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COMMISSION

October 15, 2019

Hand Delivered

Gwen R. Pinson, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RE: Case No. 2019-00256, Implementation of the Net Metering Act

Dear Ms. Pinson:

Please find attached the Written Comments of Kentucky Solar Industries Association concerning the implementation of the Net Metering Act.

Should you have any questions or concerns regarding the attachment, please contact me at your earliest convenience.

Best regards,

Matt Partymiller
President
Kentucky Solar Industries Association
1038 Brentwood Ct., STE B
Lexington, KY 40511
[redacted]

Attachment (1)

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

COMMENTS OF THE KENTUCKY SOLAR INDUSTRIES ASSOCIATION

The Kentucky Solar Industries Association ("KYSEIA") provides these comments in response to the Kentucky Public Service Commission's ("Commission") July 30, 2019 Order requesting comments on the implementation of Senate Bill 100, An Act Related to Net Metering ("Net Metering Act").

KYSEIA is a trade association representing the solar industry in the Commonwealth of Kentucky. Our members range from small residential installers to one of North America's largest solar developers. Our members also span the state with active or completed projects in almost every corner of the Commonwealth.

KYSEIA members are proud to contribute to Kentucky's vital energy sector. Through the end of 2018, Kentucky had approximately 1,410 solar jobs, representing a 9% increase over 2017 and a 40% increase compared to 2015.[1] In today's changing energy landscape, energy diversity and alternative energy generation technologies are becoming increasingly important. KYSEIA's members are eager to contribute to energy diversity in the Commonwealth, while continuing to create in-state jobs, provide consumers a choice in their energy supply, and vitalize local economic development.

[1] The Solar Foundation, "Solar Jobs Census 2018," available at: https://www.solarstates.org/#state/kentucky/counties/solar-jobs/2018

Summary of Comments

Retail rate net metering has been an essential policy for facilitating the growth of distributed solar in Kentucky, as well as in dozens of other states across the nation. In implementing the Net Metering Act, the Commission should maintain the fundamentals of retail rate net metering, such as "netting"[2] during the month, and traditional rate design to ensure that distributed generation customers continue to receive fair, just and reasonable rates. Statutory restrictions limiting the size and total capacity of net metering in the Commonwealth provide robust safeguards against net metering causing significant impacts on other customers, so there is no urgency for the Commission to implement substantial changes from the status quo. Rather, the Commission should ensure that a fair and transparent process is adopted for considering changes to net metering compensation rates, rate design, or rates specific to net metering customers. KYSEIA intends to provide further detailed comments on the implementation of the Net Metering Act in specific utility rate proceedings to address the unique characteristics of each utility and any specific proposals that could impact current or future net metering customers.

KYSEIA's comments are organized into three sections. First, KYSEIA makes specific recommendations regarding the implementation of various provisions of the Net Metering Act. Next, KYSEIA outlines a process for considering changes pursuant to the Net Metering Act. Finally, KYSEIA articulates an initial set of key principles and identifies additional issues for the Commission as it considers adopting specific changes.

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[2] Netting refers to subtracting the customer's gross consumption from the customer's gross generation from their net-metered system during a defined time period. Prior to the Net Metering Act, "netting" occurred over the life of a customer account, with any monthly net excess generation carried over to the next month's bill for life of the account.

The Net Metering Act Provisions

KYSEIA recommends the Commission take appropriate action to address the following issues as it implements the provisions of the Net Metering Act. KYSEIA reserves the right to provide additional and more specific recommendations on the implementation of the Net Metering Act in response to utility proposals through rate proceedings and any other relevant proceedings.

Eligible System Size

Under the Net Metering Act, facilities eligible for net metering can be sized up to 45 kW, an increase over the current 30 kW limit.[3] Since the Net Metering Act is effective on January 1, 2020, the Commission should direct utilities to abide by this new eligibility term on that date and accept any new net metering applications for eligible systems sized up to 45 kW. Any provisions in utility tariffs that specify a 30 kW eligibility limit should no longer be enforced so as not to frustrate the intent of the Kentucky General Assembly. For the remainder of 2019, utilities should be directed to review interconnection applications for systems up to 45 kW, with the understanding that any approved system over 30 kW will not be interconnected before the start of 2020.

Kentucky's Interconnection and Net Metering Guidelines ("Guidelines"), as approved by the Commission January 8, 2009, state: "Each utility with a website shall provide net metering application forms and information regarding the retail electric provider's net metering program on the website."[4] Consistent with the Commission's intent to make accurate information about net metering readily available to customers, each utility should update their website and net

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[3] KRS 278.465(2)(c).

[4] Kentucky Interconnection and Net Metering Guidelines, January 8, 2009, p. 2.

metering applications, effective January 1, 2020, stating the new eligible system size to be 45 kW.

Finally, the Commission should expressly clarify that the capacity of an energy storage system connected to a net-metered system should not count against the eligible system size threshold for a net-metering system. Notably, the 45 kW statutory restriction under the Net Metering Act only applies to the definition of an "eligible electric *generating* facility" (emphasis added), and not energy storage facilities paired with eligible electric generating facilities.[5] Furthermore, since net-metered solar systems are not typically capable of reliably providing the customer with power during a grid blackout without a paired energy storage system also installed, allowing the addition of an energy storage system without counting its capacity against the net-metering system size threshold is critical for enabling more Kentuckians, particularly in rural parts of the Commonwealth, to have additional options for reliable back-up power during grid outages.

Net Metering Cap

The Net Metering Act provides that a utility only has an obligation to offer net metering to new customers until "...the cumulative generating capacity of net metering systems reaches one percent (1%) of a supplier's single hour peak load during a calendar year…." (hereafter, the "1% cap").[6]

The 1% cap establishes a clear limit on net metering participation, meaning any associated impact of net metering -- positive or negative -- will necessarily be constrained.

[5] KRS 278.465(2)
[6] KRS 278.466(1).

Notably, this cap is significantly smaller than net metering caps established in many other states.[7] Therefore, the Commission need not act in haste to make changes that could deter customers from participating in net metering given this statutory provision already constrains participation to a level that is modest in comparison to other states.

The Commission should clarify that a utility under its jurisdiction that reaches its 1% cap must file a revised net metering tariff with the Commission and obtain approval prior to it ceasing its net metering offering. Until the Commission issues an order approving such a replacement tariff, the utility should be required to continue to accept and process net metering applications for eligible generators. The Commission should also define that the postmarked date, and for digital correspondence the timestamp date, of a net metering application establishes the regulatory framework in effect for that net metering customer.

Finally, since a utility's load continually changes over time, the Commission should clarify how specifically the 1% cap will be calculated for the purposes of determining when the cap has been reached. KYSEIA recommends this calculation be based on dividing the total operating net metering capacity (in MW, based on net-metered systems that have been installed and granted permission to operate) by the utility's highest historic single-hour peak load (in MW) in any prior year. The all-time highest historic peak load is consistent with a utility's true potential peak load in any given year and avoids the potential for confusion about net metering eligibility if peak load in one year is lower than the prior year. As described in the following section, transparent reporting requirements should be established so that stakeholders have clear

[7] *See, e.g.*, Net metering caps in states neighboring Kentucky: Indiana, 1.5% of a utility's summer peak load; Illinois, 5% of the utility's peak load; Missouri, 5% of the utility's single-hour peak load; Ohio, no cap; West Virginia, 3% of peak demand; Virginia, 1% of the utility's peak-load forecast. Tennessee does not have consistent net metering requirements across the state, as most of the state is within the jurisdiction of the federal Tennessee Valley Authority.

and up-to-date information about a utility's current operating net-metering capacity and single-hour peak load used in this calculation.

Reporting Requirements

Transparent and up-to-date information is essential for the Commission in implementing the Net Metering Act in a manner that minimizes customer confusion and ensures a smooth transition from the current net metering policy to a future framework. Accordingly, the Commission should direct utilities to file monthly progress reports that clearly identify both the total existing net-metered capacity on their system and the total capacity in pending net metering applications, as well as a calculation showing the overall remaining capacity available to customers based on the utility's 1% cap. KYSEIA recommends that the Commission also direct utilities to make this information easily available on the utilities' respective websites so customers can easily find information on the current status of net metering in their utility service area.

Furthermore, KYSEIA recommends that when a utility reaches 90% of its available net metering capacity, based on submitted net metering applications, it should be required to increase its reporting frequency on its website from a monthly to a weekly basis to allow potential customers and solar installers the ability to more accurately forecast when specifically the utility could reach its cap.

Public utility commissions in states in a similar position to Kentucky have taken similar action. In one recent example, the Indiana Utilities Regulatory Commission directed utilities in August 2019 to begin filing more frequent reports on net metering participation, establish net metering queues, post queue information on the utility's webpage, and update the queue information monthly as part of its implementation of Senate Enrolled Act 309 of 2017, which provided for a limited amount of capacity under the existing net metering program.[8]

Interconnection Guidelines

The Commission should continue to apply the Net Metering and Interconnection Guidelines ("Guidelines") it previously adopted in 2009, with the exception of provisions that have been superseded by the Net Metering Act.[9] The Guidelines were adopted through a transparent and inclusive process that involved the participation of a diverse group of stakeholders, including retail electric suppliers, renewable energy installers, and the Attorney General, and should therefore be maintained.

In the meantime, the Commission should establish a process, such as a new proceeding, for making necessary modifications to the Guidelines to conform with the Net Metering Act, as well as to make any additional changes that are warranted at this time, such as to improve the consistency of the Guidelines' application across Kentucky's utilities, further streamline the process of interconnecting distributed generation facilities, and make revisions to reflect advancements in technology that have occurred at a rapid pace since the Guidelines were adopted a decade ago. For example, to conform with the Net Metering Act, the Guidelines should be updated to reflect the increase in the eligible system size of a net metering facility from 30 kW to 45 kW. Since the Net Metering Act merely modified the definition of net metering, and kept the policy of net metering in place, KYSEIA believes that references in the Guidelines to "net metering" are still applicable under any changes the Commission may adopt to its net metering policy or specific utility tariffs to align with the Net Metering Act.

KYSEIA members have also reported that utilities are beginning to implement costly new

[8] Indiana Utility Regulatory Commission, General Administrative Order 2019-2, August 29, 2019.
[9] Kentucky Public Service Commission, Case No. 2008-00169.

policies for net metering customers. One example of how the Guidelines could be further modernized to reduce unnecessary and costly red tape is by removing the authority of utilities to require that net metering customers install an external disconnect switch (EDS). Many utilities in Kentucky are now requiring that a net metering customer install an expensive and duplicative lockable, solar-specific EDS adjacent to the utility meter. However, statute already requires that systems comply with the National Electrical Code (NEC) and utilize equipment listed by UL or an equivalent organization, which provides adequate assurance that systems will be safely operated.[10] For well over a decade, experts have recognized that modern rooftop solar facilities, particularly small systems such as those eligible under net metering, do not need EDS equipment to safely interconnect with the grid. In revising the Guidelines, the Commission should modify language to prevent utilities from requiring this type of expensive, duplicative, and unnecessary equipment that exceeds current NEC standards and industry best practices.

If the Commission were to consider allowing utilities to continue requiring the installation of an EDS, it should require that they demonstrate the systems and processes that they have in place for identifying when and how the EDS will be used and require the utilities to report on all instances in which an EDS was utilized as a safety precaution. These requirements would ensure that utilities are actually capable of effectively utilizing an EDS (e.g., do their internal systems even plot the locations of such systems) and allow the Commission to evaluate the reasonableness of allowing an EDS requirement in the future.

Net Metering Compensation Rate

The Net Metering Act changed the definition of net metering to mean "the difference between the a) dollar value of all electricity generated by an eligible customer-generator that is

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[10] KRS 278.465(7).

fed back to the electric grid over a billing period and priced as prescribed" by the Commission in a ratemaking proceeding and "b) the dollar value of all electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier."[11] Simply put, the Commission is tasked with determining in future utility rate proceedings a fair, just and reasonable dollar value for electricity exported by a net-metered system. KYSEIA believes that retail-rate compensation under current utility rate structures best approximates the dollar value of electricity exported to the grid.

KYSEIA notes that the statutory language pertains to net metering compensation "over a billing period." KYSEIA believes that the most reasonable interpretation of this phrase is that exports to the grid *within* a billing period, measured in kWh, should continue to be netted on a one-to-one basis against imports from the grid during the month, measured in kWh. The Commission's primary concern in implementing this provision should be focused on determining an appropriate methodology for setting a dollar value for the *net excess generation* that occurred over the month that will be applied against the future bills of a net-metering customer. This interpretation is further bolstered by practical limitations in the existing metering equipment and billing systems used by some Kentucky utilities, which might not be capable of measuring instantaneous power flows in both directions or automatically calculating and netting bill credits and debits on customer bills.

In addition, the "dollar value of all electricity" for grid exports over the billing period is presently reflected in a customer's volumetric (per kWh) rate. The statute notably does not confine compensation to specific components of electricity rates, such as energy-only costs. Rather, by specifying the "dollar value of all electricity," the compensation rate should include

[11] KRS 278.465(4).

all components of an electric rate, including, for example, demand-related costs that may be recovered through volumetric rates.

Rate Design

Under the Net Metering Act, utilities can implement rates, subject to approval by the Commission, that recover "all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators."[12] KYSEIA understands this provision to permit a utility to propose separate rates, and possibly a different rate design, for new net metering customers to recover the utility's cost of serving those customers. Notably, the statute is silent on *how* the utility will recover these costs, i.e., what rate design is appropriate to recover these costs. The statute authorizes the recovery of fixed and demand-based costs, but it does not specify the manner in which these costs are to be recovered by a utility, or provide additional specificity on how to define which costs are fixed or demand-based. For example, most residential customers in Kentucky and across the nation currently pay for a utility's demand-related costs through their variable per-kWh energy rate rather than through demand charges, since residential customers are generally unfamiliar with and have a reduced capacity to respond to demand charge price signals relative to more sophisticated commercial and industrial customers.

The Commission must continue to exercise its exclusive jurisdiction under the law to ensure that it establishes "fair, just and reasonable rates."[13] In considering the costs to serve net-metering customers, the Commission should thoroughly examine all of the costs *and* benefits of net metering and ensure that utilities conduct a rigorous and transparent class cost-of-service

[12] KRS 278.466(5)
[13] KRS 278.040(2) and KRS 278.042(1).

study to support claims relating to the costs to serve net metering customers compared to non-net-metering customers. Indeed, the Commission has previously acknowledged it has "broad authority to consider all relevant factors presented during a rate proceeding, which would include evidence of the quantifiable benefits and costs of a net-metered system."[14]

The onus is on the utility to demonstrate that the proposed rate design and specific rates are fair, just and reasonable. A *de minimis* difference in the net costs to serve net-metering and non-net-metering customers, for example, would not be sufficient evidence to support a separate rate design or rates for net-metering customers. For example, a recent study examining the economic impacts of net metering to Kentucky customers in 2016 found the impact for a non-participating residential customer of Louisville Gas and Electric ("LG&E")/Kentucky Utilities (KU) was negligible, on the order of only 1 to 2 cents *per year.*[15] That result parallels the conclusion from national study by the U.S. Department of Energy's Lawrence Berkeley National Laboratory, which found, "For the vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future."[16] Likewise, if a utility eschews a robust examination of net metering impacts by deeming such a pursuit as too costly, the Commission should consider it as *prima facie* evidence that the impacts of net metering are too minimal in either direction to merit substantively changing rates. Given the very small number of customers participating in net metering currently, the Commission should exercise caution to avoid prematurely changing rates based on insufficient or minimal

[14] Kentucky Public Service Commission, Letter to Senator Brandon Smith Re: Senate Bill 100, House Floor Amendment 1, February 18, 2019.
[15] Tom FitzGerald, "The Economic Impact On Kentucky Residential Customers of Energy "Sold" to Utilities from Net Metering Solar Customers in 2016," Kentucky Resources Council, February 28, 2018.
[16] Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context," Lawrence Berkeley National Laboratory, January 2017, available at: http://eta-publications.lbl.gov/sites/default/files/lbnl-1007060.pdf

information. The Commission may find that additional data collection and study are needed to ensure that rates applied continue to be fair, just and reasonable.

The Process for Implementing the Net Metering Act

The Commission should take this opportunity to articulate a clear process for implementing the provisions established in the Net Metering Act prior to any utilities initiating a rate proceeding provided by KRS 278.466(3). This process should encourage transparency and data sharing, enable stakeholder participation, establish a robust methodology for informing any net metering rate reforms, promote consistent policies across all Kentucky utilities, and foster stability and predictability for consumers.

Implementing the Net Metering Act involves complex issues in determining an evidence-based compensation rate, rate design, and rates. KYSEIA emphasizes that there is also a lack of urgency in making these changes given the nascent solar market in the state combined with the "guardrails" established in the statute via the 1% cap and 45 kW limit on eligible system size. Therefore, KYSEIA urges the Commission to err on the side of establishing a more deliberative process, and avoid rushing to judgement on these matters and adopting a poorly vetted proposal that could destabilize the private solar market by changing a critical policy that already strictly limits participation and thereby minimizes potential impacts to non-participants.

Accordingly, KYSEIA recommends a two-step approach, addressed in turn below, to properly consider these important issues:

- <u>Step 1</u>: The Commission should conduct a thorough investigation into net metering in the Kentucky context and determine a methodology for establishing the dollar value of net electricity generated by an eligible net-metering customer over a billing period.

- Step 2A: Utilities should make proposals on implementing the Net Metering Act in their next electric base rate case filed on or after January 1, 2020, supported by specific information, and congruent with the methodology established by the Commission in Step 1.
- Step 2B: The Commission should evaluate utility proposals and stakeholder counter-proposals using traditional ratemaking principles for designing rates and taking into full consideration the benefits provided by net-metered systems to the grid, other customers, and the public more broadly.

As shown above, Step 2 involves separate phases where Phase A focuses on review of how a utility has applied the methodology and the results. This phase allows the Commission to reach a decision on the nature and magnitude of any problem that requires action. Phase B focuses on developing solutions that mitigate the problem from the suite of potential options available. We designate these as phases rather than separate steps because they may take place in a single regulatory proceeding and to some degree overlap one another. Despite this overlap, they represent the two distinct needs of (1) problem identification and (2) solution identification.

Step 1: A Single Investigation into Net Metering in Kentucky

First, the Commission should open a new proceeding to investigate net metering in the Kentucky context to create a standardized approach that all jurisdictional utilities should be required to adhere to in their individual ratemaking proceedings that implement the provisions of the Net Metering Act. Through this initial proceeding, or a concurrent proceeding, the Commission should also consider adopting changes to its Guidelines to conform with the Net Metering Act, as described above. The ultimate guidance provided by the Commission from a generic proceeding investigating net metering could help streamline future ratemaking proceedings, reduce redundancy of discussions on complex topics, efficiently use staff resources, and improve consistency across utilities in the ultimate outcomes, leading to more equitable results for customers. In contrast, multiple concurrent utility ratemaking proceedings separately adjudicating similar issues under the Net Metering Act could result in major differences across the utilities that could be detrimental to customers, inefficiently use Commission and staff resources, be costly for potential intervenors, and, ultimately, be costly to all ratepayers.

As part of its initial investigation, the Commission should consider having an independent study conducted on the benefits and costs of net metering in Kentucky. The Commission may be eligible to receive free technical assistance for such a study from nationally recognized independent experts, such as national laboratories (e.g., Lawrence Berkeley National Lab, National Renewable Energy Laboratory, and Pacific Northwest National Laboratory),[17] the U.S. Department of Energy Solar Energy Technologies Office,[18] and the Regulatory Assistance Project.[19] Numerous states have conducted such studies on net metering to better identify the impacts, both positive and negative, of net metering on customers, utilities, and society more generally before any changes to net metering were adopted.[20] Most studies have found that the value of retail rate net-metered solar exceeds the costs.[21] Comprehensively studying net metering

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[17] *See, e.g.*, Electricity Markets and Policy Group, "Technical Assistance to States," Lawrence Berkeley National Laboratory, available at: https://emp.lbl.gov/research/technical-assistance-states.

[18] U.S. Department of Energy, "State and Federal Finance and Solar Technical Assistance Programs," available at: https://www.energy.gov/eere/solar/state-and-federal-finance-and-solar-technical-assistance-programs.

[19] Regulatory Assistance Project, "About," available at: https://www.raponline.org/about/.

[20] *See, e.g.*, Mark Muro and Devashree Saha, "Rooftop Solar: Net Metering is a Net Benefit," Brookings Institution, 2016, available at https://www.brookings.edu/research/rooftop-solar-net-metering-is-a-net-benefit/#; ICF, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar," May 2018, available at: https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf?la=en&hash=1E4AD2DDBCE6B6D8ACC98A1182312E8FCF183D3F; *See generally*, SEIA, "Solar Cost Benefit Studies," *https://www.seia.org/initiatives/solar-cost-benefit-studies*.

[21] Gideon Weissman, Emma Searson, and Rob Sargent, "The True Value of Solar: Measuring the Benefits of Rooftop Solar Power," Environment America and the Frontier Group, July 2019.

in the specific Kentucky context is therefore a critical first step to assessing this policy and determining what, if any, substantive changes are warranted based on the evidence.

KYSEIA agrees with the Commission[22] that each utility in the Commonwealth has "unique characteristics," with varying costs to serve their customers, and therefore specific net metering compensation rates and rate design will be determined in individual utility proceedings. However, an initial proceeding to examine net metering issues applicable to all utilities would be useful to reduce administrative burden on the Commission and minimize the costs of stakeholders participation, while resulting in a common set of principles, methodologies, and data transparency and reporting standards. It would also help build the record for the Commission to consider when examining a net metering compensation rate and rate design proposals in individual rate proceedings.

<u>Step 2A: Utilities Proposals in Rate Proceedings</u>

On or after January 1, 2020, utilities can make specific proposals for implementing a compensation rate under net metering. The Commission should require that a utility provide sufficient evidence in their individual ratemaking proceedings to prove that a subsidy or cost-shift exists if the utility is requesting a reduction in the existing effective compensation rate from the retail rate to an alternative under KRS 278.465(4)(a). Likewise, if parties demonstrate that net metering results in a societal net benefit for Kentuckians, the Commission should consider *increasing* the compensation rate above the implied retail rate compensation current in place via 1:1 netting to correct any subsidy provided by net metering customers to non-net-metering customers. A comprehensive cost-benefit analysis and cost-of-service study will therefore be key to developing the evidentiary record and necessary to support any changes to net metering.

[22] Kentucky Public Service Commission, Letter to Senator Brandon Smith Re: Senate Bill 100, House Floor Amendment 1, February 18, 2019.

The Commission should strive to ensure that all interested stakeholders can participate fully in these proceedings. This must include allowing solar parties the opportunity to intervene as full participants in any relevant proceedings before the Commission, including any additional investigation into the implementation of the Net Metering Act, as well as through the individual utility ratemaking proceedings. It is critical that solar industry participants be afforded the opportunity to rebut any assertions made by utilities or other parties with respect to important distributed generation policies like net metering, which materially impact their current and future business in the Commonwealth.

Step 2B: Commission Consideration of Policy Adoption

If the Commission finds that net metering compensation or rate reforms are necessary based on compelling evidence demonstrating that existing rates to net metering customers are not fair, just, and reasonable, it should employ traditional ratemaking principles in designing compensation rates and rate design for new net metering customers. The Commission should consider any changes to the net metering compensation rate simultaneously with any proposals to change the rate design and rates applicable to new net metering customers under KRS 278.466(5). The burden of proof for justifying all changes to the compensation rate or rate design applicable to net metering customers should be on the utility, as it would be with any other utility rate proposal.

If the Commission determines that a substantial subsidy or cost-shift exists between non-net-metering customers and net-metering customers, it should consider reasonable reforms to address it -- but avoid drastic action that could destabilize this growing industry. For example, moving from retail rate compensation to a pure avoided cost compensation could result in a roughly 70% reduction in the effective compensation rate for excess generation,[23] not including any changes to rate design that could further erode the economics of solar, which could be a cataclysmic shock to the industry. Even in states with substantially higher amounts of solar deployment, policymakers have generally avoided such a drastic change in favor of policies upholding the principle of gradualism.

For example, lawmakers in Nevada established a second generation net metering framework for systems sized 25 kW or less in which customers can continue to net their consumption and generation within a month, and the compensation rate for net excess generation over a month gradually declines as the utility reaches successive milestones of additional installed net-metering capacity.[24] Monthly net excess generation produced by these systems is compensated equal to a percentage of the rate the net-metered customer would have paid for a kWh of electricity supplied by the utility at the time the net-metered customer fed the kWh of excess electricity back to the utility, beginning with 95% and phasing down eventually to 75%.

Nevada provides one example of an approach to addressing concerns about subsidization in balance with consideration of the scale of the issue, impacts on the industry, certainty for customers, and generally accepted ratemaking principles. We look forward to a more detailed discussion of all potential options with the Commission, but emphasize that defining the nature and magnitude of the problem, if any, is a pre-requisite to crafting effective solutions.

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[23] *E.g.*, Reducing effective compensation for net-metered customers in LG&E's service territory from the Energy Charge of $0.09253/kWh for Residential Service to the Rate B: Non-Time Differentiated Rate of $0.02758/kWh under its Small Capacity Cogeneration and Small Power Production Qualifying Facilities tariff would be a 70.2% decrease (excluding any additional payments, if any, for capacity).

[24] Nevada Assembly Bill 405 of 2017.

Principles for Rate Design and Net Metering Reforms

Quantifying Benefit and Cost Categories

The Commission has broad authority to consider both the benefits and the costs of net metering systems in utility rate proceedings.[25] Especially when considering the benefits of net metering systems, the Commission should ensure all relevant benefits categories are included for consideration and appropriately quantified.[26] Moreover, all components of the net metering cost-benefit equation should be evaluated collectively, including export compensation, payment of distribution demand costs, and payment of production demand costs. Any net benefit (e.g., lower energy-related costs compared to non-net-metering customers) should be able to offset net costs (e.g., underpayments of distribution capacity costs) in this analysis. The total net system and societal impacts should be collectively evaluated to determine rates that are fair, just and reasonable.

Figures 1 and 2, respectively, depict the range of benefit and cost categories previously considered in net metering and distributed solar valuation studies and the magnitude of the quantified benefits and costs. It is important to note that while the range of benefits for distributed solar shares some overlap with utility-scale solar (e.g., avoided environmental costs), the two are not identical. For example, additional benefits provided by net-metered solar systems that are not necessarily provided by utility-scale solar located geographically separate from the load served include avoided transmission capacity, avoided distribution capacity, and avoided

[25] *See* Kentucky Public Service Commission, Letter to Senator Brandon Smith Re: Senate Bill 100, House Floor Amendment 1, February 18, 2019, citing *Kentucky Public Service Com'n v. Commonwealth ex rel. Conway*, 324 S.W.3d 373, 383 (Ky. 2010) finding that the Commission has "plenary authority to regulate and investigate utilities and to ensure that rates charged are fair, just, and reasonable under KRS 278.030 and KRS 278.040."

[26] *See, e.g.*, Jason Keyes and Karl Rabago, "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," Interstate Renewable Energy Council, October 2013.

line losses. Accordingly, it is appropriate that the compensation rate provided for generation by distributed solar reflects these additional benefits provided.

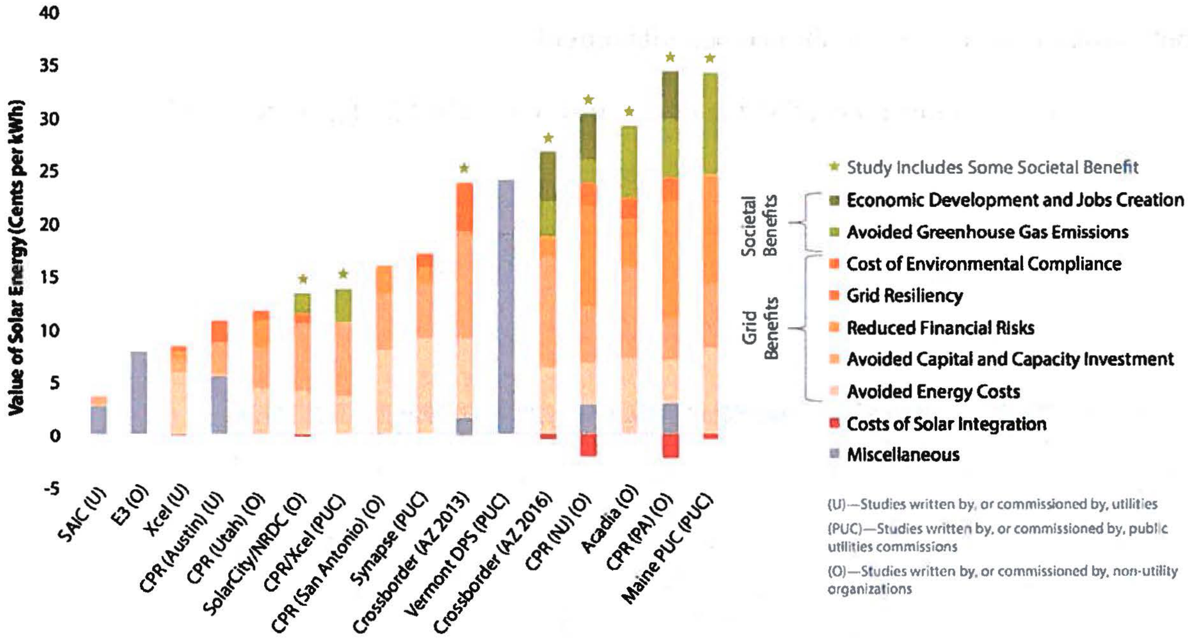
Figure 1: Comparison of Value Categories Across Net Metering Studies[27]

		Arkansas - Crossborder Energy 2017	Nevada - E3 2016	Louisiana - Acadian Consulting Group 2015	South Carolina - E3 2015	Mississippi - Synapse 2014	Vermont - VT Public Service Dept 2014	Washington DC - Synapse 2017	Georgia - Southern Company 2017	Hawaii - Clean Power Research 2015	Maine - Clean Power Research 2015	Oregon - Clean Power Research 2015	Minnesota - Clean Power Research 2014	Utah - Clean Power Research 2014	New York - BCA Framework 2016 + VDER Phase One	California - LNBA Framework 2016	Total
Utility System Impacts																	
G	Avoided Energy Generation	●	●	●	●	●	●	●	○	○	●	○	○	●	◌	○	15
	Avoided Generation Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	◌	○	15
	Avoided Environmental Compliance	●	●			•	●	●	◌		•	○		●		◌	10
	Fuel Hedging	●			●	●		●		○	●	○	•	●			9
	Market Price Response	●					●	●		○	●				○		6
	Ancillary Services		●		●	○		○	○	○					○	○	8
T	Avoided Transmission Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	◌	○	15
	Avoided Line Losses	●	●		●	●	•	●	○			○		•	◌	○	11
D	Avoided Distribution Capacity	●	●	•	•	•	●	●		○	○	○	○	•	◌	○	14
	Avoided Resiliency & Reliability	○				○		○							○	○	5
	Distribution O&M			●					○						○	○	4
	Distribution Voltage and Power Quality									○	○	○	○		○	○	6
C	Integration Costs	●	●	●	●	○		●	○	○	●	○	○		○	○	13
	Lost Utility Revenues	●	●	●	●	●	●								○		7
	Program and Administrative Costs		●	●	●	●	●	○							○		7
Societal Impacts																	
S	Avoided Cost of Carbon	●					●	●		○	●		○		◌	○	8
	Other Avoided Environmental Costs	●	●			○		○		○	●		○		○	○	9
	Local Economic Benefit	●				○		○									3

Included	●
Included/represented in another category	•
Discussed but not monetized/quantified	○
For NY, included in VDER Phase One	◌

27 ICF, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar," May 2018, Figure 3, p. 19.

Figure 2: Quantification of Benefits Categories in Value of Solar Studies[28]



Cost of Utility Solar Investments

The evaluations depicted in the figures above reflect a bottom-up approach to determining the costs avoided by distributed solar generation. However, another way to view the costs and benefits distributed solar is in reference to the costs incurred by utilities for utility-owned systems, which in turn are passed through to their customers. The virtue of this alternative frame of evaluation is that it places the costs of distributed solar to other customers, if any, on par with the costs those same customers pay for utility-owned assets. It holds utility investments and customer investments to the same standard of evaluation, which is both logical and fair because any net costs associated with either affect ratepayers in the same way.

In practice, this translates to two outcomes. First, the cost of utility-owned solar is a proxy for what has been determined to be fair cost to ratepayers for a large, centralized solar facility that delivers only a portion of the value provided by distributed solar facilities that serve

[28] Gideon Weissman, Emma Searson, and Rob Sargent, "The True Value of Solar: Measuring the Benefits of Rooftop Solar Power," Environment America and the Frontier Group, July 2019.

load at the point of consumption. Second, the assumptions and methodology used in evaluating proposals to build utility-owned assets have applicability to the Commission's evaluation of the costs and benefits of distributed solar. For instance, this should include consideration of the future costs of carbon emission regulation as well as future costs of coal combustion residual remediation.

For example, Duke Energy Kentucky owns and operates a total of 6.8 MW of solar at the Crittenden and Walton sites.[29] LG&E and KU jointly own and operate the 10 MW E.W. Brown solar facility. Both sets of facilities serve as proxies of a reasonable cost of solar for Kentucky ratepayers. Fairness to distributed solar owners dictates that their compensation not be less than what the utilities earn as solar generation owners up to the respective size of their portfolios. In fact, compensation to distributed solar owners should be higher because small distribution-connected facilities avoid line losses and produce avoided transmission and distribution costs.

KYSEIA does not possess cost information for the Duke facilities. For KU and LG&E, while the actual revenue requirements are redacted from the utilities' filings, the reported costs total $36 million for the Brown facility. With the benefit of the 30% federal investment tax credit, the net cost of the facility totals $25.2 million.[30] LG&E and KU reported production of 17,448 MWh from the facility in 2017.[31] A simple calculation of the cost of energy from the facility indicates the cost of energy production from this facility is close to the utilities' retail rates (and significantly above the utilities' avoided cost rates). Meanwhile this facility is significantly larger than the total amount of net-metered capacity installed on their distribution networks. This amount could serve as a minimum compensation benchmark for a similar amount

[29] https://news.duke-energy.com/releases/duke-energy-unveils-plans-for-its-first-solar-power-plants-in-kentucky
[30] KYPSC Order. https://psc.ky.gov/pscscf/2014%20Cases/2014-00002//20141219_PSC_ORDER.pdf
[31] https://lge-ku.com/live-solar-generation/historical-data

of customer-owned solar in the LG&E and KU territories, to which adders for other localized values should be added to fairly account for the benefits of serving load directly at the point of consumption with clean generation.

Ratemaking issues

The Commission should consider the following ratemaking principles as it implements the Net Metering Act.

1) **Cost causation:** The Commission should ensure that electric rates reflect the net costs actually caused by the customer who pays them. In determining the net costs caused by a specific group of customers, such as net metering customers, the Commission should holistically examine the customer class's usage. For example, net metering customers often provide a benefit to the grid by exporting power during periods of high peak demand on hot summer afternoons, offsetting expensive peak generation or market purchases by suppliers.
2) **Stability or gradualism:** The Commission should continue to adhere to the ratemaking principle of gradualism, which provides that stable rates with gradual changes are preferable to sudden, dramatic shifts that could have adverse impacts on customers. For example, utilities in a rate case will often limit the requested rate increase to a specific customer class even if their class cost-of-service study indicates the existing rates for the customer class are not providing full cost recovery of that customer class's cost of service. In applying the Net Metering Act, the Commission should strive to ensure that rate changes to net-metering customers reflect this principle. For example, the

Commission should exercise caution with respect to demand rates and high fixed charges, which are new and unfamiliar rate structures for residential customers.[32]

3) **Simplicity, ease of understanding, and customer acceptance:** Rates should be understandable by customers and provide them options to respond to price signals. Overly complex rates and rates that have new and confusing concepts should be avoided in favor of alternatives. For example, demand charges are unfamiliar to most residential customers and a dramatic departure from how they have been charged for electricity for the past century.[33] High fixed charges, in addition to deviating from traditional cost-based rate design principles, are also unlikely to be acceptable to customers because they reduce a customer's ability to control their bill.

4) **Efficient use of service:** Rates should encourage efficiency and discourage wastefulness. In the present context, rates should be designed to provide effective price signals to customers and promote beneficial behaviors, such as encouraging energy efficiency. In contrast, rate designs that give customers little control over their electric bills, such as high fixed charges or capacity charges based on a net-metered system's size, should be avoided. Likewise, noncoincident demand charges based on a customer's peak usage will result in a "mismatch between the system coincident peak costs used to set prices and the actual costs incurred at the time of the customer's noncoincident peak," and should be avoided because it provides an inaccurate price signal to customers.[34]

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[32] Jim Lazar and Wilson Gonzalez, "Smart Rate Design for a Smart Future," Regulatory Assistance Project, 2015, available at: http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf

[33] *Id.*

[34] *Id.* at p. 37.

Numerous resources have been published on establishing compensation rates and rate design for distributed generation customers that can serve as a useful reference to the Commission.[35]

Categories of Net Metering Customers

KYSEIA recommends that the Commission provide clarification on how the Net Metering Act impacts various categories of net metering customers, and uniformly apply its instruction across all jurisdictional utilities. KYSEIA recommends the Commission consider three categories of net-metering customers and make the following determinations with respect to each category:

1) **Existing Net Metering Customers:** The Commission should clarify that "Existing Net Metering Customers" include all customers submitting a net metering application up through the date of the Commission's final order in the applicable utility's rate proceeding that establishes the net metering compensation rate and rate design applicable to "Net Metering 2.0 Customers." Net metering customers are expressly grandfathered for a period of 25 years under their existing net metering tariff and identical rate design to non-net-metering customers. The Commission should direct utilities to provide Existing Net Metering Customers written proof of their status as grandfathered customers so that there is clear documentation on the system's eligibility. This will also provide needed clarity if the Existing Net Metering Customer sells or conveys their premise to a new

[35] *Id. See also*, Solar Energy Industries Association et al., "Principles for the Evolution of Net Energy Metering and Rate Design," May 2017, available at: https://www.seia.org/sites/default/files/NEM%20Future%20Principles_Final_6-7-17.pdf; AC Orrell, JS Homer, and Y Tang, "Distributed Generation Valuation and Compensation," Pacific Northwest National Laboratory, February 2018, available at: https://www.districtenergy.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=0103ebf1-2ac9-7285-b49d-e615368725b2&forceDialog=0; National Association of Regulatory Commissioners, "NARUC Manual on Distributed Energy Resources Rate Design and Compensation," 2016, available at: https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

customer during their grandfathering period.[36] The Commission should also elaborate on the conditions under which a net-metering customer can expand their system in the future while still maintaining their grandfathered status. For example, a grandfathered net-metering customer should be able to maintain their grandfathered status if they subsequently add an energy storage system, replace components of an existing system (e.g., a solar panel that needs replacement due to a manufacturing defect), or install additional solar panels such that their system is designed to meet up to the customer's annual electricity usage.

2) **Net Metering "2.0" Customers:** As used here, a Net Metering "2.0" Customer refers to a customer that submits a net metering application under new compensation rates and tariffs adopted pursuant to the Net Metering Act based on a final order in a utility's rate proceeding that is initiated on or after January 1, 2020. KYSEIA interprets the Net Metering Act to provide that these new tariffs and rates should only apply to a customer who submits a new net metering application *after* the Commission issues its order in their utility's rate proceeding that establishes the net metering tariff and rate design provided by the Net Metering Act. Until that point in time, a customer that submits a net metering application should continue to be eligible for the current net metering tariffs and rates for the full 25-year grandfathering period.

3) **Post-Net Metering Customers:** KYSEIA also recommends that the Commission consider establishing a process now for determining the rates and tariffs applicable to a customer who installs generating equipment after their utility reaches its 1% cap. While net metering deployment is currently limited, the Commission should not wait to

[36] KRS 278.466(6).

establish such a process for developing a future policy until after a utility reaches its 1% cap, which could result in a "cliff" when a utility reaches its cap if no replacement policy is in place. Such a scenario could result in market upheaval and trigger job losses. The Commission is empowered to establish such a policy through its exclusive jurisdiction over utility rates and its mandate to set fair, just and reasonable rates.

Market Issues

KYSEIA recommends the Commission consider how its policy decisions with respect to the Net Metering Act could impact the solar industry, its employees, and its customers. To encourage the continued, sustained growth of beneficial distributed generation and the energy jobs these technologies provide to Kentuckians, KYSEIA urges the Commission to specifically consider the following principles when implementing changes to its long-established policies and rate design applicable to customers with generating equipment:

- **Predictability:** Solar companies and potential customers should have a clear understanding of how and when policies could change, which customers will be impacted, and how they can participate in discussions regarding possible changes. Like a utility investing in a power plant, a customer investing in a net-metered system should have sufficient predictability in their compensation rate and rate design to be able to reasonably forecast their costs and revenues when making their investment decisions without unreasonable risks of major future changes that could materially impact the payback of such an investment. Moreover, customers must have access to the data necessary to predict the payback of their investment. As an example, net metering customers faced with demand charges would be unable to predict the value of solar energy without historic demand interval data from their utility – data that is not currently collected by utilities and available to review by most residential customers. The Commission should avoid changes that are sudden, apply retroactively, or are a dramatic departure from its previous policies and ratemaking.

- **Stability:** The Commission should ensure that any changes to compensation and rate design are gradual, reasonable, and based on the evidence. Any changes adopted to net metering compensation and rate design should reflect the principle of gradualism, such as by phasing-in changes over time, implementing policies that are understandable and acceptable to consumers, and commensurate with the overall benefits and costs identified. The Commission should avoid actions that could fundamentally destabilize the market.
- **Consistency:** A net metering customer from one utility should be treated like a similarly situated net metering customer of another utility. The Commission should strive to maintain a congruent policy for distributed generation across jurisdictional utilities and avoid a balkanized patchwork of policies that could result in the inequitable treatment of customers based on their utility provider, notwithstanding the unique considerations that will apply to each utility.
- **Fair accounting of benefits provided:** The Commission should ensure that all benefits of net metering systems are fully accounted for, quantified, and included in any analysis on which it bases its decisions. Utilities should be directed to provide such a transparent and comprehensive analysis when implementing the Net Metering Act in their rate proceedings. A utility's failure to seriously attempt to measure certain benefit categories should not result in the utility being permitted to assign no value to a benefits category.

<u>National Perspective</u>

Finally, while the Commission should focus on acting in the public interest for Kentuckians, a nuanced examination of other state policies can help inform its perspective. Retail rate net metering, which provides bill credits to customers for the kWh they export to the grid during a month on a 1:1 basis, is currently one of the most widely deployed state energy policies in America related to distributed solar. Currently, 39 states offer retail rate net metering for small distributed generation facilities. Retail rate net metering has been a critical component to the growth of distributed solar, resulting in total U.S. solar installations eclipsing 2 million in 2019.[37] Retail rate net metering has also been key to the success of the national solar industry, which now boasts 242,000 jobs and billions of dollars of investment.[38]

The success of retail rate net metering is attributable to several characteristics. Perhaps most importantly, retail rate net metering provides a reasonable compensation rate to the customer for the electricity generated by the net-metered system and delivered to the grid. In addition, the simplicity and intuitiveness of retail rate net metering have been key to gaining consumer acceptance by allowing customers to easily understand how electricity generated by a generating facility will be valued, and to calculate the payback period on their investment.

As solar adoption has increased in recent years, some states have considered modifications to their net metering policies. Importantly, policymakers in most states that have conducted robust investigations into net metering have decided to maintain the fundamentals of net metering, such as maintaining the practice of netting kWh exported to the grid during a month with kWh imported from the grid and consumed by the customer. Notably, some of the

[37] Solar Energy Industries Association, "United States Surpasses 2 Million Solar Installations," May 9, 2019, available at https://www.seia.org/news/united-states-surpasses-2-million-solar-installations.
[38] The Solar Foundation, "National Solar Jobs Census 2018," available at https://www.thesolarfoundation.org/national/.

changes states have made to net metering in recent years have been to strengthen and expand net metering.[39] While some other states that have reduced compensation for net metering exports, many of these examples have occurred in places with *very high levels* of distributed solar. At high solar penetration levels, a "duck curve" has been shown to reduce net midday demand, depressing the value of midday energy. However, such an effect depends on local conditions, and solar penetration far in excess of what Kentucky has experienced.

Examples of net metering reforms that other jurisdictions with higher amounts of solar net metering are implementing include maintaining "netting" within a monthly billing period and slowly stepping down the compensation rate that carries over month-to-month (e.g., Nevada), shifting new net metering customers to time-of-use rates (e.g., California), or applying a minimum monthly bill to customers (e.g., Hawaii). In states like Nevada and Maine where regulators initially failed to heed the principle of gradualism when adopting changes to net metering policies, reforms to net metering were ultimately reversed after significant job losses, consumer complaints, and political pushback.

Finally, to put the Commonwealth into context, as of June 2019, Kentucky's four investor-owned utilities had installed only 6.7 MW of net-metered capacity in their service areas, a modest amount compared to most other state markets.[40] For comparison, the three investor-owned utilities in Hawaii have 461.5 MW,[41] or nearly 69 times as much net-metered capacity, despite having a population that is roughly one-third the size of Kentucky's. States with large amounts of net-metering capacity with mature solar markets like Hawaii will have vastly

[39] *E.g., see* South Carolina H 3659, enacted May 16, 2019, extended the availability of retail-rate net metering through June 1, 2021 (several utilities had reached or were close to reaching their percentage-based caps at the time); Maine HP 77 and SP 565, enacted April 2, 2019, and June 26, 2019, respectively, restored retail-rate net metering and expanded the eligible system size; Connecticut House Bill 5002, enacted June, 28, 2019, extended the eligibility of residential net metering for approximately two years.
[40] U.S. Energy Information Administration, Form EIA-826M, June 2019.
[41] *Id.*

different considerations -- and resulting policy prescriptions -- than states with nascent solar markets, such as in Kentucky today.

KYSEIA recommends the Commission follow the lead of states that have taken a deliberative, evidence-based approach in evaluating net metering. These states have generally maintained "netting" within the monthly billing period, and considered modest changes to the compensation rate or rate design only after significant levels (i.e., well in excess of Kentucky's 1% cap) of net-metering were in place. The compensation rate for monthly net excess generation should therefore be maintained at the full retail rate, and existing rate designs kept constant, with consideration of changes to these policies only occurring after a comprehensive cost-benefit analysis has been conducted. Along with such an analysis, a utility should demonstrate in a cost-of-service study in a rate proceeding that net metering is having a significant impact. Both a cost-benefit analysis and a cost-of-service study are common practices that other states and utilities have followed when considering net metering changes. If the Commission then determines a significant impact exists and should be addressed, it should adhere to traditional ratemaking principles, such as gradualism, in making changes.

A good example of the approach just described is adopting a gradual adjustment in the compensation rate for monthly net excess generation as a utility reaches successively higher thresholds of installed net-metering capacity, as has been done in Nevada for net-metered systems up to 25 kW. Significant changes to rate design are likely to be unwarranted and unreasonable in the near-to-mid-term given the limited number of net-metering customers, so KYSEIA recommends the Commission avoid unpopular or untested changes that could have unintended consequences. Based on the statutory 1% cap in place in Kentucky, a significant impact is unlikely to occur until after a utility reaches its cap, so many of these discussions may be more appropriate for consideration when the Commission considers a policy for Post-Net Metering customers, rather than for Net Metering 2.0 customers.

Conclusion

KYSEIA appreciates the opportunity to provide these comments for the Commission's consideration. KYSEIA looks forward to providing additional, more detailed comments in this or additional proceedings, and in particular the utility's forthcoming rate proceedings in which they will implement the provisions of the Net Metering Act. KYSEIA is also attaching to its comments here two resources cited above on rate design and net metering cost-benefit analyses as references for the Commission.

Respectfully submitted,

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EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future.* 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?.* September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments.* July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts.* December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues.* July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina;* and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On.* 2013. For Keyes, Fox & Wiedman.
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- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.
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- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues.* 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

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EDUCATION

School of Public and Environmental Affairs (SPEA), Indiana University, Bloomington, Indiana
Ph.D. coursework (three semesters, 2012-2013), Public Affairs (Environmental Policy & Policy Analysis)
M.S. in Environmental Science, 2012, *Top GPA Award*
Master of Public Affairs, 2012, *Top GPA Award*, Concentration: Environmental Policy

University of Oxford, Oxford, United Kingdom
Six-week graduate school program on climate change governance and environmental regulation, 2011

Indiana University, Bloomington, Indiana
B.S., Psychology, 2009, with *Highest Distinction*, Honors Notation, and Phi Beta Kappa honors
Certificate, Liberal Arts and Management Program (honors-level interdisciplinary business program)

RELEVANT EXPERIENCE

Senior Policy Research Analyst, January 2019 - Present
Policy Research Analyst, May 2018 – December 2018
Independent Contractor, July 2017-April 2018
Policy Research Analyst, March 2016 – June 2017
EQ Research LLC, Cary, North Carolina and Indianapolis, Indiana

- Manage EQ Research's regulatory tracking services on U.S. electric utility rate cases, including reviewing and summarizing 100+ electric rate cases, managing EQ Research's rate case database, monitoring anticipated rate cases, and composing bi-weekly research updates to clients on electric utility rate developments.
- Provide consulting and data services on state clean energy policy to businesses, government entities, and organizations.
- Actively research, track, and analyze hundreds of Midwestern state energy bills and regulatory proceedings on utility regulation, renewable energy, energy storage, and electric vehicles for EQ Research's policy tracking services.
- Provide policy research and analysis and regulatory monitoring, engagement support, and compliance assistance to Community Choice Aggregation programs, which allow local governments in California to procure clean power and electricity, while partnering with the existing electric utility for transmission and delivery services.
- Conduct clean energy policy and market research; analyze data; and author reports, memos, and other deliverables responsive to client needs.

Researcher, August 2017 – January 2018
Earth Island Institute, Indianapolis, Indiana

- Developed, researched, and authored more than 100 wiki pages on existing and planned coal, LNG terminals, and oil and gas pipelines for the CoalSwarm and FrackSwarm projects, which provide clearinghouses on global coal and natural gas infrastructure projects.

Policy Analyst, June 2014 – March 2016
North Carolina Clean Energy Technology Center, N.C. State University, Raleigh, North Carolina

- Co-created, managed, and served as lead author and editor for *The 50 States of Solar*, a quarterly report series that comprehensively tracks state regulatory and legislative distributed solar policy developments.

- Led informational solar workshops and provided technical assistance to local governments, including solar financial and policy analysis, reports, case studies, fact sheets, and public-facing solar guides as part of the U.S. Department of Energy (DOE) SunShot Solar Outreach Partnership.
- Created an internal database for tracking solar regulatory and legislative policy proposals, and queried and analyzed the data to answer policy questions, identify trends, and develop reports.
- Tracked and updated summaries of more than 500 utility, local, state, and federal policies and incentives for the nationally recognized Database of State Incentives for Renewables and Efficiency (DSIRE) project.

Doctoral Research Analyst in Environmental Policy, August 2012 – December 2013
SPEA, Indiana University, Bloomington, Indiana

- Collaborated with Prof. Shahzeen Attari to answer research questions related to energy and water consumption and conservation.
- Lead-authored peer-reviewed research on the most effective actions U.S. households can take to voluntarily conserve water use.

Climate Corps Fellow, June 2012 – August 2012
Environmental Defense Fund, Cary, North Carolina

- Quantitatively benchmarked the energy efficiency of 90+ North Carolina fire stations and authored case studies highlighting the most effective local fire station energy efficiency initiatives.
- Evaluated local government energy efficiency and clean energy projects to identify cost-effective solutions.

Sustainability Intern, October 2011 – April 2012
Office of Sustainability, Indiana University, Bloomington, Indiana

- Analyzed Indiana University's energy use data to determine emissions sources and trends.
- Collected and analyzed quantitative and qualitative sustainability metrics for Indiana University to submit to external sustainability rating organizations.
- Benchmarked the university's sustainability progress relative to peer institutions.

SELECT ARTICLES, REPORTS & PUBLICATIONS

- Inskeep, B. **Four Flavors of Grid Modernization in the Midwest.** April 12, 2019. Published by EQ Research.
- Inskeep, B. **States Charting Paths to 100% Targets.** March 15, 2019. Published by EQ Research.
- Makhyoun, M. and B. Inskeep, **Ten Things to Know about CCAs in California.** February 13, 2019. Published by EQ Research.
- Inskeep, B. **EQ Research's Q4 2018 GRC [General Rate Case] Update.** January 15, 2019. Published by EQ Research.
- Inskeep, B. **EQ Research's Q3 2018 GRC Update.** October 16, 2018. Published by EQ Research.
- Argetsinger, B. and B. Inskeep. **Standards and Requirements for Solar Equipment, Installation, and Licensing and Certification.** January 2017. Published by the Clean Energy States Alliance.
- Barnes, C., J. Barnes, B. Elder, and B. Inskeep. **Comparing Utility Interconnection Timelines for Small-Scale Solar PV, 2nd Edition.** October 2016. Published by EQ Research.
- Barnes, J., B. Inskeep, and C. Barnes [with Synapse Energy Economics]. **Envisioning Pennsylvania's Energy Future.** October 2016. Published by the Delaware Riverkeeper Network.

- Inskeep, B., et al. **The 50 States of Solar.** February 2015, April 2015, August 2015, November 2015, February 2016. Lead author & editor for five quarterly editions. Published by the NC Clean Energy Technology Center.
- Inskeep, B., et al. **Utility Ownership of Rooftop Solar PV.** November 2015. Published by U.S. DOE SunShot Solar Outreach Partnership.
- Inskeep, B., and A. Proudlove. **Renewable Cities: Case Studies.** Published by U.S. DOE SunShot Solar Outreach Partnership, October 2015.
- Inskeep, B., K. Daniel, and A. Proudlove. **Delaware Goes Solar: A Guide for Residential Customers.** June 2015. Published by U.S. DOE SunShot Solar Outreach Partnership.
- Inskeep, B., and A. Proudlove. **Homeowner's Guide to the Federal Investment Tax Credit for Solar PV.** Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Inskeep, B., and A. Proudlove. **Commercial Guide to the Federal Investment Tax Credit for Solar PV**. Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Daniel, K., B. Inskeep, and A. Proudlove. **Understanding Sales Tax Incentives for Solar Energy Systems.** Published by U.S. DOE SunShot Solar Outreach Partnership, March 2015.
- Inskeep, B. and A. Shrestha. **Comparing Subsidies for Conventional and Renewable Energy.** Published by NC Clean Energy Technology Center, March 2015.
- Inskeep, B., K. Daniel, and A. Proudlove. **Solar on Multi-Unit Buildings: Policy and Financing Options to Address Split Incentives.** Published by U.S. DOE SunShot Solar Outreach Partnership, February 2015.
- Daniel, K., B. Inskeep, et al. **In-State RPS Requirements**. Published by NC Clean Energy Technology Center, November 2014.
- Inskeep, B. and S. Attari. **The Water Short List: The Most Effective Actions U.S. Households Can Take to Curb Water Use.** *Environment: Science and Policy for Sustainable Development* 56, No. 4, 2014: 4-15.

PARTICIPATION AT PUCs & UTILITY STAKEHOLDER MEETINGS

- **Assisting in drafting comments, testimony, and supporting research and analysis,** *March 2016 – Present,* Topic areas included net metering, rate design, utility cost recovery, grid modernization, integrated resource planning.
- **Indiana Utility Regulatory Commission,** *September 2019,* Testified as a ratepayer at Public Hearing against IPL's proposed $1.2 billion grid modernization plan that would raise customer bills by $10.50.
- **Vectren Stakeholder Meeting,** *August 2019,* Vectren Integrated Resource Plan Stakeholder Meeting #1, Participated on behalf of Citizens Action Coalition as a Board Member.
- **Indiana Utility Regulatory Commission,** *May 2018,* Testified as a ratepayer at Public Hearing against IPL's proposal in its rate case to increase it fixed customer charge from $17 to $27, which would have been the highest fixed charge among investor-owned utilities in the nation.

PRESENTATIONS

- **Planning for the Solar Revolution**
  Poster presentation at Solar Power International, Salt Lake City, Utah, September 2019
- **Policy Considerations for Accelerating the U.S. Clean Energy Transition**

Invited by Prof. Sanya Carley to give lecture to graduate energy economics class at Indiana University School of Public and Environmental Affairs, Bloomington, Indiana, March 2019.

