentucky in a home designed for solar generation. He did not invest in solar because of climate change, but for economic reasons. Mr. Karrer asserts that it is time to deregulate utility companies and allow consumers to make their own deal with utility providers. Mr. Karrer compares deregulation of electric utilities to deregulation of telecommunications industry. Mr. Karrer believes that competition needs to be reintroduced in electricity, and that it is time for electric companies to be deregulated because the monopoly is no longer beneficial.

John Cotten
9:18:41
He lives in Danville, Kentucky and is General Manager of Wilderness Trace Solar and Vice President of the Kentucky Solar Energy Foundation. He states that the largest portion of his business is solar tied to the grid and that his customers make the decision to go solar based on 1:1 credit from utility company. Mr. Cotten explains that the 1:1 credit attracts customers because installations run $23,000-$30,000 and the average payback period is 8 to 11 years. Mr. Cotten notes that the end of the 30 percent federal tax credit will lengthen that to approximately 13 years. Mr. Cotten states that the bulk of his customers are over 55 and a high percentage are ex-military. When asked if lower income individuals are priced out of the solar energy world, he says some people take out loans to install solar. When asked, he spoke about a program to install solar in southeast Kentucky. Mr. Cotten disagrees that solar is only for affluent individuals and explains that a mechanism to bring solar to low income is needed, such as providing wholesaling kits to companies working with low income individuals.

Tom Morris
9:29:07
He is from Bowling Green, Kentucky and operates a small sustainable housing company. He does not believe the Chamber of Commerce represents his interests. States that low cost energy is an oxymoron because there are societal costs to low energy costs and cheap energy is not always cheap. States that battery technology is developing and many solar generating customers may use that to remove themselves from the grid. The value of a kilowatt hour is based on when it is produced and when there is a demand for it. Electric companies should produce detailed data to show solar energy generators are subsidized by the electric company and therefore are hurting the low-income customer. He has not seen data to verify this.

Ronald Whitmore
9:33:42
He lives in Alvaton, Kentucky, is a retired pharmacist, and worked in eastern Kentucky. He is familiar with health care issues in relation to power production. The full value of rooftop solar includes avoided external costs of increased health and environmental costs. Rooftop solar's economic value goes beyond the bill and there are significant economic benefits. These benefits are well documented and quantified.

Josh Fredrick
9:37:35
He lives in Louisville, Kentucky, and operates a small solar installation business. He works in solar to fight climate change. He urges the Commission to consider the effects of climate change. Difficult to put a price on externalities. As solar becomes more affordable it can be made available to low income customers.

David Netherton
9:40:51
He is a construction worker from Shelbyville, Kentucky. He compares fossil fuels to wooden fences that weaken and decay over time. Mr. Netherton says Kentucky adopted dry stone masonry to replace wooden fences. He explains that current fossil fuels are like wooden fences because they are neither safe nor reliable. He states that we must think generations ahead, like our forefathers did when choosing dry stone fencing. He states that rooftop solar customers should receive more than a 1:1 credit.

Eve Polley
9:45:05
She is a concerned citizen from Louisville, Kentucky. Ms. Polley is worried about de-incentivizing rooftop solar by reducing the 1:1 compensation rate. She would like to one day have solar generators at her home. Ms. Polley requests that the Commission consider medical costs associated with fossil fuels when determining net metering compensation rates.

Carrie Ray
9:46:41
She lives in Lexington, Kentucky, and works for a nonprofit to help lower energy bills for small businesses and non-profits by installing solar panels. She claims a 129 percent increase in interest in rooftop solar by small businesses. Solar is not a luxury, it is a way to provide services to the community, by lowering utility bills of small businesses. Manufacturing rates in Kentucky have gone down, but utility demand charges have gone up. After 1:1 net metering ended in Indiana the solar industry declined by 93 percent. The commercial projects she has worked on are in eastern Kentucky, primarily in Kentucky Power's territory. She estimates her company has made a $1.7 million investment in solar in eastern Kentucky.

Jessie Rathburn
10:00:55
She is from the Motherhouse of the Sisters of Loretto in Loretto, Kentucky. The Sisters have committed to reducing their carbon footprint. Solar is working for Kentucky. She encourages the Commission to use evidence based, Kentucky specific data when making decisions on net metering.

Cathy Clement
9:55:26
She lives in Lexington, Kentucky, and urges the Commission to collect reliable Kentucky specific data before setting the rates for solar generated electricity fed back to the grid. Ms. Clement states that the Commission should consider the societal costs of fossil fuels. Ms. Clement further states that externalities are costs that must be paid by someone. Ms. Clement believes that the 1:1 credit is the only positive step Kentucky has taken toward considering the external costs of using fossil fuels and that Kentucky should not go backward by changing the 1:1 credit. Ms. Clement states that the Commission must stand in for market forces.

Dennis Neyman
10:03:52
He is an organic berry farmer from Goshen, Kentucky. He invested in solar panels for a rental house and his church. Mr. Neyman urges the Commission to keep net metering at least where it is now with the 1:1 credit. He is aware of non-profits and houses of worship in Louisville seeking to install solar panels in low-income communities and believes the 1:1 credit is needed so that the use of solar by low-income individuals can increase.

Andy McDonald
10:06:16
He is a customer of Kentucky Utilities, operates an organic farm in Frankfort, Kentucky, and has a rooftop solar system. He develops and consults on solar energy projects. Mr. McDonald states that net metering is a simple and effective system that allows him to contribute to making Kentucky a healthier place to live. He wants others to have access to affordable solar energy and that net metering has allowed people to make investments in solar energy and decrease emissions. Mr. McDonald states that, by changing the net

metering compensation rate, there is a risk of fixing a problem that does not exist. He urges one administrative case to determine a single methodology to determine the value of net metering and distributed generation. He believes these are values that can be quantified. He says the rate impact on non-solar ratepayers from solar generators is 1 cent per month. When asked if he is suggesting that the Commission establish a value of solar, he indicated that he supports something along those lines.

Jack Morris
10:20:54
He lives in Stamping Ground, Kentucky and has been a net metered customer since 2016. Mr. Morris states that the value of solar has been determined in different places to be more than the retail rate and at others well below retail rate. He further states that concerns that rooftop solar generators do not meet the same safety concerns as a monopoly utility are exaggerated. He claims the utilities are trying to devalue the energy put back on the grid.

Chris Zitelli
10:24:44
He is a solar installer from Louisville, Kentucky. Mr. Zitelli states that in more mature markets solar is valued at even more than a retail rate. Mr. Zitelli maintains that job creation and business development are important issues, and that solar installers are providing jobs and buying from local material suppliers. He states that if we care about making renewable energy available to lower income people, investments must be made. He further states that new affordable housing construction in Louisville includes solar. Mr. Zitelli explains that programs to subsidize solar for low-income ratepayers need to be developed.

Karl Rabago
10:30:07
He is from Denver, Colorado, and is the Principal of Rabago Energy. He has been active in electric utilities for 30 years. He states that the Commission must hold utilities to a high standard of proof when they request a change in net metering rates. Mr. Rabago maintains that it is the right of all Kentuckians in the solar generation marketplace to participate in subsequent rate cases. He further maintains that everyone has a stake so everyone should have an opportunity to participate. Mr. Rabago states that the Commission should preserve the fundamentals of net metering by establishing a net metering compensation rate as the full retail rate; adopting a comprehensive framework with a valuation of solar analysis; prohibiting utilities from discriminating from non-utility generation; and taking time to engage with stakeholders. Mr. Rabago is skeptical of parties claiming subsidization, asserting that the data is not there and that eligible generators do not create a cost to utilities merely because they do not use what the utility has to sell. Mr. Rabago maintains that net metering can encourage customer investment and private dollars in the Commonwealth, and that the legislature wants net metering to continue.

Sister Joetta Venneman
10:36:00
She represents the Sisters of Charity of Nazareth in Nazareth, Kentucky. The Sisters are considering the Earth one of the poor and are committed to reducing greenhouse gases. They see storms and natural disasters as a sign of global warming and they are using solar to reduce carbon emissions. Sister Venneman urges the Commission to consider documented costs and benefits of solar in establishing net metering compensation rates.

Sarah Lynn Cunningham
10:39:34
She lives in Louisville, Kentucky, and is a Licensed Professional Engineer with a solar installation business. She states that the Chamber of Commerce does not represent her interests. She was active in the legislative process and declares that the utilities never produced a single study to show that solar generators are a burden on the utility companies. Ms. Cunningham maintains that the provision in the Net Metering Act that entitles electric utilities to recover costs necessary to serve eligible generators is unfair unless costs includes avoided costs. She states that, even if avoided costs cannot be valued perfectly, you cannot zero them out. She states that the Commission should make utilities make their case. Ms. Cunningham further states that the utilities should not control the sun.

Virginia Bush
10:44:45
She is representing the congregation of Saint William Catholic Church in Louisville, Kentucky, and is a nurse. The church installed solar panels because of pollution issues in the city. The church's zip code has the worst health outcomes in the state, leading the church to try and reduce their impact on the environment as environmental issues contribute to health problems. The church says this is an ethical issue. Ms. Bush maintains that coal generated electricity is no longer the cheapest form of energy. She urges the Commission to consider the effect on the environment and health of continuing to burn fossil fuels to generate electricity.

Rachel Norton
10:48:48
She lives in Lexington, Kentucky. Ms. Norton led an effort in Lexington called "Solarize Lexington," which resulted in 25 rooftop solar installations. She states that, on a national level, it is not possible to separate the externalities like health benefits of reduced carbon emissions and the cost of solar. Ms. Norton urges the Commission to preserve the benefits of solar for all people and not just companies or the wealthy.

Joetta Prost
10:51:43
She lives in Hebron, Kentucky, and has rooftop solar at home. Ms. Proust asks that the Commission look at the value of solar for all of Kentucky, such as the environmental benefits of solar which help fight climate change. Ms. Proust states that Kentucky should be a leader into a future of clean, reliable, renewable energy.

E Gail Chandler
10:56:33
She is retired, lives on a fixed income in Shelbyville, Kentucky, and is from a coal background. Four years ago she bought into solar to keep expenses stable since energy costs were rising. Ms. Chandler reports that her system should be paid off in ten more years. She states that reducing the size of the credit by even a little bit makes solar cost prohibitive for people like her.

Laura Cole
10:58:16
She lives in Lexington, Kentucky, and is not in the income bracket to afford solar panels. Ms. Cole believes that the 1:1 net metering credit should be left intact because we need to pivot into solar very quickly. She purchased into the solar shares from Kentucky Utilities because she could absorb a small cost, and wanted to encourage utilities to move toward solar. Ms. Cole maintains that Kentucky could be a leader in solar and that the future is solar.

Earl Hampton
10:59:56
He lives in Glencoe, Kentucky and has rooftop solar units that reduced his electric bill by 75 to 80 percent. Mr. Hampton wants a cleaner, greener world and wants Kentucky to use solar. Mr. Hampton urges the Commission to keep the net metering compensation rate at a 1:1 credit.

Alex Hay
11:03:18
He lives in Lexington, Kentucky, and works in the solar industry, but does not do business in Kentucky. Mr. Hay states that the key benefit of consumer-generated solar to the utility is that solar delivers electricity during high demand periods when utilities are using peaker generation units and energy is at its highest cost. Mr. Hay further states that distributed generation reduces the need to invest in transmission systems by increasing the resiliency of the power grid and by allowing utilities to recover from outages quicker. Mr. Hay maintains that non-solar customers benefit from consumer-generated solar because the reliability of the grid is improved and the utility will not need to invest as much in infrastructure, meaning rates for all are kept low. Mr. Hay states that solar industries in other states, like Georgia, are huge parts of the economy. He would like to keep the 1:1 credit and allow the industry to grow. Mr. Hay urges the Commission to look at the materiality of any impact on the utility from solar generators.

Phillip Woolery
11:10:13
He lives in Lexington, Kentucky. Mr. Wollery states that we are in a climate crisis and lives are on the line, noting that the last few months of 2019 were the hottest months on record. He claims that distributed solar is cheaper than the alternative and that net metering is the best way to help average people benefit from solar energy. Mr. Woolery suggests displaced coal workers work in solar installation and other clean energy.

Wallace McMullen
11:15:58
He lives in Louisville, Kentucky and is the Chairperson of the Kentucky Energy Society. His income is $26,000 annually and he had no difficulty installing solar panels. He acknowledges utility companies argue rooftop solar generators are not paying their fair share of electricity demand cost, and states that utilities are not acknowledging reduced costs. Mr. McMullen maintains that reduced line loss and reduced environmental compliance costs are all a result of distributed solar. Mr. McMullen further maintains that this is not a net metering issue, but a ratemaking issue. He states that if a customer lowers his electric usage by becoming energy efficient then there is no discussion of increasing rates for energy efficient customers. He further states that, if that reduction is because of solar generation, then the utility company claims the generator is not paying his fair share. Mr. McMullen states that fair, just and reasonable net metering compensation rates need to include consideration of all benefits and costs.

Kris O'Daniel
11:21:23
She lives in Washington County, Kentucky. Ms. O'Daniel notes that rate cases are expensive for utility companies and that the cost of electricity is actually an average of costs because the actual costs vary due to time of day and demand. Ms. O'Daniel contends that ratepayers have reason to be concerned because there has been a 36 percent decline in the last five years in industrial electricity sales, signally that coal-generated electricity is dropping in demand. She maintains that demand for zero carbon electricity generation must also be considered, noting that stock prices for renewable energy companies are rising. She states that higher wholesale prices for coal fired electric companies is expected, and that Kentucky must enter zero carbon generation sooner rather than later.

Anastasia Kaufmann
11:30:54
She lives in Louisville, Kentucky and is with Kentuckians for The Commonwealth. Ms. Kaufmann states that utility companies would benefit tremendously if solar generation was suddenly out of reach for most Kentuckians. She maintains that this would effectively secure utilities a monopoly on the use of solar power, and that it is unfair and unjust for utilities to invest in solar and then charge ratepayers while lobbying to reduce the net metering compensation rate. She urges the Commission to consider benefits, quantifiable and not, that solar provides to Kentucky, such as reduced pollution, improved public health, grid stability/infrastructure benefits, and good paying jobs.

Joshua Bills
11:36:57
He lives in Berea, Kentucky and is a commercial energy efficiency expert. Mr. Bills states that any customer class who has a demand charge should be allowed to keep 1:1 net metering. In regard to the impact on low-income customers, Mr. Bills encourages Kentucky to adopt Oregon's policy that unused credits from net metering are transferred to low income customers enrolled in assistance programs. Mr. Bills contends that, from the substation point of view, rooftop generation is the same as an energy efficiency measure, such as insulation.

Maria Truitt
11:42:25
She lives in Union, Kentucky and is with Kentuckians for The Commonwealth. Ms. Truitt maintains that until solar reaches ten percent of energy demand there is no issue of cost-shifting. She states that utility companies are not seeking to protect ratepayers, but instead are protecting themselves. She argues that utility companies will benefit from greatly reducing solar electric generation. She contends that utility companies are investing in solar, but do not want individuals to be able to do the same. Ms. Truitt states that communities of color and low-income communities are disproportionately impacted by environmental pollution and that reducing pollution by increased use of solar energy helps these populations achieve better health outcomes. Ms. Truitt states that solar jobs are higher paying than other energy jobs.

Nikita Perumal
11:48:09
She lives in Lexington, Kentucky, and rents her home, but hopes to invest in rooftop solar when she has her own home. Ms. Perumal states that the time and day of the hearing made it difficult for all interested parties to participate. She advocates granting intervention in rate cases and scheduling hearings at a time when "working folks" can participate. She states that consistency in the rules and methodology is important as the Commission looks at net metering. Ms. Perumal requests that the Commission consider the cost of administration of a new system because adopting a new system for net metering might be more expensive than keeping the current system, when the costs of administering and litigating the new system are taken into account.

Whitney Wurzel
11:57:09
She is from Cox Creek, Kentucky and is with New Pioneers for a Sustainable Future, a non-profit dedicated to sustainable renewable energy. Ms. Wurzel states that environmental sustainability supports economic sustainability, and that rooftop solar net metering allows people to invest in a sustainable future. She maintains there is a need for a thorough and effective study on the benefit of solar energy. Ms. Wurzel states that if the net metering compensation rate is reduced, so too is the ability for rural communities to utilize solar power.

Dale Shunk
11:59:52
He is a retired Methodist minister living in Wilmore, Kentucky. Mr. Shunk worked with Solar Samaritans in Pennsylvania to provide the working poor with solar. He states that the efficiency of solar is better and prices are getting lower. Mr. Shunk explains that generating clean energy is important to him and that he once wrote grant proposals to obtain rooftop solar for the poor. He states that leasing solar panels is an option for low-income people. Also, that do-it-yourself kits are available for $8,000-$10,000 and an electrician can hook it up to the grid. He urges the Commission to keep net metering rates high. He gave an example of solar panels on a town gazebo generating energy credits for a town and being used to power Christmas lights. When asked he said maintenance of the solar panels for low-income beneficiaries in Pennsylvania was done by the agency who purchased them and that the agency leased the panels to the low-income beneficiaries for $5 a month.

Alice Melendez
12:06:00
She is from Paris, Kentucky. She notes that this September was the hottest, driest September on record, and that climate change is a reality that needs to be accepted, so we can embrace change. She further states that increasing energy efficiency and using rooftop solar to reduce energy bills is important for low-income people. Ms. Melendez explains that many people living in close proximity to a coal-fired power plant are low income and bear many of the health consequences of burning fossil fuels. Thus, the costs of the existing system fall more heavily on persons with a low income.

Edward Roberts
12:10:33
He lives in Mt. Sterling, Kentucky and is using solar at home. He is a board member and a physician at a non-profit clinic that provides healthcare to uninsured and under insured people. Dr. Roberts states that solar panels installed at the clinic resulted in $1,300 of savings in electric bills and that the savings were used to obtain medical and dental supplies. Dr. Roberts states that reducing the 1:1 net metering credit will make solar something only the wealthy can afford and will end a burgeoning new solar industry. He further states that, in 8 out of 11 studies, the value of solar was found to be more than the retail rate. Dr. Roberts notes that coal-fired plants put mercury in the air and water, and that he has treated patients with mercury poisoning from eating fish caught in Kentucky waters.

Richard Levine
12:16:08
He lives in Lexington, Kentucky, is co-director for Center for Sustainable Cities, and is a former architecture professor at the University of Kentucky. Mr. Levine discussed how other countries are mandating energy standards and putting in low cost solar, pointing to the construction of eco-cities in China. Mr. Levine also discussed solar projects in Kentucky, such as the first net-zero school. Mr. Levine states that solar is affordable, and that the utility companies do not want to change, but we must change.

Marley Green
12:21:30
He lives in Whitesburg, Kentucky and is representing Appalshop, a non-profit arts and media company. He reports that, since June, Appalshop has used solar and experienced a 70-80 percent reduction in energy costs. Mr. Green states that Appalshop wants to promote a new and growing local economy, with job creation from solar technology. He states that rising energy costs are threatening non-profits and arts groups. He notes that electric rates have gone up 50 percent in ten years and that, by installing solar, customers can lock in electric rates for years to come. He asks the Commission to support these opportunities by leaving the 1:1 compensation rate as it is. He also asks the Commission to consider the benefits of solar to grid stability and stable energy costs.

Patti Draus
12:26:50
She lives in Lexington, Kentucky. Ms. Draus notes that the Kentucky Coal Museum has solar panels now, which are used to keep costs down. Based upon her volunteer activities, Ms. Draus states that the housing market in Harlan County consists of many poorly insulated dwellings, which results in high electric bills that residents cannot afford. Ms. Draus maintains that keeping the 1:1 net metering rate will assist those who can get solar panels in Harlan County to reduce their energy costs.

Ron Schneider
12:39:36
He lives in Louisville, Kentucky. Mr. Schneider states that utilities have not presented evidence that solar customers increase costs for non-solar customers. He maintains that the coming climate catastrophe will increase insurance rates. He also maintains that an increase in the flat fee rate is another way to punish people who use renewable energy.

Brenda Martin
12:33:30
She lives in Russell, Kentucky and her family is considering getting solar panels. Ms. Martin states that there is a synergistic aspect to this because helping different parts of the community helps to make the community itself healthy. She maintains that lower income people do not have the same advocates as the utility companies or privileged individuals, who can speak for themselves, and that the rich should not profit at the expense of our environment or our youth.

Teri Faragher
12:39:10
She is from Versailles, Kentucky, and installed solar panels in 2013 because she and her husband wanted to be a part of the solution and not a part of the problem. She states they could not afford rooftop solar without 1:1 net metering credit. She views her relationship with Kentucky Utilities as a partnership and urges everyone to place the common good of Kentuckians above private interest. She states that the transition to renewable energy is not a matter of if, it is a matter of when, and that it is time to move into the future and increase renewable energy use.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2019-00256 DATED DEC 18 2019

Lawrence Berkeley National Laboratory
Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment

THIRTY-ONE PAGES TO FOLLOW

LBNL-183185

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment

Naïm R. Darghouth, Ryan Wiser, Galen Barbose, Andrew Mills

Energy Technologies Area

June 2015

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

SunShot
U.S. Department of Energy

Disclaimer

LBNL-183185

Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment

Prepared for the
Office of Energy Efficiency and Renewable Energy
Solar Energy Technologies Office
U.S. Department of Energy

Naïm R. Darghouth, Ryan Wiser, Galen Barbose, Andrew Mills

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

June 2015

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Acknowledgements

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. We would particularly like to thank Elaine Ulrich, Christina Nichols, Craig Connelly, and Minh Le of the U.S. Department of Energy for their support of this work, and Easan Drury and Ben Sigrin of the National Renewable Energy Laboratory for their assistance with the SolarDS model. For providing comments on an earlier draft, the authors thank Justin Baca (Solar Energy Industry Association), Lori Bird (National Renewable Energy Laboratory), Daniel Boff (U.S. Department of Energy), Susannah Churchill (VoteSolar), Karlynn Cory (National Renewable Energy Laboratory), Ahmad Faruqui (The Brattle Group), Nathan Phelps (VoteSolar), Benjamin Sigrin (National Renewable Energy Laboratory), Lisa Schwartz (Lawrence Berkeley National Laboratory), Tom Stanton (National Regulatory Research Institute), John Sterling (Solar Electric Power Association), James Tong (Clean Power Finance), and Joseph Wiedman (Keyes, Fox & Wiedman LLP). Jarett Zuboy provided excellent editorial assistance. Of course, any remaining omissions or inaccuracies are our own.

Table of Contents

List of Figures

List of Tables

Abstract

The substantial increase in deployment of customer-sited solar photovoltaics (PV) in the United States has been driven by a combination of steeply declining costs, financing innovations, and supportive policies. In many U.S. states, a customer's underlying retail rates drives their electricity bill savings from PV under net metering, as all PV generation is effectively compensated at those rates. The current design of those rates and the presence of net metering has elicited concerns that the possible under-recovery of fixed utility costs from PV system owners may lead to *increased* retail prices for all electricity customers, leading to a feedback cycle of *rising* deployment and rate levels. However, a separate and opposing feedback loop could offset this effect, at least partially; if retail rate reforms lead to rates that better reflect temporal patterns in wholesale electricity prices, this could lead to *decreases* in customer bill savings from PV as PV deployment increases, and hence *lower* overall adoption levels. In this paper, we examine U.S. deployment impacts of these two feedback dynamics through 2050 for both residential and commercial customers, across states. Our results indicate that, at the aggregate national level, the two feedback effects nearly offset one another and therefore produce a modest net effect, although their magnitude and direction vary by customer segment and by state. We also model aggregate deployment trends under various rate designs and net-metering rules, accounting for feedback dynamics. Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures; whereas flat, time-invariant rates with net metering are found to lead to higher deployment levels, moving towards time-varying rates, rate structures with higher monthly fixed customer charges, or compensation at levels lower than the full retail rate can dramatically erode aggregate customer adoption of PV in the long term.

1 Introduction

Deployment of distributed solar photovoltaics (PV) has expanded rapidly in the United States, growing by over 400% since 2010 in terms of total installed capacity and averaging 40% year-over-year growth in capacity additions (GTM and SEIA 2015). This rapid growth has been fueled by a combination of steeply declining costs, the advent of innovative financing options, and supportive public policies at the federal, state, and local levels. Key among the supportive policies has been net energy metering (or simply net metering or NEM), which typically compensates each unit of PV generation at the customer's prevailing retail electricity rate. Net metering allows homes and businesses with onsite PV systems to offset their electricity consumption regardless of the temporal match between PV production and electricity consumption. As state incentive programs and federal tax credits are phased out, net metering has become increasingly pivotal to the underlying customer economics of distributed PV.

The rapid growth of net-metered PV has provoked concerns about the financial impacts on utilities and ratepayers (Accenture 2014, Kind 2013, Brown and Lund 2013, Eid et al. 2014). Central to these concerns is the contention that net metering at the full retail electricity price allows PV customers to avoid paying their full share of fixed utility infrastructure costs, thus requiring the utility to raise retail prices, including for non-PV customers, to recover those costs in full (Borlick and Wood 2014). Compounding that concern is the possibility of the feedback effect where increased retail electricity prices accelerate distributed PV adoption, resulting in even higher prices as fixed utility infrastructure costs are spread over an ever-diminishing base of electricity sales (Cai et al. 2013, Costello and Hemphill 2014, Felder and Athawale 2014, Graffy and Kihm 2014).

A wide array of corrective measures—ranging from incremental changes to utility rate design to fundamental changes to utility business and regulatory models—has been suggested to address concerns about under-recovery of fixed costs associated with distributed PV and other demand-side resources (Bird et al. 2013, Fox-Penner 2010, Harvey and Aggarwal 2013, Jenkins and Perez-Arriaga 2014, Lehr 2013, SEPA and EPRI 2012, McConnell et al. 2015). Proposals to modify rate designs for PV customers come in many varieties (Faruqui and Hledik 2015, Linvill et al. 2013, Glick et al. 2014). Frequently they entail reallocating a portion of cost recovery from per-kilowatt-hour volumetric charges to fixed customer charges and/or per-kilowatt demand charges (NC Clean Energy Technology Center 2015), while other proposals involve replacing net metering with alternate mechanisms that compensate PV customers for all or some PV generation at a price different than the retail electricity rate (e.g., using a feed-in tariff or value-of-solar tariff; Blackburn et al. 2014).

Decision-making on these issues, however, is hampered by several key informational gaps. Fundamentally, significant disagreement exists about whether, or the extent to which, net-metered PV under existing rate designs causes retail electricity rates to increase. One aspect of that disagreement revolves around the question of feedback effects: Does distributed PV lead to ever-spiraling rate increases as each successive rate increase further accelerates PV adoption? Prior studies of this issue have generally remained conceptual and hypothetical; few have sought to quantitatively examine the magnitude or likelihood of effects, with the notable exceptions of Cai et al. (2013), Chew et al. (2012), and Costello and Hemphill (2014). Furthermore, analyses and discussions of retail rate feedback effects have focused only on the possible positive feedback associated with under-recovery of fixed costs. A separate – and potentially offsetting – feedback may occur when increasing PV penetration causes a shift in the temporal profile of wholesale electricity prices (see Table 1). Numerous studies have demonstrated that the capacity value and wholesale market value of PV erode as penetrations increase (Mills and Wiser 2013, Hirth 2013, Gilmore et al. 2015), and Darghouth et al. (2014) explored the implications of this effect for time-based retail rates and the customer-economics of PV systems. No studies to our knowledge, however, have estimated the impact of this effect on the deployment of distributed PV or contrasted it with the fixed-cost feedback mechanism that is the focus of current broader literature.

Key informational gaps also exist with respect to the effect of rate-design changes on PV deployment. Studies have focused on the impacts of retail rate structure on the customer economics of PV (Mills et al. 2008, Darghouth et al. 2011, Ong et al. 2010, Ong et al. 2012) but generally have not translated those findings into deployment effects. Where deployment effects have been explored (e.g., Drury et al. 2013), analyses have considered a relatively narrow range of retail rate structures and have not accounted for the two possible feedback effects between PV deployment and retail electricity prices noted above. Understanding these deployment impacts will be critical for regulators and other decision makers as they consider potential changes to retail rates—whether to mitigate adverse financial impacts from distributed PV or for other reasons—given the continued role that PV may play in advancing energy and environmental policy objectives and customer choice.

Table 1. Feedback mechanisms between PV adoption and retail electricity prices addressed in this paper

Rate Feedback Effect	Description	Affected Rates
Fixed Cost Recovery Feedback	Increases in average retail rates required to ensure fixed-cost recovery	Flat and Time-varying
Time-varying Rate Feedback	Changes in the timing of peak and off-peak periods under time-varying rate structures	Only Time-varying

Our research builds on the aforementioned literature and addresses critical informational gaps for decision makers by modeling customer adoption of distributed PV under a range of rate designs. The analysis leverages the National Renewable Energy Laboratory (NREL) Solar Deployment System (SolarDS) model, which simulates PV adoption by residential and commercial customers within each U.S. state through 2050 and has been used widely for scenario analysis of future PV-adoption trends (Denholm et al. 2009). We build on prior applications of this tool (e.g., Drury et al. 2013) by incorporating the two key feedback mechanisms between PV adoption and retail electricity prices mentioned previously: (a) increases in average retail rates required to ensure utility fixed-cost recovery and (b) changes in the timing of peak-to-off-peak periods under time-varying rate structures (see Table 1). In doing so, we show whether and under what conditions retail rate changes caused by distributed PV might accelerate or decelerate future PV deployment. Given these feedback dynamics, we then consider deployment trends under a range of possible changes to retail rate design and net-metering rules, including widespread adoption of fixed customer charges, flat vs. time-varying energy charges, feed-in tariffs, and "partial" net metering (whereby PV generation exported to the grid is compensated at an avoided-cost rate). Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures, but that concerns over feedback effects may be somewhat overstated as the two feedback mechanisms operate in opposing directions.

2 Data and Methods

This section describes the SolarDS model, data sources, and assumptions, followed by descriptions of our analysis scenarios and our methods for modeling electricity rate feedbacks. One item on scope deserves note upfront: we do not explore customer defection from the grid as a possible result of combined solar/storage solutions, which may go through substantial price reductions over the study period (Bronski et al. 2014). The reason for this is that the primary tool used in this analysis (SolarDS) is not equipped to evaluate storage solutions or defection decisions.

2.1 SolarDS model, data sources, and assumptions

The SolarDS model simulates the customer adoption of distributed PV using a bottom-up approach (where customer-adoption decisions depend on an economic comparison between PV system costs and reduction in the customer's electricity bill) with data from 216 solar resource regions and more than 2,000 electric utilities. It is an economic model, and assumes that deployment is driven by economic considerations. There are two central elements to the model:

1) **Customer economics of PV.** SolarDS calculates PV system lifetime cash flows based on simulated PV output from NREL's PVWatts model for 216 solar resource regions (Dobos 2014), utility-specific average revenue per kWh (a proxy for retail rates) from U.S. Energy Information Administration (EIA) Form 861, and assumptions about PV system costs, performance degradation rates, and state and federal incentives.