- **Solar Equipment, Installation, and Licensing & Certification: A Guide for States and Municipalities**
  Webinar presentation on report findings sponsored by the Clean Energy States Alliance, February 2017.
- **Distributed Solar PV Trends in Net Metering and Rate Design**
  Invited to give presentation at Solar Asset Management Conference, San Francisco, California, March 2016.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at Kerr-Tar Councils of Government, Henderson, North Carolina, November 20, 2015.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at NC Clean Energy Technology Center, Raleigh, North Carolina, November 19, 2015.
- **North Carolina in Context: Regional and National Trends**.
  Panel presentation at University of North Carolina Clean Energy Forum, Chapel Hill, North Carolina, September 2015.
- **Net Metering Updates**.
  Panel presentation at Solar Power International, Anaheim, California, September 2015.
- **The 50 States of Solar: Trends in Net Metering Policies and Rate Design.**
  Poster presentation at Solar Power International, Anaheim, California, September 2015.
- **Net Metering and Rate Design Trends**.
  Panel presentation at Intersolar North America, San Francisco, California, July 2015.
- **Distributed Disruption: The Economics and Policy Behind the Distributed Solar PV Boom**.
  Invited by Prof. Sanya Carley to give lecture to graduate energy economics class at Indiana University School of Public and Environmental Affairs, Bloomington, Indiana, April 2015.
- **Solar Powering Your Community: Addressing Soft Costs and Barriers**
  Led all-day local government solar workshop at Grand Valley State University's Michigan Alternative and Renewable Energy Center, Muskegon, Michigan, May 5, 2015.
- **The Water Short List: The Most Effective Actions to Reduce Household Water Consumption**
  Poster presentation at the International School on Energy Systems, Seeon, Germany, September 2014.
- **More Than a Drop in the Bucket: How U.S. Households Can Reduce Water Consumption by 70%.**
  Presentation at the 13th Annual Association for SPEA Ph.D. Students Conference, Bloomington, IN, March, 2013.

AWARDS & HONORS

- 2013-2014 Sustainability Research Development Grant
- 2012 Top GPA Award, M.S. in Environmental Science
- 2012 Top GPA Award, Masters in Public Affairs
- 2011 SPEA Merit Award

- 2006 Liberal Arts and Management Program Writing Excellence Award
- 2005-2009 Indiana University Honors Recognition Scholarship

VOLUNTEER SERVICE

Citizens Action Coalition, Indiana, February 2019 – present
Board Member

Solar Power International, 2014 – 2016
Education Committee Member for the largest solar conference in America

SPEA, Prof. Evan Ringquist Research Team, Bloomington, Indiana, 2011
Volunteer Researcher on Environmental Justice

The Nature Conservancy, Indianapolis, Indiana, 2010
Volunteer Researcher on Economic Development and Community Green Space

Worldwide Opportunities on Organic Farms, Moab, Utah, July 2008
Volunteer Farmer in Sustainable Agriculture

Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar

May 2018

Prepared for:
The U.S. Department of Energy

Submitted by:
ICF

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DISCLAIMER

Executive Summary

Net energy metering (NEM) has helped fuel the adoption of distributed solar across the country. As deployment of solar and other distributed energy resources (DERs) continues to grow, regulators and stakeholders are investigating issues such as how current NEM rate structures reflect the costs and benefits of distributed solar, whether different tariff mechanisms could better align compensation with the value of distributed solar, and how a broader valuation framework could facilitate the maximization of system benefits from DER adoption.

Numerous cost-benefit studies related to NEM have been conducted by a variety of entities, and these studies have often produced widely differing results. This meta-analysis examines a geographically diverse and broad selection of studies from 15 States that explore the costs and benefits of distributed solar. It is not meant to be comprehensive, but rather reviews a representative sample of the most recently published material. The studies represent an evolution of approaches to solar value analysis, and, while the selection captures different approaches and methodologies, every study either identifies or quantifies a defined set of cost-benefit categories related to net metering or distributed solar.

Eighteen categories that could represent positive values (avoided costs) or negative values (incremental costs) are considered in two or more of the studies. Overall, studies tend to converge on at least three value categories: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Common components were more likely to affect the bulk system, have a large net impact, and be readily quantifiable. Less commonality is found across value categories affecting the distribution system, which have incremental impacts and may require more complex approaches to quantification. The set of value categories included, and whether these categories represent costs or benefits, significantly affects the overall results of a given study.

Figure 1. Comparison of value categories across studies

Included	●
Discussed but not monetized/quantified	○
Included/represented in another category	●
For NY, included in VDER Phase One	○

		Arkansas - Crossborder Energy 2017	Nevada - E3 2016	Louisiana - Acadian Consulting Group 2015	South Carolina - E3 2015	Mississippi - Synapse 2014	Vermont - VT Public Service Dept 2014	Washington DC - Synapse 2017	Georgia - Southern Company 2017	Hawaii - Clean Power Research 2015	Maine - Clean Power Research 2015	Oregon - Clean Power Research 2015	Minnesota - Clean Power Research 2014	Utah - Clean Power Research 2014	New York - BCA Framework 2016 + VDER Phase One	California - LNBA Framework 2016	Total
Utility System Impacts																	
G	Avoided Energy Generation	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	15
G	Avoided Generation Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	15
G	Avoided Environmental Compliance	●	●			●	●	●	○		●	○		●		○	10
G	Fuel Hedging	●			●	●		●		○	●	○	●	●			9
G	Market Price Response	●					●	●		○	●				○		6
G	Ancillary Services		●		●	○		○	○	○					○	○	8
T	Avoided Transmission Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	15
T	Avoided Line Losses	●	●		●	●	●	●	○			○		●	○	○	11
D	Avoided Distribution Capacity	●	●	●	●	●	●	●		○	○	○	○	●	○	○	14
D	Avoided Resiliency & Reliability	○				○		○							○	○	5
D	Distribution O&M			●					○						○	○	4
D	Distribution Voltage and Power Quality									○	○	○	○		○	○	6
C	Integration Costs	●	●	●	●	○		●	○	○	●	○	○		○	○	13
C	Lost Utility Revenues	●	●	●	●	●	●								○		7
C	Program and Administrative Costs		●	●	●	●	●	○							○		7
Societal Impacts																	
S	Avoided Cost of Carbon	●					●	●		○	●		○		○	○	8
S	Other Avoided Environmental Costs	●	●			○		○		○	●		○		○	○	9
S	Local Economic Benefit	●				○		○									3

Values that are numerically quantified are represented in the chart with a solid dot. Values that are discussed, but not quantified, are represented in the chart with an open dot. Some studies combined more than one value into a broader category and, where possible, these rolled-up values are noted with a solid red dot. For a more detailed discussion of this chart, see the section "Comparison of Value Categories."

Other important differences led studies to arrive at diverse conclusions. Some differences are caused by variables that are geographically and situationally dependent, while other differences are driven by the input assumptions used to estimate their value. Studies use a range of assumptions for factors that influence results, such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates. Furthermore, the stakeholder perspective—whether costs and benefits are examined from the view of customers, the utility, the grid, or society at large—is a key influencer of the methodology employed by the studies and their resulting direction and outcomes.

Overall observations from this analysis show, not surprisingly, that a major challenge in studying and developing an approach to NEM, the value of solar, and DER valuation is that some value components are relatively easy to quantify, while others are more difficult to represent by a single metric or measure. This meta-analysis highlights the different value categories, approaches, and assumptions used in NEM cost-benefit analysis, value of solar studies, and DER valuation frameworks, emphasizing commonalities and differences between them, and how they are evolving over time.

CONTENTS

Definitions of Key Terms

Some key terms used throughout this report are defined below.

Behind-the-meter: A generating unit, multiple generating units, or other resource(s) at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from, and including, the generation set-up to the metering point is considered to be "behind-the-meter."[1]

Distributed energy resource (DER): A DER is a resource sited close to customers that can provide all or some of their immediate electricity and power needs, and also can be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and located close to the load. Examples of different types of DER include solar photovoltaic, wind, combined heat and power, energy storage, demand response, electric vehicles, microgrids, and energy efficiency.[2]

Distributed solar: Small-scale photovoltaic facilities installed behind-the-meter, typically at residential or commercial sites.

Interconnection cost: The one-time cost (for hardware, labor, etc.) of connecting a distributed photovoltaic system or other DER installation to the local distribution grid, usually to allow the installation's owner to sell any excess electricity production to the local utility. This cost is usually paid by the installation owner, and should be distinguished from the cost of "interconnection studies," which the utility also may require the owner to fund. Such studies may be required, for example, to ensure that connecting the additional distributed photovoltaic system on a given distribution feeder will not affect local voltage stability or otherwise disrupt service to other customers on that feeder.

Net energy metering [or net metering] (NEM): Congress defined "net [energy] metering service" as "service to an electric consumer under which electric energy generated by that consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."[3]

Value of solar (VOS): Value of solar is an alternative to NEM. The VOS method calculates each of the benefits and costs that distributed solar provides to, or imposes on, the electric system to arrive at a single VOS rate, typically expressed in cents per kilowatt-hour. This is the rate at which customers are

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[1] North American Electric Reliability Corporation (NERC). February 2017. *Distributed Energy Resources: Connection Modeling and Reliability Considerations*. Available at http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

[2] National Association of Regulatory Utility Commissioners (NARUC). 2016. *Distributed Energy Resources Rate Design and Compensation Manual*. Available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

[3] Energy Policy Act of 2005, Sec. 1251, Net Metering and Additional Standards, (a)(11). For additional information, see *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005*, Kenneth Rose and Karl Meusen, March 22, 2006, p. 10.

compensated for electricity generated by their grid-connected distributed photovoltaic systems. Unlike NEM, the VOS tariff dissociates the customer payments for electricity consumed from the compensation they receive for solar electricity generated. Under a VOS tariff, the utility purchases some (i.e., the net excess) or all of the generation from a solar installation at a rate that is independent of retail electricity rates.[4]

[4] National Renewable Energy Laboratory (NREL), U.S. DOE. 2015. *Value of Solar: Program Design and Implementation Considerations*. Available at https://www.nrel.gov/docs/fy15osti/62361.pdf.

Introduction

Net energy metering (NEM) is a method that adapts traditional monthly metering and billing practices to compensate owners of distributed generation facilities for electricity exported to the grid. The customer can offset the electricity they draw from the grid throughout the billing cycle. The net energy consumed from the utility grid over the billing period becomes the basis for the customer's bill for that period. The level of compensation varies by State, depending on the policies in place. In some States, utilities compensate NEM customers for excess generation at the full retail rate, while other States specify something other than the retail rate.[5]

NEM is credited with being one of the main policy drivers behind the widespread and rapidly increasing adoption of distributed solar photovoltaic (PV) across the United States. According to the U.S. Energy Information Administration (EIA), residential small-scale solar PV capacity has increased significantly in recent years, reaching 7.4 gigawatts (GW) in 2016, a 43 percent increase from 2015. Small-scale PV capacity (systems less than 1 megawatt [MW]) in the commercial and industrial sectors has also grown, with combined capacity in those two sectors increasing 26 percent in 2016, reaching nearly 5.8 GW. This growth is projected to continue, with EIA forecasts reaching 13.7 GW in the residential sector and 8.2 GW in the commercial and industrial sectors in 2018.[6]

NEM has traditionally been used as a mechanism for compensating PV customers, typically residential and commercial customers with behind-the-meter solar, for electricity they produce onsite. However, opportunities and challenges associated with the increasing penetration of solar and other distributed energy resources (DERs) are causing utilities and policymakers to examine methods to address the full range of costs and benefits associated with these behind-the-meter resources.

New economic conditions that arise with the introduction of distributed solar in a utility service territory can affect utilities and ratepayers, and are some of the main challenges leading to investigations of NEM. Concerns related to the ability of the utility to recover its fixed costs for operating the grid have led to questions about how NEM affects cost recovery. Similarly, the impact that net-metered PV may have on non-solar customers has initiated analyses of how NEM and other solar pricing models may affect retail electricity prices. Nevertheless, NEM has been introduced as an effective mechanism to compensate customers with onsite PV generation and has successfully enabled increased deployment of distributed solar PV.

Stakeholders across the country are debating the future of NEM, and many States are undertaking policy actions to amend NEM laws and rules or to study the value of solar (VOS) through cost-benefit analysis.[7] In addition, some States are engaged in legislative, regulatory, and rate design discussions related to NEM successor tariffs, including States with currently low penetrations of distributed PV. As the

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[5] For additional information on net metering, see National Renewable Energy Laboratory (NREL), U.S. DOE. State, Local, & Tribal Governments, Net Metering. Available at https://www.nrel.gov/technical-assistance/basics-net-metering.html.

[6] U.S. Energy Information Administration (EIA). July 11, 2017. "EIA adds small-scale solar photovoltaic forecasts to its monthly Short-Term Energy Outlook." Available at https://www.eia.gov/todayinenergy/detail.php?id=31992.

[7] North Carolina Clean Energy Technology Center. 2017. *The 50 States of Solar: Q4 2016 Quarterly Report & Annual Review, Executive Summary*. Available at https://nccleantech.ncsu.edu/wp-content/uploads/Q42016_ExecSummary_v.3.pdf.

deployment of other distributed resources, such as storage, energy efficiency measures, demand response, and electric vehicles, is expected to grow, some regulators and utilities are working on broader valuation methodologies to provide a foundation for understanding the comprehensive benefits and costs associated with increased DER deployment on the grid. This understanding can then be used to inform pricing, program, and procurement strategies that serve multiple objectives, including maximizing benefits for all customers.

These policy and regulatory trends have spurred a significant amount of analysis by States, utilities, and other stakeholders to examine the costs and benefits of net metering and the value of DERs more broadly. In this report, ICF reviews a selection of 15 studies to identify broad themes and highlight emerging issues that influence how stakeholders are studying the impacts of net metering and distributed solar.

The studies that are the focus of this meta-analysis have different objectives, ask different questions, and arrive at different results. In summary, the review demonstrates a historic lack of consensus around a preferred methodology for valuing the costs and benefits of distributed solar, and emphasizes how choices about input assumptions and the perspective from which value is assessed is a strong influencer of study results. The meta-analysis also demonstrates a shift toward more comprehensive and defined approaches to valuing distributed solar and DERs more broadly.

Approach

This report is a meta-analysis of 15 studies related to the costs and benefits of NEM and distributed solar. The selection was made by collecting a broad list of more than 40 relevant studies, and narrowing it based on a set of criteria to ensure that the sample reviewed represents a balanced cross section of the most recently available material from a variety of stakeholder groups and prepared by various research firms. The following criteria guided study selection:

- The study identifies a set of value categories that can be applied to distributed PV.
- The study was released in 2014, or later, and was not included in earlier meta-analyses.
- The selection includes studies from different regions of the country.
- The selection includes studies from jurisdictions with different amounts of PV adoption.
- The selection includes studies prepared by different research firms or utilities.
- The selection includes studies that were sponsored or commissioned by different organizations (e.g., State utility commissions, utility companies, consumer advocates, environmental groups).

Each study was carefully reviewed and categorized using a matrix to allow for comparison and to uncover trends.

This report begins with a summary of key observations. Next, it describes how the studies were selected and groups them into three types: NEM cost-benefit analyses, VOS/NEM successor studies, and broader DER value frameworks. Then, it identifies and defines the value categories included and notes factors that influence how values are quantified. After that, the report provides a more detailed comparison of the value categories and discusses some of the methodological elements and input assumptions that can cause findings to vary. The last section provides brief summaries of each of the studies reviewed.

Key Observations

Studies represent an evolution of approaches to solar value analysis.

States, through their regulated utilities, have historically relied on NEM as a mechanism for compensating distributed solar; however, the increasing penetration of solar and associated technologies is causing utilities and policymakers to examine how NEM addresses the full range of costs and benefits of distributed solar. As distributed solar penetration continues to rise, some regulators and utilities have started developing broader valuation methodologies and frameworks that can be applied to distributed solar, as well as other distributed resources, in a technology-neutral way. These valuation frameworks can then be used to inform how these resources might be compensated for the services they provide through appropriate pricing, programs, and procurement strategies for PV and other DERs. The studies in this review represent an evolution of approaches and include studies that analyze NEM, studies on VOS, and documents that establish broader DER value frameworks. These frameworks are currently in development and, in many ways, are a work in progress.

Evolution of Value to the Distribution System

Assessing the value of DERs requires analysis of broader impacts on the wholesale system and locational net benefits on the distribution system. Bulk system value categories, such as avoided energy generation, avoided generation capacity, and avoided transmission capacity, are relatively common and generally simple to quantify.

Similarly, incorporating distribution system value components in a staged order, starting with values that are the largest and most readily quantifiable, is a practical approach to capturing near-term value. For example, distribution capacity deferral represents a value component with long-term and substantial value that may be a good first step, and several States, including New York and California, have quantified it. As a second step, States may look toward the additional value of increasingly complex components such as reliability, resilience, and voltage management.

The main takeaway is that the quantification of locational value beyond avoided or delayed investment in capital costs is an ongoing process that continues to evolve. For more information on the evolutionary pathway of distribution system value components, see *Missing Links in the Evolving Distribution Markets* (De Martini, et al., 2016).

Overall value depends substantially on which costs and benefits are included and monetized in a study.

ICF's review identified 18 value categories considered in two or more of the studies. Three value categories, all on the wholesale power system, are included in all studies: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Ten or more of the studies included value categories related to avoided environmental compliance costs, avoided line losses (including transmission and distribution), avoided distribution capacity, and integration costs (a negative value). Less common value categories tended to be those that are more challenging to quantify. The set of value categories included, and whether these categories represent costs or benefits, have a significant impact on the overall results of a given study.

Approaches to defining the value categories and methods for quantifying them vary across studies and affect the results.

Common terms and definitions of those terms are not uniformly applied across the studies to refer to the value categories, and the categories are not always defined to include the same elements.

Furthermore, not all studies include a quantitative value; some only discuss how a value could be calculated. Still, there is some degree of alignment across many, but not all, of the categories, which makes it potentially possible to establish common definitions and identify similar or otherwise nuanced approaches to quantifying values for categories across the studies. This review identifies examples of how studies differ in their definitions of categories and quantification approaches to demonstrate how these decisions can affect the findings.

The perspective from which value is assessed affects which value categories are included and how they are quantified.
Cost and benefit considerations change depending on the perspective from which the value is being assessed. Depending on the perspective taken—a utility's business perspective, the ratepayer's consumer perspective, or the grid operator's technical perspective—particular value categories may be more or less relevant. Furthermore, an analysis focused only on utility and ratepayer values will produce different results from an analysis that considers broader policy goals affecting society at large. The perspective also influences whether some categories are included as costs or as benefits. Many of the studies consider multiple perspectives by applying a range of cost-effectiveness tests typically used by utilities to assess the costs and benefits of energy efficiency programs for different stakeholder groups.[8] In analyzing the results or findings from the selection of studies, it is important to consider to whom the benefits and costs accrue and how that perspective affects outcomes.

Studies use a range of input assumptions for factors that influence results, such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates.
A range of input assumptions are used in quantifying values for the cost-benefit categories. This review identifies several assumptions used in the studies for important factors such as marginal unit displacement, solar PV penetration, integration costs, externalities and societal values, and discount rates associated with the analysis. Just as values are sensitive to differences in which value categories are included, how they are quantified, and where the value accrues, they are also influenced by choices in input assumptions. Each of these factors are discussed in the section "Input Assumptions."

Selection of Studies Analyzed

ICF conducted a literature search to determine relevant studies from across the country to include in this meta-analysis. After identifying more than 40 relevant studies prepared over the past decade, the list was narrowed to a selection of 15.[9] The goal was not to analyze an exhaustive list, but to review a sample that represents a balanced cross section of the most recently available analyses sponsored by organizations with different perspectives and prepared by various research firms. Table 1 lists the selection of studies reviewed.[10] Appendix A provides a citation and brief summary of each study

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[8] The traditional cost-effectiveness tests—the Participant Cost Test (PCT), Utility Cost Test (UCT), Rate Impact Measure (RIM), Total Resource Cost (TRC) Test, and Societal Cost Test (SCT)—and the perspectives addressed by each test are discussed further in the section "Stakeholder Perspective."

[9] The full list of studies considered for inclusion is included as Appendix C.

[10] We use the term "studies" to refer to the documents reviewed in the meta-analysis for simplicity; however, some may be more accurately described as reports or other materials. For some States, we relied on utility commission orders, staff reports, working group recommendations, or other documentation of the costs and benefits currently being considered by regulators. For other States, we relied on documents that provide only a

analyzed. Note that more than one document was reviewed in New York and California as a reflection of ongoing regulatory activities.

Table 1. Selection of studies analyzed

State	Year	Study Sponsor	Prepared by
Arkansas	2017	Sierra Club	Crossborder Energy
District of Columbia	2017	Office of the People's Counsel	Synapse Energy Economics
Georgia	2017	Southern Company	Southern Company
California	2016	California Public Utility Commission (CPUC)	CPUC/Energy and Environmental Economics (E3)
Nevada	2016	State of Nevada Public Utilities Commission	E3
New York	2016	New York Public Service Commission (PSC)	NY Department of Public Service (DPS) Staff
Hawaii	2015	Interstate Renewable Energy Council	Clean Power Research
Louisiana	2015	Louisiana Public Service Commission	Acadian Consulting Group
Maine	2015	Maine Public Utility Commission	Clean Power Research
Oregon	2015	Portland General Electric	Clean Power Research
South Carolina	2015	South Carolina Office of Regulatory Staff	E3
Minnesota	2014	Minnesota Department of Commerce	Clean Power Research
Mississippi	2014	Public Service Commission of Mississippi	Synapse Energy Economics
Utah	2014	Utah Clean Energy	Clean Power Research
Vermont	2014	Public Service Department (PSD) Staff	VT PSD

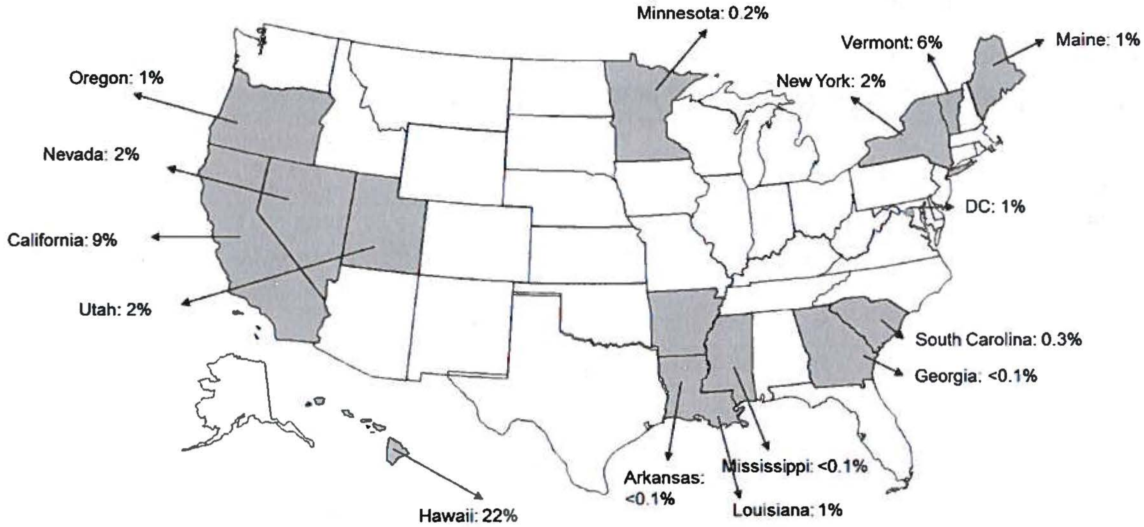
All of the studies reviewed are from 2014 or later. Half were commissioned by State utility commissions and the remaining studies were commissioned by utility companies, consumer advocates, environmental groups, research organizations, or other State agencies. A handful of firms specialize in preparing cost-benefit studies, and this report includes a sample prepared by different firms. However, some firms prepared more than one study of the 15 studies reviewed here; Synapse Energy Economics prepared two studies, Energy and Environmental Economics (E3) was involved in three of the studies, and Clean Power Research prepared five studies.

The selection reflects geographic diversity and includes States with different amounts of distributed PV adoption and growth. Five studies are specific to a single utility service territory, with the remaining studies focused on a single State or the service territories of multiple utilities in the same State. Figure 2 indicates States where the studies came from and the estimated penetration of NEM PV nameplate capacity as a percentage of peak load in those States in 2016.[11]

methodology for assessing costs and benefits in a certain jurisdiction, rather than verifying whether benefits outweigh the costs or vice versa.

[11] We estimate PV penetration by dividing NEM PV capacity (MW) by peak load (MW). For NEM PV capacity, data by State was obtained from EIA at https://www.eia.gov/electricity/data/eia861. For peak load, we map States by the National Energy Modeling System (NEMS) region and use *Annual Energy Outlook* (AEO) 2016 sales data (MWh), adjusted for transmissions losses, to calculate net energy needed to meet load in the State. Net energy is divided by the load factor for the NEMS region to derive peak load. Transmission losses and load factor are obtained from

Figure 2. Geographic diversity of studies and estimated PV penetration, 2016



While the selection captures different approaches and valuation methodologies, every study either identifies or quantifies a defined set of cost-benefit categories related to net metering or distributed solar. In general, cost of service studies are not considered because they are fundamentally different from cost-benefit analyses.[12] Cost of service studies are used to estimate and allocate the embedded and operating costs across groups of customers, and are more geared toward cost allocation and rate design than distributed solar and DER valuation.[13]

As part of a broader literature review, ICF reviewed existing meta-analyses of solar studies, checked the individual studies included for relevance, and avoided replicating evaluation of studies that had been previously reviewed, where possible.[14] For more information on solar PV cost-benefit studies prepared

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U.S. Energy Information Administration (EIA). 2016. *Annual Energy Outlook.* Available at https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

[12] The studies from Louisiana and South Carolina include sections on cost of service; however, our review did not address these components. In addition, New York ordered utilities to calculate utility marginal cost of service (MCOS) to determine distribution value components in their Value of DER Phase One tariff.

[13] Barbose, Galen; John Miller; Ben Sigrin; Emerson Reiter; Karlynn Cory; Joyce McLaren; Joachim Seel; Andrew Mills; Naïm Darghouth; and Andrew Satchwell. 2016. *On the Path to SunShot: Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65670. Available at http://www.nrel.gov/docs/fy16osti/65670.pdf.

[14] Existing meta-analyses of solar studies include Weissman, Gideon, and Bret Fanshaw. 2016. *Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society.* Available at https://environmentamerica.org/sites/environment/files/reports/AME%20ShiningRewards%20Rpt%20Oct16%201.1.pdf; Institute for Energy Innovation. 2017. *Solar Energy in Michigan: The Economic Impact of Distributed Generation on Non-Solar Customers.* Available at https://www.instituteforenergyinnovation.org/impact-of-dg-on-nonsolar-ratepayers; and Rocky Mountain Institute (RMI). 2013. *A Review of Solar PV Benefit & Cost Studies.* Available at https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf.

prior to 2014, see the Rocky Mountain Institute's meta-analysis, *A Review of Solar PV Benefit & Cost Studies.*[15]

Types of Studies

The studies in this review represent an evolution of approaches to solar value analysis and can be broadly grouped into three types: NEM cost-benefit analysis, VOS/NEM successor studies, and broader DER value frameworks. In general, these groupings reflect differences in policy context as many States have considered changes to NEM policies in recent years. Table 2 identifies how the studies were grouped and the following discussion summarizes the three types.

Table 2. Grouping of study types

Type of Study	Number Reviewed	Description of Study Type	States/Prepared by
NEM Cost-Benefit Analysis	6	Evaluate costs and benefits of a NEM program; study whether NEM is creating a cost-shift to non-participating ratepayers.	▪ Arkansas (Crossborder) ▪ Louisiana (Acadian) ▪ Mississippi (Synapse) ▪ Nevada (E3) ▪ South Carolina (E3) ▪ Vermont (VT PSD)
VOS/NEM Successor	7	Discuss the impacts of NEM and consider options for reforming or realigning rates with the net impacts of distributed solar in ways that go beyond net metering.	▪ District of Columbia (Synapse) ▪ Georgia (Southern Company) ▪ Hawaii (CPR) ▪ Maine (CPR) ▪ Minnesota (CPR) ▪ Oregon (CPR) ▪ Utah (CPR)
DER Value Frameworks	2	Reflect the elements of regulatory activities that look at VOS as part of a more precise approach within a framework that can be applied to other DERs.	▪ California LNBA (CPUC) ▪ New York BCA (Department of Public Service Staff)

Six of the studies can be considered NEM cost-benefit analyses. These tend to evaluate the impact of extending an existing or launching a new NEM program, or study whether an existing NEM program is creating an unfair cost-shift to non-participating ratepayers. This issue, sometimes called cross-subsidization, refers to a potential shift in costs away from solar PV customers, who might avoid paying for some fixed grid costs, toward non-PV customers, who make up the difference of these grid costs in their rates.[16,17] For example, the study from Vermont included an analysis of "the existence and magnitude of any cross subsidy created by the current net metering program."

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[15] Rocky Mountain Institute (RMI), 2013.

[16] For more information on the cost recovery and cost-shift issues associated with DER in rate making, see NARUC, 2016, *Distributed Energy Resources Rate Design and Compensation Manual.*

[17] A 2017 report from the Lawrence Berkeley National Laboratory (LBNL) explored the potential rate impacts of distributed solar and concluded that the effects are small compared to other issues, such as the impact of energy efficiency and natural gas prices on retail electricity prices. However, the study found that for States and utilities

Seven of the studies can be considered VOS/NEM successor studies. These analyses tend to discuss the impacts of NEM and consider options for reforming or realigning rates to account for the net impacts of distributed solar in ways that may go beyond NEM. For example, Minnesota passed legislation in 2013 requiring the development of a methodology to calculate a VOS tariff as an alternative to NEM. The Minnesota study included in this review documents the methodology approved by the Minnesota Public Utilities Commission, which would be used by utilities to calculate the rate at which electricity generated by PV customers is compensated.[18]

The New York and California studies can be considered broader DER value frameworks, which look at VOS within a methodological framework that can be applied to other, customer-sited technologies in addition to solar. In New York, the Department of Public Service (DPS) staff developed a benefit-cost analysis framework, known as the "BCA Framework," for utilities to evaluate DER alternatives as substitutes for traditional investments. More recently, DPS established the Phase One Value of DER (VDER) methodology, which transitions away from traditional NEM and provides the basis for a "Value Stack" tariff, under which compensation is calculated using five of the most readily quantifiable DER values. Efforts are currently underway in Phase Two of VDER to develop a Value Stack tariff for smaller residential rooftop solar and other DER technologies. Similarly, in California, the California Public Utilities Commission (CPUC) set up the Locational Net Benefit Analysis (LNBA) Working Group to develop a methodology for the three investor-owned utilities to use to value DER by location. CPUC approved the LNBA for use by utilities in demonstration projects and the framework continues to be refined.

Instead of a single valuation methodology for distributed solar, these frameworks are evolving to account for the temporal and locational value associated with DER projects at specific locations and with specific generation profiles and characteristics, and are being used to inform the next approach to compensating DER in these States. In the DPS report from New York that was reviewed for this meta-analysis, the authors describe NEM as an important and easy-to-understand compensation mechanism that effectively fostered solar PV in the State, but say that NEM provides an "imprecise and incomplete signal of the full value and costs of DERs."[19] The ongoing proceedings are aimed at developing pricing for DERs that better reflect the actual values they create.

While all of the studies provide a methodology for considering the costs and benefits of distributed PV, the three types of studies have different objectives, ask different questions, and arrive at different results. The NEM studies tend to apply the value categories (which are discussed in detail in the next section) to investigate the fairness of a compensation structure. The VOS studies use the value categories to administratively determine a compensation rate that is more precise than the NEM approach. The Value of DER frameworks apply the value categories in a way that aligns compensation

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with exceptionally high distributed solar penetration levels, the effects could begin to approach the same scale as other important drivers. See Barbose, Galen. 2017. *Putting the Potential Rate Impacts of Distributed Solar into Context*. p. 31. Available at https://emp.lbl.gov/sites/default/files/lbnl-1007060.pdf. Note: LBNL's study is not included in this meta-analysis because it does not attempt to provide a cost-benefit analysis of distributed solar, support an approach to defining a value of solar, or provide a valuation framework for other DERs.

[18] Minnesota Public Utilities Commission (MN PUC). 2014. Order Approving Distributed Solar Value Methodology. Docket No. E-999/M-14-65. April 1, 2014. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bFC0357B5-FBE2-4E99-9E3B-5CCFCF48F822%7d&documentTitle=20144-97879-01.

[19] New York Department of Public Service (NY DPS), 2016(b), p. 4.

with system value and grid services provided, while also providing a method for integrating the value of DERs into utility system planning processes. Several studies derive an actual VOS, while others present an approach to quantification, but do not derive specific values to populate those categories.

These fundamental differences in scope and objective make it difficult to directly compare outcomes because studies do not always have a common goal or seek to investigate the same issue(s). Grouping the studies into three types based on objective (NEM, VOS, or DER Value Frameworks) helps to compare studies that are similar to each other; however, not all studies fit squarely into one of the three types. For example, the study from the District of Columbia is classified as VOS, but it also includes a NEM cost-shift analysis. The study from Georgia is classified as VOS, but it is intended to be a broad framework that is also applicable to utility-scale solar. Summaries of each study are provided in Appendix A and clearly indicate the analytical goal or objective of a study and the related outcomes.

In addition to different objectives driving varied outcomes, the perspective from which value is assessed influences which value categories are included and is likely to produce different results. Further still, regional factors, including regulatory structures, weather conditions, and wholesale and distribution grid characteristics, can drive differences and, in some cases, the application of the same analytic method in different areas can produce dissimilar results. The goal of the study, the perspective from which costs and benefits are evaluated, and relevant regional factors are not always explicitly stated in a study, further complicating direct comparison.

With these issues in mind, the selection of studies result in a range of findings related to the costs and benefits of NEM and distributed solar. Of the six NEM studies, two demonstrate that total benefits exceed total costs, two conclude that costs exceed overall benefits, and two found that NEM-related cost-shifting was either *de minimus* or "close to zero." Of the seven VOS studies, three quantify a State-specific VOS, while four provide a methodology but do not produce a specific estimate. Lastly, the two Value of DER frameworks provide a methodology for assessing costs and benefits, but do not produce a specific estimate. Table 3 summarizes the principal findings of the studies reviewed.

Table 3. Summary of principal findings

State	Year	Prepared by	Principal Findings
NEM Cost-Benefit Analysis			
Arkansas	2017	Crossborder	Benefits of residential distributed generation (DG) exceed the costs; do not impose a burden on other ratepayers.
Nevada	2016	E3	Cost-shift amounts to a levelized cost of $0.08/kWh for existing installations.
Louisiana	2015	Acadian	Costs associated with solar NEM installations outweigh their benefits.
South Carolina	2015	E3	NEM-related cost-shifting was *de minimus* due to the low number of participants.
Mississippi	2014	Synapse	NEM provides net benefits under almost all of the scenarios and sensitivities analyzed.
Vermont	2014	PSD	NEM results in "close to zero" costs to non-participating ratepayers, and may be a net benefit.
VOS/NEM Successor			
District of Columbia	2017	Synapse	Utility system VOS is $132.66/MWh (2015$); cost-shifting remains relatively modest.
Georgia	2017	Southern Company	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Hawaii	2015	CPR	Provides a methodology for assessing costs and benefits. Preliminary results suggest a net benefit.
Maine	2015	CPR	Value of distributed PV is $0.337/kWh (levelized).
Oregon	2015	CPR	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Minnesota	2014	CPR	Provides a methodology for assessing VOS; no specific estimate is produced.
Utah	2014	CPR	VOS is $0.116/kWh levelized.
DER Value Frameworks			
California	2016	CPUC	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
New York	2016	NY DPS	Provides a methodology for assessing costs and benefits; no specific estimate is produced.

Value Category Definitions

ICF's review identified 18 value categories that were considered in two or more of the studies.[20] Studies differed greatly in the selection of categories, approaches to quantification, and the selection of assumptions. This section presents a set of common definitions to define and refer to categories, and discusses important characteristics about each category, such as which assumptions matter to its resulting value. Table 4 lists the value categories and identifies the parts of the system that reflect these

[20] An assortment of miscellaneous categories were not assessed in more than one study. Some provide a slightly different take on one of the more common categories described later in this section. Examples include an "SREC SIPE" category used in the District of Columbia study to address the potential Supply Induced Price Effect associated with solar renewable energy certificates; a "generation remix" category used in the framework from Georgia to represent the impact that a large penetration of renewable resources could have on system commitment, dispatch, and future generation build-out; and a net non-energy benefits category used in the BCA in New York, which relates to avoided utility or grid operations (e.g., avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts), or incurred costs (e.g., indoor emissions, noise disturbance).

values, including the value to the generation system (G), the transmission system (T), the distribution system (D), the cost categories (C), and the external value to society (S).[21] The table also shows whether the category represents a cost or a benefit, and the frequency with which each value category is addressed in the studies.

Table 4. Summary of value categories used in studies

	Value Category	Benefit (+) or Cost (-)	Number of Studies Addressing this Category
Utility System Impacts			
G	Avoided Energy Generation	+	15
G	Avoided Generation Capacity	+	15
G	Avoided Environmental Compliance	+	10
G	Fuel Hedging	+	9
G	Market Price Response	+	6
G	Ancillary Services	+/-	8
T	Avoided Transmission Capacity	+	15
T	Avoided Line Losses	+	11
D	Avoided Distribution Capacity	+	14
D	Avoided Resiliency & Reliability	+	5
D	Distribution O&M	+/-	4
D	Distribution Voltage and Power Quality	+/-	6
C	Integration Costs	-	13
C	Lost Utility Revenues	-	7
C	Program and Administrative Costs	-	7
Societal Impacts			
S	Avoided Cost of Carbon	+	8
S	Other Avoided Environmental Costs	+	9
S	Local Economic Benefit	+	3

The number of studies addressing a value category is the sum of the studies that quantify an actual value (including a zero value) or provide an approach to quantifying the value within a methodology. Two studies provided "placeholders" for certain categories and these are considered "addressed" and included in the sum, where applicable. Categories that were not addressed are those that are entirely absent or explicitly not intended for inclusion in valuation. For a more detailed look at which studies addressed a particular value category, see Figure 3 in a following section, "Comparison of Value Categories."

[21] Most studies did not indicate a system level for cost categories, so we do not assign one.

Utility System Impacts

Generation

Avoided Energy Generation

This value category reflects the avoided cost of generating energy from system resources due to the output of distributed solar PV or other DERs. The cost of operating the displaced marginal generating resource is the primary driver of determining the value, and this value is sensitive to several assumptions about what that marginal unit is and therefore what comprises the cost of that avoided generation. The price of fuel for the generation resource displaced on the margin is a dominant factor in the value. Studies from regions with Independent System Operators (ISOs) tend to calculate avoided energy generation based on wholesale market prices. In non-ISO regions, natural gas is typically assumed to fuel the marginal unit, and most studies rely on natural gas price forecasts and standard assumptions for heat rates, depending on whether the marginal unit is assumed to be combined cycle or a combustion turbine.

Avoided energy also can address additional factors, including assumptions about variable costs for the displaced marginal unit, such as variable operations and maintenance costs, which are generally low.[22] Depending on the study, the avoided cost of energy also can include avoided environmental compliance costs and other factors that are part of the wholesale price. For example, in California, utilities can use locational marginal prices to determine avoided energy costs, and the avoided cost of carbon allowances from its cap and trade program are embedded in the wholesale energy value.[23] In contrast, the study from Nevada uses the hourly marginal wholesale value of energy, excluding the regulatory price of carbon dioxide emissions.[24] All of the studies evaluated include the avoided wholesale energy category, but with different assumptions. Studies that use locational marginal prices are also implicitly accounting for transmission congestion on the system to supply wholesale power to that node or aggregation of nodes.

Avoided Generation Capacity

This value category reflects the amount of central generation capacity that can be deferred or avoided due to the installation of distributed PV or other DERs. Key drivers include the effective capacity of a DER (i.e., coincidence with system peak) and system capacity needs.[25] The value is calculated based on the avoided cost of the marginal capacity resource and the effective capacity of the distributed resource. Similar to avoided energy generation, some studies assume natural gas combustion turbines

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[22] Rocky Mountain Institute (RMI), 2013, p. 25.

[23] California Public Utilities Commission (CPUC). 2016(a). *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. pp. 23, 27. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF.

[24] Price, S.; Z. Ming; A. Ong; and S. Grant. 2016. *Nevada Net Energy Metering Impacts Evaluation 2016 Update*. San Francisco, CA: Energy and Environmental Economics, Inc. p. 32. Available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.

[25] Rocky Mountain Institute (RMI), 2013.

and sometimes combined cycle units for the plant being deferred, while others use estimates from capacity markets if they exist in the region.

Several studies apply an Effective Load Carrying Capacity (ELCC) method to measure the amount of additional load that can be met by the distributed resource. For solar PV, the ELCC can be significant because PV generation may be reliably available at peak times and can effectively increase the grid's generating capacity.[26] On the other hand, in places where solar generation is more variable or not coincident with the peak, and in places with increasing solar penetration, solar may not provide capacity at times when it is needed. Assumptions about future load growth, future solar growth, and their impact on the shape and timing of the system peak also affect the ability of variable distributed resources to avoid or defer system capacity needs. All studies include this category.

Avoided Environmental Compliance

This value category reflects the avoided cost of complying with Federal, regional, State, and local environmental regulations. This could include the compliance costs of either existing or anticipated carbon emissions standards or standards related to other criteria pollutants. Several studies include avoided environmental compliance within the avoided energy generation value category, which eliminates the need for this separate value category. Some studies may address the avoided cost of purchasing renewable energy to comply with State renewable portfolio standard (RPS) requirements; this meta-analysis includes those avoided costs here. The value depends on State-specific targets and the current generation mix. This value does not include any avoided societal costs, which includes the social cost of carbon, and is addressed separately and discussed in the Societal Benefits section below. Ten out of the 15 studies include avoided environmental compliance. Three specifically address avoided RPS costs and only the study from the District of Columbia quantifies it.[27]

Fuel Price Hedging

This value category reflects the avoided costs to the utility based on reduced risk and exposure to the volatile fuel prices of conventional generation resources. Because renewable generation has no fuel costs, the cost of solar generation is not subject to fluctuations in fuel price. The forecasted price of fuel for the displaced marginal resource is the primary driver of this component. This value can be assessed as a benefit to the utility or a broader benefit to society. From the utility perspective, the value reflects their reduced risk in fuel price volatility. From the societal perspective, it can reflect the benefit that all customers may experience from reduced utility rate fluctuations. Nine studies include the fuel hedging category.

Market Price Response

This value category reflects a change in wholesale energy or capacity market prices due to increased penetration of renewable generation. As PV penetration increases, the demand for conventional

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[26] The ELCC of a power generator represents its ability to effectively increase the generating capacity available to a utility or a regional power grid without increasing the utility's loss of load risk. See Perez, R.; R. Margolis; M. Kmiecik; M. Schwab; and M. Perez. 2006. *Update: Effective Load-Carrying Capability of Photovoltaics in the United States.* Conference Paper. Golden, CO: National Renewable Energy Laboratory. NREL/CP-620-40068. Available at https://www.nrel.gov/docs/fy06osti/40068.pdf.

[27] This category does not apply in all States. For the District of Columbia, there is a solar carve-out within their RPS, which sets a specific target for solar PV generation from grid-connected systems and significantly affects the value.

generation and capacity resources may be reduced, which could have the effect of lowering energy prices. Six studies include market price response. Most studies approximate the market price suppression effect using analysis based on the 2013 Avoided Energy Supply Cost (AESC) study.[28]

Ancillary Services

This value category reflects any increase or decrease in costs associated with the need for generation reserves to provide grid support services such as reactive supply, voltage control, frequency regulation, spinning reserve, energy imbalance, and scheduling. The ability to monitor and control distributed PV and other DERs is an important factor that affects the ability of these variable resources to provide ancillary services at the time of need.

Regions of the country with established markets for ancillary services may find it easier to include and quantify this category. Some of the frameworks reviewed gave an approach to quantifying avoided ancillary services. For example, E3 uses 1 percent of avoided energy in the South Carolina study.[29] In New York, the BCA uses a 2-year average of ancillary service costs, but recognizes that a case-by-case approach would be more accurate.[30] Eight studies include this value category. Some studies may assume an increase in ancillary services as a component of integration costs, discussed below.

Transmission

Avoided Transmission Capacity

This category reflects the avoided costs of transmission constraints from the addition of distributed PV or other DERs, which may or may not defer planned transmission infrastructure upgrades or replacements. The characteristics of the bulk system and DER penetration levels may influence this component. All studies include this value category, although several combine it with avoided distribution capacity and apply a single value for avoided transmission and distribution capacity.[31] The studies took various approaches to calculate the avoided cost of transmission capacity as a result of the installation of NEM eligible solar PV systems. Most commonly, the benefits were calculated by assessing the utility's marginal cost of load-related transmission capacity, as opposed to any specific line cost analysis. Inputs to the calculation include historical transmission capacity expenditures, which can be

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[28] The 2013 AESC study was prepared by Synapse and was sponsored by a group representing the major electric and gas utilities in New England, as well as efficiency program administrators, energy offices, regulators, and advocates. Synapse conducted prior AESC studies in 2007, 2009, and 2011, and is currently conducting a 2018 study (http://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england).

[29] Patel, K.; Z. Ming; D. Allen; K. Chawla; and L. Lavin. 2015. *South Carolina Act 236: Cost Shift and Cost of Service Analysis*. San Francisco, CA: Energy and Economics, Inc. p. 11. Available at http://www.regulatorystaff.sc.gov/electric/industryinfo/Documents/Act%20236%20Cost%20Shifting%20Report.pdf.

[30] New York Department of Public Service (NY DPS), 2016(a), Appendix C, p. 7.

[31] Stanton, E.; J. Daniel; T. Vitolo; P. Knight; D. White; and G. Keith. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Cambridge, MA: Synapse Energy Economics, Inc. Available at https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf; Dismukes, D. 2015. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.* Baton Rouge, LA: Acadian Consulting. Available at http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5; Norris, B. 2014. *Value of Solar in Utah*. Clean Power Research. Available at https://pscdocs.utah.gov/electric/13docs/13035184/255147ExAWrightTest5-22-2014.pdf; and Patel, et al., 2015.

based on publicly available Federal Energy Regulatory Commission (FERC) Form 1 data or data provided by the utility, and the load-carrying contribution made by solar PV.

Avoided Line Losses

This category reflects the value of energy that would otherwise be lost due to inefficiencies in transmitting and distributing energy over long distances from the central station to the point of consumption. EIA estimates that electricity transmission and distribution losses average about 5 percent of the electricity that is transmitted and distributed annually in the United States.[32] Losses are generally calculated by developing an average loss factor, and they vary based on time of day and the characteristics of the utility system. Avoided line losses also may be reflected in other value categories. For example, several of the studies prepared by Clean Power Research employ a loss savings factor approach instead of using a separate value category to address line losses.[33] Studies may include both energy-related and capacity-related losses. Eleven studies include this value category.

Distribution

Avoided Distribution Capacity

This category reflects the avoided costs due to the DER's ability to reduce load and defer or avoid planned distribution infrastructure upgrades or replacements to the distribution system. The value is sensitive to load growth rate at the distribution feeder or substation level, locational load shape characteristics, and penetration of DERs and their coincidence with load on that feeder or substation. All studies except one include this value category. Some studies combine it with avoided transmission capacity and apply a single value for avoided transmission and distribution capacity.

Avoided Reliability and Resiliency Costs

This category reflects avoided costs to the distribution system from the reduction in the frequency and duration of utility grid outages and the provision of back-up services, which reduce the impacts on customers. Five studies include this category; however, it is challenging to quantify, and no study in this review calculates a specific value.[34] The study from Mississippi includes a discussion of the value categories that it did not monetize and describes how avoided outage costs could be represented in cost-benefit analyses using a value of lost load estimation, or the amount that customers would be willing to pay to avoid interruption of their electric service. However, the study indicates that there is not "sufficient evidence to estimate the extent to which solar NEM would improve reliability" at this time.[35] The study from the District of Columbia discusses reliability in terms of outage frequency, duration, and breadth in its treatment of societal benefits, but indicates that it is difficult to "credibly forecast" when smart inverters will be deployed, how they will be used in reducing outages for

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[32] U.S. Energy Information Administration (EIA). Frequently Asked Questions, How much electricity is lost in transmission and distribution in the United States? Available at https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

[33] For a detailed description of the loss savings factor approach, see Norris, 2015(a), p. 17.

[34] The terms "resilience" and "reliability" are sometimes used interchangeably and are not clearly defined or distinguished in the studies.

[35] Stanton, et al., 2014, p. 35.

distributed solar customers, and how these deployments may result in lower expenditures for the utility.[36]

Distribution Operations and Maintenance (O&M)
This category can be assessed as either a cost or a benefit. It generally reflects any increase or decrease in O&M costs associated with utility investments in distribution assets and infrastructure services as a result of deploying distributed solar on the distribution system. Four studies include distribution O&M as either a cost or a benefit. In some studies, the negative value could be assumed to be included in the integration cost category, discussed later in this section.

Distribution Voltage and Power Quality
This category can be assessed as either a cost or a benefit. It generally reflects any increase or decrease in the costs of maintaining voltage and frequency on the distribution system within acceptable ranges during electric service delivery, and to potentially improve power quality. Six studies include the value of distribution voltage and/or power quality costs, but none of the studies quantify it. Some studies may address this value within ancillary services or integration costs, discussed in the next section.

Costs

Integration Costs
This category reflects costs incurred by the utility to integrate and manage distributed solar and other DERs on the utility grid. For example, investments may be required to support voltage regulation, upgrade transformers, increase available fault duty, and provide anti-islanding protection.[37] Integration costs may include scheduling, forecasting, and controlling DERs, as well as procurement of additional ancillary services such as reserves, regulation, and fast-ramping resources.[38] Most studies do not specify what specific investments are assumed to be included in integration costs or whether integration costs are assumed to apply at the distribution or transmission level. However, the studies from the District of Columbia, Louisiana, and South Carolina include interconnection costs, which is typically a distribution system-level consideration. Thirteen studies include this category.[39]

Lost Utility Revenues
This category reflects the loss of revenues to the utility due to reduced retail customer loads associated with customer-sited DERs. Lost revenues are the result of NEM participants paying smaller electric bills and are equivalent to customer bill savings. The value represents a potential cost-shift, and is applied when determining whether utility rates for all customers will increase, which some studies evaluated

[36] Whited, M.; A. Horowitz; T. Vitolo; W. Ong; and T. Woolf. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting*. Cambridge, MA: Synapse Energy Economics. p. 49. Available at http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.
[37] Bird, L.; M. Milligan; and D. Lew. 2013. *Integrating Variable Renewable Energy: Challenges and Solutions*. Available at https://www.nrel.gov/docs/fy13osti/60451.pdf.
[38] National Efficiency Screening Project (NESP). 2017. *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*. Available at https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf.
[39] The framework developed in Georgia does not specifically reference "integration costs" but it includes costs associated with support capacity, which we consider costs associated with integration. Similarly, the study from Louisiana does not specifically reference integration costs, but it does include interconnection costs and we consider that value as a cost associated with integration.

using the Rate Impact Measure (RIM) test.[40] Seven studies include this value category, while others argue that lost revenues are not a new cost created by net-metered systems.[41]

Program and Administrative Costs
This category reflects the costs incurred by the utility to administer various DER incentive programs. It can include both the cost of State incentive payments and the cost of administering them, compliance and reporting activities, personnel, billing costs, and other administrative costs to implement and maintain a formal program. Seven studies include this value category.

Societal Impacts

Benefits

Avoided Cost of Carbon
This category reflects avoided costs to society from reduced carbon emissions. It does not include avoided costs to the utility related to carbon emissions otherwise included in avoided energy costs or avoided environmental compliance value categories. This category is meant to capture additional avoided costs that accrue to broader society from mitigating climate change. Eight studies include this value category and three quantify it based on the Social Cost of Carbon developed by the U.S. Environmental Protection Agency. Studies may use a netting out process, such as the one described in the study from Maine, to ensure that this value category only reflects the net social costs of carbon and does not double-count avoided utility costs associated with carbon emissions that are embedded in energy prices.[42]

Other Avoided Environmental Costs
This category reflects the societal value of reduced environmental impacts related to public health improvements from reduced criteria air pollutants (SO_2, NOx, etc.), methane leakage, and impacts on land and water. Avoided criteria pollutants are addressed in nine of studies as a separate category from the impact of emissions prices on allowance markets that may be included in the avoided generation cost category. Four studies discuss avoided impacts on land and water. Two studies discuss avoided methane leakage.

Economic Development
This category reflects economic growth benefits such as jobs in the solar industry, local tax revenues, or other indirect benefits to local communities resulting from increased distributed solar deployment. Local economic benefit is challenging to quantify and is heavily influenced by assumptions. Three studies

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[40] The purpose of the RIM test is to indicate whether a resource will increase or decrease electricity or gas rates. When regulators take steps to allow utilities to recover lost revenues through rate cases, revenue decoupling, or other means, then the recovery of these lost revenues will create upward pressure on rates. If this upward pressure on rates exceeds the downward pressure from reduced utility system costs, then rates will increase, and vice versa (NESP, 2017).

[41] Stanton, et al., 2014, p. 33.

[42] Norris, B.; P. Gruenhagen; R. Grace; P. Yuen; R. Perez; and K. Rabago. 2015. *Maine Distributed Solar Valuation Study*. Prepared for Maine Public Utilities Commission by Clean Power Research, Sustainable Energy Advantage, LLC, and Pace Law School Energy and Climate Center. p. 35. Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

discuss this value category; only the study from Arkansas quantifies a value and includes it in its assessment of societal costs.[43]

Comparison of Value Categories

The following section provides a more detailed comparison of how the categories are treated across the studies. Figure 3 identifies which studies include each category. Values that are numerically quantified in the study are represented on the chart with a solid dot. Values that are discussed, but not quantified, are represented on the chart with an open dot. Some studies combined more than one value into a broader category and, where possible, these rolled-up values are noted with a solid red dot. For New York, the BCA includes a broader set of value categories than the Value of DER (VDER) Phase One Tariff. An open red dot indicates that the value category is also included in VDER Phase One.[44]

Included	●
Included/represented in another category	●
Discussed but not monetized/quantified	○
For NY, included in VDER Phase One	○

[43] Beach, R. Thomas, and Patrick G. McGuire. 2017. *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc*. Crossborder Energy. p. 28. Available at https://drive.google.com/file/d/0BzTHARzy2TlNbHViTmRsM2VCQUU/view.

[44] For Phase One of VDER, five categories make up the Value Stack: energy, capacity, environmental, demand reduction value, and locational system relief value. Because VDER uses locational marginal prices (LMPs), we assume that the common value categories associated with "avoided transmission capacity" and "avoided line losses" are included, because transmission congestion and losses are implicitly embedded in the LMP. However, the LMP does not factor in avoided costs from deferring transmission upgrades nor apply a specific line loss percentage. For the two distribution system values—demand reduction and locational system relief—we use the common value category associated with "avoided distribution capacity" as a rough substitute, but VDER values are more specifically aimed at measuring peak load reduction in higher value areas.

Figure 3. Comparison of value categories across studies

		Arkansas - Crossborder Energy 2017	Nevada - E3 2016	Louisiana - Acadian Consulting Group 2015	South Carolina - E3 2015	Mississippi - Synapse 2014	Vermont - VT Public Service Dept 2014	Washington DC - Synapse 2017	Georgia - Southern Company 2017	Hawaii - Clean Power Research 2015	Maine - Clean Power Research 2015	Oregon - Clean Power Research 2015	Minnesota - Clean Power Research 2014	Utah - Clean Power Research 2014	New York - BCA Framework 2016 + VDER Phase One	California - LNBA Framework 2016	Total
Utility System Impacts																	
G	Avoided Energy Generation	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	15
G	Avoided Generation Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	15
G	Avoided Environmental Compliance	●	●			●	●	●	○		●	○		●		○	10
G	Fuel Hedging	●			●	●		●		○	●	○	●	●			9
G	Market Price Response	●					●	●		○	●				○		6
G	Ancillary Services		●		●	○		○	○	○					○	○	8
T	Avoided Transmission Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	15
T	Avoided Line Losses	●	●		●	●	●	●	○			○		●	○	○	11
D	Avoided Distribution Capacity	●	●	●	●	●	●	●		○	○	○	○	●	○	○	14
D	Avoided Resiliency & Reliability	○				○		○							○	○	5
D	Distribution O&M			●					○						○	○	4
D	Distribution Voltage and Power Quality									○	○	○	○		○	○	6
C	Integration Costs	●	●	●	●	○		●	○	○	●	○	○		○	○	13
C	Lost Utility Revenues	●	●	●	●	●	●								○		7
C	Program and Administrative Costs		●	●	●	●	●	○							○		7
Societal Impacts																	
S	Avoided Cost of Carbon	●					●	●		○	●		○		○	○	8
S	Other Avoided Environmental Costs	●	●			○		○		○	●		○		○	○	9
S	Local Economic Benefit	●				○		○									3

Included	●
Included/represented in another category	●
Discussed but not monetized/quantified	○
For NY, included in VDER Phase One	○

The most common categories were impacts on the bulk power system: avoided energy generation, avoided generation capacity, and avoided transmission capacity (all the studies include them). The second most common categories, included in 10 or more studies, were avoided environmental compliance, avoided line losses (including transmission and distribution), avoided distribution capacity, and integration costs.