   For input parameters, we assumed the installed prices for PV systems follow a trajectory that draws from the SunShot PV price target (a 75% price decline from 2010 levels by 2020), as described in the U.S. Department of Energy's *SunShot Vision Study* (U.S. Department of Energy 2012): residential PV system prices fall to $1.60/W in 2020 , and commercial PV system prices fall to $1.34/W in 2020 (in 2013 U.S. dollars per peak watt-direct current), assuming an exponential decline in prices through 2020.

   PV compensation under net metering with flat, volumetric retail rates (as are common for U.S. residential customers) is determined by the average electricity rate distribution in each state (differentiated by commercial and residential customers). For retail rates that are time-varying (time-of-use, real-time pricing, or otherwise), we used the System Advisor Model (Blair et al. 2014) to calculate PV-induced bill savings with and without time-of-use rates, using 2013 rates available to residential customers in each state's largest utility. The ratio of bill savings with time-varying rates to that with flat rates as calculated through this approach was then used to estimate the customer's bill savings from PV under time-varying rates for other utilities in the state, and for both residential and commercial customers. Our demand-charge methodology for commercial customers was not changed from the original SolarDS model; for demand charges that apply to commercial customers, SolarDS assumes that PV can displace 20%–60% of demand charges, depending on the building type, insolation, and season, as calculated using the EnergyPlus model for the original SolarDS. Rate escalation assumptions are from EIA's *Annual Energy Outlook* (EIA 2014a), extrapolated to 2050.

Average utility-specific rates, solar renewable energy credit (SREC) prices, and available state and utility incentives were updated to 2013 levels. State and utility incentives were updated as per the Database of State Incentives for Renewable Energy (DSIRE) database (NCSU 2014). All state incentives and SREC prices are assumed to ramp down linearly to reach zero in 2030, except for incentives that identify an earlier end-date. The federal investment tax credit (ITC) was set to 30% for residential and commercial systems in 2014, and is assumed to revert to zero for residential customers and to 10% for commercial customers at year-end 2016. We assume that 70% of residential systems installed are third-party owned and hence benefit from the commercial ITC.

2) **Customer adoption.** Customer adoption depends on a comparison of electricity bill savings and the cost of the PV system (the "cash flow"). Using the PV system's lifetime cash flow, SolarDS adoption decisions are based on time-to-net-positive cash flow (i.e., payback period) for residential customers and internal rate of return for commercial customers.[1] SolarDS uses highly non-linear customer adoption curves linking payback and rate of return to adoption rates as a percent of maximum market size (adoption curves are available in Denholm et al. (2009)). Maximum market size is based on the number of solar-appropriate households for the residential sector and the available solar-appropriate roof space for commercial customers (see Denholm et al. (2009) for details related to residential and commercial building stock assumptions).

   The size distribution of PV systems in the residential sector is based on the distribution of existing PV installations (Barbose et al. 2014).[2] For the commercial sector, PV system size is determined using roof size limitations and load assumptions from Denholm et al. (2009). In each geographical area considered, we aggregated adoption from each customer segment under each rate type and then summed up all installations to the state and national level.

---

[1] We assume that customers do not foresee the changing rates due to PV penetration levels, and expect net metering to continue to be available over the lifetime of their system.

[2] We recognize that the distribution of PV system sizes may change with time. Lower prices provide some customers incentive to install larger systems, while some rate design choices, such as partial net metering, would encourage smaller systems.

Additional details about the input assumptions for and methodologies used in SolarDS are documented in Denholm et al. (2009).

2.2 Retail rate design and PV compensation scenarios

Eight rate design and PV compensation scenarios are modeled in this analysis, including a reference scenario that provides a baseline (see Table 2). This set of scenarios is by no means intended to be exhaustive, but rather consists of a representative and tractable number of the broader universe of potential rate design options. All scenarios include residential and commercial customer segments and project deployment of customer-sited PV through 2050.

For the reference scenario, we assumed a continuation of the current mix of rate designs and determined the proportion of customers facing flat rates, time-varying rates, and—for commercial customers—demand-charge rates using data from EIA Form 861 and previous SolarDS assumptions (Denholm et al. 2009). We assumed full net metering for the reference scenario, where all customer PV generation is effectively compensated at the retail rate.

Table 2. Rate design and PV compensation scenario assumptions

Scenario	Customer retail rate assumptions	PV compensation assumptions
Reference	Reference mix of flat rates, time-varying rates and demand charges from EIA Form 861 data	Net metering
$10 fixed charge	Reference mix, but with residential rates adjusted with $10 monthly charge	Net metering
$50 fixed charge	Reference mix, but with residential rates adjusted with $50 monthly charge	Net metering
Flat rate	All residential and commercial customers on flat rates	Net metering
Time-varying rate	All residential and commercial customers on time-varying rates	Net metering
Partial net metering	Reference mix	PV generation that displaces instantaneous load compensated at retail rates; PV generation exported to the grid compensated at avoided-cost rate
Lower feed-in tariff	not applicable	All PV generation compensated at $0.07/kWh
Higher feed-in tariff	not applicable	All PV generation compensated at $0.15/kWh

For the scenarios with monthly fixed customer charges, residential PV generation is assumed to only displace the variable portion of the rate. The variable portion of the rate is then calculated for each utility, such that the combination of the variable portion and fixed customer charge is equal to the utility-reported total revenue data from EIA Form 861. For the flat rate and time-varying rate scenarios, all customers are assumed to be on either the flat rate or the time-varying rate, respectively; these scenarios are designed to bound the potential rate mix options. For partial net metering, the PV generation that displaces instantaneous load is assumed to be compensated at the underlying retail rate, while PV generation exported to the grid—assumed to be 50% and 30% of total PV generation for residential and commercial customers, respectively (E3 and CPUC 2013)—is compensated at a lower, avoided-cost rate. That rate depends on regional PV penetration and natural gas prices. Detailed methods for determining PV energy and capacity value can be found in the next section. For the feed-in tariff scenarios, all PV generation is compensated at stipulated (and admittedly somewhat arbitrary) "lower" and "higher" fixed prices, independent of the customer's retail rate.

2.3 Modeling rate feedbacks

The original SolarDS model assumes that retail rate structure and prices are independent of regional PV deployment and escalates those prices at a stipulated rate (e.g., based on retail price projections from the EIA *Annual Energy Outlook*). However, retail rates—and hence the economics of customer-sited PV—are projected to change with increasing PV deployment (Darghouth et al. 2014). In this analysis, we model two separate but interconnected retail-rate feedback mechanisms: fixed-cost recovery and time-varying rate feedback. The factors driving the time-varying rate feedback also affect the partial net metering PV compensation scenario, because exported PV generation is assumed to be compensated at an avoided-cost rate, which is dependent on the regional PV penetration level.

2.3.1 Fixed-cost recovery feedback

When PV is compensated at a retail rate greater than the underlying reduction in the utility's costs from PV (as described in more detail later in the text), we use a fixed-cost recovery adder to supplement the rates such that the utility still achieves full cost recovery. The fixed-cost recovery adder is modeled at the state level, separately for residential and commercial customers, as follows:

$$A_{FCR} = \frac{\left(r_{avg} - v_{PV}\right) \cdot G_{PV}}{L_{tot} - G_{PV}}$$

where A_{FCR} is the fixed-cost recovery adder for residential or commercial customers, r_{avg} is the average compensation rate for residential or commercial PV customers, v_{PV} is the calculated utility cost savings from PV, G_{PV} is the total residential or commercial customer-sited PV generation, and L_{tot} is the total residential or commercial load within the state. As indicated, the fixed-cost recovery adder, A_{FCR}, is calculated separately for the residential and commercial sectors using the appropriate compensation rate, PV generation, and load values for each sector.

There is considerable debate about the degree to which PV offsets utility costs and, more broadly, about the value of PV from a societal perspective (Hansen et al. 2013, Denholm et al. 2014, Brown and Bunyan 2014, IREC 2013). We narrowly focus on the value of PV in offsetting utility costs, where the value of PV, v_{PV}, consists of three components: the energy value, the capacity value, and miscellaneous value (which includes avoided transmission and distribution losses, transmission and distribution capacity offsets or additions, and other economic cost savings). Our use of value of PV in this context excludes any additional benefits to society that are not monetized by the utility (e.g. environmental and health benefits). It also excludes shorter term consumer benefits related to lower average wholesale prices.[3]

We assume energy and capacity value depend on regional PV penetration levels, where regions are based on EIA's electricity market module zones, and PV penetration levels include both utility-scale and distributed PV.[4] For the energy value of PV, we assume for simplicity that PV electricity displaces natural gas electric generation as the marginal resources in most regions during PV generation hours. We calculate natural gas generation prices using regional EIA natural gas price projections for the electricity sector and average natural gas plant heat rates (EIA 2014). We assume PV generation displaces less efficient (and therefore more expensive) natural gas generators at low PV penetrations and more efficient ones at higher penetrations: starting from zero PV penetration, PV displaces natural gas generation that is 10% less efficient than average, and this ramps linearly to displace natural gas generation that is 20% more efficient than average at 20% PV penetration, on an energy basis; these assumptions are based on findings from Mills et al. (2013). To estimate PV penetration, we aggregate PV generation at the regional level to account for the interconnected nature of electric grids. Ultimately, this approach results in the energy value of PV decreasing with increasing regional PV penetration.

We also model the declining capacity value of PV with increasing regional PV penetration. Hoff et al. (2008) modeled the relationship between the capacity credit of PV and PV penetration for three electric utilities with different load profiles. Because one driver of PV capacity value is PV's contribution to generation during peak periods, the capacity credit at low PV penetrations tends to be higher for regions with afternoon (summer) peaking periods than for regions with evening (winter) peaking periods. As PV penetrations increase, the marginal capacity credit of PV falls as the net load peaks shift toward evening hours. We use the three capacity credit curves from Hoff et al. (2008) as well as data on state winter-to-summer peak ratios to

---

[3] In the short term, PV generation can reduce wholesale electricity prices levels during times during which PV generates due to the merit-order effect (Sensfuß et al 2008), hence lowering average wholesale prices, as has been observed recently in Germany and California. However, as unprofitable generators exit the market and older generators retire, new generators will be built such that, in an equilibrium state, all generators are once again profitable. This implies changing wholesale price profiles, but not lower average electricity prices.

[4] As with the PV price assumptions detailed earlier, we assumed regional utility-scale PV deployment consistent with U.S. Department of Energy (2012), modeled by NREL's Regional Energy Deployment System. Distributed PV deployment is from SolarDS scenario results from this study.

interpolate over two curves with the nearest ratio. We then calculate the capacity value of PV at the state level for any given year assuming a capacity cost of $992/kW for new natural gas generation (EIA 2014b). As with energy value, this approach results in a decline in the value of PV with increasing regional PV penetration.

We aggregate all other PV-induced utility cost savings, including avoided transmission and distribution losses as well as deferred (or incurred) transmission and distribution capacity investments and any savings from environmental compliance, into a single "miscellaneous" value adder, which we set to $0.01/kWh based on an earlier analysis (Darghouth et al. 2010) and as a proxy for these potential benefits. Though there is increasing consensus that loss savings are reasonably quantifiable, the value of PV resulting from changes in T&D capacity investments and environmental compliance costs, for example, might increase or decrease with increasing PV penetration, and hence we keep this adder independent of regional PV deployment (Cohen et al. 2014).

In addition to feeding into the fixed-cost recovery and time-varying rate feedbacks, this value of PV estimate, or utility avoided-cost, is also used for the partial net-metering scenario: that scenario assumes that all exported PV generation is compensated at a rate representing the sum of the energy, capacity, and miscellaneous value components of PV (calculated for each state based on regional PV penetration). With an export of some PV generation, this mechanism also partially replaces the fixed-cost recovery adder that compensates for the difference between the retail electricity rate and the value of PV under full net metering.

2.3.2 Time-varying rate feedback

For time-varying retail rates, such as time-of-use or real time pricing, average PV compensation is assumed to change as PV penetration increases, resulting from the shift in the value of PV with penetration. Because the design of time-varying rates varies greatly from one utility to the next, we use existing time-of-use rates as our starting point rather than designing them from the bottom up using standard rate-design methods, as the latter method might produce rates very different from existing ones. As time-varying rates aim towards reflecting marginal cost trends, we then adjust those starting-point PV compensation levels to account for changing (net) peak times and levels using the same methods as described earlier.[5]

In particular, for time-of-use or real-time rates, the average compensation for PV generation depends on the coincidence between PV generation and peak price periods. At low PV penetrations, times of PV generation and peak electricity prices coincide reasonably well for

[5] We do not adjust demand-charge savings with increasing overall PV penetration. Customer demand charges are often based on non-coincident peak load, in which case demand-charge savings from PV would not change with overall PV penetration. For simplicity, we effectively assume widespread use of non-coincident demand charges in this analysis. Demand charges may sometimes be based on coincident (net) peak load, however, in which case PV-induced demand-charge savings would decline with increased overall PV penetration. By ignoring this possibility, we understate the magnitude of the time-of-use feedback effect described later.

afternoon-peaking utilities, hence the value of PV and PV compensation based on time-varying rates can be higher than average rates, as reflected in most time-varying rates available today. As PV penetrations increase, however, the marginal generation cost decreases during the hours when PV generates, driven by the same trends that impact the energy and capacity value of PV as discussed previously;[6] because this is reflected in time-varying rates, we would expect a decrease in PV compensation levels (as found in Darghouth et al. 2014). We therefore model the reduced PV compensation under time-varying rates by decreasing the PV compensation at the same rate as the reductions in energy and capacity value with increasing PV penetration, calculated as described in Section 3.3.1.

3 Results

This section presents our results for the feedback between electricity rates and PV deployment as well as the impact on deployment of varying rate designs and PV compensation mechanisms.

3.1 Feedback between distributed PV deployment and retail electricity rates

In our reference scenario, distributed PV deployment is estimated to increase to roughly 154 GW by 2050. The aggregate or combined impact of the two modeled feedback mechanisms (fixed-cost recovery and time-varying rate) never increases PV deployment by more than 3% in any single year, versus an otherwise identical scenario without these two feedbacks (Figure 1). As such, at least in the reference case and at an aggregate national level, we see no evidence that increased retail electricity prices from distributed PV would lead to a significant acceleration in PV adoption.

The dynamics of the counteracting effects underlying this result are critical to understanding the relationship between PV deployment and retail rates.[7] If we only consider the fixed-cost recovery feedback effect (resulting from the increase in retail rates necessary to recover utility fixed costs), PV deployment increases 8% over the case without any feedback by 2050 (Figure 2). On the other hand, if we only consider the time-varying rate feedback (where bill savings for PV customers decline under time-varying rates due to reduced value of PV), PV deployment decreases by 5% compared with the no-feedback case. In effect, the two feedback mechanisms cancel one another to a large extent (again, under our reference case rate design assumptions and at an aggregate national level).

[6] Mills and Wiser (2013) have modeled the impact of increased renewables on the economic value of solar at high penetrations in California. In a separate paper, Mills and Wiser (2015) also identify strategies that could mitigate this effect, including low-cost bulk storage options or increased customer demand elasticity.

[7] Note that the two countervailing feedback effects do not sum exactly to the total feedback owing to the minor interaction between the two effects.

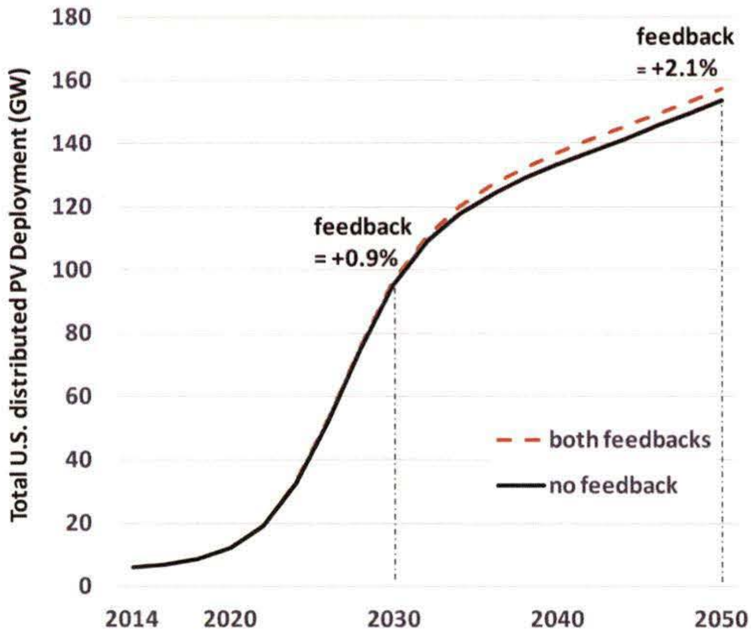

Figure 1. National distributed PV deployment under the reference scenario

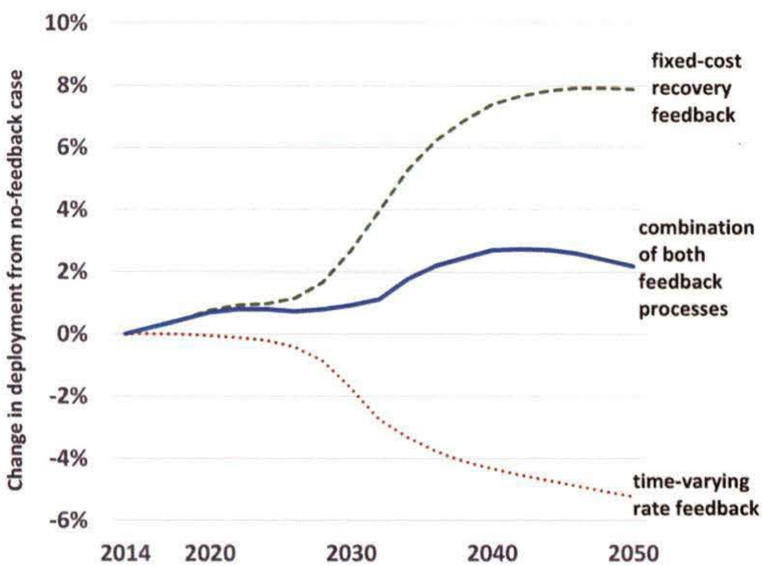

Figure 2. Percentage difference between national PV deployment with and without feedback under the reference scenario, broken out by the two feedback effects

The feedback effects differ between residential and commercial customers owing to the different retail rate structures characteristic of each sector. The rate increase resulting from the fixed-cost recovery adder is present for both flat and time-varying rates in the reference scenario. However, customers with time-varying rates experience a counteracting reduction in PV compensation due to the shifting temporal profile of time-varying rates with increased PV penetration. Most residential customers face flat, volumetric rates in the reference scenario, thus residential deployment increases through 2050 owing to the rate feedback, leveling out at just above 9% over the reference scenario without feedback (Figure 3), when considering both types of feedback. In contrast, most commercial customers face time-varying rates in the reference scenario, so total commercial deployment decreases by 15% compared with the no-feedback case. Because commercial PV deployment estimated by SolarDS is much lower than residential deployment, the net effect of the feedbacks over both customer segments is only slightly positive by 2050.

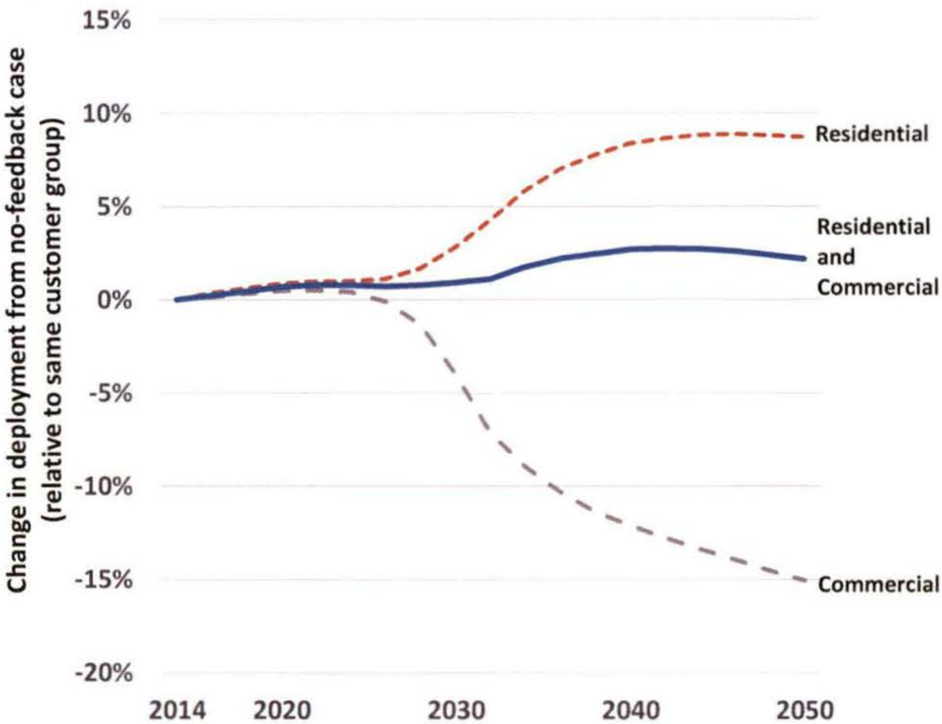

Figure 3. Percentage difference between national PV deployment with and without feedback effects under the reference scenario, broken out by market segment

The results presented to this point are at the national level, and show that the two feedback effects largely cancel each other out in the reference scenario owing to their differential impacts on residential and commercial PV deployment. At the state level, however, feedback effects vary more substantially, as shown in Figure 4 for the year 2050.

For the residential sector, the combined feedback effects increase PV deployment for most states, with a net effect ranging from a 2-6% (based on the 25th/75th percentile values among states) increase in deployment, compared to an equivalent scenario without feedbacks. The variability among states results from differences in residential PV penetration, underlying average retail rates, and percentages of customers on flat rates. States such as California with higher residential PV penetrations and predominantly flat rates experience much stronger feedback effects. States with a higher percentage of residential customers facing time-varying rates have a lower (or even negative) net feedback effect.[8]

[8] In Arizona, for example, where a substantial share of residential customers face time-varying rates, the combined effects of the two feedback mechanisms reduce residential PV deployment compared with the no-feedback case.

Because most commercial customers are already on time-varying rates, the two feedback mechanisms yield a net decrease in commercial PV deployment in most states, as a result of the time-varying rate feedback outlined in section 3.3.2. The magnitude of the commercial customer feedback effects, however, varies substantially across states (i.e., a 9-22% reduction in deployment, based on the 25th/75th percentile values among states, relative to no feedbacks), because the change in energy and capacity value due to increased regional PV penetration varies widely from one region to the next. States with winter evening peaks have a low PV capacity value, even at low PV levels, hence the reduction in value with PV penetration is not substantial and the commercial feedback effect is muted.[9]

As Figure 4 shows, in aggregate considering both feedback effects, most states have a negative total feedback effect, with the median state showing a reduction in cumulative distributed PV deployment in 2050 of 1% relative to the reference case without feedback. This is in slight contrast with Figure 1, which shows a total feedback on a national basis of +2% in 2050. This is because the national results are more-significantly influenced by states with large PV markets, particularly California. Regardless, despite widespread literature suggesting a positive feedback effect, our results suggest that the combined effect of the two relevant feedbacks, at least in the reference case, is generally modest and often negative.

[9] Note that we have chosen not to present state-level results as our focus is on trends at the national level, and while our assumptions capture the macro-level dynamics, they do not necessarily capture the state-level idiosyncrasies related to specific rate levels, mixes, or PV adoption factors, as SolarDS is not designed to make state-level projections.

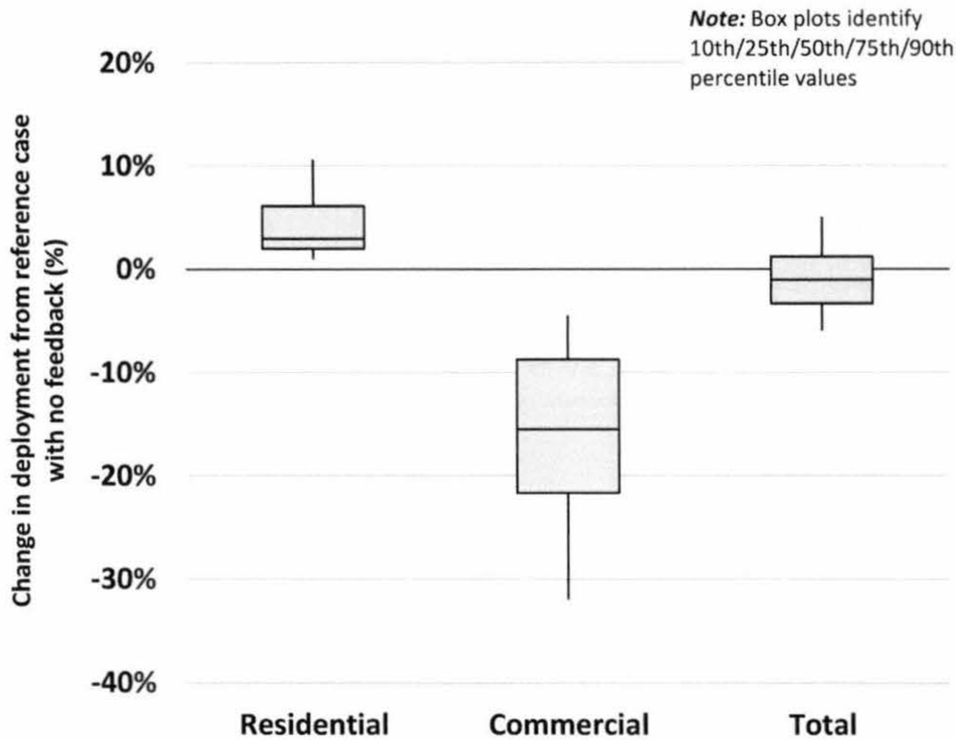

Figure 4. Distribution in feedback effects across U.S. states in 2050, for residential, commercial, and all customers

The results thus far have been for the reference scenario, which assumes residential and commercial rate distributions loosely based on 2013 levels. However, given long-term uncertainties in the rate mix, our scenarios with all customers on a flat rate vs. all on a time-varying rate bound results with respect to the rate mix assumptions (Figure 5). For the flat rate scenario in which all residential and commercial customers are served under a flat volumetric rate, feedback increases PV deployment by 3% in 2030 and 8% in 2050. For the time-varying rate scenario in which all residential and commercial customers are served under a time-differentiated rate, feedback reduces deployment by 6% in 2030 and 25% in 2050. Given the generally expected move, over time, to time-differentiated rates, it would seem that PV deployment feedback effects are predominantly in the negative direction.

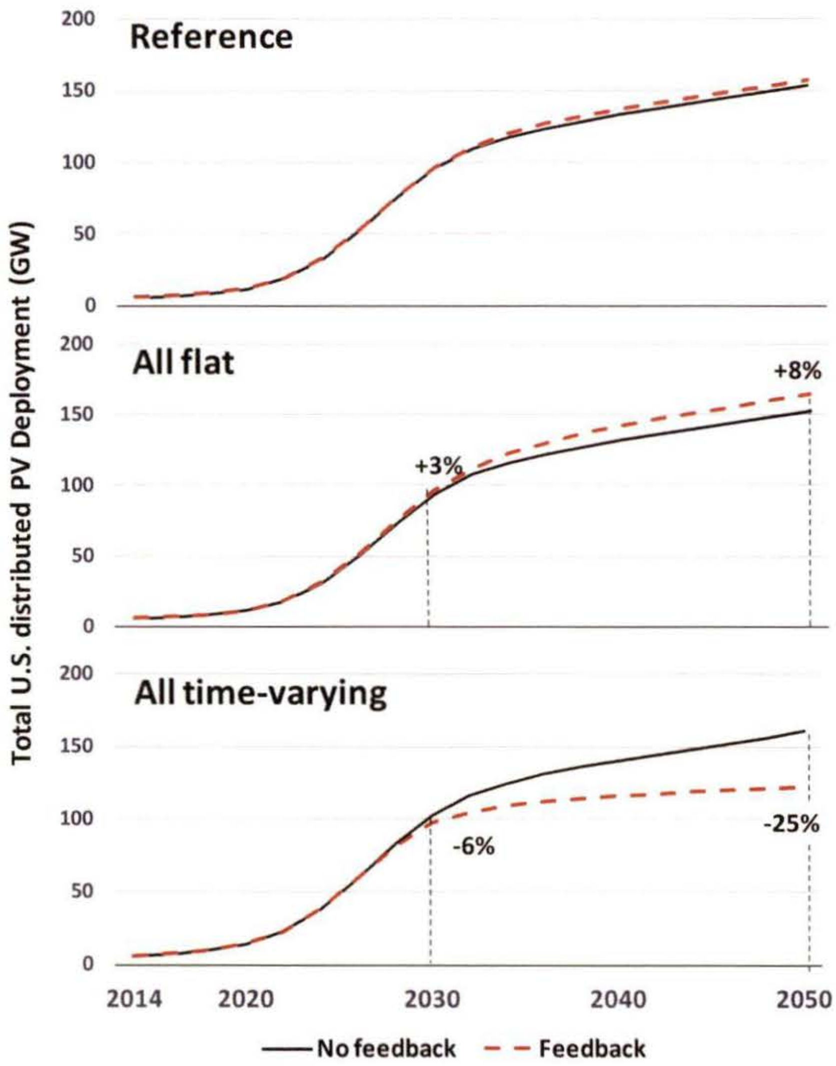

Figure 5. National distributed PV deployment with and without rate feedback for reference, flat rate, and time-varying rate scenarios

Finally, electric utilities and their regulators have begun to consider various changes to rate designs and PV compensation approaches to address concerns over fixed-cost recovery with increasing PV deployment, including the possible positive feedback effect described earlier. These changes have, thus far, been largely directed at residential customers given the prevalence of flat, volumetric rates with no demand charges and lower fixed customer charges. Two specific options sometimes discussed are increased fixed monthly customer charges, and implementation of partial net metering where instantaneous net excess PV generation is compensated at a rate consistent with utility cost savings (typically lower than the retail rate).

Figure 6 presents national residential PV deployment under the reference scenario without feedback and with feedback, and contrasts those results with the fixed-monthly customer charge and partial net metering scenarios, all with feedback. As shown, consistent with Figure 3, the fixed-cost recovery feedback effect leads to residential distributed PV deployment that is

9% higher than without feedback in the reference scenario. The application of monthly customer charges and partial net metering more than offsets this feedback effect, leading to cumulative residential PV deployment that is 17% to 77% lower than in the reference case without feedback. As such, while these rate designs might help address broader concerns from utilities and regulators related to fixed cost recovery issues, they are found to far exceed the levels needed to solely address *feedback* effects.