The least common cost-benefit categories, included in five or fewer studies, were distribution O&M, avoided resiliency and reliability, and economic development. Avoided resiliency and reliability, as well as economic development benefits, have proven to be somewhat challenging to calculate, which may explain why a number of studies did not include them. Studies that emphasize locational value, such as New York and California, may consider the resilience, reliability, and other benefits at the distribution level more effectively than studies taking statewide or system-level approaches.

Studies that do include these values describe their approaches to calculating it. The California LNBA measures system reliability/resilience by monitoring System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI) results.[45, 46] Similarly, the New York BCA Framework includes reliability/resilience values in terms of net avoided restoration costs and net avoided outages. Net avoided restoration costs are calculated by comparing the number of outages and the speed and costs of restoration before and after a project is implemented to find the difference. Avoided outage costs are similarly calculated by determining how a project affects the number and length of an outage and multiplying by the estimated costs of an outage. The estimated cost is determined by customer class and geographic region. For both avoided restoration costs and avoided outages, some portion of this value is already factored in the transmission and distribution (T&D) infrastructure costs, and this category represents the net avoided cost.[47]

Figure 4 shows the range of magnitude of value categories as a percentage of net impact. Figure 5 shows value stacks from five studies that clearly document values.[48] Avoided energy tended to provide the largest share of benefits out of all the categories. Avoided generation capacity and fuel hedging also tended to make up significant portions of the value stack. For studies that include societal benefits such as the avoided cost of carbon and other avoided environmental costs, these components can make up significant portions of the value stack, such as in the Arkansas and Maine studies, or they may have more modest values, such as in the District of Columbia and Utah studies. The size of avoided carbon

[45] California Public Utilities Commission (CPUC), 2016(a), p. 29.

[46] The LNBA currently includes the value of increased reliability from DERs where DERs can defer or avoid an otherwise necessary investment to bring reliability up to an acceptable level; however, consensus has not been reached on whether the non-capacity benefits of increased reliability associated with the frequency, duration, or magnitude of customer outages should be factored in. See California Public Utilities Commission (CPUC). 2017. *Locational Net Benefit Analysis Working Group Final Report.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code 769, and Related Matters. March 8. p. 36. Available at http://drpwg.org/wp-content/uploads/2016/07/R1408013-et-al-SCE-LNBA-Working-Group-Final-Report.pdf.

[47] New York Department of Public Service (NY DPS, 2016(a), Appendix C, pp. 2, 14.

[48] Four studies presented quantified values that we were not able to draw upon, either because they would have required visual assumptions or were otherwise incomparable.

and other environmental values depends on a number of factors, such as the generation mix being displaced by distributed PV in the region and the approach used to calculate the social cost of carbon.

Figure 4. Range of magnitude of value categories as a percentage of net impact

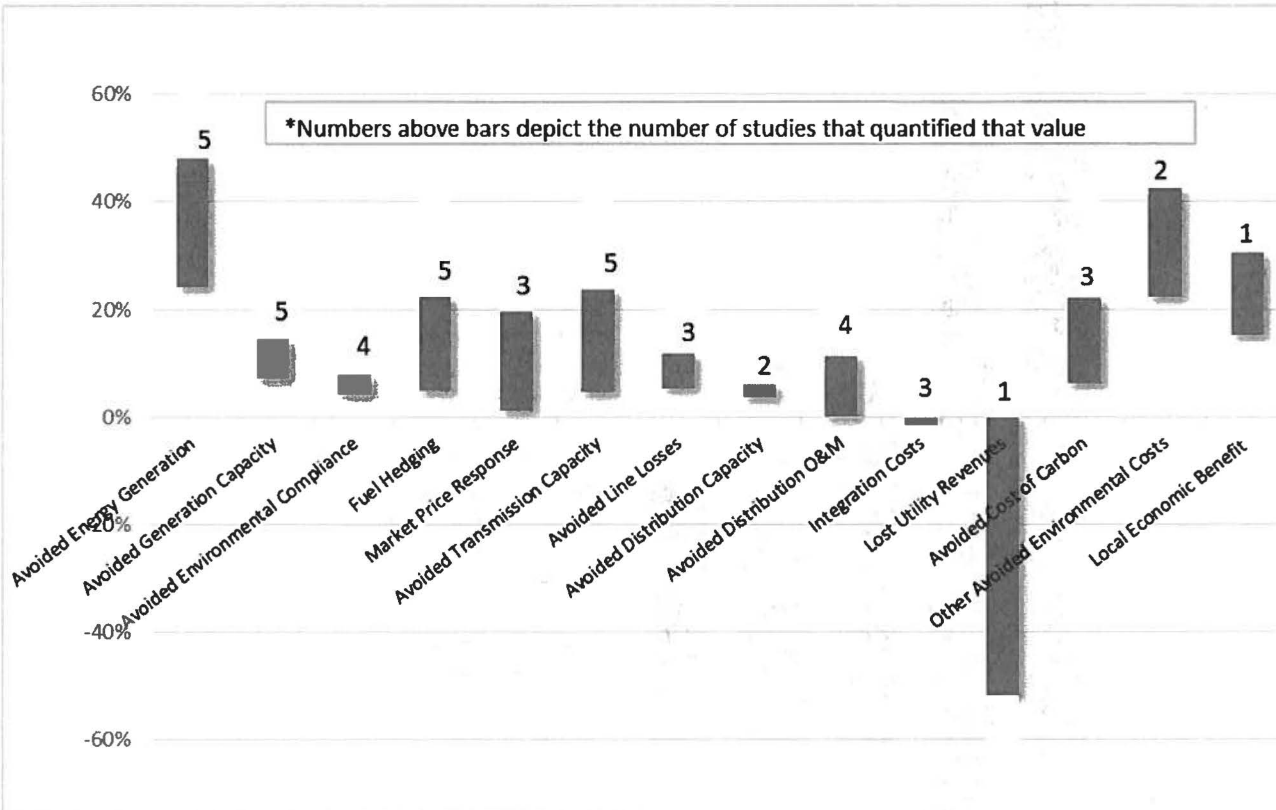
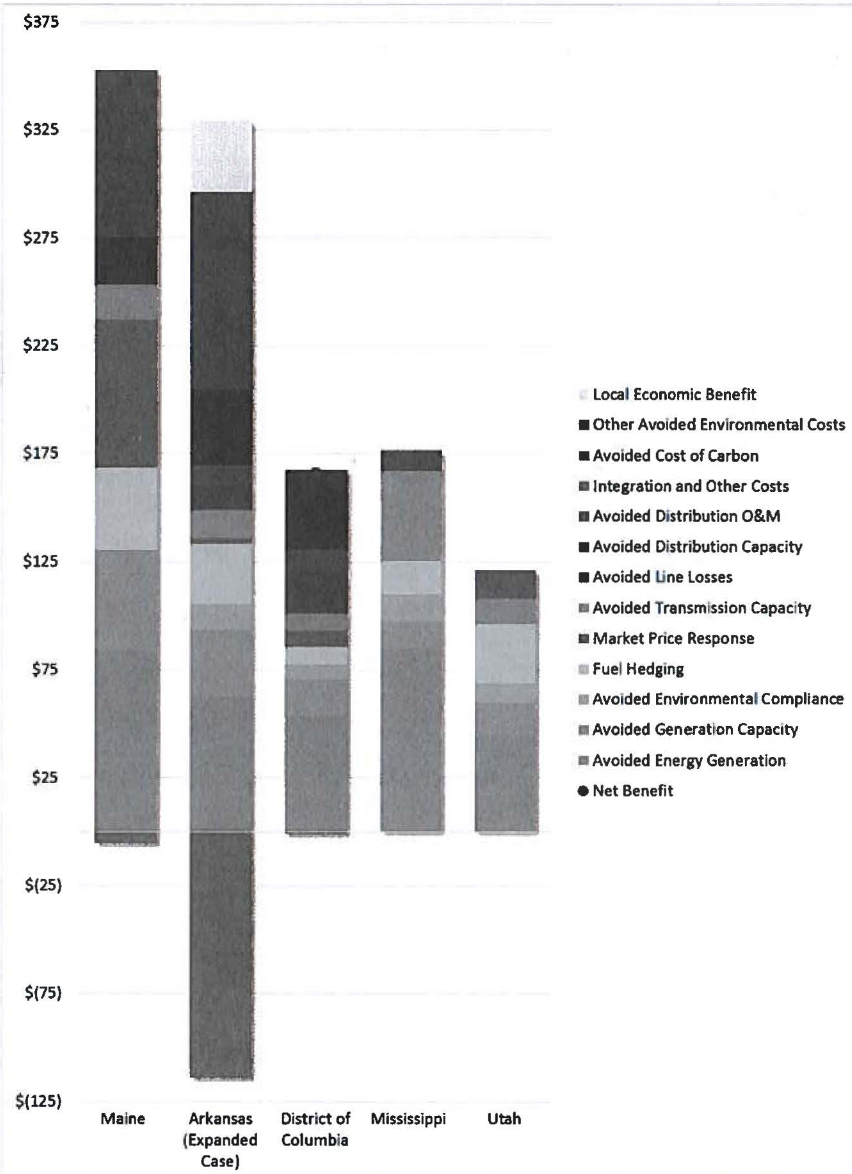


Figure 5. Comparison of value stacks (for studies that documented values)



* Values expressed in 2017 dollars per MWh, levelized over 25 years (except for the District of Columbia, which used 24 years). Studies that expressed values in varying dollar years and in dollars per KWh were converted. The Arkansas study looked at two sets of avoided costs, including an "expanded case," which includes a broader set of categories and is shown here. The District of Columbia's cost categories are included, but are not visible because the value is small. The Mississippi study considered two cost categories (reduced revenue and administrative costs) but neither value is shown because the detailed data were not found in the study. Utah did not include separate cost categories. Louisiana is not represented in the figure because costs and benefits are presented in net present value terms and do not lend themselves to comparison.

Stakeholder Perspective

In addition to the differences in value categories described above, there are differences in the perspectives of the studies that can affect the value categories included. For example, when assessing the value of NEM, distributed solar, and other DERs, it is important to recognize where the benefits or costs accrue. Costs and benefits can accrue at least to three different stakeholder groups—ratepayers, the utility, and the grid—with most studies evaluating multiple stakeholder perspectives. Some of the differences among these perspectives are discussed in this section.

From the ratepayer perspective, a customer with a PV system can experience a certain set of costs and benefits. Benefits can include a reduction in utility bills as a result of self-generation and financial incentives from the utility in the form of NEM. Costs include the capital investment in the PV system and costs associated with ongoing maintenance of the system. However, customers without PV systems also may be affected and may experience costs and benefits as a result of the systems installed by others. For example, if the utility's cost for implementing NEM exceeds the estimated benefit, the utility could increase rates for all customers to make up for the shortfall, and customers without PV would pay more as a result of the NEM program. At least five of the studies explore concerns about potential "cross subsidization" between those customers installing rooftop solar and those who do not.

From the utility's perspective, its business can experience both benefits and costs due to NEM and distributed solar. Some values that constitute a benefit for the ratepayer can present themselves as a cost to the utility. For example, the benefit of bill savings to the customer is the same as lost revenue to the utility. If and how that lost revenue is captured though different rate designs can affect both participating (i.e., with PV systems) and non-participating (i.e., without PV systems) customers.

From a grid perspective, NEM and distributed PV and other DERs can provide benefits and incur costs to the electric grid as a function of the resource's location and operational characteristics. The benefits and costs of a particular resource reflect distribution system factors such as load relief, reliability, power quality, voltage regulation, and resilience. In addition, the net benefits of these resources can reflect issues on the bulk system, such as resource adequacy and system flexibility, as well as societal benefits related to emission reductions, health impacts, and environmental justice.

Nine studies also consider a fourth perspective—the perspective of a broader society—which can result in variations in the costs and benefits assessed. For example, the value category associated with the cost of carbon can be assessed for its utility system value and its societal value. From the utility perspective, the cost of carbon reflects an emissions allowance price, either in an observed market or one used by the utility for planning purposes. The value component takes on a different, and potentially more substantial, value when it is assessed from the societal perspective, where it reflects the benefit that all society may experience from lower carbon emissions. This concept is further discussed in a later section, "Societal Values."

Many of the studies in this meta-analysis accounted for multiple perspectives in their assessments. The inclusion or omission of a given perspective is sometimes determined by the jurisdiction in which the study is being performed, either legislatively or in regulatory dockets. The following excerpt from the South Carolina study provides an example:

> "While advocates of renewable energy point to numerous environmental and societal benefits that could be included in an analysis of the Value of DER, the directive of Act 236 was to develop a methodology that would 'ensure that the electrical utility recovers its cost of providing electrical service to customer-generators and customers who are not customer-generators.' Therefore, the Methodology is limited to the quantifiable benefits and costs currently

experienced by the Utility. Likewise, the analysis performed for this report focuses on the quantifiable benefits and costs to the Utility with recognition that those benefits and costs experienced by the Utility are ultimately passed on to its ratepayers."[49]

One approach, taken by seven of the studies, to assess various stakeholder perspectives is to apply one or more of the set of cost-effectiveness tests that are typically applied to energy efficiency programs. These include the Total Resource Cost (TRC) test, Utility Cost Test (UCT), Participant Cost Test (PCT), Societal Cost Test (SCT), and Rate Impact Measure (RIM) Test. Figure 6 provides an overview of the tests. For more information on these cost tests, see the National Efficiency Screening Project's 2017 *National Standard Practice Manual.*[50]

Figure 6. Overview of cost-effectiveness tests (adapted from the National Efficiency Screening Project)

Test	Perspective	Key Question Answered	Summary Approach
Utility cost	The utility system	Will utility system costs be reduced?	Includes the costs and benefits experienced by the utility system
Total Resource Cost	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the costs and benefits experienced by society as a whole
Participant Cost	Customers who participate in an efficiency program	Will program participants' costs be reduced?	Includes the costs and benefits experienced by the customers who participate in the program
Rate Impact Measure	Impact on rates paid by all customers	Will utility rates be reduced?	Includes the costs and benefits that will affect utility rates, including utility system costs and benefits plus lost revenues

[49] Patel, et al., 2015 p. 7.
[50] NESP, 2017.

Figure 7 notes which of the five traditional cost-effectiveness tests were used by the studies in this meta-analysis as an indicator of the perspectives considered. For studies that did not apply cost-effectiveness tests, either cost-effectiveness was not assessed or other analytical methods were used such as the Cost of Service or Revenue Requirements approaches. When evaluating the results of the studies, the perspective of which stakeholders' lens or lenses were applied should be noted.

Figure 7. Summary of cost-effectiveness test used in studies

			Cost-Effectiveness Test				
State	Year	Prepared by	PCT	UCT	RIM	TRC	SCT
Arkansas	2017	Crossborder	√	√	√	√	√
District of Columbia	2017	Synapse		√			√
Georgia	2017	Southern Company					
California	2016	CPUC	√		√		
Nevada	2016	E3	√	√	√	√	√
New York	2016	NY DPS		√	√		√
Hawaii	2015	CPR					
Louisiana	2015	Acadian					
Maine	2015	CPR					
Oregon	2015	CPR					
South Carolina	2015	E3			√		
Minnesota	2014	CPR					
Mississippi	2014	Synapse	√			√	
Utah	2014	CPR					
Vermont	2014	PSD					

Input Assumptions

This section includes a discussion of input assumptions that can cause studies to arrive at different outcomes, including assumptions about the displaced marginal unit, PV penetration levels, treatment of integration costs, inclusion of externalities, and choices about discount rates.

Displaced Marginal Unit

Generation from distributed solar is assumed to displace the marginal generation unit, resulting in avoided energy costs. Generators are generally dispatched in merit or lowest cost order to meet load, and the resource displaced on the margin is the next highest cost generator that can reduce its output in response to solar output. More than one method is used in the studies to estimate which plants are on the margin. Some studies use a typical generator, such as a combined-cycle gas turbine, or a blended mix of generators, as a simple proxy for the avoided generator. Most studies use wholesale market prices based on historical locational marginal prices. A third approach is to use a dispatch model or some other form of production simulation run to estimate what resource is on the margin when distributed solar is expected to displace generation.

Assumptions about the efficiency of the marginal unit (heat rates) and the price of fuel for the marginal unit are dominant factors in avoided energy input costs. In most cases, natural gas was assumed to be the marginal fuel. Most studies estimate future natural gas prices using EIA's *Annual Energy Outlook* or some other source, such as New York Mercantile Exchange (NYMEX) gas futures. In Hawaii, oil-fired generation is predominant and the study recommends using futures for oil instead of natural gas, and transportation to the island would have to be factored in. The study from Maine also acknowledged that fuel oil may occasionally be the marginal fuel and, in such cases, natural gas displacement was used as a simplifying assumption.[51] In New York, Locational Based Marginal Pricing (LBMP) is used, which represents the cost of the marginal generator plus congestion pricing.[52] The Georgia study uses an hourly approach to estimate the cost of avoided energy, and does not assume a single fuel or technology.[53] For a more detailed look at assumptions from the individual studies on displaced marginal units, see Appendix C.

Solar Penetration

A 2012 report from the Lawrence Berkeley National Laboratory (LBNL) examined changes in the economic VOS PV at relatively high penetration levels and identified a decrease in value components as penetration increases.[54] For penetrations of 0 percent to 10 percent, LBNL found that the primary driver was a decrease in capacity value because additional PV is less effective at avoiding new non-renewable generation capacity at high penetration than at low penetration. For penetrations of 10 percent and higher, the primary driver was a decrease in energy value because additional PV starts to displace generation with lower variable costs at higher penetration levels. In California, a glut of solar generation in the middle of the day from both the central station and distributed solar has contributed to a situation where solar generation is exported to surrounding States during high solar/low load periods.

ICF reviewed the studies for considerations related to PV penetration and to identify what ranges of PV penetration levels were considered. Penetration level is expressed in terms of total distributed solar nameplate capacity as a percentage of total peak capacity. The 15 studies generally considered current or near-term penetration levels with estimates ranging from 0.2 percent to 6 percent, as shown in Table 5. The table also indicates estimated penetration of NEM PV capacity as a percentage of peak load in 2016 for the States where the studies came from.[55]

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[51] Norris, B. 2015(b). *Valuation of Solar + Storage in Hawaii: Methodology*. Prepared for the Interstate Renewable Energy Council (IREC) by Clean Power Research. p. 11. Available at http://www.irecusa.org/wp-content/uploads/2015/06/IREC-Valuation-of-Solar-Storage-in-HI_Methodology_2015.pdf; Norris, et al., 2015, p. 19.

[52] New York Department of Public Service (NY DPS), 2016(a), Appendix C, p. 5.

[53] Southern Company. 2017. *A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia*. Revised May 12, 2017. p. 9. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=167588.

[54] Mills, Andrew, and Ryan Wiser. 2012. *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California*. Berkeley, CA: Lawrence Berkeley National Laboratory. p. 7. Available at https://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf. Table ES.1 shows decomposition of the marginal economic value of PV in 2030, with increasing penetration from 0 percent to 30 percent.

[55] We estimate PV penetration by dividing NEM PV nameplate capacity (MW) by peak load (MW). For NEM PV capacity, data by State was obtained from EIA at https://www.eia.gov/electricity/data/eia861. For peak load, we map States by NEMS region and use AEO 2016 sales data (MWh), adjusted for transmissions losses, to calculate net energy needed to meet load in the State. Net energy is divided by the load factor for the NEMS region to derive peak load. Transmission losses and load factor are obtained from AEO 2016.

Table 5. PV penetration assumed in studies reviewed

State	Year	Prepared by	PV Penetration Specified in Study	Estimated PV Penetration (2016)
Arkansas	2017	Crossborder	Below 5%	0.1%
District of Columbia	2017	Synapse	Current levels	1%
Georgia	2017	Southern Company	Unspecified	<0.1%
California	2016	CPUC	Unspecified	9%
Nevada	2016	E3	Approx. 3%	2%
New York	2016	NY DPS	Unspecified	2%
Hawaii	2015	CPR	Unspecified	22%
Louisiana	2015	Acadian	0.5%	1%
Maine	2015	CPR	Approx. 0.2%	1%
Oregon	2015	CPR	Unspecified	1%
South Carolina	2015	E3	2% in 2021	0.3%
Minnesota	2014	CPR	Near-term level	0.2%
Mississippi	2014	Synapse	0.5%	<0.1%
Utah	2014	CPR	Unspecified	2%
Vermont	2014	PSD	Approx. 6%	6%

Studies that only present methodologies or valuation frameworks tended not to specify assumptions about penetration levels, but some discuss the need to reflect penetration increases. For example, in Minnesota, the change in PV penetration level is accounted for in an annual adjustment to account for the impact of higher solar penetration on hourly utility load profiles and Effective Load Carrying Capacity (ELCC) and Peak Load Reduction (PLR) calculations.[56] ELCC and PLR are used in some studies in calculations of avoided generation capacity and avoided transmission and distribution capacity.

Some studies also may consider higher penetration rates in considerations related to integration costs. For example, the studies from Arkansas and Oregon reference a 2014 report by the Pacific Northwest National Laboratory (PNNL) for Duke Energy that indicated a trend of increasing PV integration costs at successively higher PV levels in the utility's service territory.[57] While solar generation for the nation is likely to remain below 3 percent over the next 5 years, some States are expected to reach much higher levels.[58] Nevada, California, Hawaii, and Vermont are all projected to have more than 20 percent of their generation from solar by 2021, which could affect value categories.[59]

Integration Costs

The majority of studies include costs incurred by the utility to integrate distributed solar; however, very few specify which costs they are referring to or differentiate between costs on the bulk power system or

[56] Norris, B.; M. Putnam: and T. Hoff. 2014. *Minnesota Value of Solar: Methodology.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources by Clean Power Research. pp. 5–6, p. 17. Available at https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

[57] Beach and McGuire, 2017, p. 34; Norris, 2015(a), p. 25; and Pacific Northwest National Laboratory (PNNL). n.d. *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas.* Available at http://www.pnucc.org/sites/default/files/Duke%20Energy%20PV%20Integration%20Study%20201404.pdf.

[58] Feldman, D.; D. Boff; and R. Margolis. 2016. *Q3/Q4 2016 Solar Industry Update*. Available at https://www.nrel.gov/docs/fy17osti/67639.pdf.

[59] Ibid., p. 9.

the distribution system. A 2015 National Renewable Energy Laboratory (NREL) report defines integration costs as the change in production costs associated with a system's ability to accommodate the variability and uncertainty of the net load.[60] That report investigated four components of production costs: cycling costs, non-cycling variable operations and maintenance costs (VO&M), fuel costs, and reserves provisioning costs. It did not include capital and other fixed costs.

Four studies reviewed in the meta-analysis quantify values for integration costs that ranged from $1.00/MWh to $5.00/MWh. Several studies rely on existing literature to either estimate their integration costs or reference findings with modifications based on assumptions about PV penetration levels.[61] Existing literature discussed in the selection of studies as a basis for integration cost include:

- A 2014 study by PNNL prepared for Duke Energy on PV integration in the Carolinas, which estimates integration costs in the range of $1.43/MWh to $9.82/MWh based on the level of penetration.[62]
- A 2014 study by Idaho Power to estimate the costs of the operational modifications necessary to integrate intermittent generation from solar plants, which estimates costs ranging from $0.40/MWh to $2.50/MWh for PV capacity ranging from 100 MW to 700 MW.
- A 2013 study prepared by Xcel Energy on the costs and benefits of distributed PV on the Public Service Company of Colorado system.[63]
- The 2014 integrated resource plan of Arizona Public Service, which estimated integration costs on its system of $2.00/MWh in 2020.[64]
- A 2010 New England Wind Integration Study (NEWIS) prepared for ISO-New England by GE, Enernex, and AWS Truepower.[65]

Some studies identify the need for further research and evaluation on the costs of integrating increased solar PV to accurately account for the cost burden on the utility.[66] In California, the LNBA Working Group's report indicates that "bulk-system-level costs" associated with renewable integration are

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[60] Stark, Gregory B., P.E. 2015. *A Systematic Approach to Better Understanding Integration Costs.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-64502. Available at https://www.nrel.gov/docs/fy15osti/64502.pdf.

[61] Beach and McGuire, 2017; Price, et al., 2016; and Norris, et al., 2015.

[62] PNNL, n.d.

[63] Xcel Energy Services, Inc. 2013. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*. Available at http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf.

[64] Arizona Public Service (APS). 2014. *Integrated Resource Plan.* Available at http://www.azenergyfuture.com/getmedia/c9c2a022-dae4-4d1b-a433-ec96b2498e02/2014_IntegratedResourcePlan.pdf/?ext=.pdf.

[65] GE Energy. 2010. *New England Wind Integration Study.* Available at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf. NEWIS results were considered in the Maine study (p. 37) as an upper bound on solar integration costs. NEWIS assessed the operational effects of large-scale wind integration in New England, and the Maine analysis assumes that distributed solar will have lower variability than wind because of its more distributed nature.

[66] Whited, et al., 2017; Norris, et al., 2014; New York Department of Public Service (NY DPS), 2016(b); Norris, 2015(a); and Stanton, et al., 2014.

included, but there is no consensus on whether this category should represent costs associated with increasing hosting capacity or facilitating interconnection.[67] Two studies—Vermont and Utah—did not address integration costs.

Societal Values

The decision to include externalities—such as carbon emissions, criteria pollutants, economic development, or other values that accrue to society—can have a significant impact on study results, and agreement was not found across the studies on the inclusion or exclusion of these values. The study from Mississippi describes these externality costs as "environmental damages incurred by society (over and above the amounts 'internalized' in allowance prices)" and indicates that avoided costs from displaced air emissions are "a benefit to the State and can be considered in benefit and cost analysis without necessarily including these non-market costs in an avoided cost rate."[68] Still, the study does not monetize these benefits.

The study from Hawaii describes the issue further: "In general, it is more difficult to obtain consensus on the inclusion or exclusion of environmental components and other societal values. This is partly due to the fact that they are not the utility avoided costs (i.e., they are not expenses incurred by the utility or collected in rates) and partly because the methodologies rely on more speculative assumptions."[69]

Overall, nine studies include societal benefits. The studies from Oregon, Louisiana, Utah, South Carolina, and Georgia explicitly do not include societal benefits. A common rationale for this exclusion is that societal benefits do not accrue as savings in the form of avoided costs to the utility, which means the benefits cannot be passed along to ratepayers. This choice is a general reflection of the perspectives considered in a study.

Carbon Emissions

Most studies include avoided costs to the utility of complying with carbon regulations, either within the avoided energy generation component of the value categories, or a separate category for avoided environmental compliance. However, only some consider the societal value of reduced carbon emissions. Three studies—Arkansas, Maine, and the District of Columbia—calculate societal values related to carbon emissions. Each used the Social Cost of Carbon developed by the U.S. Environmental Protection Agency as a starting point for estimating the value.[70] Table 6 shows the range of values.

Table 6. Range of societal carbon values ($/MWh)

State	Unadjusted Societal Value of Carbon	Dollar Year of Unadjusted Value	Adjusted Value to 2017$
Arkansas	$35.90	2018$	$35.15
Maine	$21.00	2015$	$21.72
District of Columbia	$36.00	2016$	$36.76

[67] California Public Utilities Commission (CPUC), 2017, p. 20.
[68] Stanton, et al., 2014, p. 34.
[69] Norris, 2015(b), p. 14.
[70] The source for estimates of the social cost of carbon is the Federal Government's Interagency Working Group on the Social Cost of Greenhouse Gases. See *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Updated August 2016). Available at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

Criteria Pollutants and Other Avoided Environmental Costs
Of the nine studies that include societal values for other avoided environmental costs besides carbon, two included values related to criteria pollutants, which tended to be higher than the societal value ascribed to carbon. For example, in the Arkansas study, avoided carbon costs were valued at \$35.90/MWh compared to \$84.40/MWh for criteria pollutants.[71] Similarly, in the study from Maine, avoided carbon costs were valued at \$21.00/MWh compared to \$75.00/MWh for criteria pollutants.[72] A few studies discussed other benefits, such as avoided methane leakage, water use, and land use benefits, but only the Arkansas study estimated non-zero values for these categories. The values were \$8.00/MWh in reduced methane leakage and \$1.20/MWh in avoided water use benefits. Land use benefits were described as "small and positive" but could vary.

Economic Development
The studies from Mississippi and the District of Columbia discussed the societal value of increased economic development, but only the study from Arkansas estimated a non-zero value. In the Mississippi study, economic development benefits, "including job creation and the potential for increased home value," were not monetized because a societal cost test analysis was not performed.[73] The District of Columbia study indicated that increased distributed solar "may contribute new jobs to the District, resulting in reduced unemployment and need for social services while increasing tax revenue," but these benefits were not given a value due to insufficient data.[74] For Arkansas, economic development value was estimated at \$33.60/MWh based on an assumption that 22 percent of residential system PV costs are spent in the local economy where the systems are located.[75]

In addition, the study from Louisiana included a solar installation benefits category, which included economic benefits calculated using the Jobs and Economic Development Impact (JEDI) model developed by the National Renewable Energy Laboratories.[76] The study does not differentiate these benefits as societal impacts, but does indicate the portion that is direct, indirect, or induced.

Discount Rate

Discount rates are applied in calculations of the utility's avoided costs and in calculation of societal benefits, if they are included. The higher the discount rate, the lower the value of the long-term benefits of distributed PV and other DERs. For more information on how benefits can be affected by different discount rates, and a summary of the types of discount rates that could be used, see the National Efficiency Screening Project's 2017 *National Standard Practice Manual*.[77]

In general, studies take similar approaches to applying discount rates. For avoided costs from the utility perspective, most studies use a utility-specific weighted average capital cost (WACC) rate as the discount rate. The District of Columbia study was an exception, which found that an alternative discount rate (below Pepco's WACC) was justified because many avoided costs are not capital costs and the

[71] Beach and McGuire, 2017, pp. 26–27.
[72] Norris, et al., 2015, p. 49.
[73] Stanton, et al., 2014, p. 44.
[74] Whited, et al., 2017, p. 151.
[75] Beach and McGuire, 2017, p. 29.
[76] Dismukes, 2015, p. 121.
[77] NESP, 2017, p. 73.

District's policy goals place a strong emphasis on long-term benefits. For avoided costs from the societal perspective, most studies use the societal discount rate of 3 percent in real dollars.

Conclusion

This meta-analysis examines a representative sample of recent studies on the costs and benefits of NEM. It finds that, with widely varying goals and policy contexts, as well as differences in the categories included and the assumptions used, these studies support a range of conclusions regarding NEM policies' net benefits, cost-shifting impacts, and alignment with DER-driven values. The perspective from which value is assessed drives methodology, and decisions on value categories, quantification methods, and input assumptions have significant impacts on findings.

Because the distribution grid and retail service are regulated at the individual State level, it is understandable that there is not one common valuation framework for evaluating the costs and benefits of distributed solar and DER more broadly. That said, we believe that the development of a common set of definitions and categories would help in assisting States, utilities, and other stakeholders to work from a common starting point when endeavoring to determine the net benefit of distributed solar and DER.

Despite these significant methodological differences, the 15 studies analyzed in this paper converge on at least three common value categories, all at the wholesale or bulk power level: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Methodological approaches to calculating these common categories are generally well established, similar, and agreed upon, with the quantified result potentially differing based on a wide range of regional factors and assumptions.

Overall observations from this analysis show, not surprisingly, that a major challenge in studying and developing an approach to NEM, VOS, and DER valuation is that some value components are relatively easy to quantify, while others are more difficult to represent by a single metric or measure. Given the relative newness of evaluating the cost, performance, and therefore net benefit to the distribution grid, the majority of differences between the studies occur in this area. Still, avoided or deferred distribution capacity over a longer term planning horizon is relatively easier to quantify as opposed to the less common value categories that were identified as difficult to calculate or forecast based on data availability or lack of a widely accepted quantification process.

As States and utilities deploy new technologies that can assist in gaining a more detailed understanding of the locational and temporal value of DERs across the electricity system, it will enhance the ability to more accurately assess the costs and benefits of deploying DER on the system. This meta-analysis demonstrates how specific variables, approaches, and assumptions related to the costs and benefits of distributed PV were treated in a selection of studies from a snapshot in time, during a period when frameworks are rapidly evolving and best practices are still being defined.

Appendix A: Summaries of Selected Studies

This section includes short summaries of each study. The summaries follow a standard format, starting with the citation and continuing with three common elements: (1) the study's analytical goal or purpose; (2) any results or answers found in response to the analytical goal; and (3) the takeaways, in bullet form, that are noteworthy for the purposes of the meta-analysis.

Summaries are grouped by type of study and then presented in alphabetical order by State.

Type of Study	States (Prepared by)
NEM Cost-Benefit Analysis	▪ Arkansas (Crossborder) ▪ Louisiana (Acadian) ▪ Mississippi (Synapse) ▪ Nevada (E3) ▪ South Carolina (E3) ▪ Vermont (VT PSD)
VOS/NEM Successor	▪ District of Columbia (Synapse) ▪ Georgia (Southern Company) ▪ Hawaii (CPR) ▪ Maine (CPR) ▪ Minnesota (CPR) ▪ Oregon (CPR) ▪ Utah (CPR)
DER Value Frameworks	▪ California LNBA (CPUC) ▪ New York BCA (DPS Staff)

NEM Cost-Benefit Analysis

Arkansas

Beach, R., and P. McGuire. 2017. *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.* Crossborder Energy. Available at https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

This report provides a cost-benefit analysis of "the impacts on ratepayers of the net metering of solar distributed generation [DG] in the service territory of Entergy Arkansas, Inc. (EAI)."[78] The goal of the report is to "contribute to the Commission's review" of net metering issues in response to recent legislation directing the Arkansas Public Service Commission (PSC) to evaluate the rates, terms, and conditions of net metering in Arkansas.[79]

The report concludes that "the benefits of residential DG on the EAI system exceed the costs, such that residential DG customers do not impose a burden on EIA's other ratepayers."[80] The study summarizes the results based on the application of five cost-effectiveness tests (i.e., participant test, RIM test, program administrator cost test, total resource cost test, and societal cost test).

Noteworthy takeaways include:

- The report was commissioned by the Sierra Club and submitted to the Arkansas PSC as part of the *Joint Report and Recommendations of the Net-Metering Working Group* in Docket No. 16-027-R.[81]
- Benefits equal or exceed the costs in the total resource cost, program administrator cost, and societal cost tests.[82]
- The RIM test was used to determine that net metering does not cause a cost-shift to non-participating ratepayers.[83]
- As the cost of integration, the study uses an estimate of "$2 per MWh as the cost of additional ancillary services that may be needed to integrate solar DG into the grid."[84]
- The study found "significant, quantifiable societal benefits" from solar DG.[85]

Louisiana

Dismukes, D. 2015. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*. Baton Rouge, LA: Acadian Consulting. Available at http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5.

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[78] Beach and McGuire, 2017, p. 1.

[79] Act 827 of 2015 tasked the PSC with addressing various issues associated with net metering.

[80] Beach and McGuire, 2017, p. 2.

[81] Arizona Public Service (APS). 2017. *Joint Report and Recommendations of the Net-Metering Working Group.* Docket 16-027-R-Doc. 228. Available at http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf.

[82] Ibid., p. 3.

[83] Ibid.

[84] Ibid., p. 2.

[85] Ibid., p. 4.

The goal of this report is "to quantify the impacts and implications of NEM policies currently being used by the Louisiana Public Service Commission [LPSC] for smaller scale residential and commercial solar energy installations." Three different empirical models are used to estimate the impacts on the ratepayers of LPSC-regulated utilities: a benefit-cost analysis, a cost of service analysis, and an analysis of the income levels of customers installing solar NEM systems.

The cost-benefit analysis was the primary focus in this meta-analysis. It concludes that "the estimated costs associated with solar NEM installations outweighs their estimated benefits."[86] For instance, costs are 1.5 times higher than benefits under the baseline scenario, resulting in negative total net benefits to LPSC ratepayers of $89 million in net present value (NPV) terms.[87]

Noteworthy takeaways include:

- The study looked at three scenarios: (1) a baseline condition including just solar NEM installations to date, (2) a condition in which NEM installations would grow at their historic rate until the installed capacity reached a mandated cap of 0.5 percent of system peak for each utility and then remained flat, and (3) a case in which NEM installations grow unbounded at the utility-specific 2012–2013 growth rate until 2017, after which growth rates slow to 10 percent per year until 2020 as a result of the tax credit phase-out.
- The study also performs three sensitivity analyses (i.e., high natural gas price, high electric capacity price, and carbon price) to test for conditions under which NEM would result in ratepayer benefits. The sensitivities did not shift the results in a direction that was favorable for ratepayers.[88]
- Avoided energy benefits are substantially greater than avoided capacity benefits due to the low effective capacity VOS in Louisiana. Avoided capacity benefits represent the third largest source of benefits.[89]
- Avoided T&D benefits are relatively small, at less than $1 million, because the unit cost of avoided T&D is smaller than generation, and the effective capacity of solar NEM is relatively small.[90]
- Direct, indirect, and induced "solar installation impacts represent the single largest source of total NEM program benefits." These benefits are modeled using the Jobs and Economic Development Impact (JEDI) solar PV model developed by NREL.[91]

Mississippi

Stanton, E.; J. Daniel; T. Vitolo; P. Knight; D. White; and G. Keith. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations.* Cambridge, MA: Synapse Energy Economics, Inc. Available at https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

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[86] Dismukes, 2015, p. ii.
[87] Ibid., p. 186.
[88] Ibid.
[89] Ibid., p. 131.
[90] Ibid.
[91] Ibid., pp. 122, 132.

This report provides a description of a potential net metering policy for Mississippi and the issues surrounding it, focusing on residential and commercial rooftop solar. The report models and analyzes the impacts of installing rooftop solar equivalent to 0.5 percent of the State's peak historical demand, with a goal of estimating the potential benefits and costs of a hypothetical net metering program.

The report concludes that "net metering provides net benefits under almost all of the scenarios and sensitivities analyzed."[92]

Noteworthy takeaways include:

- At the time the report was prepared, Mississippi was one of five States without a net metering policy.[93]
- Of the value categories considered, the study finds that avoided energy costs provided the greatest benefit, followed by avoided T&D costs, and the value associated with reduced risk.
- Reduced risk includes transmission costs, T&D losses, fuel prices, and other costs. A 10 percent adder was applied to calculate avoided costs in the study.[94]
- In sensitivity analyses, variations in avoided T&D cost generated the most noticeable impact on the benefits of NEM. Projected capacity value and projected CO_2 costs had some impact, while fuel prices had a minor impact.[95]
- Of the cost-effectiveness tests used for energy efficiency in Mississippi (the TRC, RIM, and UCT), the study finds that the TRC test best reflects and accounts for the benefits of distributed generation. The authors do not recommend the use of the RIM test to analyze the efficacy of NEM.[96]
- Generation from rooftop solar panels in Mississippi will most likely displace generation from the State's peaking resources—oil and natural gas combustion turbines.[97]
- Results show that NEM participants would need to receive a rate beyond average retail in order to pursue NEM and suggest that policymakers consider an alternative to NEM, such as a solar tariff structure similar to Minnesota and the Tennessee Valley Authority.[98]

Nevada

Price, S.; Z. Ming; A. Ong; and S. Grant. 2016. *Nevada Net Energy Metering Impacts Evaluation 2016 Update.* San Francisco, CA: Energy and Environmental Economics, Inc. Available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.

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[92] Stanton, et al. 2014, pp. 2–3. See graph summarizing finding on p. 5.
[93] Walton, Robert. December 7, 2015. "Mississippi regulators approve state's first net metering plan." Utility Dive. Available at https://www.utilitydive.com/news/mississippi-regulators-approve-states-first-net-metering-plan/410341/.
[94] Stanton, et al. 2014, p. 30. For the purposes of the meta-analysis, this value is reflected in the "Fuel Hedging" category; however, it is noteworthy that the component is intended to include additional factors.
[95] Ibid., pp. 45–47.
[96] Ibid., p. 41.
[97] Ibid., pp. 1, 21.
[98] Ibid., p. 50.

This report provides an update to the 2014 report, *Nevada Net Energy Metering Impacts Evaluation*, which calculated the costs and benefits of renewable generation systems under the State's NEM program.

The goal is to "investigate the impact of existing NEM PV systems as well as the projected impact of future NEM PV systems," following the same methodological framework as the 2014 report, but incorporating the most up-to-date utility data. It evaluates the cost-effectiveness of NEM from five different perspectives to assess the costs and benefits of the NEM program.

The report concludes with the following base case results for each of the five perspectives of cost-effectiveness:

- Participant Cost Test (PCT): Solar is not cost-effective for customers who install PV systems; however, the net cost to participating customers is relatively small, at $0.02/kWh, for existing systems.[99]
- Ratepayer Impact Measure (RIM): There is a cost-shift from NEM customers to non-participating customers that amounts to a levelized cost of $0.08/kWh for existing installations.[100]
- Program Administrator Cost Test (PACT): Existing and future NEM systems cause total bills collected by NV Energy to decrease.[101]
- Total Resource Cost (TRC) Test: NEM generation increases total energy costs for Nevada at a net cost to the State of $0.13/kWh for existing systems.[102]
- Societal Cost Test (SCT): The societal perspective does not significantly change the results for the costs and benefits of NEM overall.[103]

Noteworthy takeaways include:

- The finding that NEM generation is a costlier approach is mainly due to utility-scale solar power purchase agreement prices having dropped precipitously in recent years, which greatly lessens the costs avoided by NEM generation, while distributed solar costs have not dropped commensurately.[104]

South Carolina

Patel, K.; Z. Ming; D. Allen; K. Chawla; and L. Lavin. 2015. *South Carolina Act 236: Cost Shift and Cost of Service Analysis*. San Francisco, CA: Energy and Economics, Inc. Available at http://www.regulatorystaff.sc.gov/electric/industryinfo/Documents/Act%20236%20Cost%20Shifting%20Report.pdf.

The goal of this report is "to investigate and report to the Public Service Commission of South Carolina the extent to which cost shifting can be attributed to DER adoption within current rate making practices." The cost-shifting analysis examines the effects of NEM in the context of three scenarios:

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99 Price, et al., 2016, p. 6.
100 Ibid., p. 7.
101 Ibid., p. 8.
102 Ibid., p. 9.
103 Ibid., p. 10.
104 Ibid., p. 13.

(1) historical DER adoption, (2) future DER adoption without utility incentives offered through DER programs, and (3) future DER adoption with incentives from DER program participation.

The report concludes that prior to Act 236, NEM-related cost-shifting was *de minimus* due to the low number of participants.[105] Furthermore, it states that "if utilities were to reach the DER adoption targets set in Act 236 without additional incentives, the cost shifting would be small and difficult to isolate." Finally, the report finds that "although more data is required to draw widespread conclusions, the utilities rate structures may need to evolve to be more economically efficient and to alleviate the potential for cost shifting or for uneconomic bypass of the utilities fixed cost recovery. Specifically, fixed charges may need to increase or alternative rate designs may need to be considered."[106]

Noteworthy takeaways include:

- This report evaluates the impacts of DER in the South Carolina Electric and Gas, Duke Energy Carolinas, and Duke Energy Progress service territories.
- The study used three scenarios—low value, base value, and high value—"to capture the uncertainty associated with the future value of DER."[107] The low-value scenario is based on fewer components in the methodology (avoided energy and avoided losses). The base-value scenario "includes most components" (avoided energy, avoided losses, avoided ancillary services, avoided T&D capacity, and avoided criteria pollutants). The high-value scenario includes all of the components in the base-value scenario and approximates a value for a carbon cost placeholder.
- The report was presented to the Office of Regulatory Staff to fulfill its requirements for South Carolina's 2008 Distributed Energy Resource Program Act (Act 236).

Vermont

Vermont Public Service Department (PSD). 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*. Available at http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20FINAL.pdf.

The goal of this report is to address a legislative request directing the Public Service Department to "complete an evaluation of net metering in Vermont." It provides background describing changes to net metering contained in Act 99 of 2014, and the current status and pace of net metering deployment in Vermont. It includes an updated analysis of the existence and magnitude of any cross subsidy created by the current net metering program pursuant to Act 125 of 2012. It also provides guiding principles for net metering program design based on a review of recent literature.

The "analysis of the existence and degree of potential cross-subsidy" was the primary focus in this meta-analysis. It concludes that "the aggregate net cost over 20 years to non-participating ratepayers due to net metering under the current policy framework is close to zero, and there may be a net benefit."

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[105] Patel, et al., 2015, p. ii.
[106] Ibid.
[107] Ibid., p. 12.

Noteworthy takeaways include:

- Based on an analysis of the differences among utilities, which found that winter-peaking utilities will incur a larger share of costs, Vermont PSD recommends that the Board consider whether changes to the current program structure to allow flexibility for the program to vary by utility would better serve the State.[108]
- The report presented the results for six types of systems:
  - 4-kW fixed solar PV system, net metered by a single residence
  - 4-kW two-axis tracking solar PV system, net metered by a single residence
  - 4-kW wind generator, net metered by a single residence
  - 100-kW fixed solar PV system, net metered by a group
  - 100-kW two-axis tracking solar PV system, net metered by a group
  - 100-kW wind generator, net metered by a group
- The report provides results from the perspective of the ratepayer and a statewide/societal perspective. The ratepayer perspective uses a higher discount rate (7.44 percent) and includes a renewable energy credit (REC) value. The statewide/societal calculation uses a lower discount rate (4.95 percent), includes avoided externalized greenhouse gas costs, and does not include a REC value.[109]

VOS/NEM Successor

District of Columbia

Whited, M.; A. Horowitz; T. Vitolo; W. Ong; and T. Woolf. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting.* Cambridge, MA: Synapse Energy Economics, Inc. Available at http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.

This report provides both a VOS study framework (Part III) and a cost-shifting analysis (Part IV). The goal of the VOS study framework is "to determine the value of solar to the utility system and all electric customers in the District," using a "cost-benefit analysis in which all relevant costs and benefits are quantified and analyzed."[110] The goal of the cost-shifting analysis is to conduct a long-term rate impact analysis to understand the effects of cost-shifting from distributed solar customers to non-solar customers, which result in higher bills for non-solar customers.[111] It is "related to the value of solar conducted in Part III, but is a separate analysis that provides an entirely different perspective on customer impacts stemming from distributed solar."

The report concludes that "the utility system total value of solar for 2017–2040, when levelized with a 3 percent discount rate, is $132.66/MWh (2015$)." The societal total VOS for the same time period and

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[108] Vermont Public Service Department (PSD). 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014.* p. 28. Available at http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20FINAL.pdf.
[109] Ibid., p. 16.
[110] Whited, et al., 2017, p. 115.
[111] Ibid., p. 157.

discount rate is $194.40/MWh.[112] The cost-shifting analysis concludes in the base-case scenario that "the typical residential non-solar customer in the District would experience an additional cost of $0.28 per year on average due to distributed solar." In all cases examined, the study finds that "cost-shifting remains relatively modest at less than $1.00 annual impact per residential customer."113

Noteworthy takeaways include:

- Eighteen value categories of potential costs and benefits associated with solar PV are considered. Sixteen were categorized as "utility system" impacts, meaning that the cost or benefit affects all customers in the utility system. Two categories (outage frequency duration and breadth, and social cost of carbon) were deemed "societal" in that they also impact people outside of the District.[114]
- The results are "highly dependent on future gas prices." The avoided energy category, which includes losses and costs associated with risk, represents about half of the utility VOS (and more than a third of the societal value).[115]
- The societal VOS is "quite dependent on the social cost of carbon," which represents a quarter of total societal value.[116]
- The report recommends a continuous update of the VOS model, acknowledging that as solar penetration increases above 10 percent of peak load, so does the likelihood that integration costs will increase.

Georgia

Southern Company. 2017. *A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia.* Revised May 12, 2017. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=167588.

This report provides a framework for determining the costs and benefits of renewable resources on the Southern Company electric system, known as the Renewable Cost Benefit (RCB) Framework. The goal of the report is to describe the RCB Framework and how it will be used, specifically related to the Georgia Power Company. The report considers 23 cost-benefit components for potential inclusion in the RCB Framework, defines and discusses each component, and makes a recommendation on whether the component should be included as a cost or a benefit. The framework provides a methodology to calculate some of the components.

The report finds 18 "in-scope renewable cost benefit components."[117]

Noteworthy takeaways include:

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[112] Ibid., p. 10.
[113] Ibid., p. 14.
[114] Ibid., p. 10.
[115] Ibid., p. 12.
[116] Ibid.
[117] Ibid.

- The document recognizes five different categories of solar to differentiate the type being evaluated (i.e., utility-scale transmission, utility-scale distribution, distributed greenfield, distributed metered, and distributed behind-the-meter).[118]
- The framework finds five cost categories: distribution operations costs, ancillary services – reactive supply and voltage control, ancillary services – regulation, support capacity (flexible reserves), and bottom-out costs. A sixth category, generation remix, may be either a benefit or a cost.[119]
- The avoided energy cost category includes a number of components and represents the "energy-related costs that are avoided on the Southern Company electric system in any given hour (including components associated with marginal replacement fuel costs, variable operations and maintenance, fuel handling, compliance-related environmental costs, intra-day commitment costs, and transmission losses)."[120]
- The Framework does not include societal costs or other externalities.[121]

Hawaii

Norris, B. 2015(b). *Valuation of Solar + Storage in Hawaii: Methodology.* Prepared for the Interstate Renewable Energy Council (IREC) by Clean Power Research. Available at http://www.irecusa.org/wp-content/uploads/2015/06/IREC-Valuation-of-Solar-Storage-in-HI_Methodology_2015.pdf.

The goal of this report is to provide a preliminary "methodology that could be used to value solar energy coupled with battery storage in Hawaii."[122] The methodology is "intended to estimate the value (i.e., the net benefits minus costs, which accrue to the utility and its customers from grid connected, behind-the-meter distributed hybrid solar/storage resources." The report "proposes a strawman of benefit categories" and an overview of the computation of those categories.[123]

The report concludes that the methodology "advances the prior art developed for solar-only valuation studies," and if certain new elements related to hybrid resources are incorporated, "a state-of-the-art evaluation could be performed that would determine the benefit provided by solar energy dispatched after sundown to meet Hawaii's evening peak."[124]

Noteworthy takeaways include:

- The study draws extensively on methods used to value solar-only resources, but adds requirements to incorporate storage.
- An estimate of the benefits of distributed solar alone (including energy benefit and other benefits) is not included. However, the study suggests that readers could "suppose the benefit

[118] Southern Company, 2017, p. 3.
[119] Ibid.
[120] Ibid., p. 7.
[121] Ibid., p. 30.
[122] Norris, 2015(b), p. 1.
[123] Ibid., p. 10.
[124] Ibid., p. 21.

of solar alone is $0.20 per kWh." Then the analysis suggests that "net generation coming from the hybrid system would have a value of $0.20 + $0.103 = $0.303 per kWh."[125]

- The study suggests a more comprehensive analysis, "including the use of actual utility system load and cost data, a model of hourly dispatch, and other factors rather than the simplified assumptions," is required. The study serves as an example to give a rough approximation.[126]
- Frequency regulation is included as a benefit and identified as a value component that "has not been included in solar-only studies" but indicates that "storage has the ability to charge and discharge in response to signals from the grid operator in order to help regulate frequency."[127]
- The Avoided Distribution Capacity Cost category "may be problematic for Hawaii because HECO [Hawaiian Electric Company] is facing the possibility of cost increases in order to support solar in the distribution system."[128]

Maine

Norris, B.; P. Gruenhagen; R. Grace; P. Yuen; R. Perez; and K. Rabago. 2015. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission by Clean Power Research, Sustainable Energy Advantage, LLC, and Pace Law School Energy and Climate Center. Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

This goal of this report is to provide a methodology to value distributed solar for three utility territories in Maine: Central Maine Power, Emera Maine's Bangor Hydro District, and Maine Public District. The report concludes the overall value of distributed PV is $0.337/kWh.[129]

Noteworthy takeaways include:

- The distributed PV value is calculated for a set of benefit-cost categories for Central Maine Power and levelized over 25 years. Levelized results for the other two utility service territories are not shown.
- The results indicate that the levelized value of avoided market costs (including energy supply, transmission delivery, and distribution delivery) is lower than the levelized value of societal benefits (net social cost of carbon, SOx and NOx, market price response, and avoided fuel price uncertainty).
- Avoided energy costs, market price response, and net social cost of SOx deliver the largest values.
- Market price response and avoided fuel price uncertainty are included as societal benefits.
- This study includes placeholders for three value components:
  - Avoided natural gas pipeline costs, not included but left as a future placeholder if the cost of building future pipeline capacity is built into electricity prices

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[125] Ibid., p. 3.
[126] Ibid.
[127] Ibid., p. 16. The inclusion of frequency regulation in this study is represented in the meta-analysis within the broader category of "ancillary services." However, it is noteworthy that the value was only included as a value component because of the storage element.
[128] Ibid., p. 12.
[129] Norris, et al., 2015. See summary table on p. 56.

- Avoided distribution capacity cost, not included but left as a future placeholder if the peak distribution loads begin to grow (requiring new capacity)
- Avoided costs of voltage regulation, not included but left as a future placeholder if new interconnection standards come into existence, allowing inverters to control voltage and provide voltage ride-through to support the grid

Minnesota

Norris, B.; M. Putnam; and T. Hoff. 2014. *Minnesota Value of Solar: Methodology.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources by Clean Power Research. Available at https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

This report provides the methodology to be used by Minnesota utilities adopting a VOS tariff as an alternative to net metering. The goal of the VOS tariff is "to quantify the value of distributed PV electricity." The report provides the methodology and details each step of the calculation.

The report concludes that the methodology can be used to develop a credit for solar customers. An example calculation shows a value of $0.135/kWh.

Noteworthy takeaways include:

- This study was commissioned in response to 2013 legislation and provides an optional alternative compensation mechanism for utilities to adopt customer-owned distributed PV in place of current NEM.
- Some of the value components correspond to minimum statutory requirements, including "the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."[130]
- Any "non-required components" were selected only if they were based on known and measurable evidence of the cost to the utility.[131]
- The tariff is updated annually for enrolling customers based on new PV penetration data.
- The avoided fuel cost value "implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments."[132]
- In the example calculation, avoided fuel cost contributes to approximately 50 percent of the value.[133]
- Avoided voltage control cost and solar integration cost components are included as placeholders and are "reserved for future updates to the methodology." Solar integration costs are "expected to be small, but possibly measurable."[134]
- Credit for systems installed at "high value locations (identified in the legislation as an option)" is included as optional and is addressed in the "Distribution Capacity Cost" section. This is the value component "most affected by location."[135]

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[130] Norris, et al., 2014, p. 3.
[131] Ibid.
[132] Ibid.
[133] Ibid., p. 49.
[134] Ibid., pp. 40, 3.
[135] Ibid., p. 3.

Oregon

Norris, B. 2015(a). *PGE Distributed Solar Valuation Methodology.* Prepared for Portland General Electric by Clean Power Research. Available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2015-08-13-distributed-solar-valuation.pdf?la=en.

The goal of this report is to provide "a methodology to calculate the avoided costs that result from distributed solar production delivered to the Portland General Electric (PGE) distribution system." The resulting methodology is "designed primarily for determining the benefits and costs of the gross energy produced by a PV system prior to netting with local load," and methods for calculating export energy are not included. These considerations should be taken into account when applying this methodology in valuing energy provided by NEM systems.[136]

The report concludes with a methodology that gives a levelized value of distributed solar denominated in dollars per kWh, based on "several distinct value components, each calculated using separate procedures."

Noteworthy takeaways include:

- Avoided energy includes three components: avoided fuel costs, avoided variable O&M cost, and avoided fixed O&M cost.
- For solar integration costs, Clean Power Research recommends that PGE should either estimate a dollar amount per MWh cost using best judgment from the available studies performed elsewhere, develop its own integration cost methodology, or assume that the cost is negligible.[137]
- Clean Power Research does not recommend to PGE whether any of the societal benefits should be included or excluded from a benefit-cost study.[138]
- The treatment of avoided fuel price uncertainty would be different, depending upon metering arrangements. If solar generation is used to serve loads behind-the-meter, then this benefit accrues to the solar customer by avoiding energy purchased from the utility. If the energy is delivered to the grid directly for use by PGE in serving its customers, then the benefit accrues to all customers.[139]
- The study analysis period is 20 years.[140]
- The methodology is concerned primarily with the benefits and costs for distributed solar generation, but also can be modified for use with utility-scale resources (connected to transmission) by eliminating avoided transmission and distribution costs, and the loss savings factor.
- The methodology can be used for other generation technologies other than solar, but it does not include dispatch strategies or other methods to produce an assumed generation profile. (A profile is needed as an input to the methodology).

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[136] Norris, 2015(a), p. 6.
[137] Ibid., p. 25.
[138] Ibid., p. 36.
[139] Ibid., p. 34.
[140] Ibid., p. 9.

Utah

Norris, B. 2014. *Value of Solar in Utah.* Clean Power Research. Available at https://pscdocs.utah.gov/electric/13docs/13035184/255147ExAWrightTest5-22-2014.pdf.

The goal of this report is to estimate the value of solar in Utah for the territory served by Rocky Mountain Power. The results conclude that the total levelized VOS with all components included is $0.116/kWh, assuming a 25-year system lifetime.

- The value is based on avoided utility costs from the electricity produced by distributed PV.
- The VOS is the sum of six value categories: fuel, plant O&M, generation capacity, T&D capacity, avoided environmental costs (compliance), and fuel price guarantee value.
- The value does not include societal benefits "because they do not represent savings to the utility."
- The value represents the "long term contract rate at which a utility would be economically indifferent, based on the assumptions of this study. In other words, if a utility were to credit customers with a fixed amount of $0.116 per kWh produced by distributed PV over 25 years, the amount paid would offset the savings to the utility in generating and delivering the energy to the customer."[141]
- Utah Clean Energy and Rocky Mountain Power provided economic and technical assumptions and data.
- The analysis is performed in separate steps. First, the economic value is calculated based on perfect load match and no losses. The result is then modified using "Load Match" factors (based on ELCC) to reflect the match between PV production profiles and utility loads. Finally, a "Loss Savings" factor is applied to reflect the distributed nature of the resource.

DER Value Frameworks

California

California Public Utilities Commission (CPUC). 2016(a). *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF.

California Public Utilities Commission (CPUC). 2016(b). *Decision Adopting Successor to Net Energy Metering Tariff.* Rulemaking 14-07-002. Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering. January 28. Available at http://www.cpuc.ca.gov/General.aspx?id=3934.

California Public Utilities Commission (CPUC). 2017. *Locational Net Benefit Analysis Working Group Final Report.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code 769, and Related Matters.

[141] Norris, 2014, p. 12.

March 8. Available at http://drpwg.org/wp-content/uploads/2016/07/R1408013-et-al-SCE-LNBA-Working-Group-Final-Report.pdf.

These documents detail the most recent and significant decisions related to development and use of the Locational Net Benefit Analysis (LNBA) methodology to assess the costs and benefits of distributed solar in California. All three were reviewed for this meta-analysis. The first document provides the final report of the LNBA Working Group, a group established by CPUC with a goal of developing a methodology for investor-owned utilities to use to value DERs. The second document provides the Assigned Commissioner's Ruling, which refined and authorized the use of the LNBA methodology by utilities for demonstration projects. The third document reflects CPUC's decision to adopt a NEM successor tariff.[142]

Noteworthy takeaways include:

- In May 2016, a few months after the NEM successor tariff was adopted, CPUC approved use of the LNBA methodology in the utility's Distribution Resource Planning (DRP) Demonstration B projects.
- Some of the LNBA value categories already existed in the Distributed Energy Resources Avoided Cost Calculator (DERAC) used to calculate the cost-effectiveness of utility energy efficiency programs. CPUC adjusted DERAC and updated certain value categories, such as energy and capacity, with more location-specific inputs via locational marginal price.
- Policymakers continue to work toward approving a uniform LNBA tool. CPUC is expected to review the NEM successor tariff in 2019 and explore compensation structures other than NEM.
- In their final report, the LNBA Working Group requested clarification from CPUC on "how 'integration costs' should be captured in the tool."[143]

New York

New York Department of Public Service (NY DPS). 2016(a). *Order Establishing the Benefit Cost Analysis Framework. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.* January 21. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d.

New York Department of Public Service (NY DPS). 2016(b). *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding. Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program. CASE 15-E-0082.* October 27. Available at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwij59DitKrXAhUq6YMKHQYsBZIQFggoMAA&url=http%3A%2F%2Fdocuments.dps.ny.gov%2Fpublic%2FCommon%2FViewDoc.aspx%3FDocRefId%3D%257B59B620E6-87C4-4C80-8BEC-E15BB6E0545E%257D&usg=AOvVaw3i5PwEpAeHYti_MhoW1BZ7.

[142] The NEM successor tariff (NEM 2.0) decision was adopted in January 2016 and established utility-specific interconnection fees for customer-sited DG, modified non-bypassable charges and rules related to system size, and changed NEM customers over to time-of-use rates.
[143] California Public Utilities Commission (CPUC), 2017, p. 18.

These documents provide the most recent decisions within the New York Reforming the Energy Vision (REV) proceeding related to development and use of a benefit-cost analysis (BCA) framework for utilities to evaluate DER alternatives. Both were reviewed for this meta-analysis.

The first document establishes the BCA Framework that guided utilities in developing their own, individual BCA Handbooks. The goal of the BCA Framework is to provide consistent statewide methodologies for calculating the benefits and costs of DER investments.

The second document provides the DPS staff's recommendations to establish the Phase One Value of DER (VDER) methodology, which transitions away from the traditional NEM model. It provides the basis for a "Value Stack" tariff, under which compensation is calculated using the readily quantifiable DER values from the BCA Framework.

Noteworthy takeaways include:

- The VDER methodology uses a more limited set of value categories than the BCA Framework. Five categories make up the Value Stack: energy, capacity, environmental, demand reduction, and locational system relief value.
- Staff recommendations identify some value categories that may be added in a later phase of the effort, including other distribution system values not reflected in the demand reduction value, reduced SO_2 and NOx emissions, non-energy benefits, environmental justice impacts, and wholesale price suppression.
- Subsequent versions of utility BCA Handbooks are expected to have greater locational and temporal granularity.

Appendix B: List of Possible Studies to Include

This appendix contains the full list of literature considered for inclusion in the meta-analysis. The list was compiled in November 2017. A check mark in the last column indicates whether the document was included in the meta-analysis. Note that more than one document was reviewed in New York and California as a reflection of ongoing and interrelated regulatory activities.

Title	Year	Sponsor	Prepared by	Included
The Benefits and Costs of Net Metering Solar Distribution Generation on the System of Entergy Arkansas	2017	Sierra Club	Crossborder Energy	√
Value of Solar Study: Distributed Solar in the District of Columbia	2017	Office of the People's Counsel	Synapse Energy Economics	√
A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia	2017	Georgia Power	Georgia Power	√
Solar Energy in Michigan: The Economic Impact of Distributed Generation on Non-Solar Customers	2017	Institute for Energy Innovation	Institute for Energy Innovation	
PUCO Order – Investigation to Determine the Resource Value of Solar	2017	Public Utility Commission of Oregon	Public Utility Commission of Oregon	
Locational Net Benefit Analysis Working Group Final Report, Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code 769, and Related Matters, March 8	2017	California Public Utility Commission (CPUC)	Locational Net Benefit Analysis (LNBA) Working Group	√
Testimony – Value of Distributed Generation in Arizona	2016	The Alliance for Solar Choice	Crossborder Energy	
Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking 14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	2016	CPUC	CPUC	√
Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B, Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	2016	CPUC	CPUC	√
PV Valuation Methodology Recommendations for Regulated Utilities in Iowa	2016	Midwest Renewable Energy Association	Clean Power Research	

Title	Year	Sponsor	Prepared by	Included
PV Valuation Methodology Recommendations for Regulated Utilities in Michigan	2016	Midwest Renewable Energy Association	Clean Power Research	
Nevada Net Energy Metering Impacts Evaluation 2016 Update	2016	State of Nevada Public Utilities Commission	Energy and Environmental Economics (E3)	√
Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding; Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Case 15-E-0082, New York Department of Public Service	2016	NY Public Service Commission	NY Department of Public Service Staff	√
Order Establishing the Benefit Cost Analysis Framework, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, State of New York Public Service Commission	2016		NY Public Service Commission	√
PV Valuation Methodology Recommendations for Regulated Utilities in Wisconsin	2016	Midwest Renewable Energy Association	Clean Power Research	
Valuation of Solar + Storage in Hawaii: Methodology	2015	Interstate Renewable Energy Council	Clean Power Research	√
Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers	2015	Louisiana Public Service Commission	Acadian Consulting Group	√
Value of Distributed Generation: Solar PV in Massachusetts	2015	Acadia Center	Acadia Center	
Maine Distributed Solar Valuation Study	2015	Maine Public Utility Commission	Clean Power Research	√
Net Metering in Missouri: The Benefits and the Costs	2015	Missouri Energy Initiative	Missouri Energy Initiative	
Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society	2015	Frontier Group and Environment America Research & Policy Center	Frontier Group and Environment America Research & Policy Center	
Distributed Generation-Integrated Value (DG-IV): A Methodology to Value DG on the Grid	2015	Tennessee Valley Authority		
The Benefits and Costs of Net Energy Metering in New York	2015	E3		
PGE Distributed Solar Valuation Methodology	2015	Portland General Electric	Clean Power Research	√
South Carolina Act 236: Cost Shift and Cost of Service Analysis	2015	South Carolina Office of Regulatory Staff	E3	√

Title	Year	Sponsor	Prepared by	Included
Value of Distributed Generation: Solar PV in Vermont	2015	Acadia Center	Acadia Center	
Minnesota Value of Solar: Methodology	2014	Minnesota Department of Commerce	Clean Power Research	√
Net Metering in Mississippi	2014	Public Service Commission of Mississippi	Synapse Energy Economics	√
Value of Solar in Utah	2014	Utah Clean Energy	Clean Power Research	√
Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014	2014	Public Service Department (PSD)	PSD	√
2013 Updated Solar PV Value Report	2013	Arizona Public Service Company	SAIC	
The Benefits and Costs of Solar Distributed Generation for Arizona Public Service	2013		Crossborder Energy	
Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation	2013	CPUC	E3	
Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California	2013	Vote Solar Initiative	Crossborder Energy	
Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System	2013	Xcel Energy Services	Xcel Energy Services	
A Review of Solar PV Benefits & Costs Studies	2013	Rocky Mountain Institute		
The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina	2013	North Carolina Sustainable Energy Association	Crossborder Energy	
2014 Value of Solar at Austin Energy	2013	Austin Energy	Clean Power Research	
The Value of Distributed Solar Electric Generation to San Antonio	2013	U.S. DOE SunShot Initiative	Clean Power Research and Solar San Antonio	
Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California	2012	U.S. DOE Office of Energy Efficiency & Renewable Energy and Office of Electricity Delivery & Energy Reliability	Lawrence Berkeley National Laboratory	
Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment	2012	CPUC	E3	

Title	Year	Sponsor	Prepared by	Included
The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania	2012	The Mid-Atlantic Solar Energy Industries Association and The Pennsylvania Solar Energy Industries Association	Clean Power Research	
The Potential Impact of Solar PV on Electricity Markets in Texas	2012	Solar Energy Industries Association and The Energy Foundation	The Brattle Group	
Designing Austin Energy's Solar Tariff Using a Distributed PV Calculator	2012	Austin Energy	Clean Power Research and Austin Energy	

Appendix C: Input Assumptions for Displaced Marginal Unit

State	Marginal Unit	Detailed Assumptions (Avoided Energy)	Page No. From Study
Arkansas	Gas-fired generation, uses MISO LMPs	"Solar DG on the EAI [Entergy Arkansas, Inc.] system avoids marginal generation, **principally gas-fired generation** in the MISO [Midcontinent] South market area. To estimate these avoided costs, we have used **recent MISO locational marginal prices (LMPs)** for the Arkansas Hub, weighted by a standard output profile for a solar array in Little Rock, and escalated these LMPs using the long-term forecast of natural gas prices from the Energy Information Administration's (EIA) *Annual Energy Outlook 2017* (AEO 2017)."	p. 9
California	Uses DERAC values; option to use LMP prices	In the approved LNBA [Locational Net Benefit Analysis] Methodology Requirements Matrix for Demonstration Project B, utilities are required to "**use DERAC values**," also known as the 2016 Distribution Energy Resource Avoided Calculator or 2016 Avoided Cost Model.[144] "For the secondary analysis, the IOUs [independently owned utilities] may also estimate the avoided cost of energy using **locational marginal prices (LMPs)** for a particular location, as per the method described in SCE's [Southern California Edison's] application."	p. 27, CPUC, 2016(a)
District of Columbia	Uses PJM LMPs	"To calculate the total avoided energy benefit across each year, we correlate each hour's generation in PVWatts to a system marginal energy cost, based on historical data for the PJM Interconnect for 2015. This study **uses 2015 locational marginal prices for the PEPCO zone of PJM** ..." and "For future years, we assume these prices follow the trajectory of regional electricity generation system prices within EIA's *Annual Energy Outlook* (AEO) 2016, released in September 2016."	p. 128
Georgia	Uses hourly production cost model	"... Avoided Energy Cost used in the Framework reflects the projected fuel and technology expected to represent the marginal unit for dispatch in any given hour in which the renewable resource is expected to be producing electricity. It does not reflect any specific single fuel or any specific single technology." "Avoided energy cost projections are developed using the Production Cost model. The Production Cost model is a complete electric utility/regional pool analysis and accounting system that is designed for performing planning and operational studies. It is an **hourly production cost model** that has the fundamental goal of minimizing total production cost while providing detailed projections of fuel cost and pool accounting, including individual unit information."	p. 9; p. 49

[144] For more information on how DERAC calculates energy price forecast, see https://drpwg.org/wp-content/uploads/2017/11/LNBA-Item-4.i-Locational-Avoided-Energy-Revised-Proposal.docx.

State	Marginal Unit	Detailed Assumptions (Avoided Energy)	Page No. From Study
Hawaii	Oil-fired generation is predominant; futures for fuel oil would be used	"In the solar-only methodologies, natural gas has been assumed as the displaced fuel. In Hawaii, **oil-fired generation is predominant**, so adjustments would have to be made accordingly. **Futures for fuel oil would be used instead of natural gas**, and transportation to the island would be factored in."	p. 11
Louisiana	Uses natural gas combustion turbine as a proxy for the marginal unit	"Natural gas-fired generating resources have dominated new incremental generation over the past decade and continue to serve as the 'marginal' unit in most regional wholesale power markets given their relatively low capital costs and operating flexibility. Thus, an **advanced natural gas-fired combustion turbine**, with an assumed thermal efficiency of 9,750 British thermal units per kWh (Btu/kWh), serves **as an appropriate proxy for the marginal unit** setting energy prices in wholesale power markets over the next decade, and correspondingly, serves as an appropriate proxy for estimating avoided energy costs. A constant natural gas price of $3.50/MMBtu was used to estimate the fuel component of this avoided energy cost."	p. 112
Maine	Assumes natural gas displacement	"This methodology assumes that **PV displaces natural gas** during PV operating hours. During some hours of the year, other fuels (e.g., oil) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the overall value."	p. 19
Minnesota	Assumes natural gas displacement	"This methodology assumes that **PV displaces natural gas** during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase."	p. 5
Mississippi	Assumes displacement of gas and oil peaking resources (combustion turbines)	"Marginal unit: Mississippi's 2013 generation capacity includes 508 MW of natural gas and petroleum oil-based combustion turbines (CTs). While these oil units do not contribute a significant portion of Mississippi's total energy generation, they do contribute to the State's peaking capabilities. On aggregate, these peaking resources operated 335 days in 2013—most frequently during daylight hours—and had a similar aggregate load shape to potential solar resources (see Figure 7). Our benefit and cost analysis follows the **assumption that gas and oil CT peaking resources will be on the margin** when solar resources are available and, therefore, that solar net-metered facilities will displace the use of these peaking resources. At the level of solar penetration explored in our analysis (0.5 percent), it is unlikely that solar resources will displace base load units."	p. 21

State	Marginal Unit	Detailed Assumptions (Avoided Energy)	Page No. From Study
Nevada	Uses hourly marginal wholesale prices, based on production model	"Estimate of **hourly marginal wholesale value of energy**, excluding the regulatory price of carbon dioxide emissions. Source: **Production simulation runs** from NV Energy."	p. 32
New York	Uses LBMPs from the New York Independent System Operator (NYISO)	"To forecast avoided system energy costs, utilities shall use energy price forecasts for the wholesale energy market—**Location Based Marginal Prices (LBMPs)**—from the most recent final version of the NYISO's Congestion Assessment and Resource Integration Study (CARIS) economic planning process Base Case."	p. 5, Appendix C, NY PSC, 2016
Oregon	Assumes natural gas displacement	"This methodology calculates energy value as the avoided cost of fuel and O&M, assuming that **PV displaces natural gas** during PV operating hours. During some hours of the year, other fuels may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption."	p. 9
South Carolina	Uses production simulation model based on utility's most recent IRP	"Component is the marginal value of energy **derived from production simulation runs** per the Utility's most recent Integrated Resource Planning (IRP) study and/or Public Utility Regulatory Policy Act (PURPA) Avoided Cost formulation. Based on Utility-provided forecast and E3 analysis."	p. 10
Utah	Assumes displacement of natural gas combustion turbine	"Under this study, the value is defined as the cost of **natural gas fuel** that would otherwise have to be purchased **to operate a gas turbine (CCGT) plant** and meet electric loads and overcome T&D losses. The study presumes that the energy delivered by PV displaces energy at this plant for each hour of the study period with loss calculations being based on each hour."	p. 2
Vermont	Uses hourly marginal wholesale prices, based on ISO-NE	"The Department calculated a hypothetical 2013–14 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the **hourly price set in the ISO-NE market**. This annual total value was then updated to 2015 and beyond by scaling the annual total price according to a market price forecast."	p. 11

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Smart Rate Design

For a Smart Future

Authors
Jim Lazar and Wilson Gonzalez

July 2015

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Smart Rate Design for a Smart Future

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Acronyms

AMI	Advanced metering infrastructure
CP	Coincident peak
CPP	Critical peak pricing
CRES	Competitive retail electric service
DER	Distributed energy resources
DG	Distributed generation
DR	Demand response
EV	Electric vehicle
FIT	Feed-in tariff
IDGP	Integrated distribution grid planning
IRP	Integrated resource planning
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LMP	Locational marginal pricing
MDMS	Meter data management system
NCP	Non-coincident peak
NEISO	New England Independent System Operator
NEM	Net energy metering
O&M	Operations and maintenance
PBR	Performance-based regulation
PTR	Peak-time rebate
PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic
REC	Renewable energy certificate
RPS	Renewable portfolio standards
RTP	Real-time pricing
SCADA	Supervisory control and data acquisition
SFV	Straight fixed/variable
SMUD	Sacramento Municipal Utility District
SSO	Standard service offer
T&D	Transmission and distribution
TOU	Time-of-use
VAR	Volt-ampere reactive
VOST	Value of solar tariff

Executive Summary

Introduction

For most of its history, the electric utility industry saw little change in the economic and physical operating characteristics of the electric system. Though the system provided reliable and low-cost service, little in terms of system status or customer use was known in real or near real time. For an industry in the information age, parts of the electric system can be considered rather "unenlightened."

Current advancements in technology will have marked impact on current and future rate designs. First, end-users (i.e., customers) are installing their own generation, mostly in the form of photovoltaic (PV) systems, and are connecting different types of end-use appliances with increasing "intelligence" built in; electric vehicles (EVs), too, are poised to grow rapidly as a whole new class of end-use, just as storage systems are poised to become economic. Second, utilities are deploying advanced metering and associated data systems, sometimes referred to as advanced metering infrastructure (AMI) or smart meters, and more sophisticated supervisory control and data acquisition (SCADA) systems to monitor system operations. To realize the full potential of these new systems and end-uses, regulators, utilities, third-party service providers, and customers will need to utilize more advanced rate designs than they have in the past.

Rate design is the regulatory term used to describe the pricing structure reflected in customer bills and used by electric utilities in the United States. Rate design is not only the itemized prices set forth in tariffs; it is also the underlying theory and process used to derive those prices. Rate design is important because the *structure* of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other electric market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.[1]

Rate design is important because the *structure* of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other electric market participants.

Despite its critical importance, rate design is poorly understood by the general public and often lacks transparency. The difference between a progressive and regressive design can have a large effect — 15 percent by one estimate, but it could be more — on customer usage.[2] Traditional rate designs, which charge a single rate per unit of consumption (or worse, lower that rate as consumption increases) may not serve consumers or society best. As advancements in technology and customer preferences evolve, the industry must adapt to change or risk the fate of landline telephone companies, which have lost 60 percent of their access lines since the advent of telecommunications competition.[3]

Rate design relies in strong measure upon the judicious application of certain economic guidelines. The following

1 Weston, F. (2000). *Charging for Distribution Utility Services: Issues in Rate Design.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/412

2 Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516. Appendix A provides a calculation of how rate design can influence consumption.

3 Federal Communications Commission (2014, October). *Local Telephone Competition Report*, available at: https://www.fcc.gov/encyclopedia/local-telephone-competition-reports

elements of economically efficient rate design that are necessary to address current and coming challenges in the electric industry are based on those laid out in James Bonbright's 1961 *Principles of Public Utility Rates,* and in Garfield and Lovejoy's 1964 *Public Utility Economics.* These principles require that rates should:

- Be forward-looking and reflect long-run marginal costs;
- Focus on the usage components of service, which are the most cost- and price-sensitive;
- Be simple and understandable;
- Recover system costs in proportion to how much electricity consumers use, and when they use it;
- Give consumers appropriate information and the opportunity to respond by adjusting usage; and
- Where possible, be temporally and geographically dynamic.[4]

Rates can be designed to meet (or, in the case of poor rate design, frustrate) public policy objectives to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts, including public health, among others. They are also pivotal in providing utilities the opportunity to recover their authorized revenue requirement. Revenue adequacy is a core objective of rate design, but the more constructive design ideal for rates is forward-looking, so that future investment decisions by the utility and by customers can be harmonized.

Based on these historical works, and looking forward to a world with high levels of energy efficiency, distributed generation (DG), and customer options for onsite backup supply, the following three fundamental principles should be considered for modern rate design:

- *Principle 1:* A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- *Principle 2:* Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- *Principle 3:* Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

Principles for Modern Rate Design

- **Principle 1:** A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- **Principle 2:** Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- **Principle 3:** Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

These principles and priorities should be reflected in smarter rates designed to maximize the value of technology innovations, open up new markets, and accommodate the distribution and diversification of customer-sited generation resources. This necessarily includes consideration of what those future technologies and policies could look like, with a focus on metering and billing, market structure, and pricing. In particular, rate design should provide a "price signal" to customers, utilities, and other market participants to inform their consumption and investment decisions regarding energy efficiency, demand response (DR), and DG, collectively referred to as distributed energy resources (DER). **Bidirectional, time-sensitive prices that more accurately reflect costs most closely align with the principles of modern rate design.**

Challenges in Utility Rate Design

Over the last two decades, federal, state, and local policymakers have implemented policies that have spurred the development of customer-sited DG, in particular customer-sited PV systems. The policies range from federal tax credits to state renewable portfolio standards, Net energy metering (NEM), and interconnection standards.[5]

As the costs of renewable and other DG technologies — wind turbines, small hydro, biomass, and others — have decreased, the options available to customers to procure these technologies have increased. In addition, DG systems are decentralized, modular, and more flexible technologies that are located close to the load they serve. Customers can typically purchase or lease the DG from a third party, often

4 Lazar, 2013, p. 10.

5 Steward, D., & Doris, E. (2014, November). *The Effect of State Policy Suites on the Development of Solar Markets.* NREL. See also the Energy Department's SunShot Initiative, which is a national effort to make solar energy cost-competitive with traditional energy sources by the end of the decade. Through SunShot, the Energy Department supports private companies, universities, and national laboratories working to drive down the cost of solar electricity to $0.06 per kilowatt-hour. Learn more at: http://www.energy.gov/sunshot.

with seller or third-party financing. The increasing amounts of DG are impacting the delivery method of energy, and in the future may gradually shift from an exclusively centralized source of power, such as coal, nuclear, or natural gas-fired plants, to a mix of centralized and decentralized, smaller, and customer-centric sources of energy. Rate design must efficiently and fairly incorporate DG contributions to the grid, as well as fairly allocate the benefits and costs of their use for DG customers, non-DG customers, and for the grid.

At low levels of installation of distributed renewables (e.g., under five percent of customers), few if any physical modifications are required to electric distribution systems.[6] The scenario changes once solar output exceeds total load on a given substation. This is being experienced in Hawaii, which has the highest PV penetration of any state and where more than ten percent of residential consumers have PV systems installed. Installation rates are more than twenty percent in many single-family residential neighborhoods. At this level of solar saturation, changes to distribution systems may be needed. Hawaii is serving as a laboratory as it adapts to a high-renewable environment, and this paper explores the various adaptations that this state and many other jurisdictions are exploring and implementing.

In addition to increasing penetrations of distributed renewables, other technologies that will increase in the near future will need to be considered by utilities and regulators as they navigate the changing electric system landscape. EVs are a small part of the electricity load currently, but growth in the sector is likely for many reasons — lower battery costs and emissions regulations that are pressuring the industry to find zero-emissions transportation solutions.[7] Because of the presence of batteries in the vehicles and the ability to control the timing of when they are charged, EV loads can be very different from traditional loads. Encouraging behavior that optimizes EVs' use of the grid requires that rates be designed to provide an incentive for EV owners to charge their cars at the right time. This requires time-sensitive pricing, a topic this paper explores in detail.

Interfacing with **microgrids** will be another near-future challenge for utilities. These may range from an individual apartment building or office complex with onsite generation to a municipal electric utility connected to an adjacent larger utility. These will depend on utilities for some service, and compensation to utilities is important; however, microgrids will also provide services to utilities at times, so the compensation framework needs to be bidirectional.

Storage technologies such as Tesla's new Powerwall battery could be a game changer if they can be distributed in communities, interconnected with a smart grid, and not be price-prohibitive.[8] Currently, energy supply (generation) and loads (end-uses) must be instantaneously kept in balance, even as customers change their end-uses. But the presence of significant storage on the system would allow generators to generate when they can, while allowing the storage technology to provide additional energy or absorb additional energy as loads change.

The presence of generation, storage, and smart control technologies at customer premises offers the opportunity for customers to provide a number of valuable functions to the grid. These generally fall into a category termed **"ancillary services"** and include voltage regulation, power factor control, frequency control, and spinning reserves.[9] Where system operators or third-party aggregators have the ability to control end-use loads, customer appliances can deliver DR during high cost periods or when the grid is at or near its operating capacity and may be at risk for system failures. Rate design can either enable these values to be garnered or erect barriers to them.

6 Hawaiian Electric Company, with 11-percent PV saturation, is just now beginning to invest in distribution system modifications to adapt to high levels of solar energy. See: Hawaiian Electric Company Distributed Generation Interconnection Plan. (2014).

7 MJ Bradley & Associates. (2013). *Electric Vehicle Grid Integration in the US, Europe, and China.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6645

8 "Storage" involves a series of acts: converting grid-interconnected electricity to another form of energy, holding that other form of energy for future use, and then either using it in the form stored (thermal or mechanical energy) or converting it back to grid-interconnected electricity at a different time. The individual acts that comprise this series may be referenced as, respectively, "charging," "holding," and "discharging." Pomper, D. (2011, June). *Electric Storage: Technologies and Regulation.* NRRI, p 3. To this should be added other forms of energy storage, such as water heater controls, water system reservoir management, and air conditioning thermal storage, which may provide lower cost means to shape loads to resources and resources to loads.

9 Spinning reserves refer to the availability of additional generating resources that can be called upon within a very short period of time. Different utilities and different utility markets use varying response time frames to define spinning reserve services, ranging from instantaneous to up to an hour or so.

Rate Design in Theory and Practice

Balancing Stakeholder Interests

A variety of stakeholder interests are at play in the debate over rate design, and finding common ground is not easy. Regulators face the task of fairly balancing concerns among utilities, consumers and their advocates, industry interests, unregulated power plant owners, and societal interests. The regulator accepting the charge of "regulating in the public interest" considers all of these values.

Reaffirming the Principles of Rate Design in the Wake of Change

Good rate design should work in concert with the industry's clean technologic innovations and institutional changes. Accomplishing this requires the application of well-established principles to inform the design of rates that promote economic efficiency and equity.[10] This will be critical in a future characterized by significant customer-side resource investment and smart technology deployment. The advantages for a state that embraces these efficiency and equity goals are significant, especially in maintaining a state's competitiveness and promoting customer choice and ingenuity.

Best practice rate design solutions should balance the goals of:

- Assuring recovery of utility prudently incurred costs;
- Maintaining grid reliability;
- Assuring fairness to all customer classes and sub-classes;
- Assisting the transition of the industry to a clean-energy future;
- Setting economically efficient prices that are forward-looking and lead to the optimum allocation of utility and customer resources;
- Maximizing the value and effectiveness of new technologies as they become available and are deployed on, or alongside, the electric system; and
- Preventing anticompetitive or anti-innovation market structures or behavior.

Many rate design alternatives have been suggested; most recent studies emphasize the need for time-varying pricing and for some form of DR pricing.[11] At the same time, stakeholders currently face a legacy system of non-time-of-use (TOU) rates that are either flat across all usage levels or are designed with increasing or decreasing prices for increasing amounts of consumption ("inclining block" and "declining block" rates, respectively). They may also include demand charges in addition to energy charges, although various types of TOU rates have been used.

Evaluating and Allocating Costs

The design of rates begins with a functional evaluation of the costs incurred by the utility to provide service to its customers — customer costs, distribution costs, and power supply and transmission costs. A critical step is the allocation of costs among different customer classes — residential, commercial, industrial, and others.[12] These allocations, typically based on both marginal and embedded cost studies, inform regulatory determinations of revenue responsibilities among the customer classes.

Once the customer class revenue burdens are determined, prices must be set to generate those revenues, in light of expectations of demand for electricity. The general principle that the cost-causer should pay prices that cover the costs he or she causes might also suggest that the nature of the causation and the form of the price are critically related. And, indeed, price elements have traditionally been fashioned to reflect the nature of the cost to be recovered: costs that vary directly with energy usage are recovered in energy (kilowatt-hour [kWh]) charges, costs that are driven by peak demands (whether at the generation, transmission, or distribution level) are recovered in or time-varying kWh charges, and customer-specific costs unrelated to usage are recovered in customer charges. Of course, rate designs vary greatly across customer classes and utilities generally — demand charges,

10 These principles, on the basis of which James Bonbright and Alfred Kahn, among others, framed their analyses of regulation and the public good, are long embedded in regulatory law and practice throughout the United States. See, by way of example, the National Association of Regulatory Utility Commissioners' *Resolution Adopting 'Principles to Guide the Restructuring of the Electric Industry'*, adopted July 25, 1996, NARUC Bulletin No. 32-1996, p 10.

11 See the bibliography for references to a number of current publications on rate design.

12 For a discussion of how costs are typically assigned to different rate classes, see: Lazar, J. (2011). *Electricity Regulation in the US: A Guide.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/645, Section 9.4.

for instance, are rarely imposed on low-usage customer classes — but the basic architecture is well established and ubiquitous. It has been possible only because the industry in question is a monopoly.

The logic of differentiated pricing based on the differing natures of the underlying costs — specifically, their energy, capacity, or customer-specific characteristics — can be taken only so far. All industries are characterized by some combination of variable and fixed (in the short run) costs. In competitive markets, those costs are covered (or not) by the sale of goods and services; and the prices of those goods and services represent the value of society's resources that are being put to their production — or which are saved if those goods and services are not demanded. Economic efficiency — the greatest good for the lowest total cost in the long term — is served in this way. Monopoly services, simply because they are provided by monopolies, are not entitled to pricing structures that are not sustainable in competitive markets — that is, that are adverse to economic efficiency in the long run (within the constraints of other public policy objectives).

Basic Rate Designs

The simplest form of rate design is the **flat rate**, which is derived by simply dividing the revenue requirement for a given class of customers by the kilowatt-hour sales, and charging a purely volumetric price. A very important principle of rate design is to align the incremental price for incremental consumption with long-run incremental costs, including societal costs. Use of short-run costs, dispatch modeling, or a non-renewable resource as the basis for "incremental cost" is inappropriate and misleading to the consumer and society because it fails to recognize the real costs associated with plant investment and resource choices, many of which have long-term consequences on the order of half a century or more.

Customer charges are per-month fixed charges that apply to each customer in a tariff class, regardless of their usage. This paper addresses these in great detail, to focus attention on those charges that actually change with the number of customers. Although some utilities and regulators use customer charges to recover distribution system costs, this paper demonstrates that this is neither cost-based nor economically efficient. High customer charges impose unfair costs on small-use residential consumers, including most low-income household and apartment residents. The fixed charge for residential or commercial service should not exceed the customer-specific costs attributable to an incremental consumer.

Demand charges are commonly used to recover some costs of generation, transmission, and distribution of large commercial and industrial customers. Because traditional demand charges are measured on the basis of the individual customer's peak, regardless of whether it coincides with the peaks on any portion of the system, this approach inevitably results in a mismatch between the costs incurred to serve the customer and the prices charged if the customer's peak is non-coincident with the system peak. This means a customer is charged the same rate whether they use power in times of high demand (adding to system peak and utility costs) or low demand (when utility costs are correspondingly lower). Demand charges were implemented for commercial and industrial customers in an era during which sophisticated metering was prohibitively expensive. Today, with smart meters and AMI, these metering costs are trivial. Movement away from demand charges, toward more granular time-varying energy rates, is appropriate.

A few rate analysts have recommended that demand charges be extended from large commercial customers (where these are nearly universal) to small commercial and residential consumers.[13] Some of these analysts suggest this is an appropriate way to ensure that solar customers contribute adequately to system capacity costs. This option is inapt for most situations for several reasons. The only distribution system component sized to individual customer demands is the final line transformer. The relatively small portion of cost of service represented by the line transformer required to serve solar customers amounts to only about $1/kW/month. In addition, the diversity of customer demand at any given time of the day, and the lack of understanding of the potentially complex concept, suggest against this option. **Time-differentiated prices** can more equitably recover costs that are actually peak-oriented from all customers, including solar customers. However, customer education is a crucial part of this transition.

Energy charges are per-kWh charges for electricity consumed. These can be arranged into inclining or declining block rates, into seasonal charges, and into time-varying charges. This paper finds that time-varying (and, eventually, as technology enables customers to respond, more dynamic) energy charges are the best way to reflect costs to consumers and to encourage efficient use of electricity.

13 See, e.g.: Hledik, R. (2014). Rediscovering Residential Demand Charges. *Electricity Journal,* 27(7), August–September 2014, pp. 82–96.

Table ES-1

Illustrative Residential Rate Design

Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

Time-Varying Rates

It is hard to envision an electric system future without greater use of time-differentiated pricing. Because the underlying costs of providing electricity vary hourly and seasonally, it is impossible for the customer to see to an appropriate price signal without that signal also varying over time. As smart technologies take hold, the connection between customer usage patterns and underlying costs will become apparent. As this happens, it is inevitable that time-differentiated pricing will become more widespread.

TOU rates have been in use for some time in the United States. These rates typically define a multihour time of the day as an "on-peak" period, during which prices are higher than during "off-peak" hours. In most cases, on-peak periods are limited to weekdays. TOU rates are an improvement over flat or inclining block rates because they offer some correlation between the temporally changing costs of providing energy and the customer's actual consumption of energy. However, they are usually not dynamic in the sense of capturing the real underlying changes of costs from hour to hour, day to day, or season to season. Concentrating peak-related charges into as few hours as possible produces a better customer response.

Critical peak pricing (CPP) and peak-time rebate (PTR) are a variation on the TOU concept. Under CPP, prices during a limited number of specific "critical peak periods" are set at much higher prices. The customer is given some advance notice of critical peak days, usually a day in advance. CPP is designed to produce a response — to get customers to reduce loads during critical peak periods. The CPP has been largely successful. To date, CPP rates have been voluntary opt-in rate forms, but evidence supports setting these as default rates for large groups of consumers. Under the PTR concept, rather than charging customers a high critical peak price, customers are given a large credit on their bills if they can reduce usage during a peak-time event. PTR is distinguishable from a CPP in that it is a voluntary program. Just as in the case of TOU, both CPP and PTR require the use of an interval meter or a smart meter.

Real-time pricing (RTP) charges the customer the actual prices being set in wholesale markets (for utilities that are not vertically integrated) or short-run marginal generation costs (for vertically integrated utilities) as they vary hour by hour. Prior to the introduction of smart technologies, only the largest customers would typically be on real-time rates. As newer smart technologies take hold, some form of RTP may expand to other customers who have smart appliances that can monitor prices automatically, respond accordingly, and monetize the benefits.

Rates to Compensate DG

Several jurisdictions have adopted special pricing for compensation of solar customers for the power supplied to the grid by these systems.

Originating in Europe, **feed-in tariffs** (FIT) pay a premium price for renewable energy, generally based on the cost of the resources, not the value of the output. The payments for solar were typically higher than for wind, and the payment for power from small systems was greater than for larger systems. FITs were generally designed to be an infant-industry incentive.

A **value of solar tariff** (VOST) is fundamentally different from a FIT, compensating the solar provider on the basis of the value provided, not the cost incurred. As studied by Austin, Texas, plus the states of Minnesota and

Maine, a VOST will generally provide equal or greater compensation to the solar producer than simple NEM, reflecting the combined high value of the energy and non-energy benefits provided by solar.

Net energy metering (NEM) is an approach that measures the customer's net usage from the grid, and charges that usage at the standard tariff price for electricity. In effect, NEM allows customers to exchange excess generation from their solar (or other onsite) generators at times they do not need it for power from generic grid resources (usually fossil fuels) at other times.

For utilities in which only a small percentage of consumers have installed solar systems, a simple NEM option will generally be easier to measure, more acceptable to consumers, simpler to administer, and will produce fewer significant impacts on grid-dependent customers. Another option is **bidirectional pricing**, especially where solar penetration is high. Bidirectional pricing, which would require a smart meter, would allow the customer to pay the retail rate for any power consumed and be compensated based on the full value of the energy delivered to the grid. Time-differentiated pricing for power flows in each direction may likewise be appropriate. The customer pays for power used on a TOU basis, and is credited (either the retail TOU rate or a different time-differentiated VOST) for power fed to the utility.

The three principles of modern rate design outlined earlier suggest some other considerations for solar customers:

- Only customer-specific costs should be applied to the bill for the privilege of connecting to the grid and accessing grid services.
- The cost for use of the distribution grid should be charged in relation to customer purchases of energy.
- Time-varying rates are appropriate in both directions of the transaction in which a customer is consuming and selling energy to the grid.
- Some skeptics have portrayed PV as unfairly shifting costs to other customers or of using the distribution system in some way without paying for it. This is a misapplication of rate design and cost recovery principles and practice which have never charged generators for use of the distribution system, as well as accepted cost allocation methods, which are themselves dynamic in nature.
- DG customers should be free from discrimination. Any cost imposed on a DG customer should be based on a real cost to the utility system resulting from the DG, or net of cost savings resulting from the DG. In the absence of a VOST or other data, NEM is appropriate as a proxy where PV saturation is relatively low. It is unlikely that this will overcompensate DG customers, and likely that it will still send sufficient price signals to the customer to make economic choices about whether to install DG. Where PV saturation is low, the impact on the utility system and revenues would also be quite low.

The success of DG has, unfortunately, prompted the proposal and implementation of rate designs in some states that harm existing DG customers and present a formidable barrier for customers contemplating investments in DG resources.[14]

Rate Designs That Discourage DG

A **minimum bill** charges the customer a minimum fixed charge, which entitles the customer to a minimum amount of energy. For example, a residential minimum bill might charge $20 as a minimum charge, which entitles the customer to receive their first 100 kWh energy included in the price. A flat or inclining block rate structure would then be applied for additional usage. Minimum bills are not typically considered good rate design; they have the effect of reducing the value of energy efficiency, conservation, and customer-sited DG, to the extent those efforts would otherwise reduce consumption below the minimum threshold. The key is to set the minimum bill at a level that guarantees the utility a certain level of revenue it can count on, while not penalizing the vast majority of customers.[15]

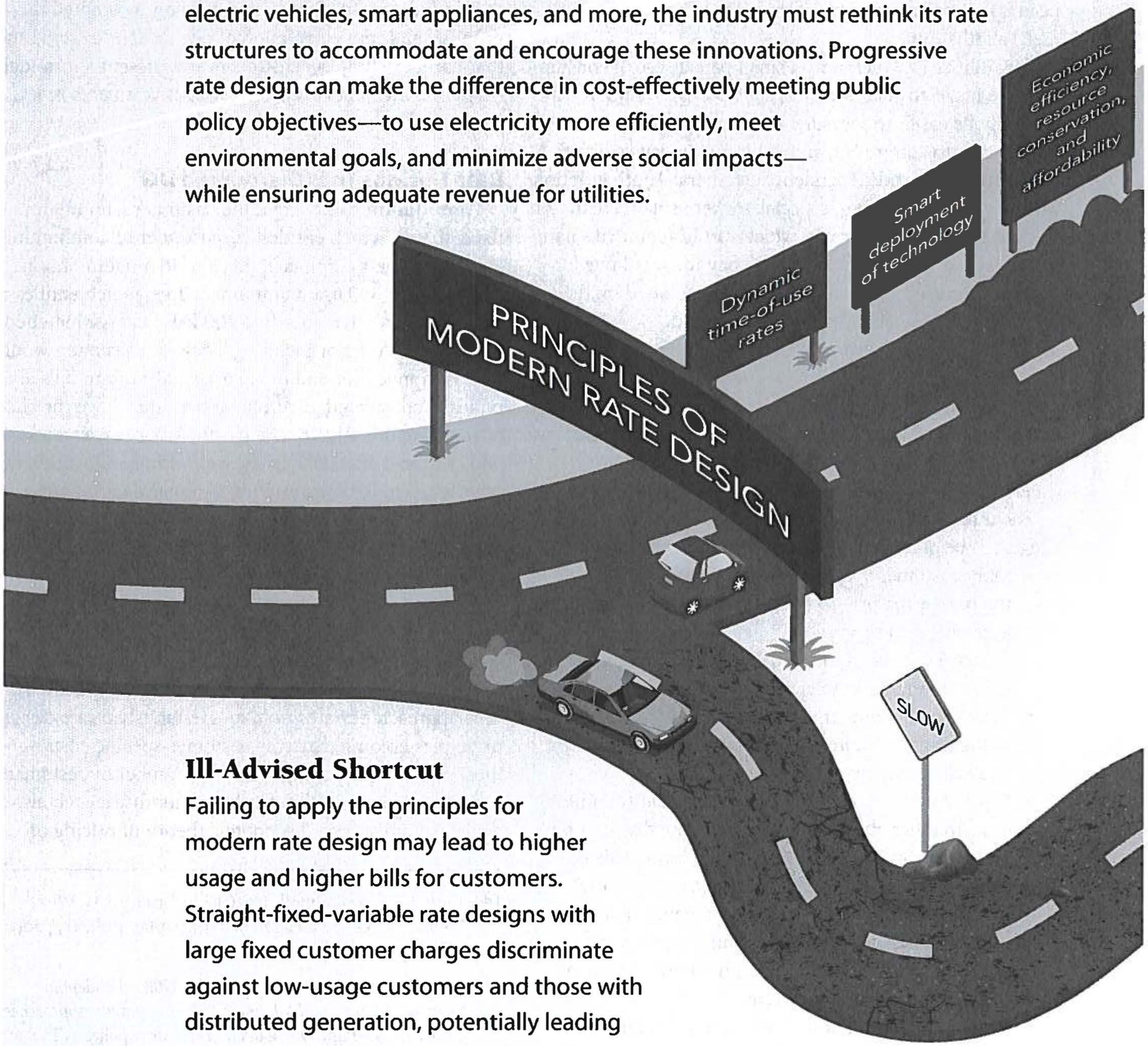
Even less desirable is **straight fixed/variable** (SFV) design. Utilities in some parts of the United States are seeking to sharply increase monthly fixed charges, with offsetting reductions to the per-unit price for electricity. This approach deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on

14 Tong, J., & Wellinghoff, J. (2015, February 13). Why Fixed Charges Are a False Fix to the Utility Industry's Solar Challenges. *Utility Dive.*

15 Lazar, J. (2014, November). *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7361

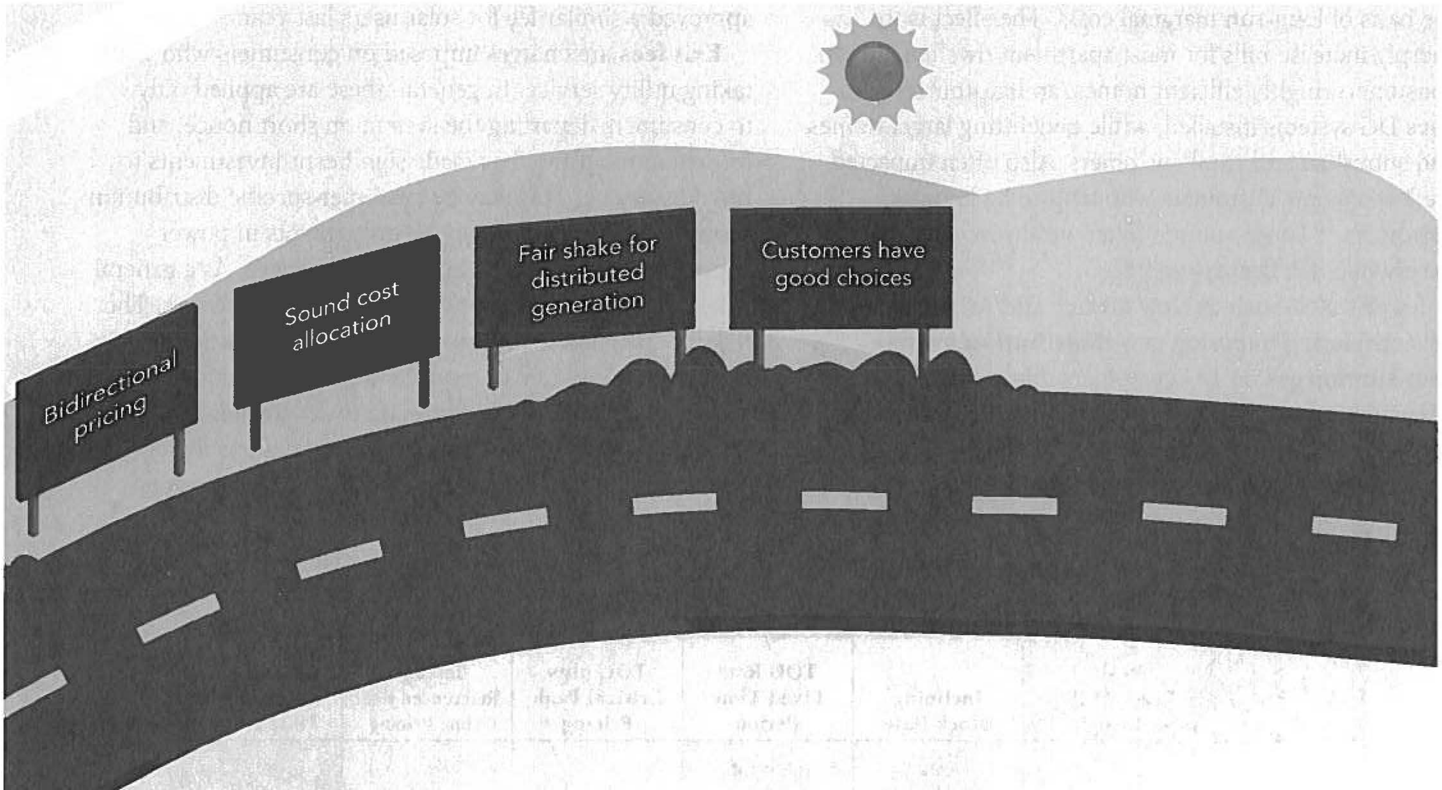
Rate Design Roadmap for the 21st Century Utility

Utilities face unprecedented changes in the way power is generated and delivered. With the ramp-up in distributed generation, energy efficiency and demand response, electric vehicles, smart appliances, and more, the industry must rethink its rate structures to accommodate and encourage these innovations. Progressive rate design can make the difference in cost-effectively meeting public policy objectives—to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts—while ensuring adequate revenue for utilities.



Ill-Advised Shortcut

Failing to apply the principles for modern rate design may lead to higher usage and higher bills for customers. Straight-fixed-variable rate designs with large fixed customer charges discriminate against low-usage customers and those with distributed generation, potentially leading customers to abandon the grid entirely.

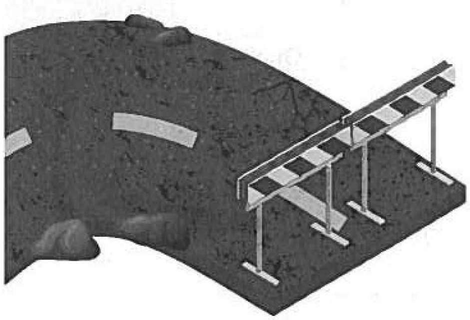


The Principles

1 A customer should be able to connect to the grid for no more than the cost of connecting to the grid.

2 Customers should pay for grid services and power supply in proportion to how much they use these services, and how much power they consume.

3 Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.



the basis of long-run marginal costs. The effect is to sharply increase bills for most apartment dwellers, urban consumers, highly efficient homes, and customers who have DG systems installed, while benefitting larger homes and suburban and rural customers. Also often impacted are low-income customers who tend to be low-use customers.[16] Large-volume (often wealthier) customers, meanwhile, see decreasing bills.

Some states, such as New Mexico and Arizona,[17] are considering imposing new **distribution system cost surcharges** on DG customers that utilities argue reflect their use of the grid, even though there are no demonstrated additional costs being incurred by the utility as a result of DG output. A Wisconsin utilities commission approved a similar fee for solar users last year.[18]

Exit fees are charges imposed on consumers who cease taking utility service. In general, these are applied only to consumers departing the system on short notice, and for whom the utility has made significant investments to provide service. This may be customer-specific distribution system investments, or may be investments in power supply intended to provide long-term service. As a general rule, exit fees are inappropriate rate design measures. The risk for customer loss is an ordinary business risk, for which the utility rate of return is the compensation.

In contrast to the approaches outlined previously, Figure 1 gives an overview of the appropriate rate designs for all customer classes for both default and optional services.

Figure ES-1

Rate Design Options by Customer Class

	Typical Pre-AMI Rate Design	Inclining Block Rate	TOU Rate Fixed Time Period	TOU plus Critical Peak Pricing	Baseline-Referenced Real Time Pricing	Market Indexed Real Time Pricing
Residential	Flat Energy Charge	Default (if kwh-only metering in place)	Default (if TOU meters or AMI in place)	Optional if AMI in place	Pilot	Not Available
Small Commercial 0-20 kw Demand	Flat Energy Charge	Not Available	Default (if TOU meters in place)	Optional if AMI in place	Pilot	Not Available
Medium General Service 20-250 kw	Demand Charge --- Flat Energy Charge	Not Available	Default (until AMI installed)	Default (after AMI installed)	Optional	Not Available
Large General Service 250-2,000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Default	Optional	Optional
Extra Large General Service >2000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Not Available	Customer Must Choose Between These Two Options	

Source: Adapted from RAP research for New England Demand Response Initiative (NEDRI), 2002

16 USEIA. (2014). Extracted by National Consumer Law Center.

17 In February, an Arizona utility voted to impose a monthly surcharge of about $50 for NEM customers (Warrick, 2015).

18 Content, T. (2014, November 14). *Regulators Agree to Increase Fixed Charge on WE Energies Electric Bills.* Milwaukee Journal Sentinel.

Enabling Smart Technology

Utilities from Maine to California have deployed smart grid upgrades or are beginning the transition to a smarter grid.[19] These upgrades promise to deliver an entirely new level of information about system operations and consumer behavior. In short, the information age is coming to the electric industry.[20] Computerizing the traditional grid with AMI and advanced SCADA systems will enable the development of new and dynamic rate offerings. Meanwhile, smart home appliances that can monitor pricing conditions and be made dispatchable by system operators will assist customers in managing their usage. Moreover, these new technologies will aid system operators in minimizing total system costs and increasing system reliability.[21] They will also help accommodate customer-owned generation, utility-scale renewable power, energy storage (both customer- and utility-scale), EVs, and microgrids.

Smart meters provide data acquisition, equipment control, and communication capability between the customer and the power grid.[22] They are able to record customer usage at a fine time scale and then communicate that information back to the utility and to the customer. This information can in turn be used to control end-use appliances in response to price signals and system conditions. When used by system controllers, they can aid in reducing loads during times of system stress. When employed by the customers or on their direct behalf, smart meters can be used to shift usage from on-peak to off-peak periods, utilizing low operating cost renewable energy.

Smart meter deployment is expected to reach 91 percent of the United States by 2022.[23] It is important to note, however, that merely installing smart meters does not alone facilitate advanced pricing. Meter data management system (MDMS) investments, billing engine modifications, and sophisticated rate studies are needed to develop advanced pricing.[24] Although smart meters can enable advanced pricing mechanisms, given the relative price-variability risks and economic rewards of different types of pricing, the desired consumer rewards of lower bills are applicable only to a subset of pricing options, primarily TOU, CPP, and RTP.

Smart meters and the associated MDMS perform multiple functions. The costs associated with smart grid investments should be apportioned so that the costs are shared by all aspects of utility service that benefit. Simply stated, to justify deployment of smart meters and an MDMS there should be an expected net savings to the utility customers over the life of the investments. No single category (energy, capacity, or customer) should be assigned costs that exceed that particular benefit.

Various technology enhancements can improve the effectiveness of more complex rate designs by enabling customers to respond to prices automatically. Some examples include smart thermostats, grid-integrated water heating, EV chargers, and vehicle-to-grid applications.

Customers who have PV systems or other onsite grid-interconnected generation or battery storage systems both take power from the grid and deliver it to the grid. Keeping track of these flows is necessary for accurate billing and crediting of services provided to the grid, when the value of customer production is a priority. Smart meters have this capability and are needed when the rate design requires knowing when power is flowing and in which direction, to more accurately value the cost of customer use and the value of customer production. Clearly if the customer is consuming most of their power during off-peak periods, and supplying power mostly during on-peak periods, the solar customer is providing significant value to the grid that

19 We use the term "smart grid" broadly to include both utility grid-side and customer investments.

20 Determining whether AMI and smart grid are projected to be cost-effective before deployment is an important consideration and one that is beyond the purview of this report. A good discussion on smart grid benefits to costs can be found in: Alvarez, P. (2014). *Smart Grid Hype & Reality.* Wired Group Publishing, ch 4-9.