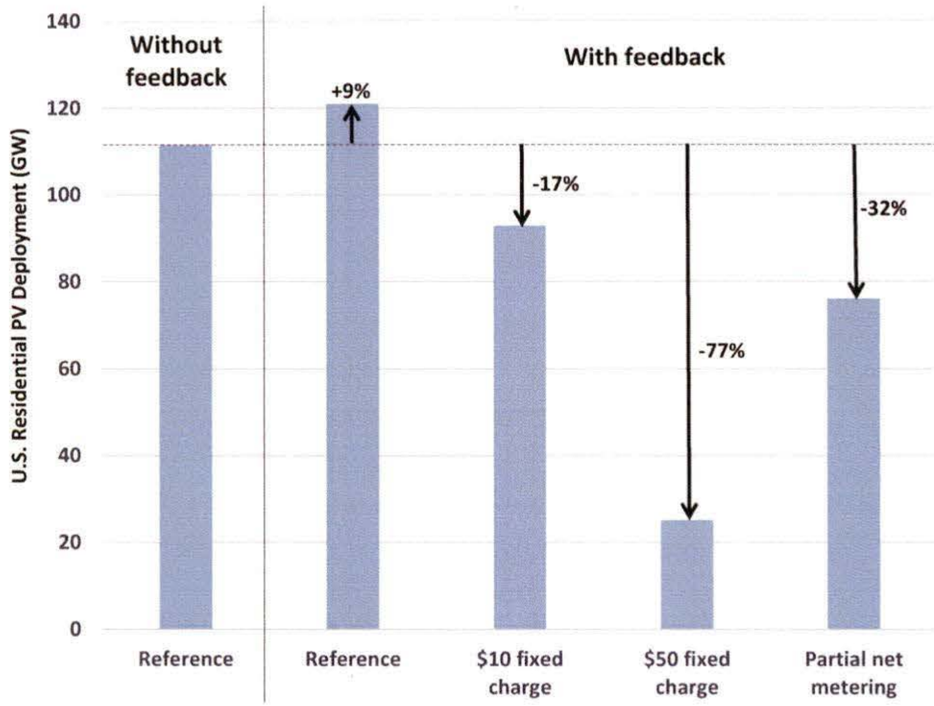

Figure 6. Assessing the degree to which fixed monthly charges and partial net metering offset fixed cost recovery feedback effects for residential customers

3.2 Impact of rate design and PV compensation mechanisms on distributed PV deployment

Whereas the previous section focused on the deployment effects of rate feedbacks, this section shows how various rate designs and PV compensation mechanisms impact total PV deployment, given the presence of those feedback mechanisms. Figure 7 shows the deployment paths for the eight scenarios listed in Table 2, with rate feedback effects included, demonstrating that PV deployment is highly sensitive to rate design choices and PV compensation mechanisms.

The flat rate scenario leads to the highest deployment in 2050, and the lower feed-in tariff scenario leads to the lowest. Most of the rate and compensation scenarios follow temporal trends similar to that of the reference scenario (with different magnitudes), but the time-varying rate scenario follows a different overall trajectory. Specifically, under the time-varying rate scenario, PV deployment is greater than in the reference scenario through about 2030, after which it falls below the reference deployment. This is because, at low solar penetrations, the higher average compensation for PV under time-varying rates boosts PV deployment. However, as regional PV penetration increases and the energy and capacity value of PV erodes, compensation for net-metered PV generation also erodes under time-varying rates, leading to lower deployment.

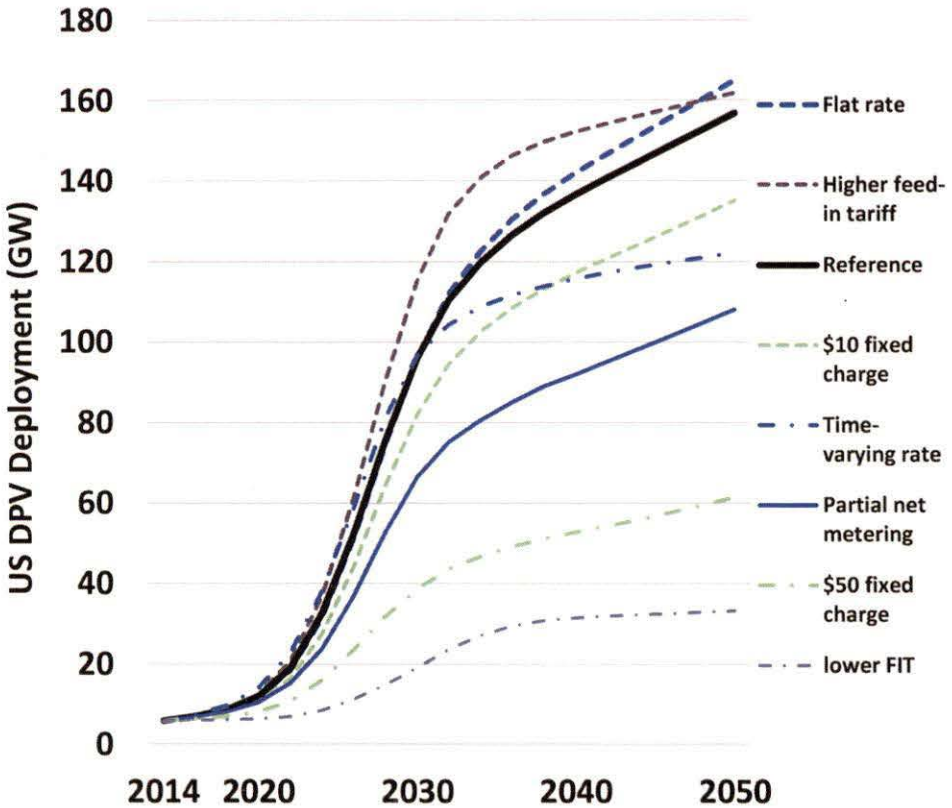

Figure 7. National distributed PV deployment by scenario (with rate feedback effects included)

Figure 8 focuses on 2050 cumulative PV deployment for each of the seven alternative scenarios relative to the reference scenario. Only the flat rate and higher feed-in tariff scenarios increase deployment; all other scenarios reduce deployment. The results indicate that, were all residential and commercial customers on a time-invariant flat rate with no fixed or demand charges, PV deployment would increase by 5% owing to the increased average compensation under that simple rate design. The higher feed-in tariff level of $0.15/kWh also increases deployment relative to the reference scenario; the difference is clearly related to the tariff's magnitude, and higher values would further increase deployment. A lower feed-in tariff level would lead to substantially lower deployment than the reference case, 79% lower for our $0.07/kWh feed-in tariff scenario. Due to the declining value of PV with increased penetration, the time-varying rate scenario leads to a reduction in cumulative PV deployment of 22% in 2050 compared with the reference scenario; as indicated earlier, time-varying rate structures actually increase PV deployment through about 2030.

Both fixed-charge scenarios reduce PV deployment in 2050: a $10/month charge applied to residential customers reduces total cumulative deployment by 14%, and a $50/month charge reduces deployment by 61%. Partial net metering, where PV generation exported to the grid (i.e., not consumed on site) is compensated at a calculated avoided-cost rate, reduces deployment by 31% because in this analysis the assumed avoided cost from PV is lower than the average retail rate, reducing average compensation and increasing the customer's PV payback time.

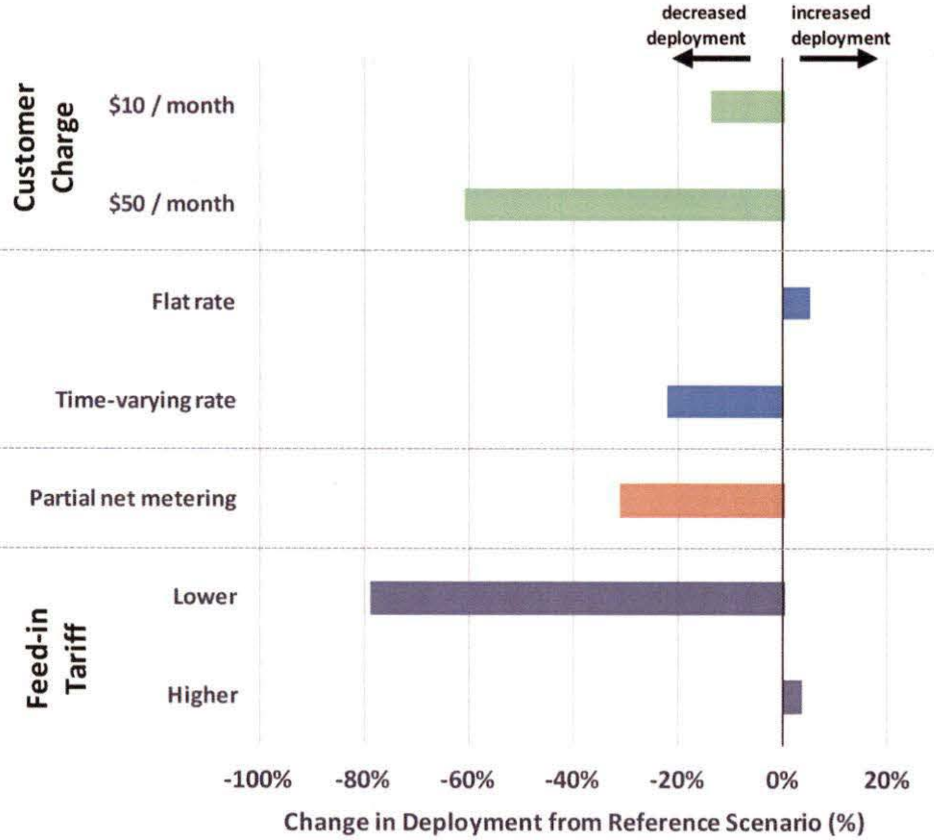

Figure 8. Change in modeled cumulative national PV deployment by 2050 for various rate design and compensation mechanism scenarios, relative to the reference scenario (with rate feedback effects included)

The distributions of PV deployment differences (compared with the reference scenario) across U.S. states vary substantially by scenario (Figure 9). For the two fixed-charge scenarios, the range is relatively small, primarily reflecting differences in the average residential retail rate and average annual customer load across states. For example, states with large annual average customer loads or high average retail rates will see a smaller impact from a given increase in fixed customer charges. The flat rate scenario increases deployment relative to the reference scenario in most states, though only by a modest amount, as a large percentage of customers are already on flat rates.

In comparison to many of the other scenarios, the significance of moving to time varying rates for PV deployment varies rather substantially across states, both in the magnitude and direction of the deployment impact. For about 75% of states, switching all customers to a time-varying rate reduces cumulative PV in 2050. The states most affected by this scenario are those with the highest PV deployment, where the energy and capacity value of PV erodes the most, along with PV compensation. In regions with low PV penetration, PV compensation under time-varying rates remains higher than the average rate, leading to higher deployment in those states under the time-varying rate scenario than under the reference scenario.

Using PV compensation mechanisms other than net metering produces a wide range of deployment impacts. In this analysis, partial net metering reduces deployment for all states, because the retail rate is always greater than the compensation that we assume applies to instantaneous net excess generation, reducing deployment. For feed-in tariffs, the impact can vary much more across states depending on average retail rates (relative to the feed-in tariff rate), the prevalence of time-varying rates, and PV penetration. For example, in states with lower PV penetration levels, even $0.15/kWh might decrease deployment, as compared with the reference scenario. The range of impacts widens with higher feed-in tariffs owing to the non-linear relationship between bill savings and customer adoption, where the marginal adoption rate increases as the payback time decreases.

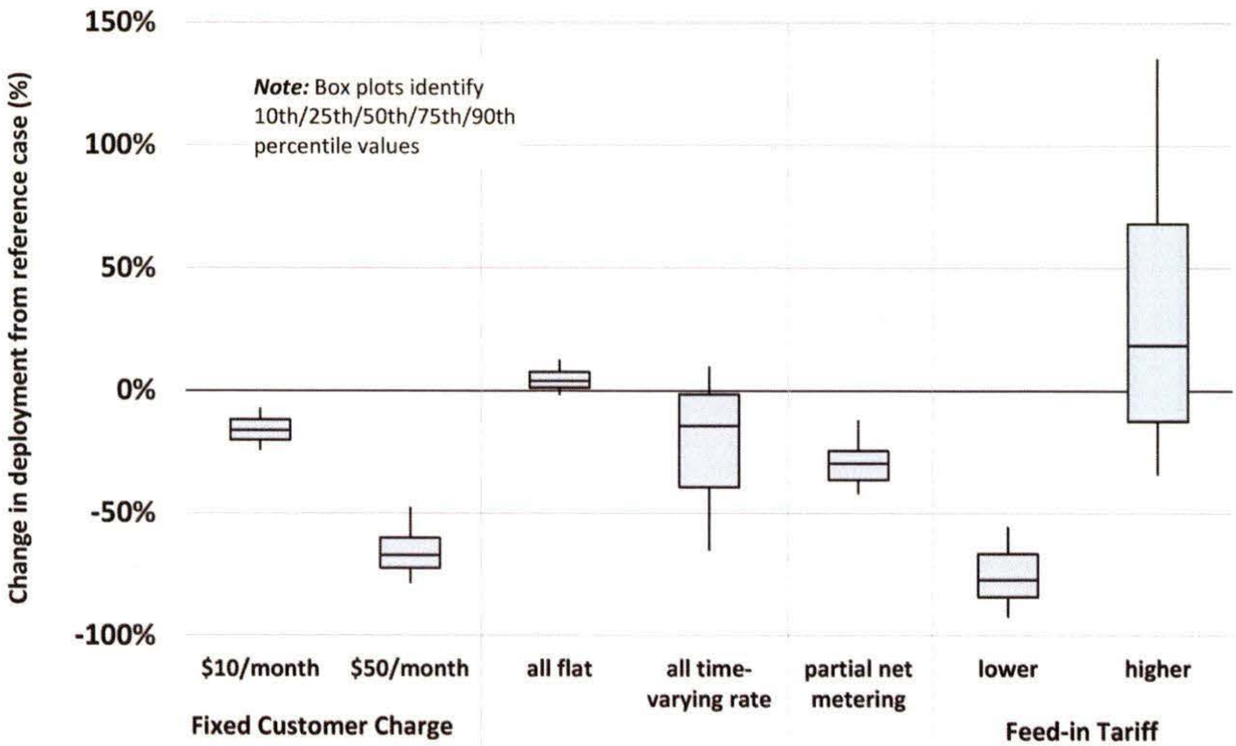

Figure 9. Distribution in deployment differences from the reference scenario for U.S. states in 2050, for all rate design and PV compensation scenarios (with rate feedback effects included)

4 Discussion and Conclusions

There has been significant recent interest in issues related to fixed-cost recovery with increasing distributed PV deployment, and concerns about the "utility death spiral" (Costello and Hemphill 2014, Felder and Athawale 2014, Cory and Aznar 2014, Blackburn et al. 2014, Satchwell et al. 2015). Some observers express concern that increases in net-metered PV adoption may threaten utility profitability, in part owing to a positive feedback loop: as PV deployment occurs, electricity rates increase because utilities must recover the same fixed costs over lower sales, making net-metered PV even more attractive for consumers, and accelerating PV deployment even further. Though our results do not speak comprehensively to the fixed-cost recovery issue or to the impact of PV on utility profitability, they do show that concerns about feedback effects—at least on a national basis—may be somewhat overstated, and that actual feedback effects are quite nuanced.

Our analysis suggests little change in national PV deployment due to rate feedback under our reference scenario, which includes customers on time-varying rates (mostly in the commercial sector) and flat rates (mostly in the residential sector).[10] This is because there are, in fact, two feedback effects of relevance—one related to fixed-cost recovery and the other related to time-varying retail rates—and these two feedbacks operate in opposing directions. The fixed-cost feedback effect is found to increase cumulative national PV deployment in 2050 by 8%. But the feedback associated with time-varying rates reduces cumulative PV deployment by 5%. Current regulatory and academic discussions that focus solely on the fixed-cost recovery feedback therefore miss an important and opposing feedback mechanism that can offset the issue of concern.

Notwithstanding these aggregate national results, the net impact of the two feedback mechanisms can vary substantially across customer segments. In general, the prevalence of flat, volumetric electric rates among the residential customer class ensures a net positive feedback effect with increasing PV deployment in most cases (increasing cumulative national residential PV deployment in 2050 by 9%). In contrast, the prevalence of time-differentiated rates among commercial customers leads to a net negative feedback effect (decreasing cumulative national commercial PV deployment in 2050 by 15%). The net effect of these feedback mechanisms also varies across states, depending on the types of rates offered, the level of those rates, and PV deployment levels. Given these differences, the total feedback effect considering both residential and commercial customers is found to be –6% to +5% in the vast majority of states, and –1% in the median case. Thus, in most states, the feedbacks operate in the opposite direction of the expressed concern and, even where in the positive direction, are rarely particularly large.

[10] As indicated earlier, but deserving reiteration here, we did not explore customer defection from the grid as a possible result of combined solar and storage solutions.

Accounting for these feedback effects, we find that retail rate design and PV compensation mechanisms can have a dramatic impact on the projected level of PV deployment. For example, wider adoption of time-varying rates is found to increase PV deployment in the medium term but reduce deployment in the longer term, relative to the reference scenario based on current rate offerings; the changing pattern of deployment over time, relative to the reference case, is due to the decreasing energy and capacity value of PV with penetration, and the impacts of those trends on time-varying retail rates. The directional impact of feed-in tariffs or value-of-solar rates, on the other hand, depends entirely on the level of the tariff that is offered in comparison to prevailing retail electricity rates. In part to address concerns about the fixed-cost feedback effect (and in part to address many other concerns), a number of utilities have proposed increased fixed customer charges, especially for the residential sector, and/or a phase-out of net energy metering. Though a variety of considerations must come into play when contemplating such changes, our analysis suggests that a natural outcome of these changes would be a substantial reduction in the future deployment of distributed PV: we estimate that cumulative national PV deployment in 2050 could be ~14% lower with a $10/month residential fixed charge, ~61% lower with a $50/month residential fixed charge, and ~31% lower with "partial" net metering. Regulators would need to weigh these impacts with many other considerations when considering changes to underlying rate designs and PV compensation mechanisms.

References

Accenture. 2014. *How Can Utilities Survive Energy Demand Reduction?* Accenture's Digitally Enabled Grid Program, 2014 edition.

Barbose, G., S. Weaver, and N. Darghouth. 2014. *Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998-2013*. LBNL-6858E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Bird, L., J. McLaren, J. Heeter, C. Linvill, J. Shenot, R. Sedano, and J. Migden-Ostrander. 2013. *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar*. NREL/TP-6A20-60613. Golden, CO: National Renewable Energy Laboratory.

Blackburn, G., C. Magee, V. Rai. 2014. "Solar Valuation and the Modern Utility's Expansion into Distributed Generation." *Electricity Journal* 27(1): 18–32.

Blair, N., Dobos, A.P., Freeman, J., Neises, T., Wagner, M., Ferguson, T., Gilman, P., and Janzou, S. 2014. *System Advisor Model, SAM 2014.1.14: General Description*. NREL/TP-6A20-61019. Golden, CO: National Renewable Energy Laboratory.

Borlick, R. and L. Wood. 2014. *Net Energy Metering: Subsidy Issues and Regulatory Solutions*. Issue Brief September 2014. Washington, DC: Innovation Electricity Efficiency (IEE), an Institute of the Edison Foundation.

Bronski, P., J. Creyts, L. Guccione, M. Madrazo, J. Mandel, B. Rader, D. Self, P. Lillenthal, J. Glassmire, J. Abromowitz, M. Crowdis, J. Richardson, E. Schmitt, and H. Tocco. 2014. *The Economics of Grid Defection: When and Where Distributed Solar Generation Plus Storage Competes with Traditional Utility Services*. Boulder, CO: Rocky Mountain Institute.

Brown, A. and L. Lund. 2013. "Distributed Generation: How Green? How Efficient? How Well-Priced?" *Electricity Journal* 26 (3): 28–34.

Cai, D., S. Adlakha, S. Low, P. DeMartini, and K. Chandy. 2013. "Impact of Residential PV Adoption on Retail Electricity Rates." *Energy Policy* 62: 830–843.

Brown, A. and J. Bunyan. 2014. "Valuation of Distributed Solar: A Qualitative View." *The Electricity Journal* 27(10): 27–48.

Energy and Environmental Economics (E3) and California Public Utilities Commission (CPUC) (2013). Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation. San Francisco, CA: California Public Utilities Commission.

Chew, M., M. Heling, C. Kerrigan, D. Jin, A. Tinker, M. Kolb, S. Buller, and L. Huang. 2012. "Modeling Distributed Generation Adoption Using Electric Rate Feedback Loops." Austin, TX: 31st USAEE/IAEE North American Conference.

Cohen, M., P. Kauzmann, and D. Callaway. 2014. "Physical and Economic Effects of Distributed PV Generation on California's Distribution System." Berkeley, CA: 19th Annual POWER Conference on Energy Research and Policy.

Cory, K., and A. Aznar. 2014. "Informing Electricity Systems of the Future: Key Analysis Needs." Electricity Journal 27(9): 73–82.

Costello, K. and R. Hemphill. 2014. "Electric Utilities' Death Spiral: Hyperbole or Reality?" *Electricity Journal* 27(10): 7–26.

Darghouth, N.R., G. Barbose, and R. Wiser. 2010. *The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California*. LBNL-3276E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Darghouth, N.R., G. Barbose, and R. Wiser. 2011. "The Impact of Rate Design and Net Metering On the Bill Savings from Distributed PV for Residential Customers in California." *Energy Policy* 39(9): 5243–5253.

Darghouth, N.R., G. Barbose, and R. Wiser. 2014. "Customer-Economics of Residential Photovoltaic Systems (Part 1): The Impact of High Renewable Energy Penetrations on Electricity Bill Savings with Net Metering." *Energy Policy* 67: 290–300.

Denholm, P., E. Drury, E., and R. Margolis. 2009. *The Solar Deployment System (SolarDS) Model: Documentation and Sample Results*. NREL/TP-6A2-45832. Golden, CO: National Renewable Energy Laboratory.

Denholm, P., R. Margolis, B. Palmintier, C. Barrows, E. Ibanez, L. Bird, and J. Zuboy. 2014. *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. NREL/ TP-6A20-62447. Golden, CO: National Renewable Energy Laboratory.

Dobos, A.P. 2014. *PVWatts Version 5 Manual*. NREL/TP-6A20-62641. Golden, CO: National Renewable Energy Laboratory.

Drury, E., P. Denholm, and R. Margolis. 2013. *Sensitivity of Rooftop PV Projections in the SunShot Vision Study to Market Assumptions*. NREL/TP-6A20-54620. Golden, CO: National Renewable Energy Laboratory.

Eid, C., .R. Guillén, P.F. Marín, and R. Hakvoort. 2014. "The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives." *Energy Policy* 75: 244–254.

Energy Information Administration (EIA). 2014a. *Annual Energy Outlook 2014, with projections to 2040*. DOE/EIA-0383(2014). Washington, DC: U.S. Energy Information Administration.

Energy Information Administration (EIA). 2014b. *Assumptions to the Annual Energy Outlook 2014*. Washington, DC: U.S. Energy Information Administration.

Faruqui, A. and R. Hledik. 2015. *An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation*. Prepared by the Brattle Group for Salt River Project. http://www.srpnet.com/prices/priceprocess/pdfx/DGRateReview.pdf.

Felder, F. and R. Athawale. 2014. "The life and death of the utility death spiral." *Electricity Journal* 27(6): 9–16.

Fox-Penner, P. 2010. *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*. Washington, DC: Island Press.

Gilmore, J., B. Vanderwaal, I. Rose, and J. Riesz. 2015. "Integration of Solar Generation into Electricity Markets: An Australian National Electricity Market Case Study." *IET Renewable Power Generation* 9 (1): 46–56. doi:10.1049/iet-rpg.2014.0108.

Glick, D., M. Lehrman, and O. Smith. 2014. *Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future*. Boulder, CO: Rocky Mountain Institute.

Graffy, E., and S. Kihm. 2014. "Does disruptive competition mean a death spiral for electric utilities?" *Energy Law Journal* 35(1): 1–44.

Greentech Media Research (GTM) and Solar Energy Industries Association (SEIA). 2015. *U.S. Solar Market Insight Report, 2014 Year in Review*. Washington, DC: GTM Research and Solar Energy Industries Association.

Hansen, L, V. Lacy, and D. Glick. 2013. *A Review of Solar PV Cost and Benefit Studies: 2nd edition.* Boulder, CO: Rocky Mountain Institute.

Harvey, H. and S. Aggarwal. 2013. *Rethinking Policy to Deliver a Clean Energy Future*. America's Power Plan. http://americaspowerplan.com/site/wp-content/uploads/2013/09/APP-OVERVIEW-PAPER.pdf.

Hirth, L. 2013. "The Market Value of Variable Renewables: The Effect of Solar Wind Power Variability on Their Relative Price." *Energy Economics*, 38(July): 218–236.

Hoff T., R. Perez, R., J.P. Ross, and M. Taylor. 2008. *Photovoltaic Capacity Valuation Methods.* SEPA report # 02-08. Washington, DC: Solar Electric power Association.

Interstate Renewable Energy Council (IREC). 2013. *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* Latham, NY: Interstate Renewable Energy Council.

Jenkins, J. and I. Perez-Arriaga. 2014. *The Remuneration Challenge: New Solutions for the Regulation of Electricity Distribution Utilities under High Penetrations of Distributed Energy Resources and Smart Grid Technologies*. CEEPR WP 2014-005. Cambridge, MA: MIT Center for Energy and Environmental Policy Research.

Kind, P. 2013. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. Washington, DC: Edison Electric Institute. http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf.

Lehr, R. 2013. *New Utility Business Models: Utility and Regulatory Models for the Modern Era.* America's Power Plan. http://americaspowerplan.com/site/wp-content/uploads/2013/10/APP-UTILITIES.pdf.

Linvill, C., J. Shenot, and J. Lazar. 2013. *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition*. Montpelier, VT: The Regulatory Assistance Project.

McConnell, E.S., S. Stansfield, and S. Baldwin-Auck. 2015. *Easing the Transition to a More Distributed Electricity System: The Changing Role of Consumers, Utilities, and Regulators within the Regulatory Compact.* Latham, NY: Interstate Renewable Energy Council.

Mills, A., R. Wiser, G. Barbose, and W. Golove. 2008. "The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in California." *Energy Policy* 36(9): 3300–3311.

Mills, A. and R. Wiser. 2013. "Changes in the Economic Value of Photovoltaic Generation at High Penetration Levels: A Pilot Case Study of California." *IEEE Journal of Photovoltaics,* 3(4): 1394–1402.

Mills, A. and R. Wiser. 2015. "Strategies to mitigate declines in the economic value of wind and solar at high penetration in California." *Applied Energy*, 147, 269-278.

NC Clean Energy Technology Center. 2015. *The 50 States of Solar: A Quarterly Look at America's Fast-Evolving Distributed Solar Policy & Regulatory Conversation.* Raleigh, NC: NC Clean Energy Technology Center.

North Carolina State University (NCSU). 2014. Database of State Incentives for Renewables & Efficiency (DSIRE). http://www.dsireusa.org. Accessed: September, 2014.

Ong, S., P. Denholm, and E. Doris. 2010. *The Impacts of Commercial Electric Utility Rate Structure Elements on the Economics of Photovoltaic Systems*. NREL/TP-6A2-46782. Golden, CO: National Renewable Energy Laboratory.

Ong, S., C. Campbell, and N. Clark. 2012. *Impacts of Regional Electricity Prices and Building Type on the Economics of Commercial Photovoltaic Systems.* NREL/ TP-6A20-56461. Golden, CO: National Renewable Energy Laboratory.

Satchwell, A., A. Mills, G. Barbose. 2015. "Quantifying the financial impacts of net-metered PV on utilities and ratepayers." *Energy Policy* 80: 133–144.

Sensfuß, F., M. Ragwitz, and M. Genoese. 2008. "The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany." *Energy Policy* 36(8): 3086-3094.

Solar Electric Power Association (SEPA) and Electric Power Research Institute (EPRI). 2012. "Utility Options for Addressing Solar Net Metering Revenue Loss and Ratepayer Equity." *Utility Solar Business Models Bulletin*.

U.S. Department of Energy. 2012. *SunShot Vision Study*. DOE/GO-102012-3037. Washington, DC: U.S. Department of Energy.

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2019-00256 DATED DEC 18 2019

Quantifying Net Energy Metering Subsidies,
Sanem Sergici, Yingxia Yang, Maria Castaner, and Ahmad Faruqui
The Electricity Journal 32, Issue 8 (2019)

SIX PAGES TO FOLLOW

The Electricity Journal 32 (2019) 106632

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/tej

Quantifying net energy metering subsidies

Sanem Sergici[a,b,c], Yingxia Yang[c], Maria Castaner[c], Ahmad Faruqui[d,e,c,*]

[a] Northeastern University, United States
[b] Middle East Technical University (METU), Ankara, Turkey
[c] The Brattle Group, United States
[d] University of Karachi, Pakistan
[e] The University of California at Davis, United States

ARTICLE INFO

Keywords:
Net energy metering
Net metering subsidies
Energy policy

ABSTRACT

Net energy metering (NEM) is the policy available in many states that promotes customer-owned rooftop solar power generation by compensating rooftop solar owners for each kWh that it generates at the retail rates. To help understand the magnitude of the residential net metering subsidies, we conducted a study to assess the subsidies for 16 US utilities with varying geographic location, size, rooftop solar penetration, and NEM policy.

1. Introduction

Net energy metering (NEM) is the policy available in many states that promotes customer-owned distributed generation (DG) resources (such as solar photovoltaic panels or PVs) by compensating DG owners for each kWh of generation at the retail rate. NEM policies were introduced when the costs of installing solar panels were much higher than they are today. The rapid adoption of PVs in recent years at an average annual growth rate of 30% from 2010 to 2018 demonstrates the effectiveness of NEM policies in helping this nascent industry take off[1] .

However, as is generally true for most incentive payments delivered through rates, NEM policies create a subsidy issue from non-DG customers to DG customers. This is simply because most of the residential rates in the U.S. are volumetric in nature. Demand driven and fixed costs of power production and delivery are largely recovered on a $ per kWh basis. As a result, when a DG customer reduces their consumption of power from the grid, they bypass costs that are fixed and/or demand driven in nature, leaving non-DG customers with the burden of paying these grid costs.[2] In addition, traditional NEM policy pays DG customers at the full retail rate for the export to the grid, even though exported DG power only avoids the generation cost but not the capacity cost of delivering services. NEM subsidies have grown with time as the number of customers on NEM has grown.