21 PR Newswire. (2013, January 8). *ComED Launches Smart Home Showcase Contest.* Available at: http://www.prnewswire.com/news-releases/comed-launches-smart-home-showcase-contest-186025412.html

22 They also provide operational benefits like reduced meter reading costs and outage detection.

23 Telefonica. (2014, January). *The Smart Meter Revolution: Towards a Smarter Future.* Available at: https://m2m.telefonica.com/multimedia-resources/the-smart-meter-revolution-towards-a-smarter-future

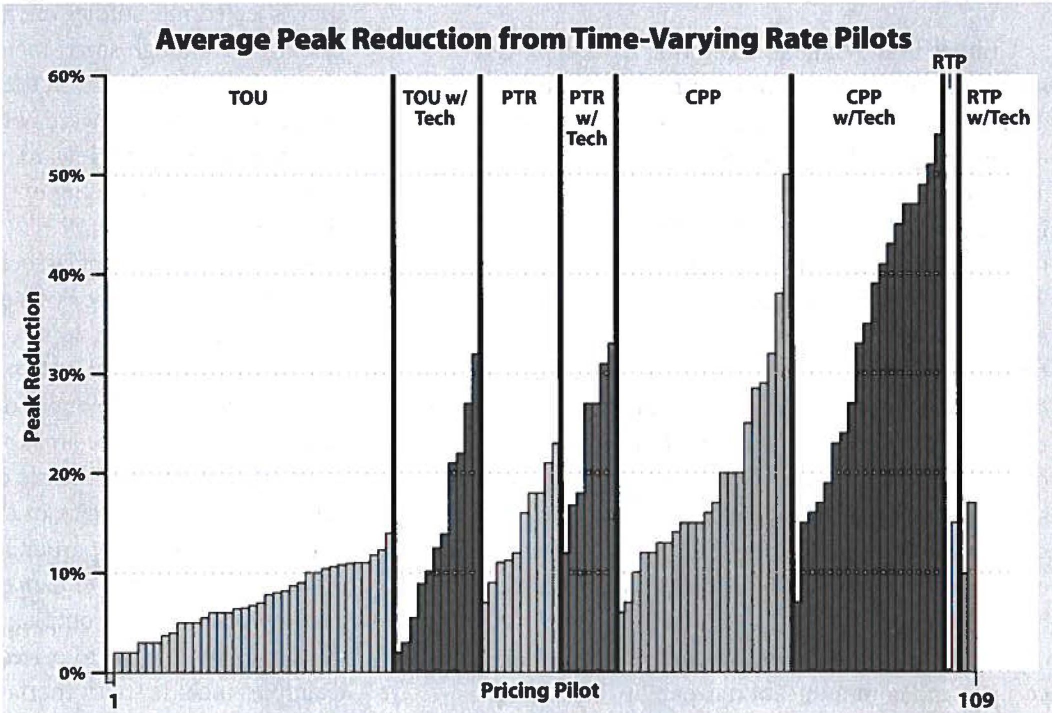
24 Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516

is not captured by simple monthly kWh NEM.[25]

The introduction of SCADA systems late in the 20th century enabled grid operators, for the first time, to see how their systems operate at a more granular level and in real or near real time. The addition of smart meters and other devices, collectively referred to as the smart grid, promises to vault the level of sophistication to an even higher level and enable more clearly defined rate designs.

Smart technologies enable distribution optimization in many ways, and rate design will play a key role in bringing customer end-uses into utilities' toolbox of solutions. In addition, it will inform the customer about opportunities to save money and to be rewarded for providing value to the overall grid. Poor rate design can impair this ability and prevent the true value of smart technologies from being realized, clogging the gears of this dynamic.

Figure ES-2



Source: Faruqui, *Time-Varying and Dynamic Pricing*, RAP, 2012

Implementing Smart Rates

"Smart rates" describe those rate designs that require the type of data collection that smart meters provide, and that are expected to produce significant peak load reductions, reduced and shifted energy consumption, improved system reliability, improved power quality, and reduced emissions. These include TOU, PTR, CPP, and RTP (all with and without technology, such as in-home displays).

The effectiveness of different TOU rate designs varies considerably. Figure ES-2 shows a comparison of pilot program peak reduction results for a variety of smart rates. CPP rates clearly show the greatest promise of delivering strong peak reductions by customers.

Currently most utilities that have smart rates offer them as optional services, especially for residential and mass market customers. Some utilities are considering making these rates applicable to all residential consumers, either as the default rate design with the ability for the customer to opt out of the rate, or as a mandatory rate design. Tools to protect customers during this transition may include dual or shadow billing, in which customers still on traditional rates are shown potential savings on their bills; customer guarantees of tariffs that provide them with the lowest bill; "hold harmless" and first-year bill forgiveness programs; and continuation of low-income rates. The critical factor in all of these is that it gives the individual customer the opportunity to compare their bill based on a traditional rate design and a more dynamic rate design.

Evidence shows that advanced pricing works best with technology enhancement to enable automated response to higher prices that can tie directly into time-differentiated prices. Over 200 time-differentiated rate tests have been conducted worldwide, with differing results. The consensus of these pilot programs is that customers respond to prices. Furthermore, enabling technologies (in home displays, smart phone applications, smart thermostats, and

25 "Net energy metering" is a pricing scheme that "pays" for the output of customer-sited generation at the same rate that the customer pays for energy delivered from the electric system.

appliances) enhance price responsiveness. TOU and CPP rates may also be more fair to customers than traditional flat rates, because customers who contribute more to the increased costs of peak usage are made to pay more, while customers who use less of the expensive peak power have the opportunity to save more.[26]

By having rates that reflect system value, customers will have the incentive to take action that over time will reduce system costs, and thus benefit all ratepayers. Overall then, rates should be lower with time-differentiation and critical peak pricing than they would be with traditional rates, owing to reductions in system costs to serve peak demands.

In order for homes to respond to dynamic pricing, either manual customer intervention or automated technology needs to be deployed. Experience shows that automated technology provides greater energy benefits by far. To achieve this, either energy management systems or smart appliances (or both) are required.

The TOU/CPP approach discussed previously is also optimal for customers who own DER. A number of compensation mechanisms have been considered by regulators for distributed resources. They range from value-to-grid approaches using avoided costs to the establishment of a system of distribution credits.[27]

One such incentive is **locational pricing**, which provides incentives for DER that are located in areas that reduce congestion. This can be beneficial to the distribution system, as critically sited DER can lead to the postponement or avoidance of costly upgrades. The pragmatic way to reflect locational values to residential and small commercial consumers is through targeted incentives for peak load management, as are typically provided by energy efficiency suppliers and DR aggregators, not necessarily through complex retail rate designs that consumers may be unlikely to understand.

Separating out the existing cost analysis into its constituent parts — energy, demand, and ancillary services — can also support smarter DR and DER investment. The ancillary services needed in providing electricity service can also promote DER investments that help the grid's reliability and resiliency.

Hawaiian Electric Company has prepared a detailed Distributed Generation Integration Plan, which may be a postcard from the future for mainland utilities preparing for a much higher uptake of solar PV. Key considerations in the overall plan include the correct sizing of line transformers, analysis of when upgrades to circuit capacity are needed, installation of voltage regulators, and additions of electricity storage in some locations. Recovering the costs of **grid modifications** associated with DG is a topic of considerable controversy. In Hawaii, where these modifications are more imminently needed, Hawaiian Electric has implemented a change to require smart inverters, and the overall plan includes installation of voltage regulators, upgrades to substations, upgrades to conductors, and implementation of DR. The determination by the Hawaii Public Utility Commission on the appropriate method for recovery of the associated costs is pending.

Hawaii may be leading the nation in change, but dockets have been convened in Arizona, Colorado, California, New Mexico, and other states examining the appropriate way to recover DG-related grid costs, including modifications needed to adapt to high levels of solar. In general, regulators will weigh issues including the recovery of existing, incremental, stranded, and new generation costs, as well as the role of the value of solar.

The outcome of these investigations will produce different results state by state. In general, states looking ahead at marginal costs will conclude that solar customers are bringing great value to the system, whereas states focused on embedded cost concepts will see stranded cost issues. Adhering to the guidelines below, which follow from the three principles of rate design outlined in this paper, should ensure that solar and other residential consumers are treated equitably.

- **Customer Charges**. Should not exceed the customer-specific costs associated with an additional customer, such as the service drop, billing, and collection.
- **Energy Charges**. Should generally be time-varying and those time differentiations should apply both to power delivered by the utility to customers, and to power delivered to the utility from customer generation. This assures that solar output is valued appropriately, and high-cost periods are reflected in the prices charged to customers using power at those times. Until smart rates are applied universally, it may

26 Traditional flat rates force all customers to a rate based on the average costs assigned to the class, to the detriment of customers who use less on-peak and therefore have less costly consumption patterns.

27 Moskovitz, D. (2001, September). *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors.* Montpelier, VT: The Regulatory Assistance Project.

be appropriate to make time-varying rates mandatory for solar customers, but optional for small-use non-solar customers (see discussion on this in Chapter VI).

- **Minimum Bills**. Where utilities have high numbers of seasonal customers who only consume power during the summer or winter, an annual minimum bill may be an appropriate rate design to ensure a minimum level of revenue from customers in this category. Otherwise, minimum bills are not a particularly desirable rate design.[28]
- **Demand or Connected Load Charges**. Demand charges are generally inappropriate for residential and small commercial customers who share distribution transformers with other consumers, and where implemented should not exceed the cost of the final transformer, about $1/kW/month. They are never appropriate for upstream distribution costs that can be recovered in a TOU rate. The illustrative rate designs eliminate demand charges entirely except for the final line transformer, including the remaining system capacity costs in TOU and CPP rates.

Optimal rate design choices may also differ according to the level of the utility's costs:

- **Low-Cost Utilities** (average revenue <$0.10/kWh). May need to retain or institute inclining block rates to ensure that the end-block of usage reflects long-run marginal costs for clean power resources, transmission, and distribution.
- **Most (Average-Cost) Utilities** (average revenue $0.10 to $0.20/kWh). Conventional NEM (of the full rate, including volumetric charges for power supply and distribution) is likely an appropriate strategy; although grid operators lose distribution revenues, their consumers gain all of the other benefits of increased renewable generation, and taken as a whole, the value of solar energy added to the system is usually equal or greater in value than the retail electricity price.
- **High-Cost Utilities** (average revenue > $0.20/kWh). Utilities that have average residential prices in excess of the long-run marginal cost of new clean-energy resources ($0.10/kWh to $0.25/kWh) may need to reflect distribution charges separately, collected from all customers receiving grid power, and crediting only a power supply rate when solar power is fed to the grid.

As emerging technologies become more mainstream, rate designs will need to adapt to changes in how customers use electricity and how it impacts the grid. DG can be viewed as a tool to strengthen the grid and rate designs of the future can encourage the utility-customer partnership to ensure the efficiency and economy of the grid. Key will be the temporal rates discussed previously, but innovations in terms of unbundling the customer-generated power to provide ancillary services and providing credits to DER that is strategically located to support the grid will be important components.

This paper also explores other utility strategies to encourage uptake of DER, including green pricing services that allow customers to pay a premium on their bills to support utilities' investment in renewable energy, and design of rates that can compensate customers for ancillary services that they provide the utility, such as the use of smart grid solutions to aid reliability.

Electric Vehicles

EVs are another emerging technology poised to play a growing role in this future, and utilities can use rate design to send EV owners the optimal price signals. Even without AMI deployment, interval TOU meters to be read manually can allow EVs to be separately metered. But a utility that has AMI has many options for providing a rate for EV owners that is appealing to the customer and remunerative to the utility. These can include a simple TOU rate, a multi-period TOU rate with a super-off-peak period, a critical peak pricing rate, or a real-time price.

For public charging stations, a wide variety of pricing schemes are used, from free charging to hourly parking to TOU rates. In states that subject EV charging stations to regulation for the resale of electricity, charging stations avoid regulation by charging for the parking space, often on a time-varying basis, and not charging for the electricity.

One of the great promises of EVs is that they will become fully grid-integrated, providing a market for off-peak power, a source for on-peak power, and multiple ancillary services.[29] This requires a combination of sophisticated

28 Lazar, J. (2014, November). *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7361

29 Lazar, J., Joyce, J., and Baldwin, X. (2008). *Plug-In Vehicles, Wind Power, and the Smart Grid.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Lazar_PHEV-WindAndSmartGrid_2007_12_31.pdf

charging units in vehicles, complex pricing, and a very smart grid. **Vehicle-to-grid** pilot programs that make use of these features are in the early stages.

Policies to Complement Smart Rate Design

Utilities find themselves at a crossroads in which they could embrace or shun rate designs that support a smarter future. The smart future will see extensive use of technology to help consumers manage their energy costs, and utility pricing that enables these savings to occur. A mix of central generation, DG, energy efficiency, DR, and customer response to time-varying pricing will provide a rich mix of reliable and environmentally friendly sources to provide quality service at reasonable costs. Consumers will increasingly have smart homes and appliances, and utilities will use AMI to collect key data from these resources and respond accordingly.

To achieve this smart future, regulators at various levels will have to take many discrete actions, including:

- Utility regulators will need to adopt time-varying and dynamic rate designs, with consumer education, shadow-billing during a pre-deployment phase, a "hold harmless" provision for the first year of implementation, and excellent customer support throughout.
- Some form of revenue regulation will be necessary to ensure that utilities retain a reasonable opportunity to earn a fair return on investment on used and useful property serving the public, and maintain access to capital at reasonable prices.
- State building energy codes will need to require home energy management systems in new homes (as most already do for commercial buildings).
- Customer-sited generation will include: smart inverters, which will provide reliability and ancillary services; customer-sited batteries which will provide service not only to the locations where they are installed, but be available to grid operators for system support; and variable solar orientation to optimize peak time production.
- Federal appliance standards must require installation of control technologies in new major appliances such as refrigerators, water heaters, furnaces, heat pumps, and air conditioners, dishwashers, clothes washers, and clothes dryers, so that they can automatically adjust to changing prices.

The "not-so-smart" future would involve movement toward high recurring fixed charges. They provide utilities with stable revenues and address their immediate concerns. In doing so, they punish lower-usage customers and discourage efficiency improvements and adoption of distributed renewables, and over time can lead to an unnecessary increase in consumption or, in the event distributed storage technologies become more accessible, promote customer grid defection. This is to say, such rates are economically inefficient and inequitable and are not justified by any fundamental principle of neoclassical economic theory. They are, in fact, nothing more than a government-sanctioned exercise of monopoly power. The adverse impacts on electric consumers and public policy goals for electricity regulation include skewed incentives against energy efficiency, customers looking to go totally off the grid, and higher bills for most low-income households.

High recurring fixed charges provide utilities with stable revenues and address their immediate concerns. In doing so, they punish lower-usage customers, discourage efficiency improvements and adoption of distributed renewables, and over time can lead to an unnecessary increase in consumption or promote customer grid defection.

The first of the principles of electricity pricing set out earlier in this paper notes that a customer should be able to connect to the grid for no more than the cost of adding that customer. The imposition of a fixed charge solely for the privilege of being a customer is not common in other economic sectors, from supermarkets to hotels and airlines, that have similarly significant fixed costs to those of utilities. Allowing utilities to impose high fixed monthly charges is an exercise of monopoly power and impedes the longstanding goal of universal service in the United States. Utilities' concern about loss of revenue is fair, but an SFV model is probably the worst option available by which to address it.

Utility cost recovery and revenue stability can be addressed many different ways, some desirable and some less desirable. In addition to fixed charges, three other options — a higher allowed rate of return, incentive regulation, and revenue decoupling — are discussed below.

In states where revenue regulation mechanisms have not been deployed, but utility revenues are erratic or declining owing to changes in usage, the market will demand a higher return on invested capital. Regulators are effectively letting the capital markets set a **higher rate of return** for the utility. But either a higher return on equity or a higher equity ratio will increase the utility revenue requirement. Thus, this laissez faire approach certainly results in higher costs to consumers over time.

Good rate design addresses the legitimate concerns of all major interests, provides a framework for stable regulation of utilities, and enables the growth of renewable energy and energy efficiency to meet electricity requirements.

Incentive regulation, or performance-based ratemaking, is another way to address the revenue loss that utilities experience if customer sales decline. If the regulator sets the achievement of a defined level of sales reduction from energy efficiency as a goal, and provides a financial reward to the utility for achieving that, the regulator can make up the lost earnings that the utility experiences. The challenge in performance-based ratemaking is to set the objectives for the utility to be achievable but challenging, and to set the rewards to be ample but not excessive.

Revenue-based regulation, or "**decoupling**," is widely used throughout the United States to insulate gas and electric utilities from revenue impacts attributable to sales variations. The essence of revenue regulation is that the utility regulator sets an allowed revenue level, and then makes periodic small adjustment to rates to ensure that allowed revenue is achieved, independent of changes in units (kW and kWh) sold. One benefit of revenue regulation is that the utility normally receives a "formula" to reflect higher costs, such as a "revenue per customer" allowance. These do tend to lead to very small annual increases in revenues. Whether prices increase depends on whether average consumption by customers is rising or declining as the number of customers change. Critics worry that these mechanisms result in annual increases, and that declining costs are not offset against rising costs, but a well-structured mechanism can address these concerns.

A well-designed revenue regulation framework is the best option to address utility revenue attrition that energy efficiency or renewable energy deployment may cause. There is no silver bullet to address the legitimate concerns of all interests. The evidence, however, demonstrates that high fixed charges have the most adverse impacts on consumers, the environment, the economy, and society. Good rate design addresses the legitimate concerns of all major interests, provides a framework for stable regulation of utilities, and enables the growth of renewable energy and energy efficiency to meet electricity requirements.

Good rate design should be accompanied by **bill simplification**. In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced. Utilities should be required to display the "effective" rate to customers, including all surcharges, credits, and taxes, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

As customers utilize greater energy efficiency and deploy more PV, the reductions in their bills can have the effect of allocating greater **cost recovery responsibility** to other customers. This is often described as a cross-subsidy. This is an unfair characterization; in fact, the system for allocating costs among customers and customer classes has always been a dynamic one that reflects the changing characteristics of all customers over time. Still, this is an important issue, and regulators will need to take care in rate design to assure that all customers share in the benefits that industry changes will bring and that no customer group is left out of the mix. This includes customers who may not be in a position to maximize smart grid usage, such as renters. If the rate design for DG customers is implemented according to the principles we have outlined, then non-DG customers should see equitable prices for energy delivered to their meters. By properly implemented, we mean that DG customers are not unduly rewarded for deploying DG; the collateral benefits of DG, such as reduced line losses, deferred and avoided distribution investments, health impacts, and other non-energy benefits are considered; and the potential for overall reductions in the price of generation is accounted for.

Conclusion

Rate design will be an important driver of utilities' success in making the transition to a clean power system. Utilities, customers, and third-party service providers will need the tools to manage the grid as efficiently as possible. Regulators will need to ensure that benefits and costs are fairly allocated. Prices that are accurate and easy to understand can reward customers for energy usage behavior that contributes to the reduction, rather than increase, of utility system costs.

Rate design will be an important driver of utilities' success in making the transition to a clean power system. Smart rate designs will need to address not only the amount consumed but also when it is consumed and its impact on costs and other customers.

Utility rate designs will have to more appropriately reflect the costs of electricity provided (or merely delivered) by the utility and the benefits that are provided to the utility system by customers. As utilities and third-party vendors develop and offer more innovative technologies (such as smart appliances that can respond to grid pricing signals), pricing will need to become even more geographically, temporally, and functionally granular and precise. Smart rate designs will need to address not only the amount consumed but also when it is consumed and its impact on costs and other customers. In addition to recognizing locational benefits in pricing, good rate design recognizes the attributes that a customer can provide in terms of energy, capacity, and ancillary services.

A small number of utilities offer some kind of dynamically priced rate to residential customers, whether it is a TOU rate or a peak-time rebate. However, for policymakers to move forward in the direction of TOU pricing on a larger scale, customer education will be important to empower informed decisions about energy use.

For DG customers specifically, the price they pay or receive for electricity they either consume or provide to the grid respectively will matter greatly in terms of encouraging or discouraging growth. Bidirectional rates with TOU pricing may offer one of the best solutions for this segment of the market. Under this rate design, the DG customer pays the full retail rate for any power consumed, just like any other customer. This customer is then compensated based on the same time periods, either using the retail rate or on a value basis. That value can be based on an analysis of the contribution of DG to the grid and can be set independently by a state public service commission.

Viewed as a quick fix to lost revenues associated with customer engagement in energy solutions, utilities are increasingly proposing SFV rates with high monthly fixed charges. Yet SFV is not a step forward, but a step backward. It discourages innovation and efficiency, penalizes low-income and apartment residents, and results in per-unit prices that fall far short of total system long-run incremental costs. The argument against SFV also follows clearly from the argument against unavoidable, recurring charges generally: it is not justified by fundamental economic principles.

Utilities have a long history of operating as monopolies, but technology means that both they and their regulators must adapt. Utilities may find they need to view their business differently. Power sector transformation will need to incorporate new tools to address this. Rate design will be an important element. The role of regulation in this power sector transformation will be to develop pathways that lead to smarter solutions that optimize the value of interconnection and two-way communication for the customer and the grid. Many of these solutions will be market-driven.

The speed at which change takes place will vary from jurisdiction to jurisdiction and will be influenced by what customers want and the utility culture. Regulators will have an important role to play in overseeing this transformation. In doing so, they should strive to avoid expensive mistakes based on defense of the legacy structure of the industry. Instead, regulators will need to focus on identifying costs and benefits of alternative strategies and seek to maximize the net value to customers and society.

I. Introduction

For most of its history, the electric utility industry saw little change in the economic and physical operating characteristics of the electric system. Large central station generating plants connected to high-voltage transmission delivered power to local distribution grids for delivery to end users, mostly by vertically integrated utilities that owned all of these components. Though reliable and remarkably low-cost, the historical electric system was, and in many ways remains, a black box to both customers and to system operators. Little in terms of the status of the system or customer use of the system was known in real- or near real-time. In short, for an industry in the information age, parts of the electric system can be considered rather "unenlightened."[1]

Today, the industry is facing a number of radical changes that will change this unintelligent landscape. Information systems are coming to the grid that will inform customers and system operators about how the system really works and how actions or failures to act can impact costs to customers and to society. Two categories of these changes will both demand and allow a more sophisticated method of pricing services to customers, a concept generally referred to in the industry as "rate design."

First, end users are installing their own generation, mostly in the form of photovoltaic (PV) systems, and are connecting different types of end-use appliances with increasing "intelligence" built in. Changes in customer usage brought about by energy efficiency and demand reductions in the face of price signals have allowed these phenomena to be recognized as virtual energy resources. In addition, the electric vehicle as a whole new class of end use is poised to grow rapidly over the coming years just as energy storage systems are poised to finally become economical. Together, these and other emerging technologies will usher in an entirely new system planning and operational dynamic. These changes, all at or near the customers' premises, will allow greater control of end-use loads and position the customer to respond to prices and system operational conditions in real-time or near real-time.

Second, utilities are deploying advanced metering, sometimes referred to as "advanced metering infrastructure" (AMI) or "smart meters," and more sophisticated system control and data acquisition (SCADA) systems that will provide system operators a new, real-time understanding of the state of the electric system, as well as the ability to communicate with generators, substations, transformers, meters, and end-use appliances.

To realize the full potential of these new systems and end uses, regulators, utilities, third-party service providers, and customers will need to utilize more advanced rate designs. Most important of these will be the more widespread use of bidirectional, time-sensitive prices that more accurately reflect cost. At the same time, regulators will need to take care to avoid potential pitfalls that would undermine the value of these new technologies.

Basics of Rate Design

Rate design is the regulatory term used to describe the pricing structure used by electric utilities in the United States. It explicitly includes the itemized prices set forth in tariffs and implicitly includes the underlying theory and process used to derive those prices. The *structure* of prices—that is, the form and periodicity of prices for the various services offered by a regulated company—has an impact on the choices made by customers, utilities, and other electric market participants which, in turn, affect resource development and utilization choices. These choices then have indirect consequences in terms of total costs to society; environmental and health impacts; and the overall economy.[2]

1 Those interested in the emerging changes and the challenges they present are invited to go directly to the sections covering Rate Design Principles and Rate Design for Specific Applications.

2 Weston, F. (2000). *Charging for Distribution Utility Services: Issues in Rate Design.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/412

Core Rate Design Principles

As one might expect, although rate design for electric utility customers is of critical importance, it is poorly understood by the general public and often lacks transparency.[3] Yet because customer energy usage choices are affected by the prices they pay, the difference between a progressive and regressive rate design can increase customer usage by as much as 15 percent.[4] Traditional simplistic rate designs that charge a single rate per unit of consumption, or worse, charge a lower rate as consumption increases, are still common in many Central and Southern states.[5] However, those traditional rate designs may not be the preferred rate for consumers, or be in the best interest of the utilities that serve them or society. Things are changing, and the industry must adapt to change or risk the fate of landline telephone companies, which have lost 60 percent of their access lines since the advent of telecommunications competition.

Rate design determines the prices consumers see and use to guide their consumption and investment choices. Prices affect how consumers use the electrical devices, appliances, and systems in our homes and factories. Electricity prices also influence how consumers invest in new equipment and the value consumers obtain from that equipment.

Most people who have ever tried their hands at designing rates for regulated utilities invariably say that it is "more art than science." Because of the shared nature of the system and the need to spread cost recovery fairly among all customers, the idea that rates should be set based on customer cost causation is a foundational concept in rate design. Analysts who ask, in a causal sense, "why" costs are incurred often reach different conclusions than those who measure, in an engineering sense, "how" costs are incurred. Rate design relies in strong measure upon the judicious application of certain economic guidelines. The following elements of economically efficient rate design necessary to address current and coming challenges in the electric industry are based on those laid out in James Bonbright's 1961 *Principles of Public Utility Rates,* and in Garfield and Lovejoy's *Public Utility Economics.* These principles require that rates should:

- Be forward-looking and reflect long-run marginal costs;
- Focus on the usage components of service, which are the most cost- and price-sensitive;
- Be simple and understandable;
- Recover system costs in proportion to how much customers use, and when they use it;
- Give consumers appropriate information and the opportunity to respond by adjusting usage; and
- Where possible, be temporally and geographically dynamic.[6]

Rate design signals public priorities about short-term and long-term economics, including especially the type and pace of future resource procurements. Rates can be designed to meet or, in the case of poor rate design, frustrate public policy objectives to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts, including public health.

Rates are also pivotal in providing utilities the opportunity to recover their authorized revenue requirement. Revenue adequacy is a core objective of rate design, but the more constructive design ideal for rates is forward-looking, so that future investment decisions by the utility and by customers can be harmonized.

Based on these traditional rate design concepts, and looking forward to a world with high levels of energy efficiency, distributed generation, and customer options for

3 This is evidenced by the number of recent rate design reports. See: Rocky Mountain Institute (RMI) eLab. (2014, August). *Rate Design for the Distribution Edge.* Available at: http://www.rmi.org/elab_rate_design#pricing_paper; RMI. (2015, February 26). *Why New Electricity Pricing Approaches are a Sheep in Wolf's Clothing* [Blog post]. Available at: http://blog.rmi.org/blog_2015_02_25_why_new_electricity_pricing_approaches_are_a_sheep_in_wolfs_clothing; and Tong, J., and Wellinghoff, J. (2015). Why fixed charges are a false fix to the utility industry's solar challenges. *Utility Dive,* February 13, 2015. Available at: http://www.utilitydive.com/news/tong-and-wellinghoff-why-fixed-charges-are-a-false-fix-to-the-utility-indu/364428/.

4 See Lazar. J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. http://www.raponline.org/document/download/id/6516. Appendix A provides a calculation of how rate design can influence consumption.

5 Worse, in that new generation, transmission and distribution resources accelerated by declining block rate designs, cost more than older resources. Also, utility capital cost forecasts are rising as are environmental costs.

6 Lazar, 2013, p. 10.

on-site backup supply, modern rate design should adhere to three basic principles:

- **Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.**
- **Principle 2: Customers should pay for grid services and power supply in proportion to how much they use these services, and how much power they consume.**
- **Principle 3: Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.**

These principles and priorities should be reflected in smarter rates designed to maximize the value of technology innovations, open up new markets, and accommodate the distribution and diversification of customer-sited generation resources. This necessarily includes consideration of what those future technologies and policies could look like, with a focus on metering, market structure, and pricing. In particular, consideration of how rates provide a "price signal" to customers, utilities, and other market participants to inform their consumption and investment decisions regarding energy efficiency (EE), demand response (DR), and distributed generation (DG), collectively referred to as distributed energy resources (DER).[7]

7 Quite a bit of background is necessary to fully appreciate the nuances of current practice, and the path to future rate designs. The reader is directed to the Guide to Appendices at the end of this document for more in-depth treatment of these issues.

II. Current and Coming Challenges in Utility Rate Design

Customer-Sited Generation

Over the past two decades, federal, state and local policymakers have implemented policies that have spurred the development of customer-sited DG, in particular, customer-sited PV systems. The policies include federal tax credits, state renewable portfolio standards (RPS), net metering, and interconnection standards.[8]

As the costs of renewable and other DG technologies have decreased, the options available to customers to procure these technologies have increased.[9] In addition to PV, other technologies available to customers are typically renewable and consist of wind turbines, small hydro, biomass, efficient cogeneration, fuel cells, and battery storage.[10] PV has been deployed by large industrial, commercial, residential, and other customers. For large commercial and industrial customers — any customers utilizing large amounts of heat for processing — combined heat and power (CHP) projects are commonly used to increase the efficiency of energy production by turning waste heat from industrial or manufacturing processes into electricity or, conversely, turning waste heat from electricity generation into process heat for industrial and manufacturing uses.

All of these resources reduce the electric grid's environmental footprint and provide a hedge against volatile fuel prices.[11] In addition, DG systems are decentralized, modular, and more flexible technologies that are located close to the load they serve. This reduces loads on transmission and distribution lines, transformers, and substations, which, in turn, reduces losses on the system, extends the life of equipment, reduces the risk of equipment failure and power outages, and can, if located at strategic points on the system and at the right time, defer or avoid system equipment replacements and upgrades. Customers can typically purchase or lease DG from a third party, often with seller or third-party financing.

Increasing penetrations of distributed renewables, especially PV, are changing the dialogue on how to fairly compensate providers of these resources (DG customers) and utilities for the services and benefits they each provide. PV is by far the most common form of customer-sited generation resource in terms of numbers of installations, and its adoption is already changing the relationship between utilities and consumers. Rate design must efficiently and fairly incorporate DG contributions to the grid, as well as fairly allocate the benefits and costs of their use for DG customers and for the grid.

At low levels of installation of distributed renewables (under 5 percent of customers), few if any, physical modifications are required to electric distribution systems. Power produced by a PV customer either serves the customer's own load or that of neighbors served by the

8 Steward, D., and E. Doris, E. (2014, November). *The Effect of State Policy Suites on the Development of Solar Markets.* National Renewable Energy Laboratory (NREL), Technical Report NREL/TP- 7A40-62506. Available at: http://www.nrel.gov/docs/fy15osti/62506.pdf. See also the Energy Department's SunShot Initiative, which is a national effort to make solar energy cost-competitive with traditional energy sources by the end of the decade. Through SunShot, the Energy Department supports private companies, universities, and national laboratories working to drive down the cost of solar electricity to $0.06 per kilowatt-hour. Learn more at http://www.energy.gov/sunshot.

9 National Renewable Energy Laboratory. (2012). *Renewable Electricity Futures Study.* Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/.

10 US Department of Energy (DOE). (2007). *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion.* Available at: http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf

11 There are other non-energy benefits, such as reducing manufacturing costs, which is good for economic development.

same substation bus. At the distribution substation, all that is observed is a lower overall load during the solar day. This is the situation in most of the United States. The low penetration scenario changes once solar output exceeds total load on a given substation. This is being experienced in Hawaii, which has the highest PV penetration of any state and where over 10 percent of residential consumers have PV systems installed. In the single-family residential sector, it is more than 20 percent in many neighborhoods. At this level of solar saturation, changes to distribution systems may be needed.

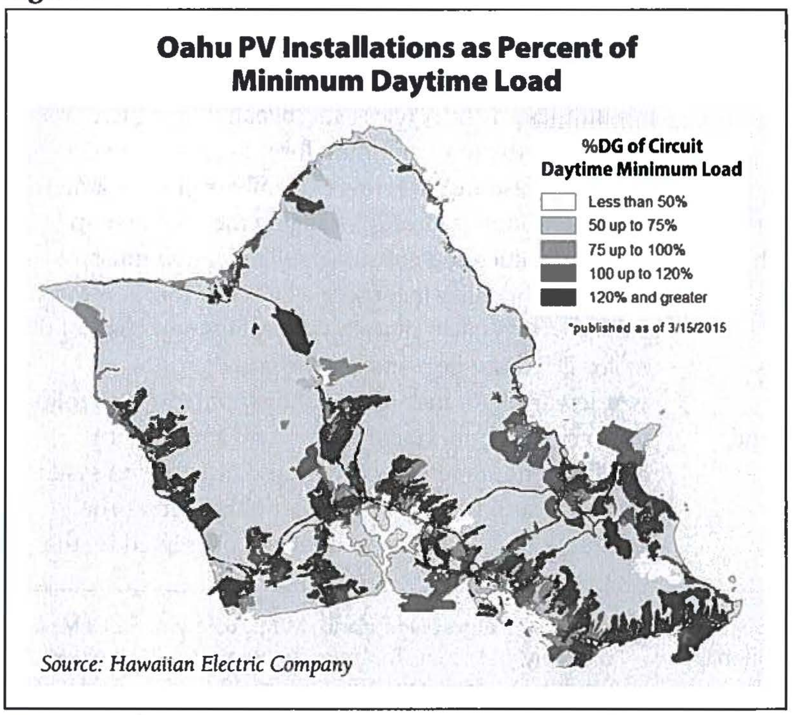
Solar penetration is measured in several ways: percent of customers, installed capacity as a percentage of peak demand, or installed capacity as a percentage of the minimum daytime load. Figure 1 is a map of the island of Oahu (Honolulu), showing which circuits have high levels of solar saturation; over half of the residential circuits have installed solar capacity in excess of 100 percent of the minimum daytime load. Therefore, it is possible (depending on the consumption of the customers that have the solar systems) for the customers' local distribution circuit to be delivering power upstream through the substation, rather than the traditional downstream flow of power from generation to transmission to distribution circuits.

Once solar penetration reaches about 10 percent of customers, as it has in Hawaii, there may be specific costs to the grid operator, such as additional voltage regulators, that are attributable to high levels of solar penetration. This does not necessarily mean that solar customers should pay different or additional charges compared with non-solar consumers because in most cases this solar penetration is helping to avoid other offsetting generation, transmission, and distribution costs.[12]

Hawaii is serving as a laboratory as it adapts to a high-renewable environment, with a mix of geothermal, hydro, biomass, wind, and solar making up an increasing percentage of electricity supply. The primary utility networks in the state recently submitted two important studies to the state PUC, addressing both distribution[13] and generation[14] planning. With the changes identified in these plans, Hawaiian Electric anticipates being able to adapt and ensure a reliable future with 65 percent renewable energy by 2030, and the state of Hawaii has adopted a legislative standard of 100 percent renewable electricity by 2045.

Adaptations that Hawaii is exploring and implementing include upgrading distribution system components such as higher capacity line transformers, increasing circuit capacity, adding voltage regulation, updating substation equipment, and investing in flexible generation to replace older units that must run continuously to be available to provide service during key hours.

Figure 1



Source: Hawaiian Electric Company

12 Also, among two solar installations, a solar installation with a smart inverter that can provide ancillary services to the grid may provide the grid with more value than a PV installation with a standard inverter. For more detail on the benefits of solar PV, see: RMI. (2013). *A Review of Solar PC Benefit & Cost Studies,* second edition. Available at: http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCost-Deck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies

13 Hawaiian Electric Company. (2014, August 26). *Distributed Generation Integration Plan.* Available at: http://files.hawaii.gov/puc/4_Book%201%20(transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5).pdf

14 Hawaiian Electric Company. (2014, August 26). *Power Supply Improvement Plan.* Available at: http://files.hawaii.gov/puc/3_Dkt%202011-0206%202014-08-26%20HECO%20PSIP%20Report.pdf

Electric Vehicles

Electric vehicles (EVs) are a small part of the electricity load currently, but growth in electric vehicles is likely for many reasons. First, the cost of batteries is declining, and this cost has historically been a major barrier to the EV market. Second, the evolution of the self-driving car is likely to stimulate a greater market for simple vehicles that can be remotely operated. EVs may be well-suited for this market segment.[15] Finally, emissions regulations are pressuring the industry to find zero-emissions transportation solutions.[16]

Electric vehicles such as the Nissan Leaf and Ford Focus can travel three to four miles per kilowatt-hour (kWh), meaning that ten kWh is functionally equal to one gallon of gasoline. An electric vehicle that travels 10,000 miles per year (800 miles per month) will use 3,000 to 4,000 kWh per year, about equal to the annual usage of a residential electric water heater or central air conditioner.

Because of the presence of batteries in the vehicles and the ability to control the timing of when they are charged, EV loads can be very different from traditional loads. If the vehicle battery capacity is adequate for a day's driving (less than 80 miles for the vast majority of drivers), the batteries can be charged at night or at other times when power is plentiful and lower cost, and impose little or no incremental peak demand for the utility system. They can even be controlled by smart transformers connected to smart grid distribution automation systems so that, in aggregate, they impose the minimum load on the system during primarily night-time charging hours.[17] However, encouraging that behavior means that rates should be designed to provide an incentive for EV owners to charge their cars when power costs are low and distribution system capacity is not congested. This requires time-sensitive pricing, a topic discussed in greater detail later in this paper.

Microgrids

Definition

In the near future, utilities will need to interface with customer- or community-owned microgrids. These may range from an individual apartment building or office complex with on-site generation to a municipal electric utility connected to an adjacent larger utility.

Lawrence Berkeley National Laboratories (LBNL) has defined a microgrid as "a localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate."[18] Large hotels and hospitals, and an increasing number of individual homes, have had on-site emergency generation for decades, but generally fall short of the definition of a microgrid due to lack of communication and control technologies to interact in a bidirectional manner with the grid. But technological progress will potentially extend implementation of this microgrid concept to thousands of customers on each major utility, and millions nationwide.

Residential Microgrid

The visual representation in Figure 2 depicts an example of a residential microgrid as envisioned by LBNL.

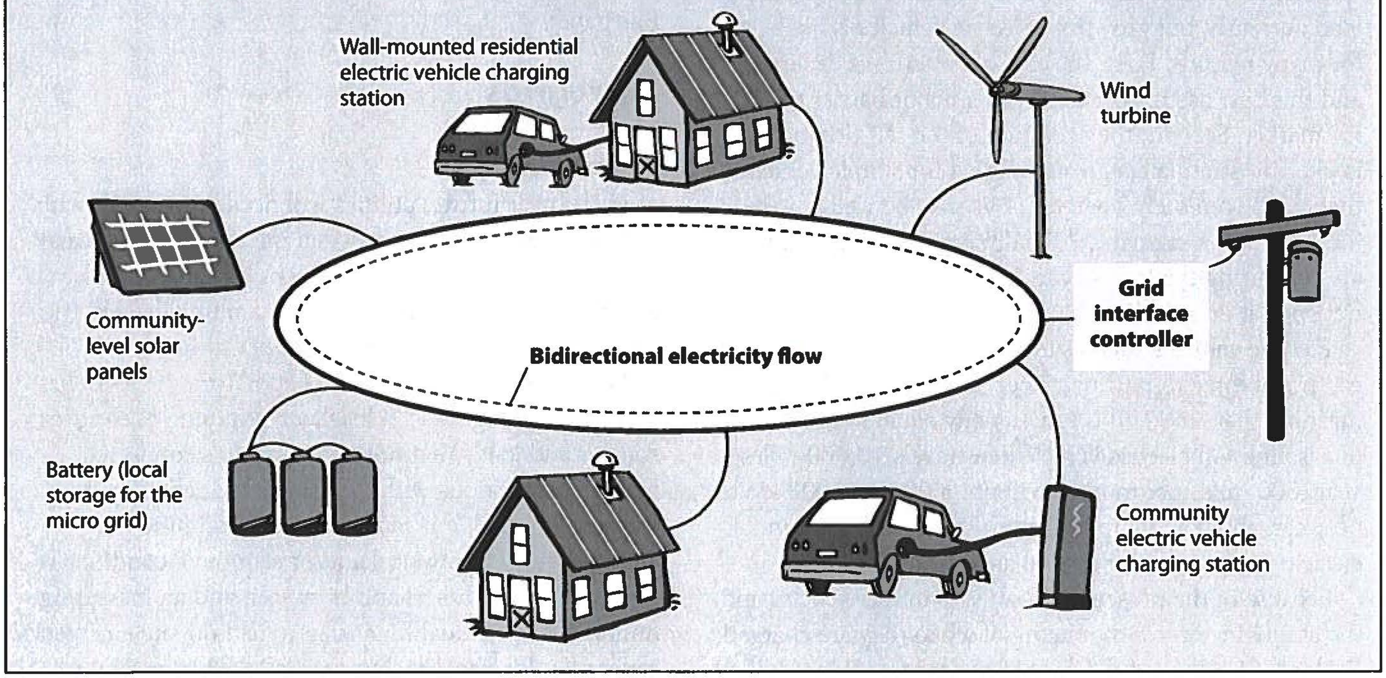
15 Lantry, L. (2015). The Car of the Future Will Be All Electric and Self-Driving. *EcoWatch*. Available at: http://ecowatch.com/2015/06/17/car-of-future-electric-self-driving/

16 This section is primarily extracted from a larger publication on electric vehicles, MJ Bradley & Associates. (2013). *Electric Vehicle Grid Integration in the US, Europe, and China.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6645

17 Hilshey, A.D. (2012). *Electric vehicle charging: Transformer impacts and smart, decentralized solutions.* University of Vermont School of Engineering. Power and Energy Society General Meeting, Institute of Electrical and Electronics Engineers (IEEE), 2012. Available at: http://www.uvm.edu/~prezaei/Papers/Hilshey_GM2012.pdf

18 Lawrence Berkeley National Laboratory (LBNL). *About Microgrids.* Available at: https://building-microgrid.lbl.gov/about-microgrids

Figure 2

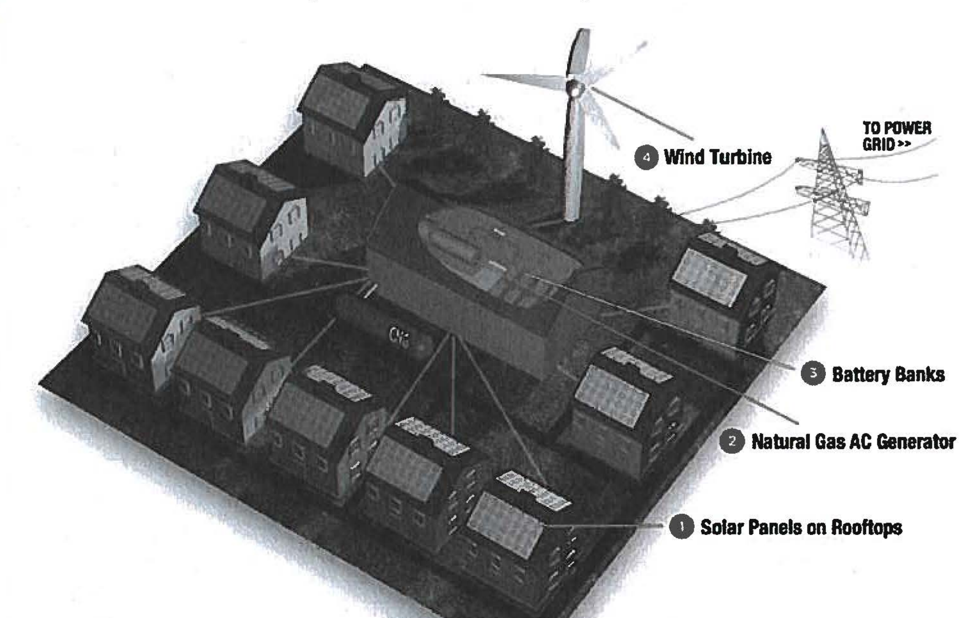


Microgrids with Community Resources

In the near future, whole communities may be planned around a microgrid concept, with single- and multi-family housing constructed with smart meters and smart appliances. These microgrids may utilize DG (both individual- and community-owned) and storage technologies as shown in Figure 3. Microgrids will depend on utilities for some service at appropriate rates; however, microgrids will also provide services to utilities at times, and so the compensation framework needs to be symmetrical and bidirectional.

Figure 3

Microgrid with Community Resources



Source: *Cleanskies.org*

19 University of California at Irvine. Cyber-Physical Energy Systems (CPES). Available at: http://aicps.eng.uci.edu/research/CPES/ (2014).

Storage

Storage technologies can be a game changer if they are distributed in communities, interconnected with a smart grid, and not price prohibitive.[20] Cheap and reliable thermal or electricity storage alters the existing electric grid paradigm by allowing immediate balancing of the system without needing to cycle power plants. In this sense, DG customers with storage can provide peak power anytime, as bubbles of renewable supplies can be stored until a later, more valuable time period. From a system operations point of view, energy supply (generation) and loads (end uses) must be instantaneously kept in balance, even as customers change their end uses. This is currently done primarily by designating one or more generators to increase or decrease output in response to changes in load. The presence of significant storage on the system would allow generators to generate when they can, while allowing the storage technology to provide additional energy or absorb additional energy as loads change. Storage is a multi-attribute resource that can serve this and many other functions as outlined in Table 1.[21]

Table 1

Functional Attributes of Storage

Electric energy time shift	Time-of-use energy cost management
Electric supply capacity	Demand charge management
Load following	Electric service reliability
Area regulation	Electric service power quality
Electric supply reserve capacity	Enabling consumers to serve dedicated loads with specific types of resources
Voltage support	Renewable energy time-shift
Transmission support	Renewables capacity firming
Transmission congestion relief	Wind generation grid Integration (short-duration discharges)
Transmission and distribution (T&D) upgrade deferral	Wind generation grid integration (long-duration discharges)
Substation on-site power	

Source: Pomper, NRRI, 2011

Storage allows customers with DG resources to go off-grid if utility rate designs create an economic signal to customers that it is cheaper to completely disconnect from the grid than it is to use the grid as a backup system.[22] Storage technologies are expected to be developed both at utility scale and at the individual customer scale.

If significant numbers of customers install storage and disconnect from the grid, then this storage is not available to the grid operator for optimal management for the benefit of all electricity users. If this occurs, an expensive augmentation to the grid will be poorly utilized. If these customers remain grid-connected, their storage can be used not only for their own benefit, but also potentially for broader public benefit. The existence of storage may also make those customers' loads available for demand-response programs.

The simplest energy storage technologies are thermal and mechanical storage systems, including:

- Electric water heaters controlled to operate during low-cost hours and hold that hot water for later usage or operated in a coordinated manner to minimize their aggregate load at any point in time, thus reducing system costs and increasing system reliability;
- Ice storage systems to store "cold" to provide air conditioning when needed; and

20 "Storage" involves a series of acts: converting grid-interconnected electricity to another form of energy, holding that other form of energy for future use, and then converting it back to grid-interconnected electricity at a different time. The individual acts that comprise this series may be referenced as, respectively, "charging," "holding," and "discharging." See Pomper, D. (2011, June). *Electric Storage: Technologies and Regulation.* National Resource Regulatory Institute (NRRI), p. 3. Available at http://www2.econ.iastate.edu/tesfatsi/electricity_storage_manual.RGuttromsonJuly2011.pdf. To this should be added other forms of energy storage, such as water heater controls, water system reservoir management, and air conditioning thermal storage, which may provide lower-cost means to shape loads to resources and resources to loads.

21 Pomper, 2011, p. 9.

22 Utility rate designs should not create an artificial incentive for complete separation from the grid by small-use customers, potentially triggering a spiral of customer grid defection (e.g., see the discussion of straight fixed/variable pricing later in this paper and Appendix D).

- Mechanical storage systems that spin a flywheel, compress air or another vapor, or raise a weight when power is cheap to provide end-use service power at a later time.

Some other types of electricity storage technologies are utility-pumped storage, chemical batteries, and super capacitors. Unfortunately, these types of electricity storage have over recent history been very expensive, ranging from $60/kWh to $860,000/kWh of daily storage capacity depending on the technology.[23] However, there is excitement in the storage world that costs may soon be driven down, given the partnership between Tesla cars and Solar City to provide backup systems for PV owners. Because they necessarily come with batteries, EVs represent a potential means of electricity storage for both customers and for the grid as a whole. The limited driving range of the current supply of EVs means they have limited capacity to serve as whole-house backup systems; however, Toyota already sells such a vehicle in Japan, spurred to market after the tsunami of 2011.[24] In addition, the development of cheaper battery technology for vehicles will likely be transferred to stationary storage systems for customers and utilities; the recent announcement by Tesla of the residential "Powerwall" battery is an initial step in this direction.[25]

In 2014, about one out of five household PV systems in Germany was sold with a battery pack, and that is projected to be one in three in 2015.[26] Costs are headed down, with Bloomberg New Energy Finance predicting that residential-scale battery storage costs will fall 57 percent by 2020. Lux Research sees the global market for PV systems combined with battery storage growing from the current $200 million a year to $2.8 billion in 2018.[27]

Although it is relatively inexpensive to install limited storage to mitigate the afternoon and early-evening impact on utility peak, it is more expensive (though getting cheaper) to install sufficient storage to enable complete disconnection from the grid. Utility rates should be

Pedestrian Crossing Signals: Example of Widespread Grid Defection

The earliest economic applications of solar with storage were for remote applications, including military and national park sites where extending grid service was prohibitively expensive.

This has expanded in recent years to low-level uses of power where even a short utility line extension and billing account exceed the cost of a solar panel and battery. For example, tens of thousands of pedestrian crossing signals are being installed in urban areas with this technology, despite being adjacent to grid electric service. Low-wattage LED light bulbs, coupled with cheaper solar panels, make it cost-effective to leave out the cost of a grid connection.

The threshold size at which grid independence makes sense is a function of two interacting costs: the cost of a stand-alone system and the charges that utilities make for grid service. If the fixed charges for grid services rise, the number of applications where grid independence is economical will rise.

Graphic from: www.xwalk.com

23 Pomper, 2011, pp. 17-20

24 Carter, M. (2012, June 5). Toyota Develops System that Enables Electric Vehicles To Power Your Home. *Inhabitat.* Available at: http://inhabitat.com/toyota-develops-system-that-enables-electric-vehicles-to-power-your-home/

25 See Powerwall. *Tesla Home Battery.* http://www.teslamotors.com/powerwall. A 10 kWh system will be for backup applications will be available in the summer of 2015 for $3,500. It comes with a ten year warranty but installation and inverter costs are additional. Such a system in Southern California, under a time-differentiated rate design, is estimated to have a five-year payback. Also see: Teslarati. (2015, May 2). *A Tesla Powerwall-Powered Home: Will It Pay Off?* Available at: http://www.teslarati.com/tesla-powerwall-home-will-it-pay-off/

26 Deign, J. (2015). German Energy Storage: Not for the Fainthearted. *Greentech Media,* March 13, 2015. Available at http://www.greentechmedia.com/articles/read/german-energy-storage-not-for-the-faint-hearted. "The cost of combined PV-and-battery systems runs from about €13,000 to €25,000 ($13,800 to $26,600). Batteries make up about 30 percent of the total bill."

27 Guevara-Stone, L. (2014). Solar City and Tesla shine spotlight on solar-battery systems. *GreenBiz,* January 16, 2014. Available at: http://www.greenbiz.com/blog/2014/01/16/solarcity-and-tesla-shine-spotlight-solar-battery-systems.

structured to encourage cost-effective storage solutions (e.g., through the use of time-varying rates).

Distributed Ancillary Services

The presence of generation, storage, and smart control technologies at customer premises offers the opportunity for customers to provide a number of valuable functions to the grid. These generally fall into a category termed "ancillary services" and include voltage regulation, power factor control, frequency control, and spinning reserves.[28] In addition, where system operators or third-party aggregators have the ability to control end-use loads, customer appliances can deliver demand response during high-cost periods or when the grid is at or near its operating capacity and may be at risk for system failures. Demand response, in addition to being an economic response by customers, becomes a form of spinning reserve when placed at the disposal of system operators.

28 Spinning reserves refer to the availability of additional generating resources, which can be called upon within a very short period of time. Different utilities and different utility markets utilize varying response time frames to define spinning reserve services, ranging from instantaneous to up an hour or so.

III. Rate Design to Enable "Smart" Technology

Survey of Technology

The traditional electric utility is undergoing fundamental change. Utilities from Maine to California have deployed smart grid upgrades or are beginning the transition to a smarter grid.[29] These upgrades promise to deliver an entirely new level of information about system operations and consumer behavior. In short, the information age is coming to the electric industry.[30] Computerizing the traditional grid with AMI and advanced SCADA systems will enable the development of new and dynamic rate offerings. Meanwhile, smart home appliances that can automatically respond to prices or be dispatched by system operators or third-party service providers will assist customers in managing their usage and minimize total system costs and increase system reliability.[31] These new smart technologies will also help accommodate customer-owned generation, utility-scale renewable power, energy storage (both customer- and utility-scale), electric vehicles, and microgrids.

Various technology enhancements can improve the effectiveness of more complex rate designs, by enabling customers to respond to prices automatically. Some examples include:

- **Smart thermostats:** Can automatically change heating and cooling settings in response to real-time price changes, while allowing the consumer to manually override these. The Nest, SilverPAC Silverstat 7 Advanced, and GE Nucleus are examples of thermostats with that capability. Good pricing can be supplemented by good utility or regional wholesale power market entity programs that offer curtailment inducements based on grid value.
- **Grid-integrated water heating:** Can automatically increase hot water storage during low-cost periods, curtail water heating operation during high-cost periods, and also supply ancillary services to the utility without the consumer even noticing that this is happening. Great River Energy, serving electric cooperatives in Minnesota, is currently demonstrating this potential.[32]
- **Electric vehicle chargers:** Can be programmed to provide "economy" charges, allowing the customer to take advantage of low-cost energy when it is available.
- **Vehicle-to-grid applications:** Can enable EV batteries to flow power back to the grid during critical hours, essentially allowing the grid operator use of the EV batteries and provide a means of compensation to EV owners for supplying the energy.[33] A pilot program is underway in Maryland and Delaware to enable vehicle-to-grid service.

Smart Meters

Smart meters provide data acquisition, equipment control and communication capability between the

29 The term "smart grid" is used here broadly to include both utility grid-side and customer investments.

30 Determining whether AMI and smart grid are projected to be cost-effective before deployment is an important consideration and one that is beyond the purview of this report. A good discussion on smart grid benefits and costs can be found in Alvarez, P. (2014). *Smart Grid Hype & Reality.* Wired Group Publishing, Chapters 4-9.

31 PR Newswire (2013, January 8). *ComED Launches Smart Home Showcase Contest.* Available at: http://www.prnewswire.com/news-releases/comed-launches-smart-home-showcase-contest-186025412.html

32 Podorson, D. (2014, September 9). *Battery Killers: How Water Heaters Have Evolved into Grid-Scale Energy-Storage Devices.* E Source White Paper. Available at: http://www.esource.com/ES-WP-18/GIWHs

33 EV World. The V2G Revolution Gets a Textbook [Podcast]. Available at: http://www.evworld.com/article.cfm?storyid=1675

customer and the power grid, plus outage detection and reduced meter reading costs.[34] Smart meters are able to record customer usage at a fine timescale and then communicate that information back to the utility and to the customer. This information can, in turn, be used to control end-use appliances in response to price signals and system conditions. When used by system controllers, they can aid in reducing loads during times of system stress, thereby reducing losses on the system and wear and tear on equipment. This will help to avoid system failures and outages. When employed by the customers or on their direct behalf, smart meters can be used to shift usage from high-cost periods to periods when lower cost energy is available.

Smart Meters for Distributed Generation

Customers with PV systems or other on-site grid-interconnected generation or battery storage systems both take power from the grid and deliver power to the grid. Keeping track of these flows is necessary for accurate billing and crediting of services provided to the grid at different times of the day when the value may be very different. Smart meters have this capability, and are needed when the rate design requires knowing when power is flowing and in which direction, to more accurately value the cost of customer use and the value of customer production. Figure 4 shows the kind of data that a smart meter can record for a home with a PV system; the red shows the total on-site consumption of electricity (including sporadic 4 kW spikes of an electric water heater), and the green shows the production of PV power. Where the green exceeds the red, the customer is a net exporter to the grid. Clearly if the customer is consuming most of its power during off-peak periods, and supplying power mostly during on-peak periods, the solar customer is providing significant value to the grid that is not captured by simple monthly kWh net energy metering (NEM).[35]

Remote Disconnection and Reconnection: Challenge and Opportunity

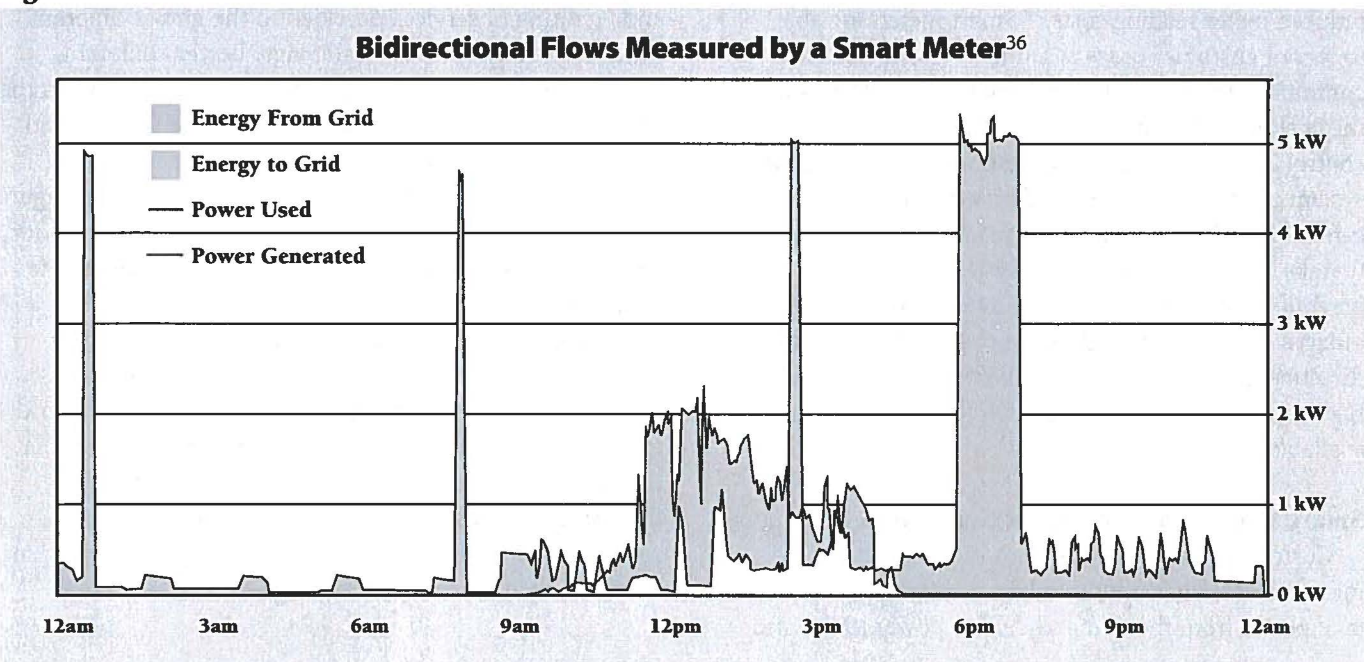
Without smart meters, when utilities disconnect service (move -out, or non-payment), they must send a service person to the premises to lock out the meter. This has a cost, normally recovered through a levy on the individual consumer. Where disconnections are effected for non-payment, it often (depending on regulatory commission rules) involves three site visits, one to post the notice of impending disconnection, one to effect disconnection, and a third to reconnect. The second and third site visits reduce the likelihood of disconnection by providing an opportunity for the consumer to make a payment at the site to avoid disconnection. With smart meters, the disconnection and reconnection can be done remotely. This has an economic benefit, but raises a social equity concern. The challenge is to realize the operational benefit of the remote disconnect and reconnect while maintaining safeguards for vulnerable populations.

Low-income advocates have a concern about this capability, because disconnection can be done without any site visit, and customers with medical needs, or who have the ability to make a field payment, are disconnected. Some utilities with remote disconnect capability have addressed this by having the site visit performed by a (lower paid and more customer-oriented) customer service agent who is better able to judge an exception or accept field payment, rather than by a (more technically trained) electrical worker. This can provide lower costs and better service than previous approaches, and avoid one or two site visits. In any event, with remote reconnection, it is possible for a customer to phone in a payment, and have service restored immediately. Regulators are becoming aware of both the promise and pitfalls of this remote capability. In some foreign countries, money transfer via prepaid cellular phone systems enables immediate payment even for consumers without credit cards or bank accounts. Further, the charge for of disconnection and reconnection to the consumer should be dramatically reduced to reflect the reduced costs to the utility.

34 They also provide operational benefits such as reduced meter reading costs and outage detection.

35 "Net energy metering" is a pricing scheme that "pays" for the output of customer-sited generation at the same rate that the customer pays for energy delivered from the electric system.

Figure 4



Smart Homes and Buildings

Smart homes and buildings are structures in which end uses such as heating, ventilation and air conditioning (HVAC); water heaters; and lighting systems are controlled by intelligent networks to minimize cost. Smart building end-use appliances may also respond automatically to conditions within the building by providing lighting or space conditioning only when people are present or reducing load in response to price signals received from the grid operator.

Smart Appliances

Smart appliances include the building systems noted above, as well as such other items as refrigerators, washers and dryers, computers or any other appliance equipped to communicate with smart grid control systems. Some smart appliances will be programmed to act on their own, based on information they can garner from their interconnection to an information system and customer preferences. Others will be controlled by other systems such as home energy management systems or demand response aggregator controls, which gather that information and provide the decision-making software.[37]

SCADA and Meter Data Management Systems

From a system management and operations standpoint, much of the electric utility system remained unchanged from its early 20th century condition until the introduction of SCADA systems late in the century. SCADA systems enabled grid operators, for the first time, to see how their systems operate at a more granular level and in real or near-real time. The addition of smart meters and other devices, collectively referred to as the "smart grid," promises to vault the level of sophistication to an even higher level. A key element of any smart grid deployment is the information system that collects data from smart meters and other measurement and control devices and transmits it to the utility. It is also used to communicate back to the customer and, increasingly, directly to customer appliances and third parties such as curtailment service providers.

A meter data management system (MDMS) enables the utility to aggregate the data of individual customers' usage at the service, transformer, and circuit level, to identify where demand response measures may be valuable, where distribution system upgrades are necessary, and where specific loads such as electric water heaters and electric

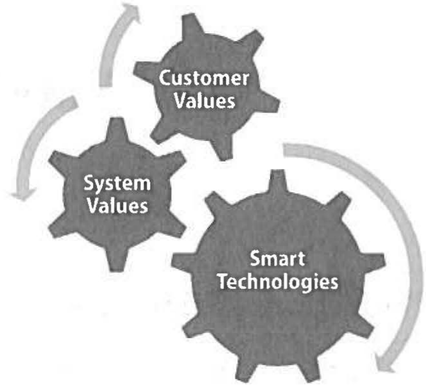
36 Courtesy of Convergence Research; the customer-identifying data has been removed to product the consumer's privacy.

37 Master meter buildings are the scourge of "smart" since the owner is not the user and so preferences can be ignored. They represent an interesting challenge to create programs to help overcome this gap, which may include deploying technology throughout the structure.

vehicles are affecting grid adequacy and efficiency. This improved information analytical capability will provide feedback to enable more clearly defined rate designs that are tied to specific operational and cost-containment goals and to assist utilities, customers, and other service providers to control end uses. Appropriate rate design strategies are also needed for the recovery of the costs of these new systems.

Dynamic Integrated Distribution Systems: Putting All the Pieces Together

Smart technologies enable distribution optimization in many ways. At an operational level, system operators have better situational awareness of the condition of the system at all times and a greater ability to modify those conditions to reduce costs and improve power quality and reliability through strategies like conservation voltage reduction and volt-VAR (volt-ampere reactive) optimization that save energy, and therefore money and resources.[38] In the longer term, smart technologies allow utilities to better assess when and where to make system upgrades or to engage in anticipatory maintenance or replacement of plants to reduce costs and improve reliability. Rate design will play a key role in bringing customer end uses into the toolbox of solutions for these issues. In addition, good rate design will inform the customer about opportunities to save money and to be rewarded for providing value to the overall grid. Poor rate design can impair this ability and prevent the true value of smart technologies from being realized, clogging the gears of this dynamic.



If rates provide appropriate rewards for locational value and ancillary services, costs can be reduced. Pragmatically, rates to consumers need to be relatively simple to be understood, but rates to aggregators of demand response and ancillary services can be more complex and temporally and geographically granular.

38 Energy savings were 2.5 percent in Xcel's SmartGridCity Demonstration Project. See Alvarez, 2014, p. 134.

IV. Rate Design Principles and Solutions

Traditional Principles

The design of rates begins with a functional evaluation of the costs incurred by the utility to provide service to its customers. A foundational notion of rate design is to charge customers in relation to the costs incurred to serve them. A critical step is the allocation of costs among different customer classes — residential, commercial, industrial, and others. Customer cost allocations determine what piece of the utility revenue requirement pie a specific class will be charged. In reaching a cost allocation determination, regulators usually will consider different approaches (embedded cost vs. marginal cost, single peak hour or multiple peak hours,[39] etc.) and review different cost of service studies. The end result is often some blend of the different approaches that hopefully match the overarching priorities of the state. Given the judgment involved, no single approach can be said to be "correct"; rate making is partly science and partly art. Appendix A of this paper "Dividing the Pie," addresses these ideas in more detail.[40]

Rate design involves the definition, allocation, and recovery of customer costs, distribution costs, power supply and transmission costs, and other general costs incurred by the utility to provide service to customers.

Customer Costs

Rate design necessarily involves tying cost causation to the type of price used to recover that cost. A simple example would be the use of a per-kWh charge for fuel costs, which reflects the fact that, as more kWhs are consumed, more fuel is consumed. In the case of customer costs, the inquiry focuses on those costs that vary with the number of customers served. This includes such costs as metering, billing and collection, and customer assistance. These costs are always quite small, typically amounting to no more than $5 to $10 a month per residential consumer.

The fixed charge for residential or commercial service should not exceed the customer-specific costs attributable to an incremental consumer. For urban and suburban residential consumers, this is the cost of a service drop, the portion of the meter cost directly related to billing for usage, plus the cost of periodic (monthly, bimonthly, or quarterly) billing and collection. Monthly billing is usually desirable, because with less frequent billing customer bills become large and potentially unmanageable. However, the size of the bills is driven by usage levels, not merely a cost of connecting to the system; thus, even the cost of billing has a usage-related component, which should be recovered in volumetric prices.

AMI enables a wide array of functions unassociated with metering or billing and collection. The role of AMI in peak load reduction, energy efficiency, system operations and reliability, and other functions of the utility clearly establish that smart meter costs do not belong exclusively in the category of customer-related costs. The incremental cost of smart meters, above and beyond what would have to be spent for older style meters, should be recovered through the same pricing mechanisms used to recover other costs associated with those other functions, and a portion of the net benefit that smart meters provides should be applied to *reduce* customer-related costs. If regulators treat smart meter costs in the same manner as traditional meters — apportioning the costs on a per-customer basis — they are ignoring a cost-follows-benefit principle.

Other cost minimization strategies may be applied to billing as well. Many banks, brokerages, and other businesses offer a discount to customers that choose electronic billing and auto-payment options; the same discounts may be extended to customers of utilities, helping to reduce the monthly billing-related cost of electricity services that is often reflected in customer charges.

39 Coincident peak (CP) is a measure of peak demand that can be as narrow as the highest single hour (1CP), the average of the four summer monthly peaks (4CP) or the average of 12 monthly system peak hours (12CP).

40 Appendix A explores how the assumptions made in the cost-allocation process can influence rate design decisions.

Distribution Costs

The basic distribution infrastructure — poles, wires, and transformers, plus associated maintenance costs — comprises approximately one-quarter of the revenue requirement for the typical electric utility. Although many utilities view these as "fixed costs," in the long run all costs are variable. Customer usage levels may change dramatically over time and there may be operational alternatives increasingly available such as on-site generation and storage. With the experienced and anticipated reduction in cost for these alternatives, the likelihood of their deployment and use will only increase, making possible the deferral or avoidance of distribution infrastructure investment. At the same time, as customer usage grows within any portion of the distribution system, upgrades and expansions will be required, resulting in greater capital and operating costs. Accordingly, it is important to recover distribution costs on the basis of the end-use consumption and, only where DG penetration is very high, consider specific additional investment in distribution facilities.

Flat Rates

The simplest form of rate design is the flat rate, which is derived by simply dividing the revenue requirement for a given class of customers by the kilowatt-hour sales, and charges a purely volumetric price.

A very important principle of rate design is to align the incremental price for incremental consumption with long-run incremental costs, including societal costs. As discussed earlier, this means that a price reflects the cost of a new renewable energy resource (or a conventional resource plus full environmental damage costs), plus the transmission, distribution, and other utility services needed to deliver that to a consumer.[41] Use of short-run costs, dispatch modeling, or a non-renewable resource as the basis for "incremental cost" is inappropriate and misleading to the consumer and society because it fails to recognize the real costs associated with plant investment and resource choices, many of which have long-term consequences on the order of a half-century or more. The issue of whether societal costs are recovered in the utility revenue requirement is immaterial to setting the incremental price correctly to guide efficient consumer response. This is one reason many utility regulators have implemented inclining block rates — to reflect both utility costs and societal costs in the incremental price per kilowatt-hour.

Demand Charges

Demand charges are sometimes used to recover the non-fuel costs of generation, transmission, and distribution of large commercial and industrial customers. These demand charges have typically been applied to the individual peak demand of each consumer, regardless of whether it occurs during system peak periods.[42]

Table 2

Typical Commercial Rate with a Demand Charge

Rate Element	Illustrative Rate	How Applied
Customer Charge	$10/mo	Independent of usage
Demand Charge	$10/kW	Customer's highest 1-hour usage per month
Energy Charge	$.10/kWh	All kWh

It is generally agreed that demand or capacity-related costs, to the extent they occur on a system, are primarily associated with the system peak demand, not the individual customer peak demand. Only very local components of the distribution system (service drop, line transformer) are sized to the individual customer load.

Because traditional demand charges are measured on the basis of the individual customer's peak, regardless of whether it coincides with the peaks on any portion of the system, this approach results in a mismatch between the system coincident peak costs used to set prices and the actual costs incurred at the time of the customer's non-coincident peak. While the revenue to be collected is represented by the system coincident peak costs, the billing units used to set the prices are the sum of all customers' individual non-coincident peaks. This results in a lower demand charge for everyone, but has the effect of requiring customers who are not contributing proportionately to the system peak to bear a greater share, while those who are contributing to the system peak bear a lesser share of

41 The alternative to using a renewable resource as the benchmark would be to include conventional resources plus the monetized cost of societal impacts; since this is unknowable, the prudent alternative is to use an emissions-free resource as the benchmark.

42 Individual peak demands measured in this manner are typically referred to as non-coincident peaks.

revenue responsibility than would occur if demand charges were based on usage during the system coincident peak.

A demand "ratchet" is a rate element that requires a customer to pay a demand charge in every month that is based on their highest usage during the year, often based on summer peak demand. These provide stable revenues to utilities, but discourage energy efficiency throughout the year, since a significant part of the cost of service is fixed and the savings from peak load reduction from energy efficiency are not realized until the ratchet period has been completed. This also has the effect of aggravating the mismatch between on-peak costs and on-peak usage, noted above.

Power Supply Costs

Power supply costs include the investment-related capital costs of power plants and transmission costs, fuel and purchased power costs, and generation and transmission operations and maintenance (O&M). In the past, many of these, such as capital costs and purchased power demand charges, were treated as demand-related costs, allocated to each customer class on a measure of demand (typically class contribution to system coincident peak, average demand, or a combination of the two). These may be reflected in individual customer demand charges, based on individual customer peak usage (not necessarily coincident to the system peak) for large-use (i.e., commercial and industrial) customers, or, preferably, in time-of-use (TOU) energy charges.

Fuel and purchased power costs, most of which were treated as energy-related costs, are typically allocated among the classes on a measure of total energy consumed (annual, seasonal, or time-varying). For electric utilities, as in other industries, capital costs, on the one hand, and short-run incremental unit costs (e.g., fuel and purchased power costs), on the other, are substitutes. A capital-intensive generating resource like wind, solar, or nuclear displaces fuel costs, typically gas or coal; a local resource like a combustion turbine displaces the need for transmission.

Likewise, a market mechanism that pays customers to reduce demand during high price periods or when the system is under stress displaces the need for generation, transmission, and distribution to meet short-term peaking requirements. In restructured and competitive wholesale power markets, however, the power supply costs discussed above in this section are nearly all recovered on a time-varying energy basis. A small portion may be recovered in capacity payments, but experience in the PJM and ISO-NE regions shows that, where allowed to compete, demand response potential quickly bids down the prices for short-duration capacity.

Principles for Rate Design in the Wake of Change

Good rate design should work in concert with the industry's clean technological innovations and institutional changes. Accomplishing this requires the application of well-established principles to inform the design of rates that promote economic efficiency, equity, and utility revenue recovery. This will be critical in a future characterized by significant customer-side resource investment and smart technology deployment. The advantages of a state that embraces these efficiency, equity, and utility revenue adequacy goals are significant, especially in maintaining a state's competitiveness and promoting customer choice and ingenuity. Unleashing the potential of new technologies will also require consideration of changing stakeholder interests as the power sector evolves.

Best practice rate design solutions should balance the goals of:

- Assuring recovery of prudently incurred utility costs;
- Maintaining grid reliability;
- Assuring fairness to all customer classes and sub-classes;
- Assisting the transition of the industry to a clean energy future;
- Setting economically efficient prices that are forward-looking and lead to the optimum allocation of utility and customer resources;
- Maximizing the value and effectiveness of new technologies as they become available and are deployed on, or alongside, the electric system; and
- Preventing anti-competitive or anti-innovation market structures or behavior.

Stakeholder Interests

Finding common ground on rate design among utilities, consumer advocates, environmental advocates, and others is not easy. The interests are different, the perspectives are different, and even the perceived public policy goals are viewed differently by different parties.

Utility Interests

Utilities tend to see costs associated with generating plant, transmission, distribution, and customer billing as "fixed costs" and generally seek a reliable method for assuring their recovery. Recently, a number of utilities have sought to recover these costs through fixed charges or demand charges, asserting that "fixed costs" should be recovered through "fixed charges." The use of high fixed charges is one avenue being pursued to provide revenue stability to the utility, independent of sales volumes and independent of whether the customer deploys energy efficiency or distributed generation.

Utilities seeking high fixed charges argue that the per-customer responsibility for distribution service is fully independent of sales volumes to the customer, because all customers must use the distribution network and should share equally in distribution system costs. In this view, when solar customers reduce their usage of grid-supplied power, their responsibility for distribution cost recovery is undiminished. They perceive that if solar customers do not pay these costs, then the burden falls either on other electric consumers (after a rate case or decoupling adjustment) or on utility shareholders.[43] From the perspective of other customers, this is no different than the earnings effect from customers who reduce their usage through conservation, energy efficiency, or departure from the system. On growing systems in the South and West, most of these reductions in cost recovery are offset by overall growth in the number of customers served by the utility.

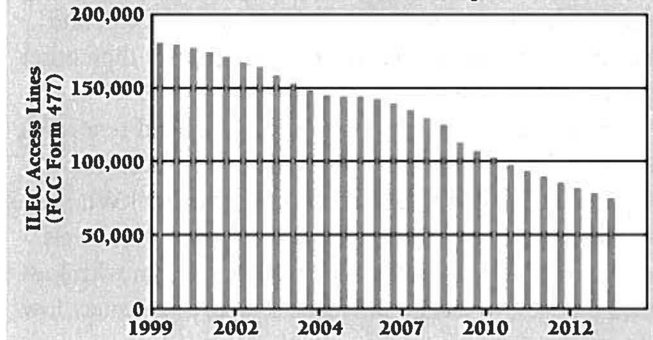
That said, no rate design can get around the basic constraint that the costs of service can only be allocated among existing customers and across their collective usage, unless the regulator finds that a portion of these costs should be disallowed from the revenue requirement. In low- or negative-growth states, this can create a schism between consumers pursuing efficiency and renewable energy sources and consumers who obtain all of their power from the grid. The issues surrounding the use of high fixed charges may have more to do with the adverse impact on low-use customers (who are often lower-income or live in urban areas or in apartments) and anti-competitive effects on competing generating resources (e.g., customer-owned DG), than recovery of costs by the utility.

Later on in this paper (see "Utility-Defensive Rate Design Principles"), as well as in Appendix D, we discuss why the use of high fixed charges may be a problematic strategy in the long run compared with alternatives. Both the telephone and cable television markets have imposed higher fixed charges. Both have seen significant customer and revenue attrition as customers have moved to competitive and volumetric alternatives. Similar results may be expected for electric utilities that employ this approach.

Consumer Interests

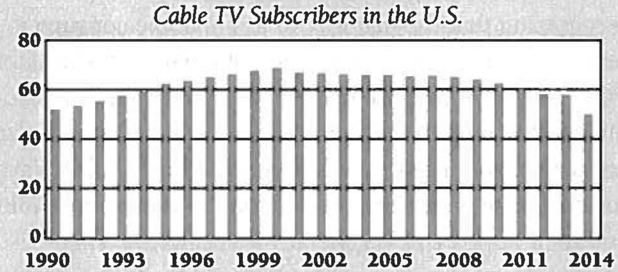
Consumers and their advocates come in many varieties. State consumer advocates may sometimes have different perspectives from low-income advocates. State consumer

How Did High Fixed Charges Work Out for the Landline Phone Companies?[44]



How About Cable TV?

Cable TV Subscribers in the U.S.



advocates are generally focused on minimizing the utility revenue requirement, and minimizing utility rate increases for all customers. They tend to favor a flat rate, and the plethora of bill riders utilized by some utilities is anathema to them.[45] Nonprofit consumer advocates mostly (but not

43 A case can be made that utility shareholders are only affected during the period between the reduction in sales to solar customers and the implementation of new rates after the utility's next rate case or potentially through a decoupling mechanism, depending on how it is structured.

44 Data from Federal Communications Commission

45 Although, in some states, consumer bills look more like long-running scorecards for regulatory battles between the utility and ratepayer advocate, showing special charges for utility victories and special credits for ratepayer advocate victories. See, for example, a residential bill from any of the large utilities in California. As a result, the consumer is often left with a clouded understanding of the prices being charged for energy and a reduced ability to respond appropriately.

always) have a pro-environment perspective. Low-income advocates may perceive their clients to be "have-nots" in the drive for distributed energy and smart technology who are adversely impacted when households with more disposable income choose to invest in solar energy or smart appliances. Their focus is on affordability for the most vulnerable populations. Occasionally, interest groups representing large-use residential consumers form, and they typically have a very different perspective than other consumer advocates.

Rate design that favors energy efficiency and renewable energy helps to minimize the overall utility revenue requirement, but may also result in higher per-kWh prices as distribution costs are spread across lower sales levels. Most consumer advocates will favor rate design with low fixed charges, to ensure universal service and protect low-use customers.

Low-income advocates have generally also favored rate designs with low fixed charges and inclining blocks, recognizing that the majority of low-income consumers will benefit. They raise skepticism about default or mandatory TOU pricing,[46] because some low-income families have little ability to shift consumption. However, they are also concerned about high-use low-income households. Part of the challenge is that the construction of these households and their appliances is generally less efficient. That has been and can continue to be addressed through energy-efficiency programs and in some states through discounted rates for low-income consumers. Part of the problem is that reaching all low-income households through energy efficiency and weatherization will take years to accomplish given the funding available and the large number of homes in need.

Further, the needs of large families, often multi-generational, sharing dwellings due to the high cost of housing are more challenging to address within rate design, except by designing rates to favor high-use consumers or by designating a customized customer baseline within an inclining block rate design. California does this for electric and gas rates by defining housing types and climate zones and setting differential baselines; some water utilities allow customers with large families or medical needs to apply for a higher baseline allowance, and this approach could be applied to electricity.[47]

Large industrial energy user advocates often prefer rate designs with higher fixed charges and low volumetric energy rates, because this minimizes their bills given their high-volume 24/7 usage. Many often seek "economic development" discounts. They engage in DR where profitable and seek to opt out of utility energy efficiency programs. This group also tends to voice concerns about the costs of RPS.

Solar Interests

The solar industry now employs more people than the coal or nuclear industry in the United States and is not a trivial interest.[48] Falling costs for PV have resulted in a surge of customer-sited PV systems. This industry is growing and regulators will be forced to grapple with the impact of solar installations on the utilities they regulate and the customers they are charged with protecting. With respect to rate design, regulators should assure that solar technology is fairly treated, while addressing the concerns of utilities and other customers.

The customer-sited solar industry has an interest in ensuring that their access to customers is unrestricted, and that those customers get the maximum economic value from an investment in solar energy. Industry representatives see pricing that recovers production or distribution costs in fixed charges as anti-competitive behavior and an unacceptable deployment of monopoly pricing power that utility regulation was created to prevent. This group favors traditional net metering, low customer charges, and inclining block rate designs that align the end block of rates with the long-run societal cost of power (including environmental, risk, and other costs). They also favor feed-in tariffs (FITs), RPS with solar carve-outs, and value of solar tariffs (VOSTs). Current research into the actual value

46 "Default" TOU pricing refers to the introduction of TOU rates for a customer class and automatically putting all customers in the class on the new rate, but allowing them to opt out. This is as opposed to offering the rate on an opt-in basis, which requires action on the part of the customer to begin using TOU rates.

47 Brown, J.M. (2014). Hundreds request more water amid Santa Cruz rationing. *Santa Cruz Sentinel*, May 17, 2014. Available at: http://www.santacruzsentinel.com/general-news/20140517/hundreds-request-more-water-amid-santa-cruz-rationing

48 Korosek, K. (2015). In U.S, there are twice as many solar workers as coal miners. *Fortune*, January 16, 2015. Available at: http://fortune.com/2015/01/16/solar-jobs-report-2014/

of solar to customers who deploy it, as well as the value to other customers, tends to support the conclusion that the value of solar equals or exceeds the "payment" to customers realized through NEM.[49]

However, solar vendors that focus on the utility-scale solar installation market may see things a little differently. They may benefit from actions that discourage rooftop solar installation in favor of central station solar facilities. To the extent that the grid has limited flexibility to accept variable power, their interests are harmed when penetration of rooftop solar begins to affect the operation of the grid. As long as the system has constraints on the overall level of intermittent resources, distributed solar and central station solar interests will potentially be in competition with one another.

Unregulated Power Plant Owner Interests

Independent power plant (IPP) owners with coal or nuclear resources are threatened by the deployment of competing generation resources, whether they are central-station renewables or distributed renewables. The presence of these resources depresses power prices in the middle of the day[50] and, depending on whether theirs is the marginal generating unit at the time, may displace the utility's own generation. This tends to make the market favor flexible resources, such as gas turbines, that can ramp up sharply in the afternoon when the solar day ends. IPPs also have a negative view of energy efficiency and DR, as these resources tend to reduce prices in both the wholesale energy and capacity markets.[51] Conversely, unregulated owners of flexible generation may welcome the deployment of variable renewable energy resources, especially if the flexibility of their plants is valued and monetized.

Societal Interests

Societal interests encompass the interests of all of the market participants, including those identified above, plus all non-market participants and interests. Society as a whole values overall economic efficiency. Societal interests also include all environmental impacts of the electric system, including carbon dioxide and criteria pollution emissions, and also other impacts such as fuel cost risk, fuel supply risk, the value of a diversified portfolio of resources, the economic development value of stimulating new resource development, efficient utilization of natural and societal resources, health impacts, health costs, and other factors.

The regulator accepting the charge of "regulating in the public interest" considers all of these values. They may in some instances be legally constrained from *monetizing* all of these in resource procurement decisions, but even then, the presence of societal interests should be identified and recognized so that legislatures and courts are aware of the constraints they have imposed and the increased costs that are incurred or benefits that are not realized when these values are not monetized.

Resource Value Characteristics

A good illustration of the different values of system resources may be found in a 2012 decision of the Vermont Public Service Board.

Figure 5 shows the multitude of measurable values of energy efficiency. These are separated into those that are typically reflected in the utility revenue requirement and those that are not, while highlighting those that vary in the short run: energy, line losses, and avoided reserves. Relatively few regulators consider risk (fuel supply risk and fuel cost risk), or difficult-to-quantify non-energy benefits (DTQNEB) in the conservation program valuation process, and most do not consider avoided water, sewer, natural gas, propane, or heating oil savings. All of these are important elements of the total value stream that electricity efficiency investments help procure.

In the context of this graphic, consumer interests reflected in utility tariff rates are in the lower portion of the graph. Utility interests, in the short run, will focus only on those items that vary in the short run; owners of unregulated generating units may share that short-run interest. Societal interests include the entire range. Rooftop

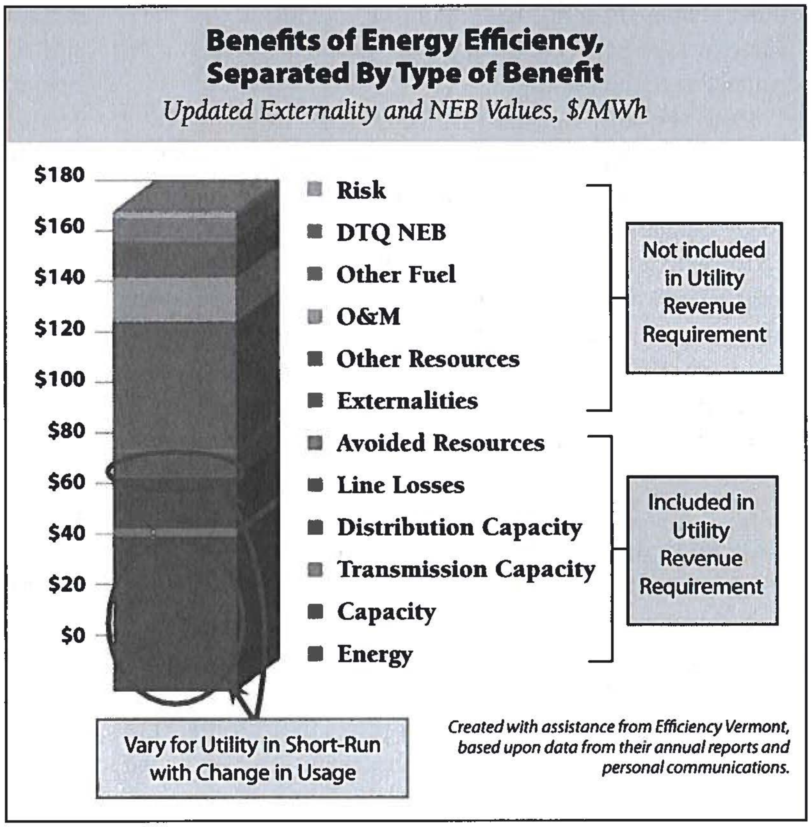
49 See, for example, Minnesota's VOST methodology at http://mn.gov/commerce/energy/businesses/energy-leg-initiatives/value-of-solar-tariff-methodology%20.jsp or Maine's at http://www.synapse-energy.com/project/value-distributed-solar-maine

50 Power prices from competitive generation can also be affected at night. For example, high winds blowing in the middle of the night can lead to negative prices.

51 Litvak, A. (2014). FirstEnergy says demand response putting power plants out of business. *Pittsburgh Post-Gazette*, November 25, 2014. Available at: http://powersource.post-gazette.com/powersource/policy-powersource/2014/11/25/FirstEnergy-says-demand-response-putting-powerplants-out-of-business/stories/201411250013

solar installers will want to embrace the entire range, while central-station solar developers will want to consider the entire group of costs at the top of the graphic —those that are not included in the utility revenue requirement as values of their product. However, they may not consider distribution costs for the utility, as their product does not displace these.

Figure 5



Principles Specific to Customer-Sited Solar Rate Design

Rate design for solar customers should adhere to the following refinements within the three basic principles of rate design discussed previously:

- **Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.** Only customer-specific costs should be applied to the bill for the privilege of connecting to the grid and accessing grid services.
  - The only truly customer-specific costs, which vary with the number of customers on a typical urban/suburban electric grid, are service drops, meters, and billing services. The grid itself does not change with the number of customers connected to it.
  - If a customer is already connected to the grid and then invests in a PV system, then a one-time cost-based fee may be appropriate to process the net metering and interconnection agreement and to inspect the installation if required. The rationale for this principle is discussed at length in Appendix D.

- **Principle 2: Customers should pay for grid services and power supply in proportion to how much they use these services, how much power they consume, and when they consume this power.** Nearly all utility services should be priced volumetrically, but may vary by time of day, season of year, and by voltage level (customers only pay for the portions of the distribution system that serves them).
  - **The cost for use of the distribution grid should be charged in relation to customer purchases of energy and not for customer-generated energy delivered to the grid.** Customer-owned generation should be treated in the same manner as other generators who supply energy to the grid. Accepted market practice is to charge consuming customers for use of the distribution system, rather than generators. High-voltage transmission rates are sometimes borne by generators seeking to sell their product to a specific utility at a specific point of delivery.
  - **Time-varying rates are appropriate in both directions.** Utility time-differentiated rate designs should treat DG customers in a symmetrical manner. If DG produces "valuable daytime power," the customers installing DG should reap that benefit through higher remuneration and likewise, if DG customers require "valuable ramping period" power, DG customers should pay higher bills for that at the same rate charged to other users at that time. Smart meters with bidirectional capability enable the utility to offer time-differentiated TOU and critical peak pricing (CPP) rates to their customer base. DG and non-DG customers who subscribe to those types of rates will be paying a more cost-based rate and therefore there is less chance for inappropriate apportionment among customers. It may also be appropriate to require

that DG customers be on a TOU rate so that what they pay for energy and what they receive in compensation more accurately reflects the utility's true costs.

- The presence of high levels of solar on a utility system may dramatically suppress the on-peak period prices that affect most utility systems during afternoon hours. If the time-varying pricing is changed to reflect this, the net effect is that non-solar customers receive lower afternoon prices as a result of solar customer investments, while solar customers receive less in the form of avoided payments to the utility. When pricing solar on a "value" basis, some of the benefits from the price reductions should continue to flow to the solar producers in recognition of the fact that it is their continued presence that creates this value for all customers.
- **The PV customer should pay for power supply and distribution service at non-discriminatory rates for all power received from the grid.** When PV customers are drawing power from the grid they should pay for power supply and distribution service, and any other generation costs, at the same price as non-PV customers. Until TOU rates are universal, a good temporary approach would be to place all solar customers on a TOU rate that has the same fixed charges applied to non-TOU customers. This would ensure that solar customers pay the full costs of power supply and grid services they receive.
- The only component of the distribution system that is sized to the individual demands of the individual customer is the final line transformer. Although these need to be sized to the maximum level of usage (in either direction) for a DG customer, this is a very small component of the total distribution system cost. DG customers seldom require more capacity to feed power to the system than they require for their night-time consumption.
- **Recovery of distribution costs as customer usage profiles change.** At the distribution level, the overwhelming majority of utility regulators have allowed distribution costs no longer being paid by consumers who generate power on-site to be recovered from remaining (and new) sales. As a practical matter, recovery of these costs across the reduced usage caused by distributed generation is no different than the recovery of newly installed distribution facilities that temporarily represent excess capacity or reductions in revenues associated with customers who reduce usage through energy efficiency, conservation, or by terminating service altogether. In all these cases, traditional cost allocation methodologies, based as they are on customer usage at any given point in time, reflect the dynamic nature of the electric system and of its utilization by customers and have always been considered "fair" at any such point in time.

Some participants in the regulatory process have portrayed PV as unfairly shifting costs to other customers or of utilizing the system in some way without paying for it. This is a misapplication of rate design and cost recovery principles and practice, which have never charged generators for use of the distribution system, as well as accepted cost allocation methods that are themselves dynamic in nature. It also mischaracterizes how and when DG customers use the distribution system, incorrectly equating injection of energy into the system with deliveries taken from the system. In truth, at any given point in time, only those customers who are taking energy from the distribution system are using that system. When injecting energy into the system, DG customers are not using the distribution system any more than a remote central-station generator is using the system — that is, not at all. In fact, when energy is injected into the distribution system at the customer's location, energy losses in that system actually go down and the net effect is a negative cost — i.e., a benefit — from the presence of the DG.

- **Principle 3: Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.** Prices paid, or amounts credited for customer generation, must consider avoided production, transmission, distribution, environmental benefits, losses, reserves, fuel cost and fuel supply risk, and other avoided costs that their power supply may provide to the public. For some utilities, this will be more than the retail rate, and for others, it will be less.
  - **DG customers should be free from discrimination. Most state statutes have provisions prohibiting discrimination among and within classifications of customers.** DG customers should be accorded the same protection. Fixed or other non-economically based charges should not be imposed on DG customers. Any cost

imposed on a DG customer should be based on a real cost to the utility system resulting from the DG, net of cost savings resulting from the DG. Just as customers who install efficient LED lighting in their homes to reduce their bills are not charged individually for the energy they do not consume, neither should solar customers who displace their purchases with solar generation.

- **NEM is a reasonable proxy for the value of solar in the absence of better information.** Solar power delivered to the grid at the distribution level is a superior product with higher value than generic "grid power" due to locational and environmental characteristics. These benefits must be considered in determining the proper fair compensation to the PV customer supplying power to the grid. In the absence of a VOST or of data on the various values of solar, it is appropriate to continue the use of NEM as a proxy for those values. It is unlikely that this will overcompensate DG customers and likely that it will still send sufficient price signals to the customer to make economic choices about whether to install DG or not.

Current and Emerging Rate Design Proposals

Many alternatives have been suggested for future rate design applications from sources as divergent as the Edison Electric Institute and the Rocky Mountain Institute. Most recent rate design studies emphasize the need for time-varying pricing and for some form of demand-response pricing. At the same time, stakeholders currently face a legacy system of non-TOU rates that are either flat across all usage levels or are designed with increasing or decreasing prices for increasing amounts of consumption ("inclining block rates" and "declining block rates" respectively). They may also include demand charges in addition to energy charges (typically for commercial and industrial users and in rare instances for high-use residential customers), although various types of TOU rates have been used.

Traditional Rate Designs

Time-Differentiated Pricing

It is hard to envision an electric system future without greater utilization of time-differentiated pricing. Because the underlying costs of providing electricity vary hourly and seasonally, it is impossible for the customer to see an appropriate price signal without that signal also varying over time. As smart technologies take hold, the connection between customer usage patterns and underlying costs will become apparent. As this happens, it is inevitable that time-differentiated pricing will become more widespread. A number of time-differentiated rates have already been utilized by utilities and are outlined below. Their importance as part of a best practices approach to rate design is discussed in the following pages (see "Best-Practice Rate Design Solutions").

Time-of-Use Rates

TOU rates have been in use for some time in the United States. These rates typically define a multi-hour time of the day as "on-peak" period, during which prices are higher than during "off-peak" hours. In most cases, on-peak periods are limited to weekdays. Some TOU rates also include a "shoulder" rate for usage occurring between on-peak and off-peak periods. In some cases, they are limited to summer or winter periods and are not applied during spring and fall periods when overall loads on the system are not as high. TOU rates require the use of a more advanced meter (i.e., an "interval" meter that can report usage for specific periods of time) than is typical for non-TOU customers. Today's advanced smart meters can also provide this function at yet a more temporally granular level.

TOU rates are common, and often required, for commercial and industrial customers of all sizes. For residential customers, they are in most cases optional if they are offered at all.

TOU rates are an improvement over flat or inclining block rates because they offer some correlation between the temporally changing costs of providing energy and the customer's actual consumption of energy. However, they are usually not dynamic in the sense of capturing the real underlying changes of costs from hour to hour, day to day, or season to season. If the high-cost hours cover too much of the day, however, customers may not be able to adjust their usage to adapt. Concentrating peak-related charges into as few hours as possible produces a better customer response and actually tracks closer to underlying increased costs, which are, themselves, concentrated into relatively few hours of the day and year.

Critical Peak Pricing and Peak-Time Rebate

Critical peak pricing (CPP) and its common variant peak-time rebate (PTR) are a more dynamic variation on the TOU concept. Under CPP, prices during specific "critical peak periods" are set at much higher prices.

Typically, under CPP, the customer agrees to pay the high price during a short (e.g., three-hour) period on a few declared "critical peak days" of the year. There is usually a maximum number of days (and total hours) that can be declared as critical — often three or four hours per day, ten to 12 days per year, or less than 1 percent of the hours of the year. Those days may also be limited to the on-peak season, usually summer or winter, depending on when the utility experiences its overall system peak. The customer is given some advance notice of critical peak days, usually a day in advance. CPP is designed to produce a response — to get customers to reduce loads during critical peak periods. The CPP has been largely successful. To date, CPP rates have been voluntary opt-in rate forms, but evidence supports setting these as default rates for large groups of consumers.

Table 3

CPP and PTR Rate Illustrations

Critical Peak Pricing	Peak-Time Rebates
CPP uses pricing to set the consumer price for consumption during critical peak events.	PRT uses customer rewards (discounts) for curtailing usage during critical peak events.
The baseline rate is lower, and customer is charges a very high price for usage in these events.	The baseline rate is higher than for CPP, but the customer receives a credit for reducing usage in these events.
Illustrative Rate Customer Charge: $5.00/mo	**Illustrative Rate Customer Charge: $5.00/mo**
Off-Peak Usage: $.08/kWh	Off-Peak Usage: $.09/kWh
On-Peak Usage: $.15/kWh	On-Peak Usage: $.17/kWh
Critical Usage: $.75/kWh	Critical Usage: -$.75/kWh

A closely related variant to CPP is the PTR. Under the PTR concept, rather than charging customers an elevated critical peak price, customers are given a large credit on their bills if they can reduce usage during a peak-time event. This requires the identification and quantification of what the customer's usage would have been (i.e., a baseline) in the absence of the usage reduction. PTR is distinguishable from a CPP in that it is a voluntary program. Failure to participate does not result in any penalty, but the customer pays a slightly higher rate to which credits are applied.[55] Table 3 compares the two approaches.

Just as in the case of TOU, CPP and PTR both require the use of an interval meter or a smart meter.

Real-Time Pricing

Real-time pricing (RTP) charges the customer the actual prices being set in wholesale markets (for utilities that are not vertically integrated) or short-run marginal generation costs (for vertically integrated utilities) as they vary hour by hour.[56] Prior to the introduction of smart technologies, only the largest customers would typically be on RTP, as it usually requires either a trained, often-dedicated, employee or a third-party service provider to constantly monitor prices and manage load in order for the customer to take advantage of this type of pricing. As newer smart technologies take hold, some form of RTP may expand to other customers who have smart appliances that can monitor prices automatically, respond accordingly, and monetize the benefits.

Feed-In Tariffs and Value of Solar Tariffs

Several jurisdictions have adopted special pricing for compensation of solar customers for the power supplied to the grid by these systems.

55 A recent US DOE study reports that average peak demand reductions for customers taking service on critical peak pricing (CPP) rates were almost twice the size (21 percent) than they were for customers participating in critical peak rebate (CPR) programs (11 percent). However, when automated controls were provided, peak demand reductions were about the same (30 percent for CPP and 29 percent for CPR). See: US DOE. (2015). *Interim Report on Customer Acceptance Retention, and Response to Time-Based Rates from the Consumer Behavior Studies.* Smart Grid Investment Grant Program. Available at: http://energy.gov/oe/downloads/interim-report-customer-acceptance-retention-and-response-time-based-rates-consumer

56 New Jersey has a pure RTP for their largest customers (i.e., hourly price based on integrated average of the past hour zonal LMP in PJM's spot market). This is different than other applications of RTP, which are predicated on system lambda or LMP out of unit commitment algorithms that are run a day-ahead.

Table 4

Feed-In-Tariff for Gainesville, Florida

Category	20-year Fixed Rate	Capacity (DC peak kilowatts)	Mounting Configuration
Class 1	$0.21/kWh	10 kW or less	Rooftop or over pavement
		10 kW or less	Ground mount
Class 2**	$0.18/kWh	>10 kw to 300 kW	Rooftop or over pavement
		>10 kW to 25 kW	Ground mount
Class 3***	$0.15/kWh	>25 kW to 1,000 kW	Ground mount

* *For projects approved and installed in 2013.*
** *Minimum capacity requirements do not apply for Class 2 projects if a Class 1 system is already installed on the parcel.*
*** *GRU did not accept Class 3 projects in 2013.*

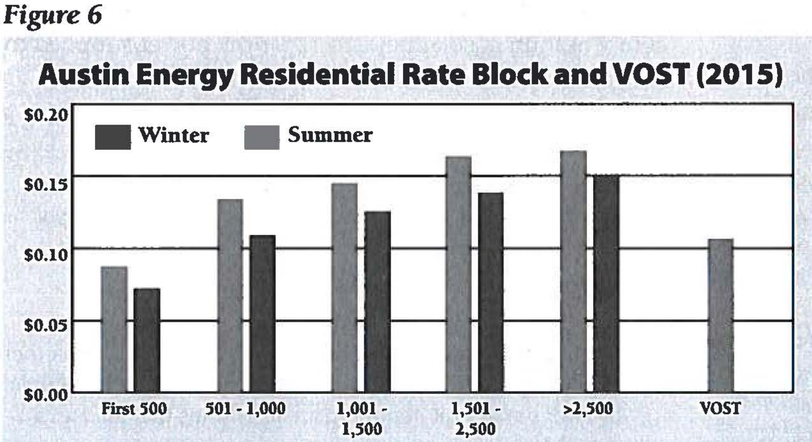
Source: Gainesville Regional Utility

Feed-In Tariffs

Originating in Europe, feed-in tariffs (FITs) paid a premium price for renewable energy, generally based on the cost of the resources, not the value of the output. The payments for solar were typically higher than for wind, and the payments for power from small systems were greater than for larger systems. FITs were generally designed to be an infant-industry incentive, providing a large and stable payment to support the decision to invest, and often were more generous in the early years to reward early adoption. Often, the FIT prices were set for the life of the resource or some extended period of time.

An example is the FIT adopted by the municipal utility for Gainesville, Florida, which applied to facilities built through 2013 and provided these customers with long-term contracts for the purchase of the output from the solar DG, as shown in Table 4.

Figure 6



Source: Austin Energy

Value of Solar Tariff

A VOST is fundamentally different from a FIT, compensating the solar provider on the basis of the value provided, not the cost incurred. Studies conducted by the city of Austin, and the states of Minnesota and Maine, showed that a VOST will generally provide equal or greater compensation to the solar producer than simple net metering, reflecting the combined high value of the energy and non-energy benefits provided by solar.

The VOST concept was pioneered by the municipal utility in Austin, Texas, which established a VOST as a way to compensate solar producers for energy that was more valuable than the average of utility resources that were reflected in rates. Simple net energy metering would have given the solar customers too little compensation given the value of their power. Since that time, Austin has raised its retail prices, and reduced the VOST. Figure 6 compares the rate blocks of the current Austin Energy residential tariff to the VOST in effect today. Small-use customers receive more benefit from the VOST than they would from a net energy metering rate.

As discussed later in this report, more recent VOST studies have shown significantly higher values than Austin has adopted. These generally consider a broader range of costs than the narrower group included in the Austin VOST.

For utilities where only a small percentage of consumers have installed solar systems, a simple net energy metering option will generally be easier to measure, more acceptable to consumers, and simpler to administer, and will produce fewer significant impacts on grid-dependent customers. If solar penetration is high, the additional costs to install smart meters capable of bidirectional measurement may be justified, and time-differentiated pricing for power flows in each direction may be appropriate. The customer pays for power used on a TOU basis, and is credited (either the retail TOU rate or a different time-differentiated VOS rate) for power fed to the utility.

Utility-Defensive Rate Design Proposals

Recent growth in DG has been very rapid. Installed solar capacity in the United States increased 30 percent in 2014 and residential installations surpassed 1 gigawatt.[57] The relative success of DG has raised concerns in electric utility boardrooms and has caught the attention of the Edison Electric Institute.[58] This success has led to the proposal and implementation of rate designs that undermine the economics for existing DG customers and present a formidable barrier for customers contemplating investments in DG resources.[59] These proposals may impair the value that DG brings to the grid and to society as a whole. Renewable solar and wind businesses that have relied on federal tax credits, state RPS directives, and NEM have a lot at stake and are reacting to preserve their business model. A primary goal of these policies was to help transform the market in order to allow volume sales to reduce the unit costs and, as has been noted above, prices have declined significantly over the past decade. The policies have been successful, and this success presents new challenges to utility regulation.

Some utilities have proposed rate designs that are intended to assure recovery of embedded system costs from solar customers. As stated in a recent article, "The industry and its fossil-fuel supporters are waging a determined campaign to stop a home-solar insurgency that is rattling the boardrooms of the country's government-regulated electric monopolies."[60] Meanwhile, states such as New York are looking to reform their utility business models to be more in line with customer preferences and choices.[61] The uncertainty created by some of these proposals could cause a disruption in clean energy investment. If implemented, these proposals may drastically curtail deployment of customer-sited DG.

High Fixed Charge Rates

The expansion of energy-efficiency programs and customer generation, coupled with a weak economy, increasingly stringent building and appliance codes and standards, and fuel switching has led to flat or declining electricity sales[62] in some parts of the United States[63] and a serious challenge to the traditional electric utility business model that ties profitability to electricity throughput.[64] Utilities have sought to shore up their revenues by imposing minimum fees or new fees to replace declining sales.

57 Doom, J. (2015). *U.S. Solar Jumps 30% as Residential Installs Exceed 1 Gigawatt.* Bloomberg Business, March 10, 2015. Available at: http://www.bloomberg.com/news/articles/2015-03-10/u-s-solar-jumps-30-as-residential-installs-exceed-1-gigawatt-i738dw27. "GTM Research expects solar demand this year will grow 31 percent to about 8.1 gigawatts."

58 Kind, P. (2013). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.* EEI, January 2013. Available at: http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

59 Tong and Wellinghoff, 2015.

60 Warrick, J. (2015). Utilities wage campaign against rooftop solar. *Washington Post,* March 7, 2015. Available at: http://www.washingtonpost.com/national/health-science/utilities-sensing-threat-put-squeeze-on-booming-solar-roof-industry/2015/03/07/2d916f88-c1c9-11e4-ad5c-3b8ce89f1b89_story.html

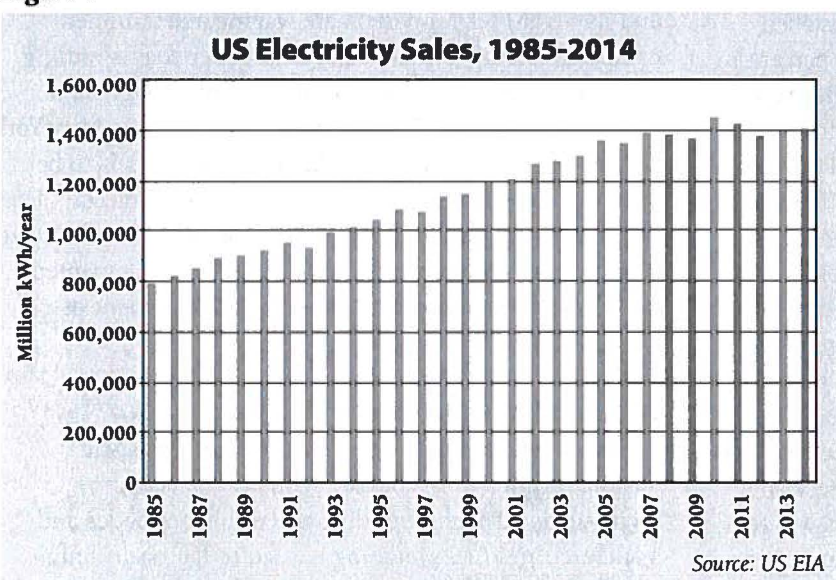
61 See New York Public Service Commission, "Reforming the Energy Vision," at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2.

62 US Energy Information Administration. (2015, April). Electric Power Monthly. Available at: http://www.eia.gov/electricity/monthly/update/archive/april2015/

63 Faruqui, A. (2012). *The Future of Demand Growth: How Five Forces Are Creating a New Normal.* Presentation before the Goldman Sachs 11th Annual Power and Utility Conference, August 14, 2012. Available at: http://www.brattle.com/system/publications/pdfs/000/004/431/original/The_Future_of_Demand_Growth_Faruqui_Aug_14_2012_Goldman_Sachs.pdf?1378772105. One counter to this perspective states that the future of the electric sector is decarbonized transport and industry and therefore electricity sales will grow significantly over the next 40 years.

64 See Kind, 2013, and Craver, T. (2013). Raising Our Game: Distributed energy resources present opportunities and challenges for the electric utility industry. *Electric Perspectives,* EEI, September/October 2013. Available at: http://www.edison.com/content/dam/eix/documents/our-perspective/2013-09-01-RAISEGAME.pdf

Figure 7



Minimum Bills

A minimum bill charges the customer a minimum fixed charge, which entitles the customer to a minimum amount of energy. For example, a residential minimum bill might charge $20 as a minimum charge, which entitles the customer to receive its first 100 kWh energy included in the price. The customer charge is usually included in the minimum bill charge. Because some customers may have total usage below the minimum energy threshold, prices for energy above the minimum will be reduced slightly to offset the additional revenue collected from those customers.

Minimum bills are not typically considered good rate design, because they have an effective "zero price" for very small levels of usage. They are better than Straight Fixed/Variable rates (discussed next), which can impose up to $50 or more as a fixed charge and impose sharply lower per-unit prices. To the extent energy efficiency, conservation, and customer-sited DG would reduce consumption below the minimum threshold, minimum bills have the effect of reducing their value. Customers considering any of these options would tend to reduce the magnitude of their effort as usage falls into the minimum-bill range because no further savings could be achieved.

The key is to set the minimum bill at a level that guarantees the utility a certain level of revenue it can count on, while not penalizing the vast majority of customers. Those most likely to be harmed with a minimum bill include seasonal households or households that are energy efficient and rely heavily on DG as their major source of energy. At the $20 per month minimum bill hypothetical, it is estimated that approximately 1.5 percent of consumption would have an incentive to increase usage to the level of the minimum bill, and over 98 percent of consumption would have a higher incentive to constrain usage.

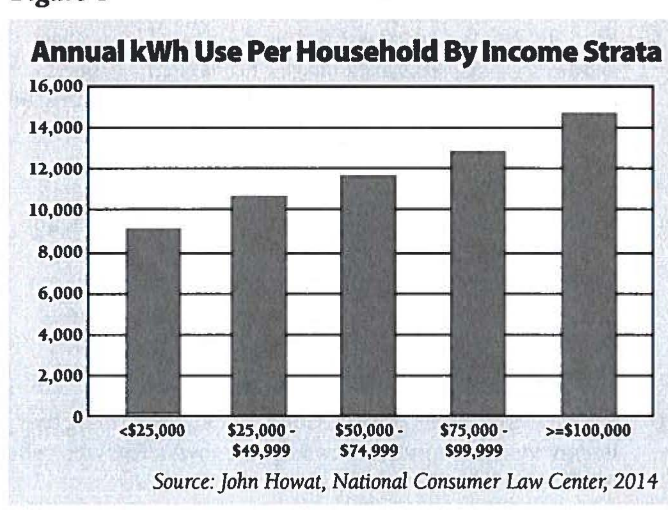
Straight Fixed/Variable Rates

Utilities in some parts of the United States are seeking changes to rate design that sharply increase monthly fixed charges, with offsetting reductions to the per-unit price for electricity. High fixed charges as part of a straight fixed variable (SFV) design can stabilize utility revenues in the near term and are easy to administer. This approach however, deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on the basis of long-run marginal costs. The effect of this type of rate design is to sharply increase bills for all low-use customers — which includes most apartment dwellers, urban consumers, highly efficient homes, and customers with DG systems installed — while benefitting larger homes and suburban and rural customers.

A common objection to this kind of rate is that it discourages conservation and DG by decreasing customer savings and increasing paybacks in customer investments and that it results in bill increases for low-volume (sometimes low-income) customers while decreasing bills for large-volume (often wealthier) customers.

Because they lower the energy rate component of the

Figure 8



customer's tariff, SFV rates discourage conservation and DG by decreasing customer savings associated with reduced consumption, thereby increasing payback periods in customer investments. SFV rates adversely impact those who have already invested efficiency and DG and may dissuade those who are considering such investments from deploying energy efficiency and DG.

Later in this paper, as well as in Appendix D, we discuss how the future is better served by reflecting costs that are not customer-specific — including nearly all distribution system costs — in usage-based (preferably time-varying) rates.

Distribution System Cost Surcharges

Some states, such as New Mexico, are considering imposing new fees on DG customers that utilities argue reflect their use of the grid. Arizona and Wisconsin have already imposed new fees on DG customers even though there may be no demonstrated additional costs being incurred by the utility as a result of DG output.[65] These new fee-based rate designs can adversely impact customers who have made investments predicated upon the stability of a historic rate design, as well as dissuade other customers from deploying DG. In some states surcharges applicable only to new solar customers are being considered. How these provisions are applied makes a difference in the impact they will have on new and existing customers. If there is a grandfathering provision for existing solar installations, they will discourage new solar installations, but not penalize customers who made investments based on expected savings.

On the other hand, commissions in Idaho, Louisiana, and Utah have rejected fixed charges on solar customers[66] while California has statutorily limited fixed charges to no more than $10 per month for all residential consumers, including any demand or other unavoidable charges.

Exit Fees

Exit fees are charges imposed on consumers who cease taking utility service. In general, these are applied only to consumers departing the system on short notice, and for whom the utility has made significant investments to provide service. This may be customer-specific distribution system investments, or may be investments in power supply intended to provide long-term service.

As a general rule, exit fees are inappropriate rate design measures. The risk of customer loss is an ordinary business risk, for which the utility rate of return is the compensation. In addition, overall growth in customers and customer usage may more than offset the losses from defecting customers, enabling utilities to redeploy resources freed up by conservation and DG to serve new customers or increased use by other existing customers.

Where specific costs are attributable to specific customers (for example, building a substation to serve an industrial facility), it may be appropriate to impose a charge based on the unamortized investment if the customer did not pay the costs of the facilities expansion as a connection charge at the time service was initiated. However, these costs are typically addressed in special contracts between the utility and the customer and not through a general exit fee tariff.