In 2016, one of the authors of this article co-authored an article published on NEM subsidies.[3] The article summarized the estimated NEM subsidies from 12 studies conducted for utilities in five western states and Hawaii and showed that subsidies per NEM customer range from several hundred dollars a year to values in excess of fifteen hundred dollars a year. In this paper, we provide an update on the magnitude of the NEM subsidies with three enhancements. First, we cover more utilities with a more diverse profile. Sixteen utilities reviewed in our paper vary in terms of their size, DG penetration levels, and span locations from the west coast to the east coast.

Second, the studies reviewed and summarized in the 2016 article were conducted by different entities using different methodologies. In this paper, we develop a single methodology to quantify the NEM subsidies and applied it consistently to all utilities included in the paper enabling side- by-side comparisons of NEM subsidies. Third, our methodology is based on a cost-of-service approach, rather than a cost-and-benefit approach as it explicitly identifies the costs avoided by NEM customers and is therefore more transparent and less subjective.

2. Scope of this assessment

In order to achieve a broad representation of the utility landscape in the U.S., we selected 16 utilities with varying geographic locations, size, DG policy, and penetration levels. The selected utilities are

* Corresponding author.
E-mail address: ahmad.faruqui@brattle.com (A. Faruqui).

[1] Solar Energy Industries Association, Solar Industry Research Data. Available at: https://www.seia.org/solar-industry-research-data

[2] Residential DG can help lower the capacity driven cost when it generates during peak hours. However, its generation profile typically does not coincide perfectly with the system coincident or non-coincident peak hours so that the avoided capacity cost is lower than the bypassed capacity cost.

[3] Faruqui et al., "Rethinking Rationale for Net Metering," Fortnightly Magazine, October 2016.

https://doi.org/10.1016/j.tej.2019.106632

Available online 21 August 2019
1040-6190/

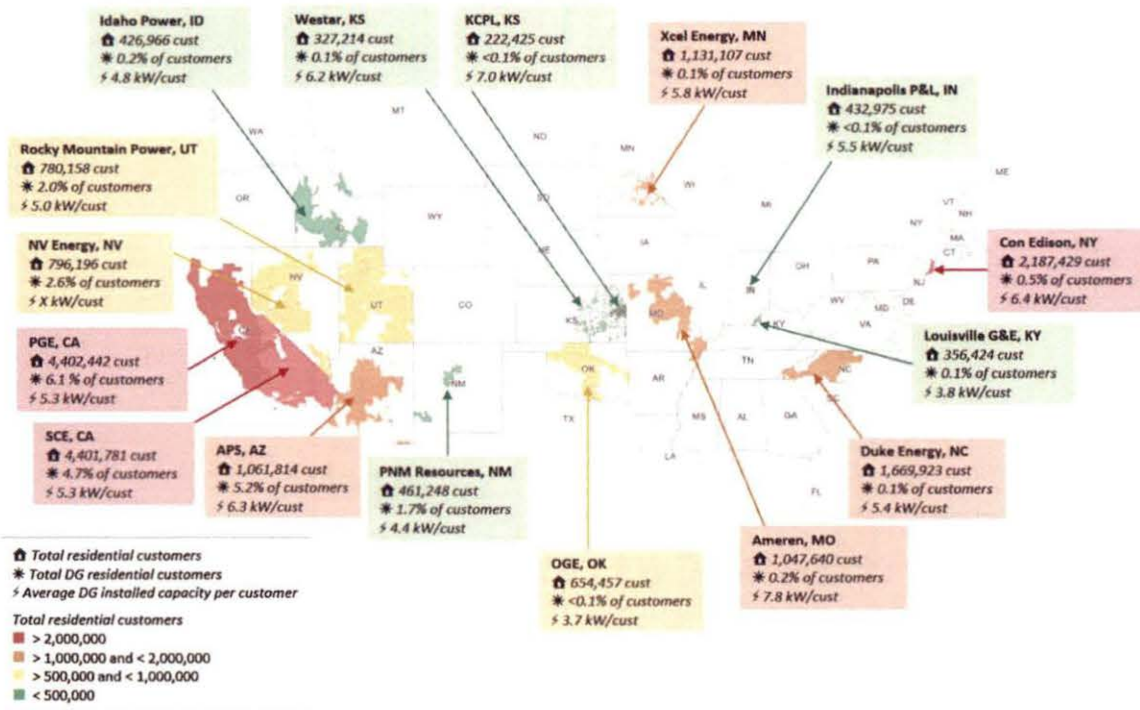

Fig. 1. Characteristics of 16 Utilities in Sample.
Source: Analysis of data in EIA Form 861 (2016).

graphically represented in Fig. 1 and span 14 states across west, midwest, northeast, and south of the U.S.[4] These 16 utilities range from utilities with 200,000 customers to utilities with 4,400,000+ residential customers. We observe a wide range of DG penetration levels in our group of utilities ranging 0.1% in states with low adoption levels such as Kansas, Indiana, and Oklahoma to 3–6% in states with high adoption levels such as Arizona, California, and Nevada.

While most states follow the traditional NEM policy in which every kWh of DG generation is credited at the retail rate, some states incorporate a separate rate for excess energy delivered back to the grid, often based on an avoided cost while some states have adopted new policies that result in a lower rate of compensation for DG generation exported to the grid. For example, Rocky Mountain Power in Utah tracks the net export to the grid separately from net consumption on a 15-minute basis and pays the net export at \$0.092/kWh, a lower rate than the average retail rate of \$0.115/kWh.[5] Arizona Public Service Company froze its net metering policy after August 2017 and implemented a new plan for rooftop solar that pays the net export to the grid at \$0.129 per kWh in 2017 (close to the residential retail rate), reduced to \$0.116 per kWh in 2018, with the rates for future years to be determined annually.[6] In 2016, California has adopted a new NEM policy, NEM 2.0, which introduced a few changes, including the requirements of paying a one- time interconnection fee, defaulting DG customers to a Time-of-Use rate, as well as applying the non bypassable volumetric charges (i.e. charges to support low-income and EE programs) on the net consumption after DG generation on each metered interval basis rather than on an annual basis.[7] The last change effectively reduces the credit for DG generation from the prior NEM policy as the accumulation of net surplus generation will not help to offset the payment of the non- bypassable volumetric charges during the times with net consumption.

3. Methodology

Based on our review of the existing literature on quantifying NEM subsidies, we have identified two widely used approaches: a "cost-of-service" approach and a "cost/benefit" approach.

The **cost-of-service approach** compares the utility revenue collected from NEM customers to the utility's costs to serve NEM customers. The difference between revenue and cost represents the NEM subsidy. Fig. 2 illustrates this approach. While this approach is conceptually straightforward, it requires the availability of recent and reliable cost-of-service data, which may not be available for every utility and for those that have a recent cost-of-service paper, they may not have analyzed and isolated the cost to serve to NEM customers.

Under the cost/benefit approach, the NEM subsidy is represented by the difference between the utility's marginal costs and marginal benefits associated with serving NEM customers. The marginal costs include revenue reduction due to DG customers' reduced electricity consumption as well as other potential cost increases associated with serving DG customers, such as initial billing set up costs, interconnection costs, incremental metering costs, and DG integration costs. The marginal benefits consist of the utility's avoided cost due to lower consumption from DG customers, such as avoided energy cost, avoided generation, transmission and distribution capacity costs.[8] Fig. 3

[4] States covered in our paper are AZ, CA, ID, IN, KS, KY, MN, MO, NC, NM, NV, NY, OK, and UT.

[5] See the rate for export for residential customers (Schedule 1, 2, and 3) in Rocky Mountain Power, Electric Service Schedule No. 136 (State of Utah) - Transition Program for Customer Generators. Available at: https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Transition_Program_for_Customer_Generators.pdf. The average retail rate is based on EIA's 2017 Utility Unbundled Retail Sales for, Available at https://www.eia.gov/electricity/sales_revenue_price/pdf/table6.pdf.

[6] Arizona Public Service, Rate Rider RCP Partial Requirement Service for New On-site Solar Distributed Generation Resource Comparison Proxy Export Rate, https://www.aps.com/library/rates/RCP.pdf

[7] CaliforniaPublicUtilitiesCommission,NetEnergyMetering(NEM).Availableat: http://www.cpuc.ca.gov/General.aspx?id=3800.

[8] Some studies that have previously evaluated these benefits also included

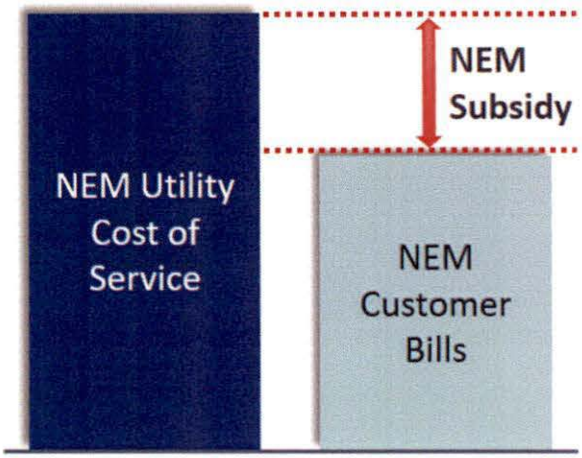

Fig. 2. Cost-of-Service Approach.

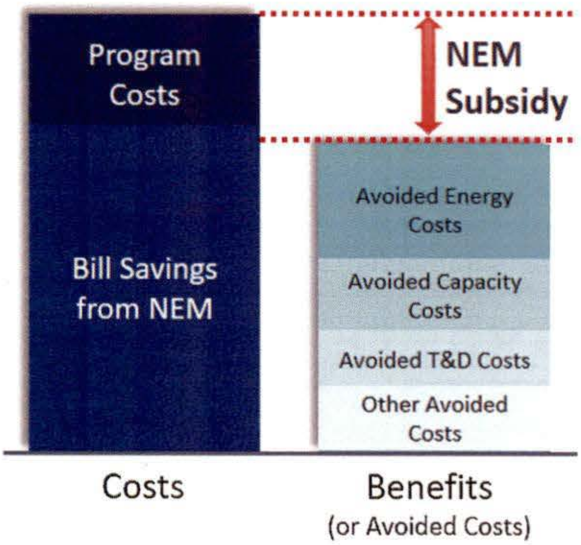

Fig. 3. Cost/Benefit Approach.
Note: Other avoided costs can include avoided costs of losses, avoided A/S reserve costs, and avoided cost of renewable purchases.

illustrates this approach. Under the cost/benefit approach, some avoided cost components, such as the avoided energy and ancillary service costs, do not require utility cost-of- service information and can be compiled relatively easily using publicly available data. However, other data will still need to be provided by utilities and may not be available at the desired accuracy, vintage and granularity, such as distribution and transmission marginal costs. Moreover, the difference between the costs and benefits may not be entirely attributed as the NEM subsidy, as it is not clear how it will be redistributed across the utility customers.

This paper utilizes the first approach because it identifies the cost and revenue associated with DG customers that, unlike avoided cost estimates, are actually reflected in the utility revenue requirement and customer rates and is more transparent. Below, we describe the implementation of this approach based on data collected from surveying utilities and researching publicly available data sources.

Step 1: Calculation of DG customers' Electricity Usage and Peak Demand

DG customers' electricity usage, including monthly energy usage (kWh) and non-coincident peak demand (kW), is required for both calculating their monthly bill and the utility cost to serve them. Some utilities provided us with the data based on their DG customer profiles. Other utilities, particularly those with low DG penetration, did not provide us with this data. For these utilities, we estimated the electricity usage for DG customers based on the profile of average residential customers.

To estimate DG customers' monthly energy usage, we first estimated pre-DG usage by adjusting average residential usage to account for the fact that DG customers in general are larger energy consumers than the average residential customer.[9] Then, we estimated the reduction in energy usage due to DG generation. We used two approaches to estimate the DG generation, one bottom- up approach and one top-down approach. The bottom-up approach estimates the reduction in energy consumption based on the average DG installed capacity per customer and the hourly production profile of solar PV in a given utility using NREL and EIA data.[10] The top-down approach estimates the energy consumption reduction based on the average for the utilities for which we have data available.[11]

To estimate the DG customer peak demand, first we used average monthly pre-DG usage and an assumed load factor to estimate pre-DG peak demand.[12] Then, we calculated post-DG peak demand based on the reduction in peak load using the Effective Load Carrying Capability (ELCC) approach based on the solar DG average capacity factor in the 1000 highest system load hours.[13] To account for uncertainties in the coincidence of DG generation with system and local peaks, we developed another scenario where the DG peak reduction is half of the reduction estimated with the ELCC approach.

In total, we created four scenarios to account for the uncertainty associated with the DG impacts on monthly usage and peak demand, as summarized in Table 1, and calculate the NEM subsidy under each scenario.

Step 2: Calculation of DG Customer Bills for pre- and post- DG

We applied the retail rate schedules to the customer usage information to estimate NEM customer bills. Most utilities provided us with the "all-in" average residential electricity price and the average monthly electricity consumption for both DG and non-DG residential customers. For utilities that did not provide us with the data, we obtained them from the EIA.[14] We first multiplied the "all-in" residential electricity price by the average residential monthly consumption to get the average monthly bill for residential customers. To calculate DG customer bills, we first subtracted the fixed monthly customer charge from the average monthly bill to calculate the volumetric portion of the monthly bill. Then, we calculated the volumetric rate in $/kWh by

(footnote continued)
external benefits such as avoided emission costs and macroeconomic impacts. See for instance: E3, Nevada Net Energy Metering Impacts Evaluation, July 2014, Chapter 5, Available at: http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf = Net-Metering-Paper.

[9] Based on the data provided by utilities for DG residential customers and average residential customers in the same utility, DG customers consume on average 76% more than non-DG customers for utilities with average residential customer usage less than 600 kW h per month. DG customers consume only 17% more on average compared to non-DG customers for utilities with average residential customer usage more than 1000 kW h per month.

[10] We used Form EIA-861 (2017) to derive the average residential DG installed capacity per customer for each utility and the NREL's System Advisor Model (SAM) to obtain annual solar profiles for the largest cities in the selected utility territories.

[11] Based on data available, we assumed that on average customer usage decreases by 60% due to DG.

[12] We estimated a load factor of 22% based on energy consumption and peak demand information from those utilities for which we had data available.

[13] We used FERC Form 714 to find the 1,000 highest system load hours in the selected utility territories.

[14] Form EIA-861 (2016).

Table 1
Scenarios to Estimate Values for Missing Data.