Best-Practice Rate Design Solutions

Overview: Rate Design That Meets the Needs of Utilities and Consumers

Figure 9 gives an overview of the appropriate rate designs for all customer classes for both default and optional services.[67]

65 In Wisconsin, the commission did not examine utility costs for DG customers, but instead determined that a fixed charge "more appropriately aligned costs." Likewise, the Arizona Corporation Commission granted an interim fixed charge increase for DG customers until the utility's next rate case without examining specific costs, rationalizing that such a move was necessary to address the "cost-shift" from DG customers to non-DG customers. See WI PSC. (2014, December). Final Decision. Docket No. 5-UR-107. Available at: http://psc.wi.gov/apps40/dockets/default.aspx; and AZCC. (2013, December 3). Final Decision. Docket No. E-01345A-33-0248. Available at: http://images.edocket.azcc.gov/docketpdf/0000149849.pdf

66 Tracy, R. (2013, July 8). Utilities Dealt Blow Over Solar-Power Systems. *Wall Street Journal*. Available at: http://www.wsj.com/articles/SB10001424127887324507404578594122250075566; and Trabish, H. (2014). Utah regulators turn down Rocky Mountain Power's bid for solar bill charge. September 3, 2014. Available at: http://www.utilitydive.com/news/utah-regulators-turn-down-rocky-mountain-powers-bid-for-solar-bill-charge/304455/

67 This is an update of a matrix developed in 2003 for the New England Demand Response Initiative, reflecting changing costs of smart grid capabilities and increased value of time-differentiation due to the high levels of variable renewable generation available today. See http://www.raponline.org/document/download/id/687.

Figure 9

Rate Design Options by Customer Class

	Typical Pre-AMI Rate Design	Inclining Block Rate	TOU Rate Fixed Time Period	TOU plus Critical Peak Pricing	Baseline-Referenced Real Time Pricing	Market Indexed Real Time Pricing
Residential	Flat Energy Charge	Default (if kwh-only metering in place)	Default (if TOU meters or AMI in place)	Optional if AMI in place	Pilot	Not Available
Small Commercial 0-20 kw Demand	Flat Energy Charge	Not Available	Default (if TOU meters in place)	Optional if AMI in place	Pilot	Not Available
Medium General Service 20-250 kw	Demand Charge --- Flat Energy Charge	Not Available	Default (until AMI installed)	Default (after AMI installed)	Optional	Not Available
Large General Service 250-2,000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Default	Optional	Optional
Extra Large General Service >2000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Not Available	Customer Must Choose Between These Two Options	

Source: Adapted from RAP research for New England Demand Response Initiative (NEDRI), 2002

Table 5

Illustrative Residential Rate Design

Rate Element	Based On The Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + transmission and distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

For residential consumers, the general rate design reflected in Table 5 will serve the needs of both utilities and consumers, providing incentives for efficiency, compensation for services received, and a pathway to a future that is less dependent on fossil generation. Differences will be appropriate for very low-cost utilities and very high-cost utilities. The issue of whether CPP or PTR is most appropriate to reflect needle-peak costs is discussed below (see "Time-Sensitive Pricing").

In the simplest of terms, this rate design recovers customer-specific costs, such as billing and collection in a fixed monthly charge, and combines power supply and distribution costs into a TOU rate framework. This enables fair recovery of costs from small and large customers, and from customers whose peak demands may occur at different times from one another, and at different times from the system peak. It also provides reasonable compensation to DG customers who supply power to the grid at certain times, and receive power from the grid at other times.

General Rate Design Structure

Demand Charges

Demand charges are usually based on the customer's metered peak usage over a short period of time (e.g., 15 minutes or an hour), regardless of whether that usage coincides with the generation peak, transmission system peak, distribution system peak, or the customer's circuit peak. In addition, demand charges are often "ratcheted," which means that the customer pays a monthly demand charge based on the maximum metered peak over a longer than one-month period — usually a year.

Demand charges were implemented for commercial and industrial customers in an era where sophisticated TOU metering was prohibitively expensive. Today, with smart meters and AMI, these costs are trivial.

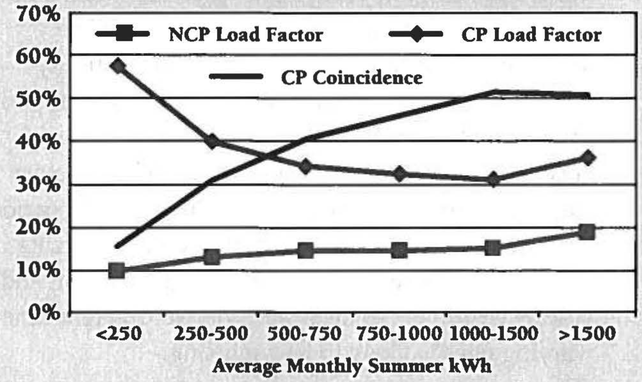
Although demand charges once served the useful function of providing a simple price signal to customers that their peak usage caused long-term costs for capacity to be incurred to meet peak demand even when those resources lay idle most of the time, they may not be appropriate in the presence of current market conditions, smart technologies, and other regulatory policies.[68] Progress with demand response and the development of robust wholesale energy markets allows utilities to meet short-term peak needs with short-term resources, obviating the need for demand charges. Given these conditions, it is more appropriate to utilize more temporally granular time-differentiated rates, in lieu of demand charges. AMI provides an opportunity to move away from the rather crude allocation of cost responsibility afforded by demand charges, and toward a cost recovery framework that is more focused on the costs that utilities and society incur to meet the daily and hourly needs of the system.

A few rate analysts have recommended that demand charges be extended from large commercial customers (where they are nearly universal) to small commercial and residential consumers.[69] Some argue that this is an appropriate way to ensure that solar customers contribute adequately to system capacity costs. This option is inapt for most situations for several reasons:

- The only component of the distribution system that is sized to the demand of the individual consumer is the line transformer, and this is a small portion of the total cost of service.
- Residential and small commercial consumers have high diversity, meaning different customers use power at different times of the day. This is particularly true for multi-family customers, where the utility never actually sees the sum of the individual customer demand on a coincident basis even at the transformer level. Small consumers "share" most of the capacity costs on a utility system. Figure 10 shows how small-use customers have lower contribution to the system ***coincident*** peak (CP), even though (relative to kWh usage) they have higher ***non-coincident*** peak (NCP) demands — which is what demand charges typically are applied to.
- Customer understanding of demand charges is poor among large commercial consumers currently exposed to them, and there is reason to believe that customer understanding would be very poor among residential and small commercial consumers. While a daily as-used demand charge for standby service is likely to be well-understood by an industrial CHP customer, this sophistication does not extend to residential or small

Figure 10

Usage Levels and Customer Coincident and Non-Coincident Peak Demand[70]



68 For example, daily "as-used" demand charges for combined heat and power standby rates may be appropriate. For a discussion of this, see.Selecky, J., et. al. (2014). *Standby Rates for Combined Heat and Power Systems.* Montpelier, VT: Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/7020

69 See, e.g., Hledik, R. (2014). Rediscovering Residential Demand Charges. *Electricity Journal,* 27(7), August-September 2014, pp. 82–96.

70 Presentation of William Marcus of JBS Energy to the Western Conference of Public Service Commissioners, 2015.

commercial users.

- Solar customers may actually contribute power to the grid during peak periods, reducing capacity costs for the system; imposing a non-coincident demand charge would be unfair in that situation. To the contrary, a time-varying NEM tariff automatically credits solar customers for this benefit and a properly designed VOST should do the same.
- The same time periods should apply to both power supply and distribution pricing. There may be periods on weekends when residential distribution circuits are congested even though power supply is not, and asking customers to keep track of two different time-varying rates is likely to be confusing.
- Time-varying prices can more equitably recover actual peak-oriented costs from all customers, including solar customers. Considerable education is needed to assist customers in the transition to default TOU and CPP/PTR pricing. As discussed, a period of shadow billing before the rate taxes effect may be an important element of this education.

A monthly fixed charge based on a transformer rental charge may be appropriate, particularly on rural systems where most transformers serve a single customer. Some utilities already apply this as a "facilities" charge, on the order of $1/kW-month, based either on the customer panel size, the measured demand, or the actual size of the installed line transformer.[71] Our illustrative rate designs include this element, in part to focus attention on how small a demand charge applied to a residential customer should be to recover only customer-specific capacity costs.

Demand charges imposed on non-coincident peak demands are not appropriate for cost recovery of any system costs upstream of the line transformer and coincidence should be tied to utilization of specific parts of the systems where costs are incurred — that is, at the generation, transmission, distribution, or even circuit level — which do not necessarily incur peak usage at the same time. For utilities in restructured markets (where utilities primarily own distribution but not transmission or generation), demand response pricing will be used to provide short-duration capacity at specific points along the distribution system, not to signal investment in generation, transmission, and distribution systems. Even for vertically integrated utilities, the presence of more robust wholesale markets means that these short-term needs can be procured on a short-term basis, rather than on a long-term "build and own" basis. A critical peak or real-time energy price more appropriately recovers this cost of providing short-duration peaking capacity from the consumers using that capacity, without penalizing other consumers whose demand may occur at other hours when high-cost resources are not needed.

Illustrative rate designs for vertically integrated systems are shown in the next section.

Pricing for Restructured Utilities

In general, pricing for restructured utilities would be similar to that for vertically integrated utilities, except that the power supply charges will be separately stated, or even separately billed.

- First and foremost, the monthly fixed charges should not exceed the customer-specific costs incurred.
- Second, demand charges should be used sparingly and only be applied to recover the cost of customer-specific capacity, typically line transformers, primarily for customers having dedicated transformers.
- Third, most distribution costs should be reflected on a TOU/CPP or TOU/PTR basis, to reflect recovery of basic distribution infrastructure costs across all hours, and to reflect recovery of long-run marginal capacity costs to "upsize" that system to meet requirements during on-peak and critical-peak hours.
- Default energy service should have the same time periods and rate differentiation as distribution charges; this avoids customer confusion.
- Consumers desiring a non-differentiated price may be able to contract with a competitive energy supplier to accept the risk of high costs during some periods and bundle the cost of risk management into a contracted price.[72]
- Considerable education is needed to assist customers in the transition to default TOU and CPP/PTR pricing. As discussed, a period of shadow billing before the

71 Manitoba Hydro, for example, imposes a residential customer charge of $7.28 on residential consumers with 200 amp and smaller panels, but $14.56 on consumers with larger electrical panels. Burbank Water and Power (California) implemented a similar approach in 2015.

72 Or some restructured states may offer standard service offer (SSO) customers both a time differentiated and fixed default rate. In this case, competitive retail electric service (CRES) providers will have a market-based price to compete against for both SSO rate types. This approach should exert some market discipline on CRES.

rate taxes take effect may be an important element of this education.

Illustrative rate designs for restructured systems are shown in the next section.

Time-Sensitive Pricing: A General Purpose Tool

TOU Energy Charges Combined with CPP

There are a number of time-varying elements of cost in the generation and delivery of energy. Defined narrowly this would only include recognition that, because the order in which generation is utilized is based on a system of economic dispatch, on-peak power generation will always be the generation with highest short-run marginal cost — that is, the least efficient power plant with highest fuel costs per kWh at that point in time.

The challenge is to set prices that are sufficiently targeted to produce the desired result, without causing too much customer confusion. The more than 100 pilots using time-varying pricing provide clear guidance on this point.[73]

In terms of customer understanding and behavioral response, experience shows that the most effective rate structure is a two- or three-period TOU price, coupled with either a CPP element or a PTR element. This rate design should recover a portion of generation, transmission, and distribution costs in each of the three major time periods, with the recovery of those costs concentrated into the on-peak periods.

Consistent with Garfield and Lovejoy's guidance as introduced earlier, a model TOU rate would ensure that:

- Every kilowatt-hour sold should make some contribution to system capacity-related costs.
- Peak-period and mid-peak-period kilowatt-hours should recover a larger share of system capacity-related costs than off-peak kilowatt-hours.
- The price for the critical peak hours should be based on the cost of operating a demand response program for those hours, because it is less expensive to induce customers to curtail usage for short periods than to build resources for those rare circumstances. But that price, applied to the consumption that does occur, served by resources built for longer periods of service. But that price would generate revenue that would contribute to cost recovery for production, transmission, and distribution costs for kilowatt-hours that flow as well.

Table 6

Cost Recovery in a TOU Rate Design

	Customer	Off-Peak	Mid-Peak	On-Peak	Peak
Generation					
Baseload		■	■	■	■
Intermediate			■	■	■
Peaking				■	■
Transmission					
Generation-Related		■	■	■	■
Reliability-Related			■	■	■
Economy Energy Related		■	■		
Distribution					
Substations		■	■	■	■
Circuits		■	■	■	■
Line Transformers	?	■	■	■	■
Meters	■	■	■	■	■
Billing and Collection					
Quarterly Costs	■				
Monthly Costs		■	■	■	■
Demand Response					■

Table 6 provides rough guidance as to what costs are reflected in each element of this type of rate design.

Illustrative rate schedules for different classes of consumers reflecting this guidance are shown in Table 7. In these rate schedules, the only demand charges imposed are for customers with dedicated transformers; all other costs are reflected in the TOU energy prices. A CPP rate is demonstrated in combination with TOU prices but not a PTR option. This reflects a judgment that the effectiveness of CPP is demonstrably superior, even though customer acceptance is higher for PTR. The advantage of PTR is that it offer s a no-risk option to introduce customers to

73 See Faruqui, A., et al. (2012). *Time-Varying and Dynamic Rate Design*. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/5131

Table 7

Illustrative Rates Reflecting Rate Design Principles

Vertically-Integrated Systems

	Unit	Secondary Voltage Classes: Residential	Small Commercial	Medium Commercial	Large Commercial	Primary Voltage Industrial	Transmission Voltage Industrial
Customer Charge	$/Month	$4.00	$10.00	$15.00	$25.00	$100.00	$200.00
Transformer Charge	$/kVA/Month	$1.00	$1.00	$1.00	$1.00		
Off-Peak	$/kWh	$0.070	$0.070	$0.07	$0.07	$0.06	$0.05
Mid-Peak	$/kWh	$0.090	$0.090	$0.09	$0.09	$0.08	$0.07
On-Peak	$/kWh	$0.140	$0.140	$0.14	$0.14	$0.13	$0.12
Critical Peak	$/kWh	$0.740	$0.740	$0.74	$0.74	$0.70	$0.65

Restructured Systems

	Unit	Secondary Voltage Classes: Residential	Small Commercial	Medium Commercial	Large Commercial	Primary Voltage Industrial	Transmission Voltage Industrial
Customer Charge	$/Month	$4.00	$10.00	$15.00	$25.00	$100.00	$200.00
Transformer Charge	$/kVA/Month	$1.00	$1.00	$1.00	$1.00		
Off-Peak	$/kWh	$0.040	$0.04	$0.04	$0.04	$0.03	$0.02
Mid-Peak	$/kWh	$0.050	$0.05	$0.05	$0.05	$0.04	$0.03
On-Peak	$/kWh	$0.060	$0.06	$0.06	$0.06	$0.05	$0.04
Critical Peak	$/kWh	$0.240	$0.24	$0.24	$0.24	$0.20	$0.15
Default Power Supply Charges							
Off-Peak	$/kWh	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Mid-Peak	$/kWh	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
On-Peak	$/kWh	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Critical Peak	$/kWh	$0.50	$0.50	$0.50	$0.50	$0.50	$0.50

dynamic pricing and gain their attention and interest.

The disadvantage of PTR is that a utility with a problematic system peak has less ability to measure and hence rely on customer participation as a means of curtailing load during a critical peak event. With CPP, those that use high volumes of electricity during peak periods pay the cost of that usage. This does not occur with PTR, where the cost is spread among all customers if the PTR response is inadequate to curb the rise in peak demand to the extent the utility was seeking. However, the regulator may reasonably prioritize customer acceptance over economic efficiency.

The illustrative rate designs below would yield approximately the revenue level of the average electric utility in the United States today. All of the rates essentially reflect the same costs. All classes served at secondary voltage have separate demand charges assessed for recovery of line transformers, the only system component sized with consideration of individual customer demands. All shared capacity costs are reflected in the TOU rates, so that customers share these costs in proportion to their usage. The larger customers may have very different usage patterns, and benefit (or be harmed) by the TOU rate design, so the average revenue for each class would not be the same, even where the underlying prices may be the same.

An Opt-Out Regime and Customer Education

TOU pricing is a more economically efficient way to charge customers for their electricity use than a fixed average rate, since it tracks more closely to the changing cost of electricity during the day and the on-peak cost of congestion on the transmission and distribution system.

Utility rate experiments have allowed customers to choose whether to participate in the rate pilots ("opt in"), and in those cases where customers had to "opt out" or are forced to be on a rate, there are typically customer protections at the end of the experiment.

From a customer enrollment perspective, however, "default TOU rate offerings are likely to lead to enrollment levels that are 3 to 5 times higher than opt-in TOU rates."[74] The SMUD SGIG-funded project provides empirical evidence that supports offering of time-varying rates to residential customers under default environments.[75] Overall, rates should be lower with time differentiation and CPP because customers would not have to pay a risk premium for the flat rate. Higher participation rates should lead to decreasing system costs that benefit all customers.

The transition to a default TOU and CPP/PTR pricing regime will require extensive customer education. Consideration should be given to the following options:

- **Dual or shadow billing:** Some customers stay on traditional billing, but are shown through their monthly bills what they could save.
- **Customer guarantee:** Each customer could be served on the tariff that provides them with the lowest annual bill during the transition period. If the complex rate results in a higher annual bill, the customer is automatically charged on the basis of the lower-cost rate.
- **"Hold harmless" and first-year bill forgiveness programs:** These provide important consumer protections during a pricing transition.
- **Multi-year data:** The development and deployment of more sophisticated bill comparison software incorporating multi-year individual customer interval data could inform a customer whether their subscription into a certain rate design offered by a competitive retail electricity supplier (CRES) would lead to higher bills than the TOU default rate, and what steps they can take to come out ahead. These could include specific energy-efficiency measures or peak reduction control technology.
- **Best practices:** Utility time-differentiated pilot programs that have worked well provide key lessons.[76]
- **Low-income rate programs:** This option can provide an important safety net for at-risk populations.
- **Deploy targeted energy-efficiency and demand-response programs:** Customers who would be worse off under TOU or CPP rates, especially low-income customers, should be targeted for energy efficiency and demand response programs that can mitigate the impact of those rates, or possibly move them from the "worse off" to the "better off" category.

74 See Faruqui, A., Hledik, R., and Lessem, N. (2014, August). Smart by Default. *Public Utilities Fortnightly.* Available at: http://www.fortnightly.com/fortnightly/2014/08/smart-default; and US DOE, 2015, which states: "Opt-out enrollment rates were about 3.5 times higher than they were for opt-in, and retention rates for both were about the same. While demand reductions for opt-in customers were generally higher, one utility found opt-out enrollment approaches to be more cost-effective than comparable opt-in offers due to significantly higher aggregate benefits and lower marketing costs."

75 George, S., et al. (2014). *SMUD Smart Pricing Options Final Evaluation,* p. 4. Prepared by Nexant for Sacramento Municipal Utility District (SMUD). Available at: https://www.smartgrid.gov/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

76 See: US DOE, 2015; US DOE. (2014, September). *Experiences from the Consumer Behavior Studies on Engaging Customers.* Smart Grid Investment Grant Program. Available at http://www.energy.gov/sites/prod/files/2014/11/f19/SG-CustEngagement-Sept2014.pdf; Lundin, B. (2014). Utilities now have a smart grid customer education model. SmartGrid News, January 8, 2014. Available at: http://www.smartgridnews.com/story/utilities-now-have-smart-grid-customer-education-model/2014-01-08; and PEPCO. (2013, March 19). AMI Implementation Customer Education Plan Phase II. Available at: https://www.smartgrid.gov/sites/default/files/Pepco_Plan_Phase_II.pdf.

V. Rate Design for Specific Applications

Rate Design That Enables Smart Technologies

Smart technologies need smart rate design in order to take advantage of their functionality. Smart meters allow utilities to manage diverse power flows. Smart meters and associated MDMS and SCADA provide the opportunity to achieve multiple benefits, including energy and demand savings and operational benefits. The common elements of utility operating benefits afforded by smart technologies are outlined in Table 8 below.

Table 8

Common Elements of Utility Operating Benefits of Smart Meters[77]

Reduced manual meter reading cost	Improved bill-to-pay time
Reduced problem investigations	Reduced uncollectible bills
Improved meter accuracy	Improved accounting
Reduced meter testing	Call center cost reductions
Elimination of lock rings	Improved asset utilization
Reduced need for use of estimated bills	Outage reporting
Reduced theft	Improved outage management
Improved read-to-bill time	Reduction in lost outage sales
Time-varying pricing for energy cost savings	Dynamic pricing for peak load control
Demand-response enablement	Reduced line losses
Identification of stressed transformers	Improved cost allocation accuracy

Smart meter deployment is expected to reach 91 percent of the United States by 2022.[78] It is important to note, however, that merely installing smart meters does not alone facilitate advanced pricing; MDMS investments, billing engine modifications, and sophisticated rate studies are needed to develop advanced pricing.[79]

Smart meters can enable advanced pricing mechanisms, but given the relative price-variability risks and economic rewards of different types of pricing, the desired consumer rewards of lower bills are applicable only to a subset of pricing options. Figure 11 shows this risk-reward tradeoff, and where smart meters become relevant and useful.

Note that in some restructured states with retail competition and smart meters, metering and billing services can (or must) be provided by a competitive provider.

Apportionment and Recovery of Smart Grid Costs

Smart meters, and the support systems necessary for them to realize their full potential, are a costly investment. These costs have been justified by the full spectrum of benefits described above, many of which are related to energy savings, peak load management, and distribution cost controls, not just the billing of consumers.

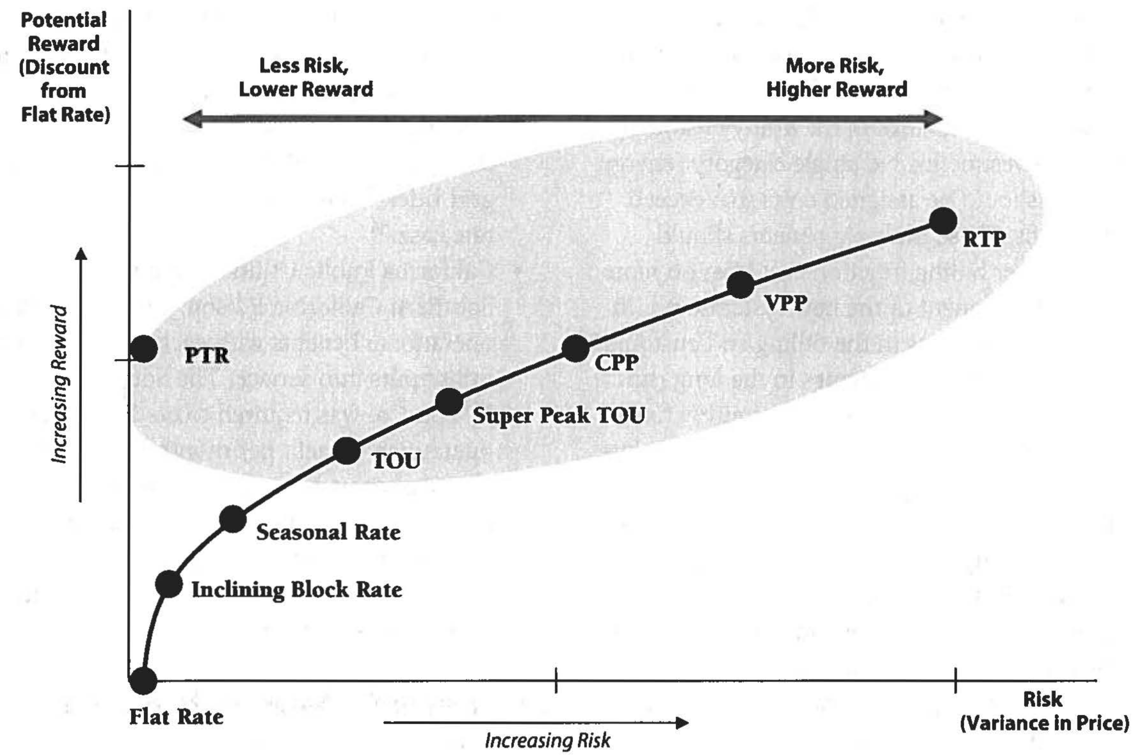
77 King. C. (2010, October 14). *Making the Business Case for Smart Meters* [Presentation]. Smart Grid Newsletter Webinar, p. 10. Available at: http://assets.fiercemarkets.net/public/smartgridnews/eMeter_Oct_14_2010_Biz_Case_Rev3_1_.pdf

78 Telefonica. (2014, January). The Smart Meter Revolution: Towards a smarter future. Available at: https://m2m.telefonica.com/multimedia-resources/the-smart-meter-revolution-towards-a-smarter-future.

79 Lazar, 2013.

Figure 11

Conceptual Representation of the Risk-Reward Tradeoff in Time-Varying Rates[80]



Therefore, these additional costs of smart meters should not be recovered in fixed monthly charges. Traditionally, in utility cost analysis, "meters" were considered a customer-related cost, allocated based on the number of customers in each class because each customer typically required one meter. Those costs were typically reflected in rates as part of the monthly customer charge.

When those meters only performed the function of providing input to the billing system, this made sense; however, smart meters are very different. Because of all of the non-billing functions that smart meters provide, a portion of the cost of smart meters and the associated data collection and data management system should be treated as energy costs, peak load management costs, distribution system reliability costs, or other types of costs, not just as customer-related costs. Smart meter functions related to capacity, reliability, or other aspects of the electric system should be recovered in the same manner as other investments made for those purposes.

Charges associated with connection and disconnection of customers are usually separately billed. Accordingly, the costs of smart meters allocated to these functions should not be included in monthly fixed charges, but should recovered through separately billed fees. Table 9 reflects the appropriate classification of costs associated with some of the more important smart

Table 9

Cost Classification Appropriate for Smart Meter and MDMS Costs

Smart Meter and MDMS Facilitates	Classification Basis
Time-Differentiated Pricing (TOU)	Energy and Demand
Dynamic Pricing (CPP), Demand Response	Demand
Bidirectional Measurement	Energy
Distribution Optimization	Capacity and Energy
Remote Disconnection and Reconnection	Separately Billed, as Applicable

80 Adapted from Faruqui et al., 2012.

meter and MDMS functions.

Smart meters and the associated MDMS perform multiple functions. The costs associated with smart grid investments should be apportioned so that all aspects of utility service that benefit share in the costs. Simply stated, to justify deployment of smart meters and an MDMS, there should be an expected net savings to the utility customers over the life of the investments. No single category (energy, capacity, customer) should be assigned costs that exceed that particular benefit. These multiple benefits should mean that the customer billing function is at least no more costly than before deployment of the new systems and, in fact, given the expected savings in the billing and customer service costs, should reflect a net savings in the long run. At the time of smart meter installation, the monthly fixed charge for billing and collection functions should therefore be reduced, to reflect the multiple anticipated benefits of a smart meter implementation. This could take place in a general rate case or during the smart grid ramp-up in a net of benefits rider that would reduce not only the monthly customer charge, but also the capacity and energy-related charges to reflect the total benefits, net of incremental costs.

To date, three separate approaches have been used for smart grid cost recovery. They are special purpose riders, riders with limits based on expected economic benefits, and traditional rate case treatment, which is subject to a prudence review.[81] The risk to consumers is greater with special purpose riders without limits and less when the utility is required to file a rate case. In a net of benefits rider approach, the smart grid investment risk is shared between customers and utility shareholders by putting the utility at risk to actually achieve the promised cost savings. In all cases, smart grid costs should be apportioned so there is a net savings to the customer billing, energy and capacity classification to reflect the multiple benefits of a smart grid implementation; in essence — rates and bills should decline as a result of smart grid deployment. This can take place in a general rate case or during the smart grid ramp-up, in a net of benefits rider. A number of regulatory examples are instructive:

- Duke Energy Ohio Smart Grid Audit and Assessment/ Ohio PUC: calculated $383 million in net present value operational benefits over a 20-year period.[82] Duke Energy Ohio agreed to reflect a total of $56 million in operational benefits for the years 2012 through 2015 in their existing net of benefits smart grid rider,[83] and to account for all benefits in the next rate case.[84]
- California Public Utilities Commission (CPUC) / Southern California Edison: $1.4246/month in smart operational benefits with each smart meter that the utility puts into service. The Southern California Edison Co. was required to credit $1.4246 of the operational benefit per month beginning eight months after the smart meter is reflected in rate base.[85]
- Oklahoma Corporation Commission/Oklahoma Gas and Electric: Immediate deduction of operational savings from the revenue requirement when smart grid systems went into service.[86]

Smart Rates for Smart Technologies

The term "smart rates" is used here to describe those rate designs that require the type of data collection that smart meters provide, and which are expected to produce significant peak load reductions, reduced energy consumption, improved system reliability, improved power quality, and reduced emissions. These include:

- TOU (with and without technology, such as in-home displays);
- PTR (with and without technology);
- CPP (with and without technology); and
- RTP (with and without technology).

Aside from the TOU-oriented rate designs, payment and credits based on specific services, such as the provision to voltage regulation, spinning reserves, frequency control or other ancillary services will need to be provided.

81 Alvarez, P. (2012). Maximizing Customer Benefits: Performance measurement and action steps for smart grid investments. *Public Utilities Fortnightly*, January 2012, p. 33. Available at: http://www.fortnightly.com/fortnightly/2012/01/maximizing-customer-benefits

82 The MetaVu Duke Energy Ohio audit report includes 26 separate operational benefit categories. See MetaVu. (2011, June 30). Duke Energy Ohio Smart Grid Audit and Assessment, p. 72. Available at: https://www.smartgrid.gov/files/Duke_Energy_Ohio_Smart_Grid_Audit_Assessment_201104.pdf

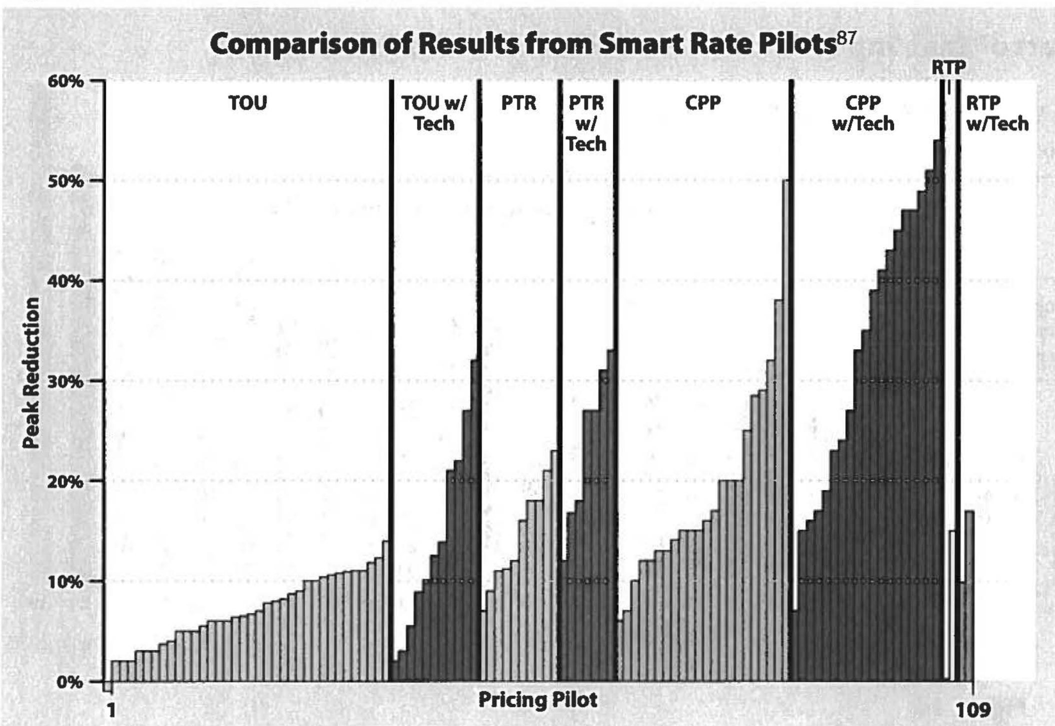
83 Settlement filed in Duke Energy Ohio Case No. 10-2326-GE-RDR.

84 Ibid.

85 CPUC Decision No. 08-09-039 (September 18, 2008), pp. 37-38.

86 Alvarez, 2014, p. 258.

Figure 12



The effectiveness of different TOU rate designs varies considerably. Figure 12 shows a comparison of pilot program peak reduction results for a variety of smart rates. CPP rates clearly show the greatest promise of delivering strong peak reductions by customers.

Looking Ahead: Smart Houses, Smart Appliances, and Smart Pricing

Evidence shows that advanced pricing works best with technology enhancement to enable automated response to higher prices that can tie directly into time-differentiated prices. Over 200 time-differentiated rate tests have been conducted worldwide, with differing results. The consensus of these pilot programs is that customers respond to prices. The modified consumption patterns "persist across several years and consecutive events."[88] Furthermore, enabling technologies (in-home displays, smartphone applications, smart thermostats, and appliances) enhance price responsiveness. TOU and CPP rates may also be fairer to customers than traditional flat rates because customers who contribute more to the increased costs of peak usage are made to pay more.[89]

By having rates that reflect system value, customers can and will take action that over the population and over time will reduce system costs, and in so doing reduce costs and thus rates for everyone. Overall then, rates should be lower with time differentiation and critical peak pricing. Utility rates include both an operating expense provision and a risk element in the rate of return to enable the utility to purchase high-cost energy as needed during extreme periods. Because customers are directly bearing this risk at the time it is experienced, the base rates for non-critical periods will logically decline slightly.

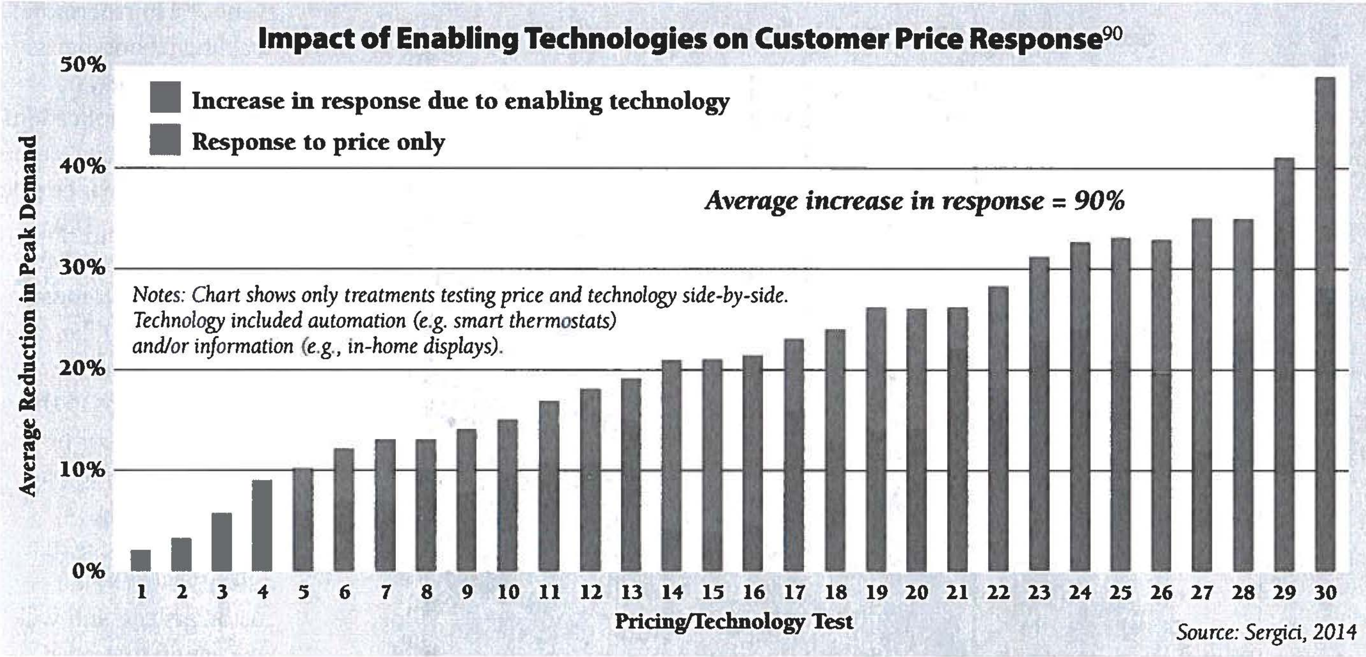
A demonstration of the power of rate design in influencing customer behavior is depicted in Figure 13, which shows results of 30 different pilot programs. The impacts on reductions in peak demand are grouped by rate type and whether customers have enabling technology.

87 Faruqui et al., 2012.

88 Sanem Sergici, S. (2014, August 6). *Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments* [Presentation]. The Brattle Group, p. 6. Available at: http://www.nga.org/files/live/sites/NGA/files/pdf/2014/1408MichRetreatDynamicPricing_Sergici.pdf

89 Traditional flat rates force all customers to a rate based on the average costs assigned to the class, to the detriment of customers who use less on-peak and, therefore, have less costly consumption patterns.

Figure 13

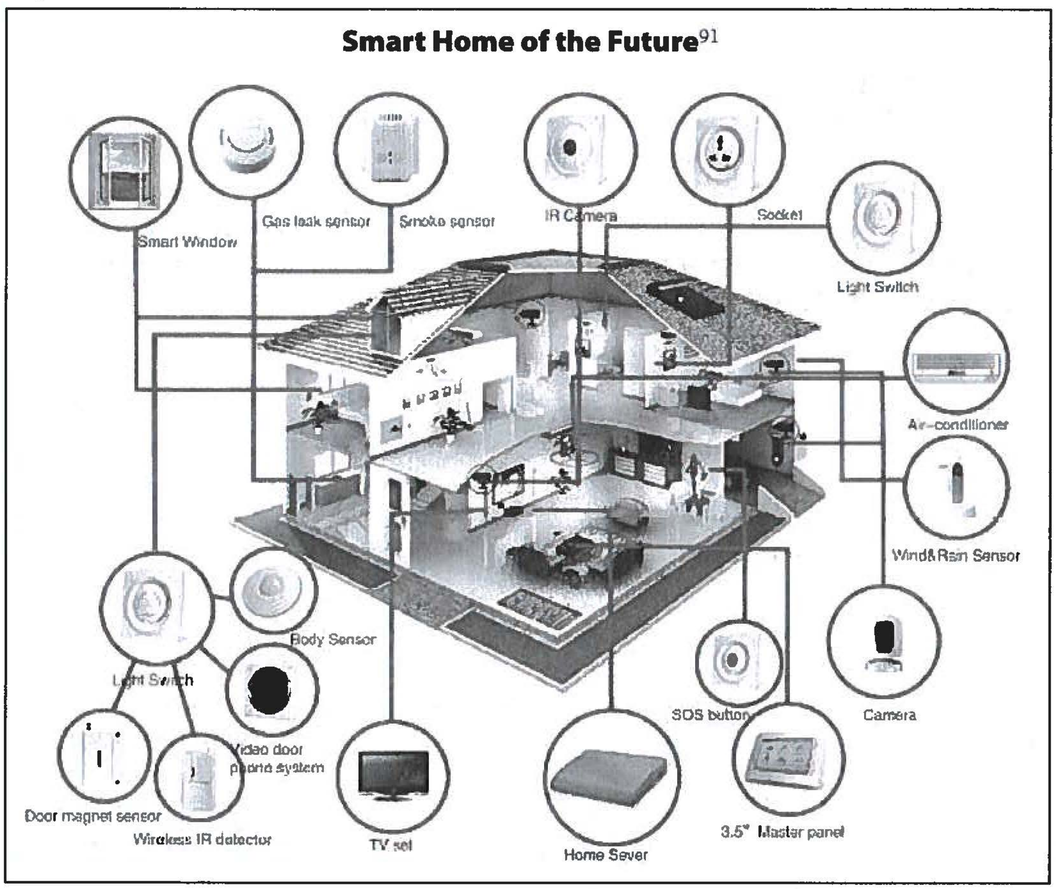


Pricing Signals for Smart Appliances

Figure 14 reflects the multitude of smart appliances in a smart home. In order to fulfill their smart functions, most of these appliances must be integrated into an energy management system, which responds to the dynamic pricing signal of the underlying rate design or connects to a customer preferences profile.

A number of technology companies are developing products that interface with a utility's smart grid deployment. General Electric, for example, has developed smart appliances that communicate with their smart thermostat to manage appliance electricity usage based on real-time utility pricing.

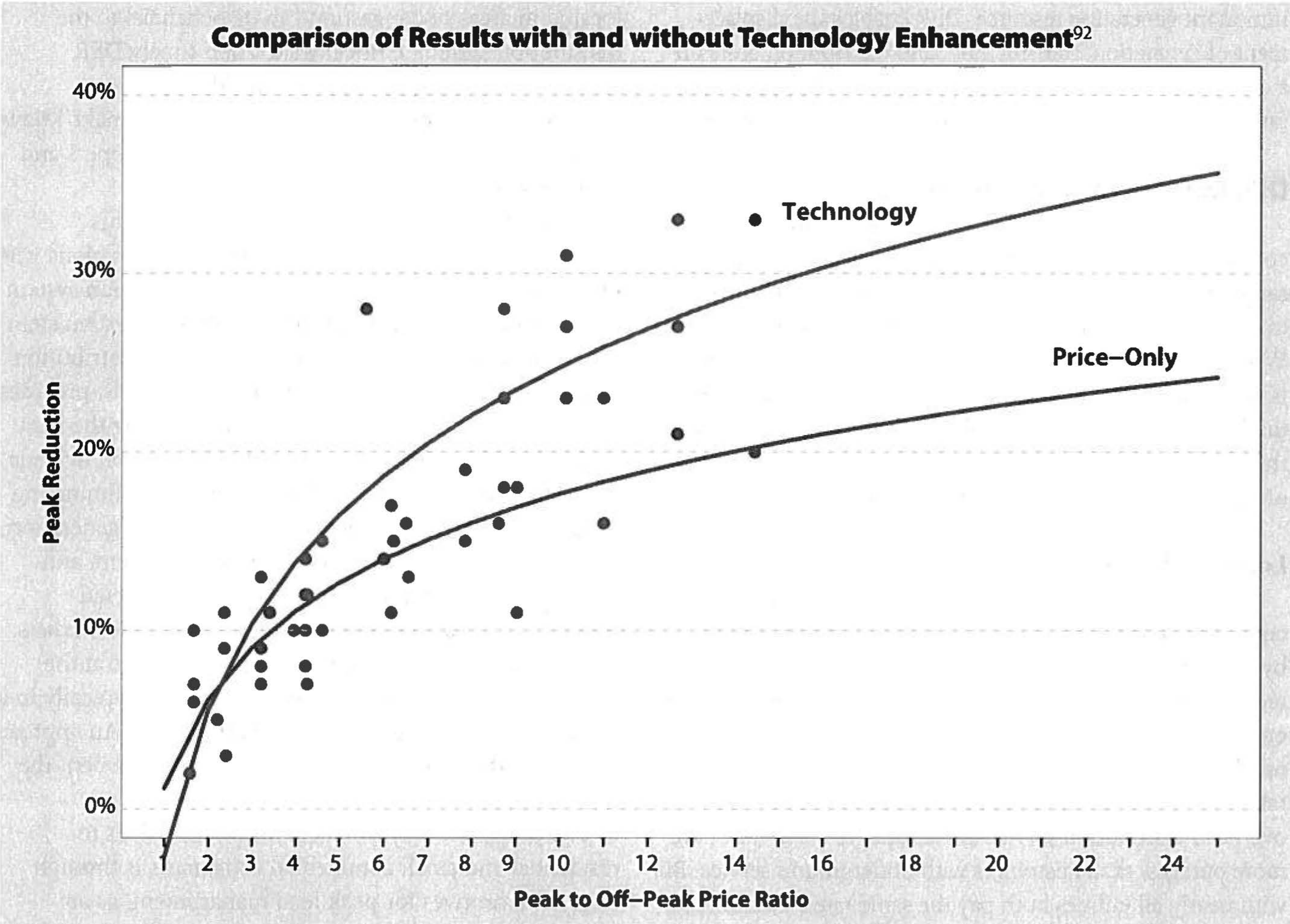
Figure 14



90 Sergici, 2014, p. 4.

91 Source: SmarterUtility.com

Figure 15



Energy Management Systems and Dynamic Pricing

In order for homes to respond to dynamic pricing, either manual customer intervention or automated technology needs to be deployed. As reflected in Figure 15, experience shows that automated technology provides greater energy benefits by far. To achieve this, energy management systems, smart appliances, or both are required.

Rate Design for Customers with Distributed Energy Resources (DER)

The term DER includes energy efficiency, distributed generation, and demand response. Realization of the potential benefits of DER requires TOU/CPP (or PTR) rate design.

Value of DER Pricing

Historically, customers were not given any price signal about the value DER provides the electric system. DG, energy efficiency, and DER were largely ignored by utilities and regulators. This changed in the late 1970s with the passage of the Public Utilities Regulatory Policies Act (PURPA), which provided for mandatory purchase of power from customer-sited generation,[93] or what we now call an FiT. It also changed with early efforts to increase end-use energy efficiency and bring it within the realm of system planning processes, through the concept of integrated resource planning (IRP).

Today, energy efficiency and demand response are recognized as important resources on the electric grid and

92 Faruqui, et al., 2012, p. 32.

93 Through payments for DG at the utility's avoided generation cost, a precursor to the FIT.

customer-sited DG is on an accelerated course to become an important generating resource. DER enables the displacement of generation, transmission, and distribution costs on a cost-effective basis. To take advantage of this, appropriate rate design and planning processes will need to be in place.

DER Compensation Framework

A number of compensation mechanisms have been considered by regulators for distributed resources. They range from value to grid approaches using avoided costs to the establishment of a system of distribution credits.[94] What value the distributed resource provides to the grid is determined using avoided cost calculations that can be made systemwide or, preferably, are location specific. While the former uses an average rate for DER, the latter is based on location-specific costs and projected growth rates.

Locational Value of DER

Postage stamp rates are a form of cost averaging among customers in the same rate class that is taken for granted by many rate analysts. Urban and multi-family customers require less investment in distribution facilities per customer or per kilowatt-hour than suburban and rural customers, but nearly all utilities charge all residential customers the same rates and do not distinguish on that basis.[95] Customers with overhead distribution service are cheaper to serve (but have more outages) than customers with underground service. But with nearly all utilities both pay the same rates. Customers with low usage may use only their ratable share of existing low-cost resources, and not require the more expensive new resources that drive many rate increases.

Providing incentives or preferential pricing for DER located in areas of congestion can be beneficial to the distribution system. Critically sited and timely DER can lead to the postponement or avoidance of costly upgrades. A distribution utility would have to make known preferential locations to prospective DER developers and provide some form of incentive.[96]

Some of the earliest energy-efficiency programs operated by electric utilities were directed at locations with impending reliability problems due to distribution system constraints.[97] "Hot spots" on the distribution system stem from congestion linked to overloading of the distribution infrastructure. Locational marginal pricing (LMP) provides a mechanism for revealing the cost of supplying the next unit (e.g., megawatt) of load at a specific location or node in order to send a price signal for avoiding or eliminating congestion. It takes into account bid prices for generation, the flow of power within the transmission system, and power transfer constraints.[98] LMP is a tool targeted primarily at organized hourly or daily wholesale markets, although its underlying framework is applicable at the retail level. However, retail customers are not typically in a position to respond to a dynamic LMP regime. An approach tailored to the retail market is required to implement the concepts of LMP at that level.

The pragmatic way to reflect locational values to residential and small commercial consumers is through targeted incentives for peak load management, as are typically provided by energy-efficiency suppliers and demand response aggregators, not necessarily through complex retail rate designs that consumers may be

94 Moskovitz, D. (2001, September). *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Moskovitz_DistributedResourceDistributionCreditPilotPrograms_2001_09.pdf

95 Commonwealth Edison and NV Energy are notable exceptions, with lower rates for multi-family consumers.

96 The State of Vermont, for example, designates specific areas for Efficiency Vermont to target with peak load reduction measures each year. See https://www.efficiencyvermont.com/About-Us/Energy-Efficiency-Initiatives/Geographic-Targeting. See also Greentech Media. (2014, July 21). Con Ed Looks to Batteries, Microgrids and Efficiency to Delay $1B Substation Build. Available at: http://breakingenergy.com/2014/07/21/con-ed-looks-to-batteries-microgrids-and-efficiency-to-delay-1b-substation-build

97 Tacoma Power, 1979, and Snohomish Public Utility District, 1983-84, both concentrated energy efficiency on electrically heated homes located on stressed distribution substations.

98 Arsuaga, P. (2002). Primer on LMP. Available at: http://www.elp.com/articles/print/volume-80/issue-12/power-pointers/primer-on-lmp.html. A nodal price in an LMP system is the incremental increase in total system cost associated with supplying the next increment of load at a specific location or bus. In a constrained system, the next increment of load at a given bus is typically supplied by adjusting the output of more than one generator, each contributing to the load in a ratio dictated by the physical attributes of each system and the location of the bus relative to other elements in the system. Typically, the output of some generators must be decreased when the output of other generators is increased, to prevent the flow on constrained lines from exceeding the constraint.

unlikely to understand. Candidate zones are those that are approaching the maximum capacity of the affected part of the grid, with low to moderate growth rates over the medium to long term.[99] When DER is placed in a congested area or otherwise desirable location with respect to the grid, a pricing approach based on the utility's avoided costs provides compensation to the DER customer. In this manner, DER that is tactically located and more valuable to the utility will receive greater compensation than DER that is built simply to serve a customer's generating load. One way to compensate the customer is through the use of a distribution rate credit, which pays a premium (above the generally applicable rate) for distributed resources that locate in an area targeted for near-term distribution upgrades and which accommodate postponement or avoidance of the upgrade. The same is true for other DER resources such as demand response and energy efficiency.

All of these scenarios offer opportunities for better association of costs with prices. The question for regulators may be more a matter of customer acceptance than one of theory, because customers located physically close to one another, but served on different distribution circuits, would see different pricing and programmatic incentives. In addition, regulators would want to consider whether the costs associated with any form of location pricing, especially where whole new rate classes are created, is worth the benefits to the affected customers.

Other Benefits of DER

Separating out the existing cost analysis into its constituent parts — energy, demand, and ancillary services — can also support smarter demand response and DER investment. Providing a market for DER-provided ancillary services will support DER investments that help the grid's reliability and resiliency. For example, Germany (and a current proposal in Hawaii) requires smart solar inverters to perform certain functions, such as power ramping and volt/VAR control, which lead to more grid stability and improved power quality. DER with smart inverters are more expensive, but more valuable than DER with older inverters and should be compensated for providing that value.

Recovery Strategies for DG Grid Adaptation Costs

Recovering the costs of grid modifications associated with DG is a topic of considerable controversy. Even without a need for grid modification, in the absence of a revenue restoration mechanism such as decoupling (see "Revenue Regulation and Decoupling"), solar installations operated with NEM reduce utility revenues and may result in reallocation of non-generation costs to remaining consumers if growth on the system does not absorb these costs. With very high levels of renewable energy, additional distribution system and generation costs will likely be incurred to integrate more distributed and intermittent resources. Utilities and consumer advocates may seek to recover these costs during the hours that DG customers are net consumers from the grid. However, whether this is appropriate depends on the associated benefits that DG provides to all non-DG customers.

In Hawaii, where these modifications are more imminently needed, Hawaiian Electric has proposed a significant revision in compensation to solar generators as part of a proposal to raise the cap on allowed levels of solar installation. The Hawaiian Electric proposal in the short run includes lower compensation to new solar producers for power fed to the grid, and in the long run includes higher monthly fixed charges to recover grid costs. The reaction has been hostile from affected interests — consumers and the solar industry alike. The Hawaii PUC Chairman reached an agreement[100] with Hawaiian Electric to resume rapid approval of solar connections, but without approval of the lower compensation for power fed to the grid; consideration of higher fixed charges was retracted by the utility in the context of a pending merger application.

This work in Hawaii may be a postcard from the future for mainland utilities. The overall plan to adapt to high levels of DG in Hawaii, motivated in large measure by a determination to dramatically reduce the amount of fuel oil required by the Hawaiian economy,[101] includes

99 See Shirley, W. (2001). *Distribution System Cost Methodologies for Distributed Resources.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf

100 Hawaii PUC. (2015, February 27). PUC Chair and HECO President Sign Agreement to Address Residential PV Interconnection [Press release]. Available at: http://puc.hawaii.gov/wp-content/uploads/2015/03/NewRelease.20150227.pdf

101 For more detail on the Hawaii Clean Energy Initiative, see: http://www.hawaiicleanenergyinitiative.org/about-the-hawaii-clean-energy-initiative/.

the following examples of grid modifications, beginning adjacent to the consumer premises and working upstream:

- **Line transformer:** Line transformers must be sized to handle the maximum flow in either direction. Where multiple residential or small business consumers share a transformer, the transformers are normally sized based on the estimated coincident peak usage or DG generation of the customers served by that transformer. This is significantly less than the sum of the individual customer peaks, because different consumers use power at different hours. However, if all of these customers have solar systems installed, it is more likely that they will be exporting simultaneously, and it is possible that the transformer may need to be sized to their coincident export peak, which can be larger than the consumption peak for which transformers have historically been sized. A customer-specific transformer charge is one approach for allocating and recovering the costs of such a resized transformer; a simple TOU tariff for all delivery service is another. Our basic rate design provides for direct recovery of line transformer costs from the customers using them, so a solar customer that requires an augmented line transformer capacity will bear this cost directly.
- **Circuit capacity:** Until installed solar significantly exceeds the circuit capacity, upgrades to circuit capacity will not be required. Even when the solar systems are producing their maximum output, as long as some of that generation is consumed on site at some of the generating locations, the circuit capacity will not be exceeded by exported power. However, if installed solar rises to exceed the sum of the circuit capacity plus the amount consumed on site during periods of peak generation, circuit upgrades of conductors may be required. Nevertheless, even Hawaiian Electric, depicted above, has estimated that installed solar can safely reach 250 percent of the minimum daytime load without requiring major circuit modifications if smart inverters are required.
- **Smart inverters:** Hawaii is requiring that new inverters be capable of "riding through" system disturbances, avoiding a situation where a failure of a resource on one part of the system results in other resources tripping off-line, compounding a minor outage. Requiring new inverters to also include the ability to provide voltage and frequency support to the grid may be cost-effective, and should be considered. If they are required, compensation to the owner for the value of these services needs to be addressed.
- **Voltage regulation:** High levels of solar penetration result in power being injected into the distribution circuits at different points at different times of the day. If power flows downstream from the substations to loads during non-solar hours, and upstream to substations from distributed generators during the solar day, it may be necessary to install voltage regulators at additional points along the distribution circuit. While not prohibitive in cost, these can add up across an entire electric utility service territory. At the same time, these devices enable avoidance of central station generation, transmission, and distribution substation upgrades, which are far more expensive, so all consumers generally benefit.
- **Substations:** If and when an individual circuit is generating more power from distributed generation than the consumers on the circuit are using, power will flow to the low-voltage bus of the distribution substation. In urban and suburban areas, where multiple circuits connect at the bus, excess power will simply flow to the other circuits on that bus. The substation itself will only experience a lower level of demand for power supplied from the transmission side of the substation. If flows exceed the demand of all circuits combined — something that might occur when 20 percent or more of the consumers served by a substation have PV installations — then the power will flow "backward" through the substation, meaning what is normally a step-down function becomes a step-up function. Substations may need additional voltage regulators installed or, in an extreme case, a replacement multi-tap station transformer, to accommodate reverse flows. New station transformers deliver line loss reductions and other benefits that may fully offset the incremental costs.
- **Generation:** On most utility systems in the United States, many utilities are interconnected in large networks, with tens of thousands of megawatts of interconnected generating units dispatched to meet demand in an economic fashion. Simply by retiring older, less-flexible steam generation; adding more flexible newer generation; and implementing cost-effective energy efficiency programs, demand-response programs, time-varying prices, and greater inter-regional cooperation, most regions can adapt

their power supply to a high-renewables future.[102] On island systems, like Hawaii, this is more challenging, and deployment of electricity storage may be an important component of this transition.