Scenarios	DG Energy Generation	DG Peak Load Reduction
Scenario 1	Bottom Up Approach	System ELCC Approach
Scenario 2	Bottom Up Approach	50% of Scenario 1
Scenario 3	Top Down Approach	System ELCC Approach
Scenario 4	Top Down Approach	50% of Scenario 3

dividing the volumetric portion of the bill by the average monthly consumption. We then multiplied this volumetric rate times the energy usage of DG customers both pre-DG and post-DG as calculated in Step 1 to estimate the volumetric portion of the average bills for DG customers. Finally, we added the fixed monthly customer charge to the derived DG volumetric piece to compute the average total monthly bills for DG customers for both pre-DG and post-DG. [15]

Step 3: Calculation of Cost of Serving DG customers for pre- and post- DG

Cost-of-service studies specific to residential DG customers were not available for most utilities (low penetration of DG to date has not led most utilities to consider DG customers as its own class), so we estimated the cost of serving DG customers based on cost-of-service studies for average residential customers and made the following assumptions and adjustments:

1)

1) We set the total cost of serving residential DG customers pre-DG to be equal to the average bill from these customers. This allowed us to exclude any cross-subsidies between DG residential customers and other classes prior to adoption of DG and differentiate them from the NEM subsidy.
2) To estimate the cost of serving DG customers pre DG, we assumed customer-related costs for these customers were the same as for the average residential customer, and calculated the energy-related costs based on the energy-related cost in $/kWh for average residential customers multiplied by the energy usage of DG customers pre-DG. The demand-related cost for DG customers pre-DG were estimated as the difference between total cost and customer- and energy-related costs.
3) Next, we estimated the cost of serving residential DG customers post-DG by adjusting the energy- and demand-related costs of serving residential DG customers pre-DG in proportion to the change in usage and peak demand due to DG generation

Step 4: Calculation of NEM subsidy

The difference between the cost of serving DG customers and revenue collection from the DG customers (or the bill paid by the DG customers) is the NEM subsidy.

Fig. 4 illustrates the calculations described above with regard to the pre-DG and post-DG costs, the pre-DG and post-DG bill, and the NEM subsidy as the result.

4. Results

Fig. 5 summarizes the NEM subsidy for all utilities in our sample. Six utilities provided us with all the data needed for DG customers and/or NEM subsidies, including APS, SCE, PGE, Idaho Power, Westar, and Nevada Energy. For the rest of utilities who provided partial data or no data for DG customers, we estimated the range of NEM subsidies based on the four scenarios as described in Section III and represented the range by the black lines (while the height of the bars represent the mid-point of the subsidy. For APS and SCE, we adjusted the NEM subsidies provided by the Companies to remove the inter-class subsidies between DG customers and other customer classes (prior to DG adoption) so that the results shown here only present the NEM subsidies, as described in Section III.[16]

The NEM subsidies range in $20-$100/customer/month across all utilities, representing roughly 25%–200% of the monthly bills for residential DG customers of these utilities.[17] PGE and SCE have the highest NEM subsidies at about $100/customer/month. This is not surprising given that the retail rates in PGE and SCE are relatively high in comparison to other utilities, fixed charges are virtually non-existent, and solar generation is also high due to the utilities' geographical location, both of which lead to high reductions in for DG customer bills which are in turn covered by non- DG customers. Even though the retail rates in APS and NV are not as high as PGE and SCE, high solar output still drives the NEM subsidies to be on the high end, at $60-$80/customer/month.

Another utility with relatively high NEM subsidy is ConEd in New York. As a distribution utility, ConEd's costs are driven either by demand or are fixed, with essentially no cost driven by volumetric energy. This makes ConEd particularly prone to the cost shift, as every kWh of solar generation from the DG will lead to a large bill reduction at ConEd's retail rate, with only a small corresponding cost reduction, unlike vertically integrated utilities. The ConEd example shows that the cost shift issue will be more pronounced for distribution only utilities as they are not able to benefit from the avoided energy and capacity costs unlike vertically integrated utilities.

NEM subsidies for the rest of utilities are between $20-$50/customer/month. They are less than the utilities discussed above, but still are substantial as they represent 25%–200% of DG customers' bills.

Fig. 6 summarizes the NEM subsidies in million dollars per year based on the current size of the residential DG class. The total subsidies to DG customers in PGE and SCE are the most significant, reaching $340 million/year and $250 million/year respectively, given the high subsidy on a per customer basis and the large solar DG adoption rate. NEM subsidies for APS and NV are at $42 million and $19 million per year, also as a result of the large monthly NEM subsidy and high DG penetration level. Three utilities including Rocky Mountain Power, PNM, and ConEd are in the range of $4-$9 million per year. The rest of utilities are under $1 million per year because the solar DG penetration level is still low, but will grow as DG adoption rate increases.

As a benchmark, our estimates are in the same ballpark as the NEM subsidies summarized in the 2016 PUF article cited earlier, as shown in Table 2.

5. Conclusions

The paper shows that NEM policy has led to substantial subsidy issue between DG customers and non-DG customers. The subsidies can be as high as $100/customer/month for some utilities such as PGE and SCE and add up to f $340 and $250 million per year. For other utilities such as APS, ConEd, and NV the subsidies can be in the $60-$70/customer/month and add up to $20-$40 million per year.[18] NEM subsidies

[15] Using this approach, we avoided dealing with the potential complexity of having to include various riders in the monthly bill since they are already reflected in the all-in average price.

[16] We did not make this adjustment to Nevada Energy because the pre-DG data for DG customers is not available.

[17] The percent range provided above does not include ConEd. Unlike other utilities in our paper, ConEd is a distribution only company and so the calculated monthly bill does not include energy cost. This makes the monthly bill per customer particularly low and results in a very high percentage that is not in line with other utilities that provide energy services.

[18] For PGE, SCE, APS, and RMP, because we analyzed the new NEM policies, our figures underestimate the total subsidy per year because we apply the cost shifts per customer to all residential customers whereas the majority of the residential customers are grandfathered under the traditional NEM policies that lead to larger NEM subsidies.

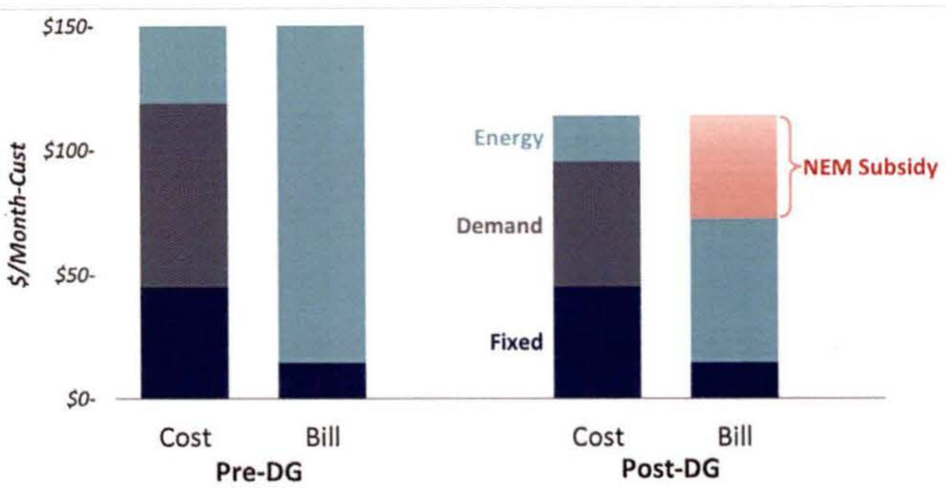

Fig. 4. Illustration of the NEM Subsidy Calculation.

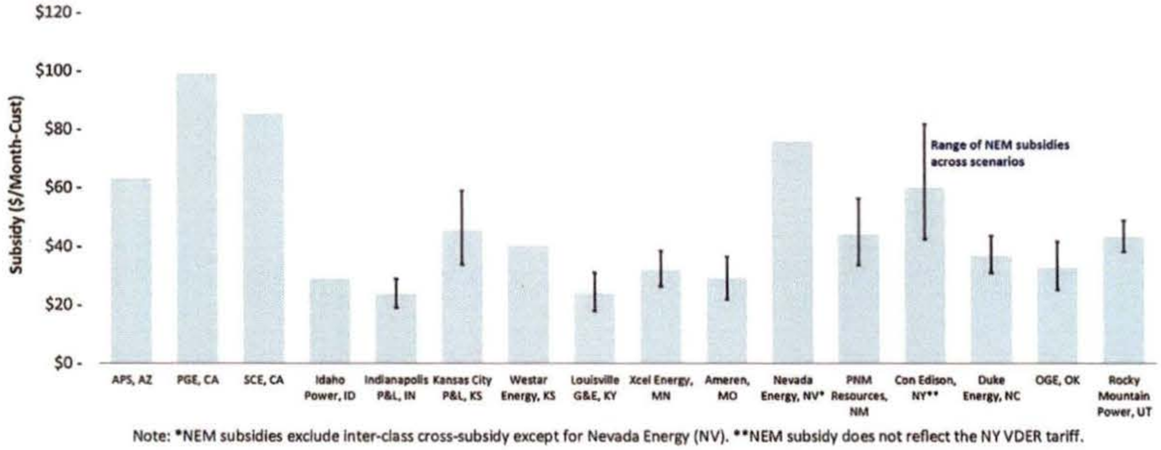

Fig. 5. NEM Subsidy by Utility.
Note: *NEM subsidies exclude inter-class cross-subsidy except for Nevada Energy (NV). **NEM subsidy does not reflect the NY VDER tariff.

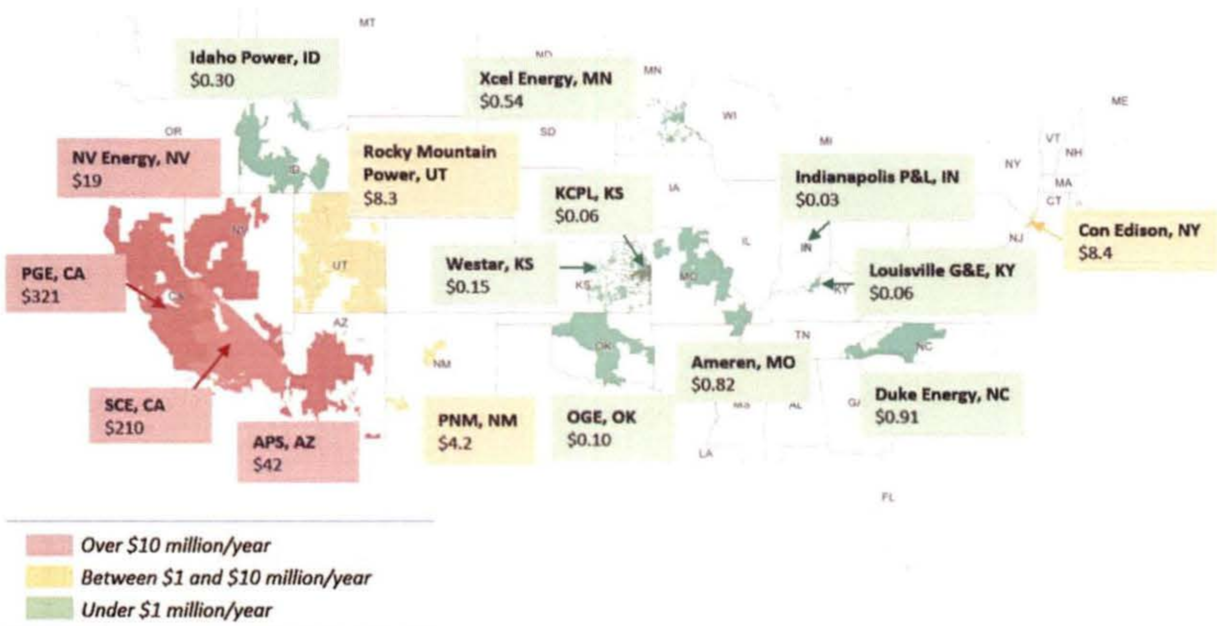

Fig. 6. Aggregate NEM Subsidy ($million/year).
Note: For utilities who did not provide the DG customer profiles, the numbers are based on average NEM subsidies across the four scenarios.

Table 2
Comparison of NEM Subsidies in this paper with the estimates in the 2016 PUF article ($/customer/month).

	APS, AZ	PGE, CA	Idaho Power, ID	NV Energy, NV
2019 Paper	$63	$99	$29	$76
2016 PUF Article	$72	$88-$146	$37	$39-$$85

for the rest of utilities are in the range of $20-$50/customer/month.

Thus, non-DG customers are currently paying tens of millions to hundreds of million dollars per year more than they should be paying. This cross-subsidization issue will get exacerbated over time as solar penetration increases because more cost will be shifted to less non-DG customers. Clearly, while the NEM policy has successfully provided the nourishing support to get rooftop PV out of its cradle when the cost was high, continuing it at a time when rooftop solar cost has come down creates an unfair treatment for non-DG customers and needs to be revised to ensure a more equitable compensation method for DG customers.

Some states, such as California, Arizona, Utah, have adopted modifications to lower the incentives for DG generation and/or to better quantify the value DG creates for the system. However, these policies typically apply to new DG customers and customers who have invested in their DG systems prior to the introduction of the new policies are grandfathered. This implies that the cross- subsidy problem will persist until these systems complete their useful lives highlighting that the positive and negative implications of these polices are long-lived. This is a good reminder for the states that have not experienced large penetrations of DG resources to revisit their net metering policies and adopt cost-based compensation methods before the problem gets worse.

Dr. Sanem Sergici specializes in program design, evaluation, and big data analytics in the areas of energy efficiency, demand response, smart grid and time-varying pricing. She regularly supports electric utilities, regulators, law firms, and technology firms on utility business and regulatory model questions. Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs in North America. She led numerous studies in these areas that were instrumental in regulatory approvals of Advanced Metering Infrastructure (AMI) investments and smart rate offerings for electricity customers. She also has significant expertise in resource planning, development of load forecasting models and energy litigation. Dr. Sergici has led the development of a variety of traditional and emerging performance incentive metrics in the context of performance based regulation for various U.S. utilities. During the early stages of the New York Reforming the Energy Vision (NYREV) initiative, Dr. Sergici led the development of a financial model to study the incentives required for and the impacts of incorporating large quantities of Distributed Energy Resources (DERs) on utility earnings and rates, which has been instrumental in the development of key regulatory incentive mechanisms. Dr. Sergici is a frequent presenter on the economic analysis of DERs and regularly publishes in academic and industry journals. She received her Ph.D. in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her M.A. in Economics from Northeastern University, and B.S. in Economics from Middle East Technical University (METU), Ankara, Turkey.

Dr. Yingxia Yang is a Senior Associate at The Brattle Group. She's been engaged in projects on rate design, distributed energy resources, integrated resource planning, wholesale market design, environmental policy analysis, power system outlook assessment. She has assisted clients including electric utilities, system operators, market participants, government entities, and trade associations across many jurisdictions in the US and other countries. Before she joined Brattle, she worked as a Senior Associate for Charles River Associates in its Energy practice and a Postdoctoral Associate at MIT Energy Initiative.

Maria Castaner is a Research Analyst at The Brattle Group. She has worked on projects on rate design, distributed energy resources, electrification of transportation (and heating) and deep decarbonization of the power sector. Prior to Brattle, she earned her B.S. degree in Chemical Engineering and Economics from the University of Pennsylvania.

Dr. Ahmad Faruqui is an internationally recognized authority on the design, evaluation and benchmarking of tariffs. He has analyzed the efficacy of tariffs featuring fixed charges, demand charges, time-varying rates, inclining block structures, and guaranteed bills. He has also designed experiments to model the impact of these tariffs and organized focus groups to study customer acceptance. Besides tariffs, his areas of expertise include demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents, including electric and gas utilities, state and federal commissions, governments, independent system operators, trade associations, research institutes, and manufacturers. Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, Saudi Arabia, and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand, New Zealand and the United Kingdom and given seminars on all 6 continents. He has also given lectures at Carnegie Mellon University, Harvard, Northwestern, Stanford, University of California at Berkeley, and University of California at Davis and taught economics at San Jose State, the University of California at Davis, and the University of Karachi. His research been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He is a member of the editorial board of The Electricity Journal. He holds BA and MA degrees from the University of Karachi, both with the highest honors, and an MA in agricultural economics and a PhD in economics from The University of California at Davis, where he was a research fellow.