- **Demand response:** Most regions of the United States have begun implementing demand response programs to reduce loads during extreme circumstances. More innovative programs, like grid-integrated water heating and storage air conditioning may be cost effective ways to add flexibility to better enable adaptation to a high-renewables future.[103]

Hawaii may be leading the nation in change, but dockets have been convened in Arizona, Colorado, California, New Mexico, and other states examining the appropriate way to recover grid costs from DG customers, including the cost of grid modifications needed to adapt to high levels of solar. In general, regulators will be faced with the following issues:

- **Value of solar:** Should the value of solar energy, including avoided generation, transmission, distribution, fuel cost risk, fuel supply risk, environmental benefits, and other factors be considered?
- **Recovery of existing distribution costs:** Should existing distribution costs be recovered volumetrically, or through some sort of fixed charge or demand charge?
- **Recovery of incremental distribution costs:** If grid modifications are incurred to adapt to increased penetration of customer-sited DG, will these costs be recovered directly from the DG customers or spread to all distribution customers?
- **Recovery of stranded generation costs:** If demand for grid-supplied power decreases, will solar customers bear a share of cost recovery for generating resources that are retired? Will non-DG (grid-dependent) customers bear these costs?[104]
- **Recovery of new generation costs:** If new flexible generation must be added to serve the more variable usage of solar customers (zero during the solar day; unchanged, i.e., traditional consumption at night), should these costs be recovered from all customers or only from solar customers?

The outcome of these investigations will produce different results, state by state. In general, states looking ahead at marginal costs will recognize that solar customers are bringing great value to the system and will enjoy lower costs over the long run, while states focused on embedded cost concepts will see stranded cost issues, but experience higher costs over the long run.

Following the guidelines below should ensure that solar and other residential consumers are treated equitably:

- **Customer charges:** Should not exceed the customer-specific costs associated with an additional customer, such as the service drop, billing, and collection.
- **Energy charges:** Should generally be time-varying and those time differentiations should apply both to power delivered by the utility to customers and to power delivered to the utility from customer generation. This assures that solar output is valued appropriately, and high-cost periods are reflected in the prices charged to customers using power at those times. It may be appropriate to make time-varying rates mandatory for solar customers, but optional for small-use non-solar customers.
- **Minimum bills:** Where utilities have high numbers of seasonal customers who only consume power during the summer or winter, an annual minimum bill may be an appropriate rate design to ensure a minimum level of revenue from customers in this category. However, minimum bills are not a particularly desirable rate design as a rule.[105]
- **Demand or connected load charges:** Demand charges are only relevant for recovery of the relatively

102 See Lazar, J. (2014). *Teaching the "Duck" to Fly.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6977

103 See Cowart, R. (2003). *Dimensions of Demand Response.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Cowart_NEDRIOverview_2003_11.pdf; and Taylor, B. and Taylor, C. (2015). *Demand Response: Managing Electric Power Peak Load Shortages with Market Mechanisms.* Beijing: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7527

104 This is normally a question for vertically integrated utilities and not for restructured utilities, where the generation is supplied separately by unregulated suppliers.

105 See Lazar, J. (2015). *Electric Utility Residential Customer Charges and Minimum Bills.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7361

small capacity costs of line transformers that are sized to the demand of individual customers. They are never appropriate for upstream distribution costs that can be recovered in a TOU rate. The illustrative rate designs apply demand charges only for line transformers, recovering all other capacity-related costs instead in TOU and CPP rates.

- **Low-cost utilities (average revenue <$.10/kWh):** May need to retain or institute inclining block rates to ensure that the end-block of usage reflects long-run marginal costs for clean power resources, transmission, and distribution.
- **Most (average-cost) utilities (average revenue $.10 - $.20/kWh):** Conventional net metering (of the full rate, including volumetric charges for power supply and distribution) is likely an appropriate strategy; while grid operators lose distribution revenues, their consumers gain all of the other benefits of increased renewable generation, and, taken as a whole, the value of solar energy added to the system is equal or greater in value than the retail electricity price.
- **High-cost utilities (average revenue > $.20/kWh):** Utilities with average residential prices in excess of the long-run marginal cost of new clean energy resources ($.10/kWh to $.25/kWh) may need to reflect distribution charges separately. For example, these rare high-cost utilities may need to apply distribution charges to all customers for the power they receive from the grid, then crediting only a power supply rate when solar power is fed to the grid. As emerging technologies become more mainstream, rate designs will need to adapt to changes in how customers use electricity and how these technologies impact the grid. DG can be viewed as a tool to strengthen the grid and rate designs of the future can encourage the utility-customer partnership to ensure the efficiency and economy of the grid. Key will be the temporal rates discussed above; but also innovations in terms of unbundling customer-generated power to provide ancillary services. Providing credits to DER strategically located to support the grid will be important. Rate designs of the future can incorporate these win-win strategies to the benefit of all stakeholders.

Rate Design for Electric Vehicles

EV Pricing without AMI

Many electric utilities offer TOU pricing to customers without fully deploying AMI. They typically install interval TOU meters that can be read manually, and some offer special pricing to EV customers. An example is the Los Angeles Department of Water and Power (LADWP), whose standard residential rate and EV rate are shown in Table 10. The EV rate is separately metered, and discounted from the optional TOU rate by excluding the customer charge ($8.00/month) and discounting the otherwise-applicable energy rates.

EVs with AMI

A utility with AMI has many options for providing a rate for EV owners that is appealing to the customer and remunerative to the utility. These can include a simple TOU rate, a multi-period TOU rate with a super-off-peak period, a critical peak pricing rate, or a real-time price. Each of these is discussed in Appendix B ("Rate Design for Vertically Integrated Utilities"). A relatively unique option,

Table 10

LADWP Standard Residential Rate and Electric Vehicle Rate March, 2015

			Optional TOU Rate			Electric Vehicle Rate		
	Summer	**Winter**		**Summer**	**Winter**		**Summer**	**Winter**
Customer Charge	None	None		$8.00	$8.00		None	None
First 350 kWh	$0.146	$0.146	**High-Peak**	$0.246	$0.149	**High Peak**	$0.220	$0.141
Next 700 kWh	$0.175	$0.175	**Low-Peak**	$0.166	$0.149	**Low-Peak**	$0.141	$0.141
Over 1,150 kWh	$0.216	$0.175	**Base**	$0.131	$0.135	**Base**	$0.107	$0.107
Minimum Bill:	$10.00	$10.00				**Minimum Bill**	$10.00	$10.00

Source: Los Angeles Department of Water and Power grid-operator controlled charging, would allow the EV owner to request an "economy charge" by a defined time (7 am, for example) and then the grid operator would ensure the vehicle was charged by the time required by taking advantage of the communication technology in the vehicle's charge controller and using the lowest-cost available hours during the charge window. The grid operator can thus spread the charging load among a diversity of EVs, and vary the battery charging rate from minute to minute to supply voltage support and frequency regulation ancillary services to the utility, further reducing the cost of service to charge EVs.

Public Charging Stations and Time-Differentiated Pricing

EV owners sometimes need to charge during the day, or when they are away from home. To do so, they need to be able to take advantage of public charging stations. The pricing schemes for public charging and workplace charging vary widely from, and include the following:

- **Free charging:** Some utilities, public agencies, and retailers offer free public charging. For the utilities and agencies, this is an overt effort to stimulate EV sales and reward EV owners. For retailers it may be a sales tool: By offering free EV charging, the retailer can attract a presumably upper-income consumer to spend an hour in their business — with an implicit assumption that the expected increased sales will more than offset the electricity cost.
- **Hourly parking:** In states where the regulation of electricity prices precludes the resale of electricity for vehicle charging, owners of EV charging stations commonly avoid regulation by charging hourly for parking, and charging nothing for the electricity. The hourly pricing can be time-differentiated to reflect both power supply costs and consumer demand for charging.
- **Time-differentiated pricing:** Some owners of EV charging stations impose time-varying rates per kWh for EV charging, corresponding to wholesale market or utility TOU prices.

To ensure that EV charging station operators are able to implement time-varying prices, regulators and legislators need to consider whether the public interest is served by imposing regulation on EV charging,[106] or whether that will discourage the availability of EV charging stations and thus suppress the EV market. Implicit in this consideration is whether the free market will function appropriately so that price regulation is not needed.

Regulators will need to determine if the public benefit of providing an infant industry subsidy to EV charging is consistent with the public interest. This consideration goes well beyond the electric utility pricing realm, into broad areas of energy security, environmental policy, and economic development.

Vehicle-to-Grid and Full System Integration of EV (Maryland/PJM RTO Pilot)

One of the great promises of EVs is that they will become fully grid-integrated, providing a market for off-peak power, a source for on-peak power, and multiple ancillary services.[107] This requires a combination of sophisticated charging units in vehicles, complex pricing, and a *very* smart grid.[108] Commonly called Vehicle-to-Grid (V2G), experiments to demonstrate this concept are underway in Maryland and Delaware through a partnership among Honda, the University of Delaware, and Delmarva Power.[109] There are many questions being addressed, including the impact of utility use of vehicle batteries on battery life, compensation mechanisms for both energy storage and ancillary services as vehicles move from service territory to service territory, and methods to ensure that EV owners always have the energy they need to reach their planned destinations. While smart charging offers imminent benefits to the grid, V2G technologies will require more time to develop.

106 Regulators can pay attention to how all customers are affected by vehicle charging, and if costs for vehicle charging are spread to all customers, it should be because all customers are likely to benefit sooner or later.

107 For a discussion of this potential, see Lazar, J., Joyce, J. and Baldwin, X. (2007). *Plug-In Vehicles, Wind Power, and the Smart Grid.* Available at: http://www.raponline.org/docs/RAP_Lazar_PHEV-WindAndSmartGrid_2007_12_31.pdf

108 Ibid.

109 See University of Delaware. (2014). UD, Honda partner on vehicle-to-grid technology [Press release]. Available at: http://www.udel.edu/udaily/2014/dec/honda-delaware-v2g-120513.html

Green Pricing

Green pricing is an optional utility rate or service that allows customers to support a greater level of utility company investment in renewable energy technologies. Participating customers typically pay a premium on their electric bills to cover the incremental cost of the additional renewable energy.[110] The funds gathered from green pricing programs are either used to develop renewable energy projects or to support existing projects by purchasing renewable energy certificates (RECs).[111] Approximately 850 utilities — including investor-owned, municipal utilities, and cooperatives — offer a green pricing option.[112]

In restructured states, a number of Competitive Retail Electricity Suppliers (CRES) offer green products such as 100 percent wind. Interestingly, these products are very competitive with other supply options with mixed fuel sources.

Because green power customers are paying a premium for a resource that does not rely on fossil fuels, they should be exempt from any fuel adjustment mechanisms that recover varying costs for these fuels. Few regulators have addressed this important issue.[113]

Customer-Provided Ancillary Services

Providing rates with time-varying energy, capacity, and ancillary service components could allow DG, energy efficiency, and DR programs to be compensated for newly recognized values that they bring to the system. Such compensation can provide additional revenue streams to these resources and make them more cost-effective for customers to deploy or utilize. It could also lead to a rebalancing of the grid investment portfolio in favor of decentralized solutions.

This is especially true in the case of ancillary services. In smart grid technology, an ancillary service supports the transmission of electricity from its generation site to the customer, may be reliability based, and may include load regulation, spinning reserves, non-spinning reserves, replacement reserves and voltage support, among other functions.[114]

For example, a smart grid's built-in communications infrastructure could enable the system operator to manage water heaters and distributed resources to provide reactive power, voltage support, and other ancillary services under some circumstances. The system operator would need to have operational control over DER in order to provide these services.[115] For this to happen with PV systems, the deployment of smart inverters would be required.[116] Germany requires solar inverters to perform certain functions, such as power ramping and volt/VAR control, which leads to more grid stability. EPRI is developing standards that set key functionalities for smart inverters to allow them to communicate with the grid.[117]

Pragmatically, it makes little sense to offer rates to residential and small commercial consumers that are so detailed that they include separate charges (or credits)

110 For a list of Green Pricing Programs by state, see: http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1.

111 Ibid. RECs, also known as renewable energy credits, green certificates, green tags, or tradable renewable certificates, represent the environmental attributes of the power produced from renewable energy projects and are sold separate from the associated commodity electricity.

112 Ibid.

113 For more information on green pricing, see the Center for Resource Solutions: http://www.resource-solutions.org/progs_bce.html.

114 FERC defines ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." See Hirst, E., and Kirby, B. (1996, February). Electric Power Ancillary Services, p. 1. Available at: http://www.consultkirby.com/files/con426_Ancillary_Services.pdf

115 Schwartz, L., and Sheaffer, P. (2011). *Is It Smart if It's Not Clean? Smart Grid, Consumer Energy Efficiency, and Distributed Generation, Part Two.* Montpelier, VT: Regulatory Assistance Project, p. 9. Available at: http://www.raponline.org/docs/RAP_Schwartz_SmartGrid_IsItSmart_PartTwo_2011_03.pdf

116 IEEE 1547 is the accepted engineering standard for distributed generation that interconnects to the grid. It was develop with an eye toward maintaining system safety and integrity, but not with an eye toward maximizing the value of DG to the system. For example, inverters meeting the IEEE 1547 standard are designed to separate the DG from load in the event the grid becomes unstable or unavailable, rather than continuing to supply energy to the customer and disconnecting from the grid altogether.

117 IEEE 1547.8, the latest update to the standard, is expected to allow inverter manufacturers to provide smart grid features.

for ancillary services. However, aggregators of demand response that can also provide ancillary services should be well-positioned to deal with detailed tariffs.

Most programs that reward customers for allowing grid-interactive control of loads for ancillary services are priced on a "virtual" rather than "measured" basis, providing a fixed monthly bill credit in exchange for allowing the utility or demand-response aggregator a defined level of control over the air conditioner, water heater, thermostat, or other controlled load. Many provide an "override" function allowing the customer to disengage participation when energy requirements are high, such as during a house party. These types of flexible arrangements greatly improve customer satisfaction and participation rates, and have been shown to have a very small impact on program performance.[118]

118 Ecofys water heater and space conditioning pilot for Bonneville Power Administration, 2012.

VI. Other Issues in Rate Design

Alternative Futures: Smart and Not-So-Smart

The Smart Future: Customers and Technology Unleashed

The smart future will see extensive use of technology to help consumers manage their energy costs, and utility pricing that enables these savings to occur. A mix of central generation, DG, energy efficiency, DR, and customer response to time-varying pricing will provide a rich mix of reliable, flexible, and environmentally benign sources to provide quality service at reasonable costs.

Consumers will increasingly have smart homes, as shown in Figure 14 (page 60), with smart appliances, water heaters, thermostats, and, in many cases, electric vehicles. These will receive information from the utility or grid operator on current conditions and prices, and respond intelligently to optimize comfort and service and minimize energy bills.

Utilities will use AMI for two-way communication, learning of conditions at individual nodes on the generation, transmission, and distribution system, and then dispatching a mix of supply resources and demand management to optimize costs, emissions, and reliability.

To achieve this smart future, regulators at various levels will have to take many discrete actions, including:

- Adopting time-varying and dynamic rate designs, with consumer education, shadow billing during a pre-deployment phase, a "hold harmless" provision the first year of implementation and excellent customer support throughout.
- Implementing some form of revenue regulation to ensure that utilities retain a reasonable opportunity to earn a fair return on investment on used and useful property serving the public and maintain access to capital at reasonable prices without erecting barriers to economic innovation.
- Implementing new state building energy codes to require home energy management systems in new homes (as most already do for commercial buildings).
- Requiring that new customer-sited generation include smart inverters, responding to provide reliability and ancillary services; enabling customer-sited batteries to not only provide service to the locations where they are installed, but to also be available to grid operators for system support; and incorporating solar orientation standards to optimize peak time production.
- Adopting appliance standards to require installation of control technologies in new major appliances such as refrigerators, water heaters, furnaces, heat pumps, air conditioners, dishwashers, clothes washers, and clothes dryers, so that they can automatically respond to changing prices.

Not-So-Smart Future

A number of electric utilities have proposed SFV rate designs in which all costs claimed to be "fixed costs" are recovered in a fixed monthly charge, and only those costs that are considered "variable" are recovered on a per-kilowatt-hour basis. While most have focused only on distribution costs, a few have gone further, proposing that the recovery of costs related to generation and transmission investment be included in monthly fixed charges.

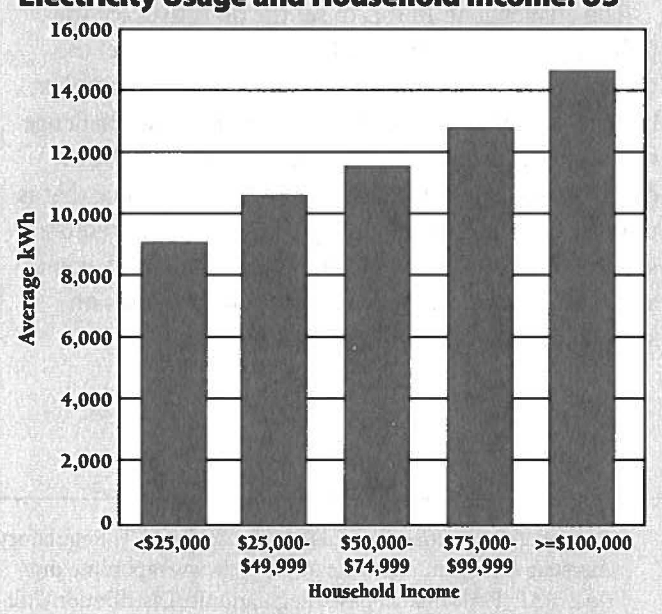
High fixed charges provide utilities with stable revenues and address their immediate concerns, but in doing so, they punish lower-usage customers, and discourage efficiency improvements and adoption of distributed renewables. Over time these charges can lead to an unnecessary increase in consumption or, in the event that distributed storage technologies become more affordable, promote customer grid defection. The adverse impacts on electric consumers and public policy goals for electricity regulation include:

- **Energy efficiency:** A higher fixed charge results in a lower per-kWh rate, which leads to disproportionate savings for larger dwellings and undermines customers' incentives to invest in efficiency improvements. For example, if a high-efficiency air conditioner will pay for itself in five years at 10 cents per kWh, that payback period doubles if the per-kWh rate drops to 5 cents per kWh due to implementation of a high fixed charge.

- **Competitive impact on renewables development:** A lower per kWh charge cuts into the potential savings from PV investments. Customers who do invest in PV are more likely to respond to a higher fixed charge (with which storage capacity would become more cost-competitive) by going totally off the grid, causing the utility to lose a customer permanently when it would be more efficient for both the customer and the grid for that customer to remain connected.
- **Low-income households:** An analysis prepared by the National Consumer Law Center shows that typical households below 150 percent of the federal poverty level use between 3 percent and 9 percent less electricity than the average of all households.[119] With a fixed rate design, most low-income customers' bills will rise despite their lower usage.
- **Apartment and urban dwellers:** As noted above, smaller units' bills rise under a higher fixed charge while larger dwellings' bills go down. This is the case despite the fact that residents of multi-family buildings tend, on a household basis, to have lower usage, and that it is actually cheaper to serve them.

Figure 16

Electricity Usage and Household Income: US [120]



- **Small-use residential consumers:** These customers are "less peaky" than higher-usage customers, and will generally benefit from time-varying pricing. While small-use customers have higher non-coincident peak relative to usage, their coincident peak is generally lower, primarily due to lower air-conditioning usage.[121]

The first of the principles of electricity pricing set out earlier notes that a customer should be able to connect to the grid for no more than the cost of adding that customer. The imposition of a fixed charge solely for the privilege of being a customer is not common in other economic sectors, from supermarkets to the travel industry that have similarly significant fixed costs to those of utilities. Allowing utilities to impose high fixed monthly charges is an exercise of monopoly power and impedes the longstanding goal of universal service in the United States. And the utility argument that fixed costs should be recovered via fixed charges is flawed with regard to both economic and accounting principles.

Utilities' concern about loss of revenue is fair, but an SFV model is probably the worst option available by which to address it. Alternatives include revenue regulation, or "decoupling," now adopted in more than half of US states; performance-based regulation; weather normalization; reserve accounts; demand charges; and connected load charges.

The regulatory and economic argument against SFV is explored in greater detail in Appendix D.

Addressing Revenue Erosion

A central theme from utilities is their concern over the decline in recovery of costs from customers who improve their energy efficiency or install their own generation — primarily PV. Improved efficiency reduces energy consumption and, therefore, utility sales across the board, while customer generation displaces utility-supplied energy. Most states have implemented NEM tariffs, which allow

119 There are exceptions to this low usage rate, typically associated with poorly insulated buildings and less efficient appliances and HVAC systems. Low-income weatherization and appliance rebate programs are helpful in this regard.

120 Adapted from John Howat of National Consumer Law Center, 2014.

121 Marcus, JBS Energy, 2015.

the DG customer to offset bills at the full retail rate. These implicitly assign a premium value to new renewable energy that is equal to the volumetric distribution price avoided by the NEM customer. Because those rates collect not just the incremental cost of generating energy delivered to the customer, but the costs of delivering that energy over the distribution and transmission systems, crediting customers with the full retail rate for the energy they produce causes a reduction in revenues that were designed to recover those costs. The rate design concepts discussed above do not address that issue. Rather, the rate designs discussed above focus on a fair and equitable allocation of costs based on the causation of those costs. Other solutions, however, are available, and this is a separate issue from revenue requirements.

Utility cost recovery and revenue stability can be addressed in many different ways, some desirable and some less desirable. Fixed charges, a higher allowed rate of return, incentive regulation, and revenue decoupling are four different approaches, all of which can serve to address the earnings volatility from sales variations. Fixed charges were previously discussed. The other approaches are discussed below.

Cost of Capital: A "Let the Capital Markets Do It" Approach

In states where revenue regulation mechanisms have not been deployed, regulators are effectively letting the capital markets set a higher rate of return for the utility. This leads to higher costs. The utility-allowed return on equity and equity capitalization ratio are the way that utilities are rewarded for taking the risks associated with serving customers at regulated prices. The return on equity is the percentage of shareholder profit allowed on the utility's plant investment, while the equity capitalization ratio is the percentage of capital in the business that is derived from shareholders (as opposed to bondholders, who get a fixed return).

If the utility enterprise is subject to earnings variations that are a part of the business, then the business is arguably riskier than a utility without such earnings variations. A utility exposed to earnings variations due to changes in customer usage may require a higher rate of return or equity ratio. Conversely, a utility with any sort of revenue stabilization mechanism (a fuel adjustment clause or a decoupling mechanism, as examples) would need a lower equity capitalization ratio, reducing the overall rate of return (but not the return on shareholder equity) and, in turn, educing the overall revenue requirement.

Either a higher return on equity or a higher equity ratio will increase the utility revenue requirement and ultimately lead to higher rates for customers. Thus this laissez-faire approach certainly results in higher costs to consumers over time.

Incentive Regulation: An "Incentivize Management" Approach

Incentive regulation, or performance-based ratemaking (PBR), is a large topic well beyond the scope of this rate design report. It is addressed in great detail in several other RAP publications.[122] However, PBR is one way to address the revenue loss that utilities experience if customer sales decline. If the regulator sets the achievement of a defined level of sales reduction from energy efficiency as a goal, and provides a financial reward to the utility for achieving that, the regulator can make up the lost earnings that the utility experiences. Similarly, if the regulator sets a specific goal for deployment of renewable generation, and provides a financial reward to the utility for achieving that, the regulator can provide for recovery of lost earnings that the utility experiences.

The challenge in PBR is to set the objectives for the utility to be achievable but challenging, and to set the rewards to be ample but not excessive. This is complex, but can address some or all of the lost revenue challenge for utilities if properly developed and monitored and can change the utility culture toward performance that is more in line with public policy goals. PBR does require significant effort on the part of regulators to implement and monitor and can impose additional expenses on stakeholders involved in utility rate cases.

122 See Lazar, J. (2014). *Performance-Based Regulation for EU Distribution System Operators*. Brussels: Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/7332; and Weston et al. (2000). *Performance Based Regulation for Distribution Utilities*. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_PerformanceBasedRegulationforDistributionUtilities_2000_12.pdf

Revenue Regulation and Decoupling: A "Passive Auto-Pilot" Approach[123]

Revenue-based regulation, or "decoupling," is widely used throughout the United States to insulate gas and electric utilities from revenue impacts due to sales variations. The essence of revenue regulation is that the utility regulator sets an allowed revenue level, and then makes periodic small adjustment to rates to ensure that allowed revenue is achieved, independent of changes in units (kW and kWh) sold. Revenue regulation does not assure a given profit level, only the allowed revenue recovery.

Because revenue regulation removes utility management's incentive to increase sales, most of the electric revenue regulation mechanisms in the United States were established to facilitate more active utility involvement in energy-efficiency programs that by their nature are intended to reduce sales. The success of those programs in California, Oregon, Washington, and other states is widely attributed to the removal of the shareholder earnings impact of lower sales.[124]

The essence of revenue regulation is that changes in sales volumes do not result in changes in revenue. This does not always mean a rate increase, because sales sometimes rise above the levels anticipated in general rate proceedings. For example, in a year with a hotter summer or colder winter, the utility would reduce rates. In the context of DG and EV, this means that the "excess revenues" from additional sales to electric vehicles may offset the "lost revenues" due to solar or energy conservation investments.

One benefit of revenue regulation is that the utility normally receives a "formula" to reflect higher costs, such as a "revenue per customer" allowance. These do tend to lead to very small annual increases in revenues. Whether prices rise depends on whether average consumption by customers is rising or declining as the number of customers change. The use of a revenue per customer adjustment may allow the utility to maintain a total revenue trajectory sufficient to delay its next general rate case, saving both the utility and the regulator the significant costs that rate cases involve.

Revenue regulation has critics, primarily state utility consumer advocates and some low-income advocates. Their concern is that these mechanisms result in annual increases, and that declining costs in some areas are not offset against rising costs in other areas, as occurs in a general rate case. A well-structured mechanism can address these concerns. It should be noted also that the alternatives to revenue regulation, such as SFV, may have even more serious adverse impacts on these constituencies.

A well-designed revenue regulation framework is the best option to address utility revenue attrition that energy efficiency or renewable energy deployment may cause, for the following reasons:

- The rates can remain volumetric, preserving incentives for efficient use of energy and for deployment of renewable resources;
- Customer bills remain very predictable, and linked to usage so customers can control the size of their bills;
- Small-use customers are not disproportionately affected, as they are with high fixed charges;
- Utilities, regulators, and intervenors avoid the cost of annual rate cases;
- If actual revenues exceed authorized revenues, customers can see a rate decrease;
- The framework provides transparency for customers to know what the level of revenues are; without decoupling, utilities who do not seek rate increases for long stretches may not be filing because their earnings are higher than authorized; and
- A periodic general rate case review of all costs and revenues ensures that any imbalance between costs and revenues does not persist. A three- to five-year periodic review is typical.

There is no silver bullet to address the legitimate concerns of all interests. The evidence, however, is that high fixed charges have the most adverse impacts on consumers, the environment, the economy, and society. Good rate design addresses the legitimate concerns of all major interests, provides a framework for stable regulation

123 For more information see: Lazar, J., Weston, R., and Shirley, W. (2011). *Revenue Regulation and Decoupling.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/902

124 See Morgan, P. (2012). *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations. Graceful Systems.* Available at: http://aceee.org/collaborative-report/decade-of-decoupling; and Howat, J., and Cavanagh, R. (2012). Finding Common Ground Between Consumer and Environmental Advocates. *Electricity Policy.* Available at: http://switchboard.nrdc.org/blogs/rcavanagh/Ralph%20Cavanagh%20and%20John%20Howat_Final.pdf

of utilities, and enables the growth of renewable energy and energy efficiency to meet electricity requirements.

Bill Simplification

In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. In many cases, they are a kind of tally of the rate-case battles won and lost by advocates and utilities, a catalogue of special charges and "trackers" dealing with particularly knotty investment and expenditure requirements. The accumulated result is often a bill that consumers find difficult to navigate. A customer's electric bill typically consists of a monthly customer charge, one or more usage blocks (or time-of-use periods), and as many as ten surcharges, credits, and taxes added to these usage-related prices.

Some utilities present all of the detail on the bill, and it can be confusing and overwhelming to the consumer. Table 11 shows an example of how the customer's bill may look with all of the detail. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced.

Alternatively, all of the detail can be provided, but the bill should "roll-up" all of the rate components, adjustments, taxes, surcharges, and credits into an "effective" rate that the consumer pays. Table 11 shows what the customer actually pays in each usage-related rate component and better informs customers what they will pay if they use more electricity, or save if they use less electricity.

Utilities should be required to display the "effective" rate to customers, including all surcharges, credits, and taxes in the effective price, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

Table 11

Customer Adjustments

Example of an electric bill that lists all adjustments to a customer's bill.

Your Usage: 1,266 kWh

Base Rate	Rate	Usage	Amount
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:	$139.74		
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design.

Base Rate	Rate	Usage	Amount
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

Source: Lazar et al, *Revenue Regulation and Decoupling*, 2011.

Customer Revenue Responsibilities

As mentioned earlier, as customers utilize greater energy efficiency and deploy more PV, the reductions in their bills can have the effect of allocating greater cost recovery responsibility to other customers. This is often described as a cross-subsidy. However, this is an unfair characterization. In fact, the system for allocating costs among customers and customer classes has always been a dynamic one that reflects the changing characteristics of all customers over time. The fact that relative cost responsibility changes from one time period to another is not conclusive of the existence of a subsidy. This is especially true given that there is no single "correct" method of allocating costs and, even if there were one, it would by necessity have to accommodate changing consumption patterns over time. It is also unfair because the direct customer investment is replacing capital and other costs that the utility would otherwise have to incur and charge to all customers. That said, this is an important issue that regulators will face as energy efficiency, customer-owned generation, and storage become more prevalent.

Changes in Customer Characteristics and Class Assignments

"Smart"-Enabled Customers

Even if all customers in a given class (e.g., residential or small commercial) are equipped with smart meters, they may not all be in the same position to deploy smart appliances or be able to finance energy efficiency or distributed generation in their homes or businesses — especially those who rent, rather than own, their homes or business premises. This may present a challenge for regulators in terms of assuring a sense of fairness among otherwise similarly situated customers. Ideally, the presence of additional smart technologies will actually lower costs for all customers, even those who do not have access to all of the smart bells and whistles. Regulators will need to take care in rate design to assure that all customers share in the benefits that industry changes will bring and that no customer group is left out of the mix.

Once past these issues, regulators should focus on rate design approaches that will maximize the value of smart technologies for customers who can take advantage of them. This includes all smart-metered customers, but also those with smart appliances and smart buildings. Without appropriate rate design, the value of smart technologies to those customers and to the electric system generally will not be realized.

DG Customers

As power producers, DG customers represent a special group of customers. Going forward, if these customers are subject to time-varying rates, they will pay for all services they receive from the utility whether at on-peak or off-peak times, and be credited for the time-differentiated value of the power they supply, also whether at on-peak or off-peak times. If they directly bear the cost of their connection to the grid (service drop, meter, billing), and if grid costs are recovered appropriately in time-varying rates, they will pay the full cost of any service they receive from the utility. The rate design principles set forth at the beginning of this paper are crafted with this in mind. The position advocated by some, that all customers have an equal cost responsibility for grid costs regardless of usage levels, is inconsistent with how the cost of infrastructure is recovered in competitive industries, and a key purpose of regulation is to enforce the pricing discipline that competition normally provides.

Non-DG Customers

Customers who have not deployed their own generation systems (non-DG customers) will likely see some increase in the prices they pay for non-generation-related costs as additional customer-sited DG comes onto the grid if this results in a sales decline. This effect will be most notable with respect to distribution costs. To the extent DG and other customer resources are replacing utility capital, overall costs in utility rates may decline.

If the rate design for DG customers is properly implemented, that is, if customers are not unduly rewarded for deploying DG, the collateral benefits of DG — such as reduced line losses, deferred and avoided distribution investments, and the potential for overall reductions in the price of generation — then non-DG customers will see equitable prices for energy delivered to their meters. Regulators should account for these benefits when considering the impact of customer-owned DG on non-DG customers.

Departing Customers

Customers who install their own generation and go "off grid" deliver a one-time decline in system costs, to the extent that system investments are deferred or avoided by their absence. However, they do not deliver many of the benefits that grid-connected DG customers provide, because they are not injecting energy into the system at any time. Thus, reduced losses, reduced wear and tear on equipment and other savings derived from their presence are not present to benefit other customers. As discussed, regulators should avoid rate design strategies that encourage customers to depart the system when their continued presence would be a net benefit to everyone.

VII. Conclusions

The future of the electric sector will likely include storage, microgrids, EVs, and more DER. Homes and businesses will use electricity more efficiently. As entrepreneurs continue to study consumer behavior and a greater understanding of the operational characteristics of the electric system is revealed through smart technologies, new technologies and applications will undoubtedly develop. Change will likely be constant and subject to iterations, refinements, and new technologies. How regulators respond to these changes will matter greatly in terms of the expansion of new frontiers or perpetuation of the status quo.

Rate design will be an important driver of the success of the utility of the future at assisting with the transition to a clean power system. Utilities, customers, and third-party service providers will need the tools to manage the grid as efficiently as possible. Regulators will need to assure that benefits and costs are fairly allocated. Knowledge of and accuracy in pricing can reward customers for energy usage behavior that contributes to the reduction, rather than increase, in utility system costs.

For DG customers specifically, the price they pay or receive for electricity they either consume or provide to the grid respectively will matter greatly in terms of encouraging or discouraging the growth of this industry. Bidirectional rates with TOU pricing may offer one of the best solutions for this segment of the market. Under this rate design, the DG customer pays the full retail rate for any power consumed, just like any other customer. This customer is then compensated based on the same time periods, either using the retail rate or on a value basis. That value can be based on an analysis of the contribution of DG to the grid and can be set independently by a state public service commission.

Whether as a separate rate or as a proxy, the commission can use the same retail generation TOU rate used for charging customers, applied to the price at the time the DG produces power to the grid. Other benefits can be layered on to reflect additional value that a DG might provide in terms of location or other attributes.

Utility rate designs will have to more appropriately reflect the cost of electricity provided by the utility and the benefits that are provided to the utility system by customers. With more innovative technologies being developed and offered by utilities and third-party vendors (such as smart appliances able to respond to grid pricing signals), the need to become more geographically, temporally, and functionally granular and more precise with pricing will expand. While rates today are typically flat or inclining, these rates only send price signals about consumption and conservation. Smart rate designs will need to address not only the amount consumed but also when it is consumed and its impact on costs and other customers.

A small number of utilities offer some kind of dynamically priced rate to residential customers, whether it be a TOU rate or a PTR. As of this publication, most dynamic residential rates are offered only on a pilot basis. Some studies like that conducted by SMUD and OG&E have produced good data demonstrating the potential benefits of TOU rates for residential (including low-income) customers and the utility system as a whole.

However, for policymakers to move forward in the direction of TOU pricing on a larger scale, customer education will be important to empower informed decisions about energy use. Customers will also need to see the value of TOU rates and should be given a choice among rate options. Providing customers with a shadow bill that compares their monthly energy bill under a flat or inclining rate with what it would have been under a TOU rate is a good tool to educate customers. Shadow bills not only educate customers as to how TOU rates work, but they also offer an opportunity for customers to analyze how that rate affects them personally and learn how they can reduce their electric bills.

Where a DG resource is located is an important factor in determining its value to the customer and to the electric system as a whole. DG that is strategically located at a load center can bolster voltage support and alleviate a utility's obligation to provide additional transmission and distribution facilities, deferring or avoiding the associated costs. Rate design that rewards customers for deploying those resources helps make the economic case to build.

Aging grid infrastructure is a nationwide problem that will cost billions of dollars to remedy, and creative solutions that combine DG, storage, advanced metering, and other technologies should be increasingly deployed to help minimize those costs.

In addition to recognizing locational benefits in pricing, good rate design recognizes the attributes that a customer can provide in terms of energy, capacity, and ancillary services. Recognizing these attributes through appropriate price signals will allow DG, DR, and energy efficiency to access new markets that can provide additional revenue streams to improve the economics of those resources for the end-use customer. It can also lead to a rebalancing of the centralized grid portfolio in favor of a mix of flexible generation and decentralized solutions. This could become increasingly more important in the wake of concerns regarding cybersecurity and the threat of massive blackouts.

A number of rate designs have been discussed here that explore the pros and cons of those rate structures that are already frequently used as well as those that are just emerging. Viewed as a quick fix to lost revenues associated with customer engagement in energy solutions, SFV rates with high monthly fixed charges are increasingly being proposed by utilities. SFV is not a step forward, but a step backward. With new technologies becoming more prevalent, it will be important that rate designs reflect actual future changes in system costs and benefits associated with customer usage in order to properly align responsibility for costs, compensate for benefits, and send the correct price signals to all customers. SFV is the antithesis of this, creating a simplistic one-size-fits-all rate that does not align cost to cost causation and has adverse consequences for urban, multi-family, low-income, and low-use customers as well as those who invest in energy efficiency, demand response, and distributed generation. By de-linking customer use from the customer's bill, SFV encourages wasteful consumption and sends misleading, incomplete price signals to the consumer.

The role of regulation in power sector transformation will be to develop pathways that lead to smarter solutions that optimize the value of interconnection and two-way communication for the customer and the grid. Many of these solutions will be market-driven.

Utilities have a long history of operating as a monopoly. As technology and innovation encroach on what was their exclusive domain, they will need to adapt and, to some degree, reinvent themselves. As such, power sector transformation will need to incorporate new tools to address these changes. Rate design will be an important element.

However, there are other instruments available to prepare for and move with these changes. They include PBR and integrated distribution grid planning (IDGP), among other tools, to help protect the financial integrity of the grid while assuring that rates are fair and affordable for all customers. PBR, for example, can help change utility motivation and culture by rewarding the utility, not through a return on investments but through behavioral changes such as expanding energy efficiency and DR programs, encouraging DG, making the grid more reliable, improving customer service, and increasing operating efficiency.

IDGP, just emerging in California and New York, can provide valuable information to regulators as to what is needed to keep the grid secure. Like an IRP, it can identify least-cost solutions that could include the strategic location of DG or the implementation of demand response and energy efficiency at a load site or some combination thereof.

The speed at which change takes place will vary from jurisdiction to jurisdiction and will be influenced by what customers want as well as utility culture. Regulators will have an important role to play in overseeing this transformation. There will be many pilots and projects implemented, including microgrids; storage via electric vehicle batteries or other sources; and energy efficiency programs from whole-house home performance programs to using smart, two-way communication technologies to manage water heaters and distributed generation in order to provide voltage support, reactive power and other ancillary services. Learning from pilots and experiments is a new duty for regulators, and will require additional resources.

A critical component of unlocking the real value of these changes will be the utilization of time-differentiated pricing and the connection of customer and system operator level technologies that will allow a more dynamic interaction between the two. Rather than the traditional model of simply building the necessary supply-side resources to meet an unmitigated demand for energy, smart grids, meters, homes, buildings, and appliances will need to become a more interconnected whole that yields a more optimum cost and engineering solution than previously experienced.

In the interim transition to this future, regulators should strive to avoid expensive mistakes based on defense of the legacy structure of the industry. In their stead, regulators will need to focus on identifying costs and benefits of alternative strategies and seek to maximize the net value to customers and society.

Guide to Appendices

These accompaniments to the main paper can be found in our online library at the links below.

Appendix A: Dividing the Pie: Cost Allocation, the First Step in the Rate Design Process

http://www.raponline.org/document/download/id/7766

Cost allocation among customer classes, commonly called the "cost of service" study, is the first step in the rate design process. In the past, cost allocation followed historically evolved methods in each state, with costs divided into "customer," "demand," and "energy" costs. With the evolution of demand response as the lowest-cost peak capacity resource, the ability to measure usage for all classes by time of day, and the use of smart meters not only for customer billing but also for energy conservation and peak load management purposes, these historical methodologies require fundamental revision.

In general, only customer-specific costs, such as billing and collection, are properly considered customer-related costs. Most grid costs and power supply costs are best treated as time-varying volumetric costs, not as simple "demand" or "energy" costs.

Appendix A provides a greater discussion of these issues. A significantly more in-depth publication is tentatively planned in 2016 and will address cost allocation.

Appendix B: Rate Design for Vertically Integrated Utilities: A Brief Overview

http://www.raponline.org/document/download/id/7767

Most electric utilities in the United States have had relatively simple rate designs for residential consumers. These consist, generally, of a monthly fixed customer charge that collects customer-specific costs like billing and collection, and one or more energy blocks that collect all other costs. Some utilities have seasonal rates, some have inclining block rates, and many offer optional time-varying rates. A few have moved to include distribution costs within the monthly fixed customer charge, while others use a minimum bill form, rather than a customer charge, to collect some revenue from very low-use consumers.

Appendix B provides a greater discussion of current rate designs. In addition, detail can be found in these previous publications on this topic:

- Distribution System Cost Methodologies for Distributed Generation (2001)
- Pricing Do's and Don'ts (2011)
- Time-Varying and Dynamic Pricing (2012)
- Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed (2013)
- Designing Distributed Generation Tariffs Fairly (2014)

Appendix C: Restructured States, Retail Competition, and Market-Based Generation Rates

http://www.raponline.org/document/download/id/7767

In states that have restructured, the power or generation portion of a customer's bill is usually not provided by the incumbent utility. The distribution utility in some restructured states can acquire the power requirements for the customer, called the Standard Service Offer (SSO) or Default Service. The SSO is typically competitively procured by the distribution utility in an auction process.

In states that allow retail competition, the customer can bypass the SSO and directly select a competitive retail energy supplier from a list of certified suppliers to provide his/her power requirements. Customers can also join governmental or community aggregations to attain supplier price discounts. The competitive retail suppliers may offer rate designs for power supply that differ significantly from the SSO rate design.

The evolution of wholesale power markets has led to the development of businesses that aggregate the demand management power attributes of one or many customers and offer this resource back into the energy and capacity market at a price.

Appendix C provides a greater discussion of these topics.

Appendix D: Issues Involving Straight Fixed Variable Rate Design

http://www.raponline.org/document/download/id/7771

Utilities in some parts of the United States are seeking changes to rate design that sharply increase monthly fixed charges, with offsetting reductions to the per-unit price for electricity. This approach deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. They mistakenly use the notion that short-run so-called "fixed" costs should be recovered through fixed charges. As a result, they do not appropriately reflect long-term costs, all of which are variable. The effect of this type of rate design is to sharply increase bills for most apartment dwellers, urban consumers, highly efficient homes, and customers with DG systems installed, while benefitting high-use larger homes and rural customers with above-average distribution costs. While these rates do provide revenue stability for utilities, there are more appropriate and economically sound approaches that should be used in their stead. The use of these rates risks placing consumers on an ill-advised consumption path, while putting the very viability of the industry in question.

Appendix D discusses how the future is better served by reflecting costs that are not individual customer-specific — including nearly all distribution system costs — in time-varying rates for usage that is beneficial to the public interest.

Glossary

Adjusted Test Year
A utility's investment, expense, and sales information used to allocate costs among customer classes and for setting prices for each customer class. Adjustments to historical data are made for known and measurable changes to reflect the operating and financial conditions the utility is expected to face when new rates are implemented.
See Also: "Test Year," "Historical Test Year."

Adjustment Clause
A rate adjustment mechanism, implemented on a recurring and ongoing basis, to recover changes in expenses or capital expenditures that occur between rate cases. The most common adjustment clause is the fuel and purchased power adjustment clause, which tracks changes in fuel costs and costs of purchased power. Some utilities have weather normalization adjustment clauses, which correct for abnormal weather conditions.
See Also: "Tracker," "Weather Normalization" and "Lost Revenue Adjustment Mechanism."

Advanced Metering Infrastructure (AMI)
A combination of smart meters, communication systems, system control and data acquisition systems and meter data management systems. Together, these allow for metering of customer energy usage with high temporal granularity; the communication of that information back to the utility and, optionally, to the customer; and the potential for direct end-use control in response to real-time cost variations and system reliability conditions. AMI is an integral part of the smart grid concept.
See Also: "Smart Meter," "Supervisory Control and Data Acquisition," "Meter Data Management System," "Smart Appliance," "Smart Technology," and "Smart Grid."

Aggregation
Bundling of multiple customers or loads to achieve economies of scale in energy markets. Aggregation also takes advantage of the diversity of loads among multiple customers and enables companies to offer price risk management services to those customers.

Aggregator
A company that offers aggregation services and products.

Allocation
The assignment of utility costs to customers, customer groups, or unbundled services based on cost causation principles.

Allowed Rate of Return
The weighted cost of capital used by the regulator to determine a utility's revenue requirement.
See Also: "Cost of Capital," "Weighted Cost of Capital," "Cost of Debt" and "Revenue Requirement."

Ancillary Service
One of a set of services offered in and demanded by system operators that generally address system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

Appliance
Any device that consumes electricity. Appliances includes lights, motors, water heaters, and electronics, as well as typical household devices such as washers, dryers, dishwashers, computers and televisions.
See Also: "Smart Appliance."

Area Regulation
Area regulation is one of the ancillary services for which storage may be especially well-suited. It involves managing "interchange flows with other control areas to match closely the scheduled interchange flows" and moment to moment variations in demand within the control area. In more basic terms, area regulation is used to reconcile momentary differences between supply and demand. That is, at any given moment, the amount of electric supply capacity that is operating may exceed or may be less than load.

Avoided Cost
The cost of providing additional power, including the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, environmental costs, and line losses associated with delivering that power.

Baseline Rate
A rate that allows all customers to buy a set allowance of energy at lower rates than additional usage.

Baseload Generation/Baseload Units/ Baseload Capacity/Baseload Resources
Electricity generating units which are most economically run for extended hours. Baseload generation is generally characterized by low short-run marginal costs (i.e., fuel) and, usually, high capital costs. Baseload resources are the "first" units dispatched to serve load. Baseload units often have operating constraints which make it difficult from an engineering or economic viewpoint to cycle their output up and down to match changes in load. Typical baseload units include coal-fired and nuclear-fueled steam generators.

Capacity
The ability to generate, transport, process, or utilize power. Capacity is measured in watts, usually expressed as kilowatts (kW) or megawatts (MW). Generators have rated capacities that describe the output of the generator at its bus bar when operated at its maximum output at a standard ambient air temperature and altitude. The capacity of some types of generation (e.g., combustion turbines) varies inversely with ambient air temperature and altitude. Transmission and distribution circuits have rated capacities that describe the maximum amount of power that can be transported across them and vary inversely with ambient air temperature. Transformers and substations have rated capacities that describe the amount of power that can be moved through their transformation systems and switching equipment. Generally, the capacity of any portion of the grid declines as temperatures rise. In some systems, components are said to be "thermally limited," or limited by their physical capability to withstand the heat produced by the electric current. In other systems, notably in the Western Interconnection, the physical configuration of the system (long transmission lines and generation that is extremely remote from load centers) presents stability issues with respect to frequency, voltage and other parameters, in which case the capacity of the system is said to be "stability limited."
See Also: "Circuit."

Capacity Firming
The use of low-cost options including demand response, interruptibility, or emergency generators to supply capacity when other generating resources, including variable renewable energy resources, are not supplying energy to the grid. The fixed costs of firming resources are generally much smaller than the cost of additional dispatchable generation capacity.

Central Station/Central-Station Power Supply
A generating unit that is not located at or near customer load. The term is usually used to denote generators that require high-voltage transmission, often over long distances, to deliver power from the generator to the load centers.
See Also: "Customer-Sited Generation" and "Distributed Generation."

Circuit
Circuit generally refers to a wire that conducts electricity from one point to another. At the distribution level, multiple customers may be served by a single circuit that runs from a local substation or transformer to those customers. At the transmission level, the term "circuit" may also describe a pathway along which energy is transported or the number of conductors strung along that pathway.
See Also: "Distribution," "Substation," and "Transformer."

Class Peak Demand
The combined demand of all customers in a single rate class at the point in time when that demand is at its maximum, usually during a specific historical or forecast year, during a specific month or a specific hour of the day. Class peak demands do not necessarily — indeed, usually do not — coincide with the system peak demand. Residential classes tend to experience their daily peak demand in the late afternoon and early evening. Commercial customers tend to experience their daily peak demand in early to mid-afternoon. Industrial customers may experience their peak demand at virtually any hour of the day, depending upon their internal processes and their ability to manage multiple types of loads.
See Also: "Peak Demand," "System Peak Demand," "Coincident Peak Demand," and "Non-Coincident Peak Demand."

Classification
A step in an embedded cost of service study in which costs are separated into demand-related, energy-related, joint, and customer-related categories.

Cogeneration/Combined Heat and Power (CHP)
A method of producing power in conjunction with providing process heat to an industry, or space and/or water heat to buildings.

Coincident Peak Demand
The combined demand of a single customer or multiple customers at a specific point in time or circumstance, relative to the peak demand of the system, where system can refer to the aggregate load of single utility or of multiple utilities in a geographic zone or interconnection or some part thereof.
See Also: "Peak Demand," "System Peak Demand," "Class Peak Demand," and "Non-Coincident Peak Demand."

Community Aggregation
The bundling of multiple customers into a single purchasing block, usually at a municipal or other local governmental level, but potentially including local microgrid or residential or commercial development aggregations.

Competitive Retail Electricity Supplier (CRES)
In states where retail competition is allowed, the party contracting with the customer to provide electric or other services.

Congestion
A condition that occurs when insufficient transfer capacity is available to implement all the preferred schedules for electricity transmission simultaneously. Congestion prevents the economic dispatch of electric energy from power sources.

Connected Load Charge
A rate design in which customers pay a fixed charge based on the capacity of their service interconnection. The bigger the capacity of the interconnection, the greater the fixed charge. Connected load charges are a way of allocating and recovering the costs of, primarily, distribution system costs.

Connection Charge
An amount to be paid by a customer to the utility, in a lump sum or in installments, for connecting the customer's facilities to the supplier's facilities.

Conservation Voltage Reduction (CVR)
Using smart distribution grid sensors and controls to ensure that distribution voltages are maintained at a uniform level just above the minimum level required by electrical equipment. Sometimes called Conservation Voltage Regulation.

Cost Allocation
Division of a utility's cost of service among its customer classes. Cost allocation is an integral part of a utility's cost of service study.
See Also: "Cost of Service Study."

Cost of Capital
The costs a utility incurs borrowing money and, in the case of for-profit utilities, issuing equity to shareholders. Cost of capital includes the interest paid on debt and what is commonly thought of as the utility's profit. For purposes of regulation, the utility's profit is considered a cost because it represents the return on investment which shareholders demand to induce them to purchase the company's stock.
See Also: "Cost of Equity," "Cost of Debt," "Weighted Cost of Capital" and "Rate of Return."

Cost of Debt
The average interest rate on all debt issued by the utility, including bonds, notes, and other instruments. In some regulatory proceedings, this is separated into long-term debt (over 1 year to maturity) and short-term debt.

Cost of Equity
The rate of return necessary for a utility to attract equity capital, as determined by the regulator using one of several different methodologies.

Cost of Service Study (COSS)
A mathematical allocation of the utility's revenue requirement among customer classes, based on the number of customers, kilowatt-hours of consumption, and capacity requirements for each class. Some states use embedded cost studies looking at historical costs, while others use marginal cost studies looking at prospective costs. There are as many ways of doing cost of service studies as there are analysts performing these studies, and the assumptions made have a significant impact on the results calculated.
See also: "Embedded Cost" and "Marginal Cost."

Criteria Pollutant/Criteria Pollution Emission
The United States Environmental Protection Agency (EPA) is mainly concerned with emissions which are or could be harmful to people. EPA calls this set of principal air pollutants criteria pollutants. The criteria pollutants are carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). These are distinct from carbon dioxide (CO_2) pollution.

Critical Peak Pricing/Critical Period Pricing (CPP)
A rate design in which a limited number of hours or other periods of the year are declared by the utility, usually on a day-ahead basis, to be critical peak demand periods. when system reliability is at risk due to generation or transmission equipment failures, and during these times, prices charged to the customer will be extraordinarily high. The purpose of critical peak pricing is to reduce demand during the small number of hours of the year when generation costs are at their highest.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Peak Time Rebate," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Curtailment/Curtailment Service
A reduction in customer load in response to prices or when system reliability is threatened. Price-responsive curtailment is made possible through specific curtailment programs or when offered in competitive markets as a resource. Utilities typically have a curtailment plan that can be implemented if system reliability is threatened. Critical loads, such as hospitals, police stations and fire stations, may be given high priority and be last to be curtailed in an emergency, while non-critical loads, such as some industrial and commercial customers, may be the first to be curtailed. Many customers enter into specific contracts specifying their protection from or willingness to be curtailed. They may also have interruptible tariffs which, in return for price discount, allow the utility to curtail service on short notice.
See Also: "Curtailment Service Provider."

Curtailment Service Provider
A party that contracts with retail customers to procure the right to curtail their service under certain conditions (based on market prices or system reliability conditions), then sells that curtailment right to a utility as a service or offers it as a service in a competitive market, where it is treated as an energy resource. *See Also: "Curtailment/Curtailment Service."*

Customer Charge/Basic Charge/Service Charge
A fixed charge to customers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage.

Customer Choice
The ability of a customer to choose an energy supplier. Customer choice is available in a limited number of jurisdictions where retail competition is allowed. In most instances, the choice is limited to generation supply. The delivery of that supply to the customer is typically still provided by the local monopoly utility.

Customer Class
A collection of customers sharing common usage or interconnection characteristics. Common customer classes include residential (sometimes called household), small commercial, large commercial, small industrial, large industrial, agriculture (primary irrigation pumping), mining, and municipal lighting (streetlights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads (electric vehicle charging or solar photovoltaic generation customers may be placed in their own subclass), the capacity of their interconnection (e.g., the size of commercial or residential service panel) or the voltage at which they receive service.

Customer-Related Cost
Costs that vary directly with the number of customers. Customer-related costs include a portion of metering, billing, and customer service costs, but do not include distribution system, transmission, or generation costs.

Customer-Sited Generation
Generation located at a customer's site. Customer-sited generation includes residential solar photovoltaic, as well as backup generating units such as are common in hospitals, hotels, and critical government facilities. Customer-sited generation is a form of distributed generation. Most customer-sited generation is "behind the meter," meaning it operates on the customer's side of the utility's meter. But it may be interconnected to the grid, which requires it to operate synchronously with the electric system and makes it subject to certain operational and equipment requirements usually specified in an interconnection agreement or tariff. Output from customer-sited renewable generation is often accounted for under net energy metering tariffs.
See Also: "Distributed Generation" and "Net Energy Metering."

Declining Block Rate
A form of rate design in which blocks of energy usage have declining prices as the amount of usage increases. Declining block rates have largely fallen out of favor because they reward greater energy usage by the customer and do not properly reflect the increased costs associated with new resources needed to supply greater usage. They also undermine the economics of energy efficiency and renewable energy by reducing the savings a customer can achieve by reducing energy purchases from the utility.
See Also: "Flat Rate," "Inclining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate," and "Straight-Fixed/Variable Rate."

Decoupling
A form of revenue regulation in which the utility's nonvariable costs are recovered through a prescribed level of revenues, regardless of the sales volume experienced by the utility. Under traditional regulation, regulators determine a set of prices (customer charge, energy charge, demand charge, etc.) that remain constant between rate cases and are based on adjusted test year sales volumes, regardless of the actual sales volume experienced by the utility. As a result, actual revenues, and implicitly utility profits, will rise or fall from expected levels as sale volumes increase or decrease. Decoupling fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume in order to maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of a fixed inflator or on the basis of the number of customers served. The latter approach is known as "revenue-per-customer decoupling." Full decoupling also has the effect of weather-normalizing revenues — that is, the effects of abnormal weather are removed so as to assure recovery of the target revenues. Decoupling was developed as a way to eliminate utility management's incentive to increase profits by increasing sales and the converse incentive to undermine end-use energy efficiency and customer-sited generation, both of which reduce sales volume. Decoupling has typically been implemented in conjunction with regulator-required, utility-sponsored energy efficiency programs.
See Also: "Lost Revenue Adjustment Mechanism," "Revenue Regulation," and "Weather Normalization."

Default Rate/Default Service/Standard Service Offer (SSO)
The rate schedule a customer will pay if a different rate option is not affirmatively chosen in a competitive or restructured framework. When new rate designs are offered or experimental rates are implemented, it is typical for the utility to either use an opt-in or opt-out approach for determining what rate a customer will pay. In opt-in cases, the default rate is usually the same rate the customer would have paid before the new rate design was made available. In opt-out cases, the default rate is the rate associated with the new rate design. In the context of competitive markets and retail competition, the default rate is the rate the customer will pay if a competitive alternative is not affirmatively chosen by the customer.
See Also: "Opt-In," "Opt-Out," and "Default Service Customers."

Default Service Customers

Electricity consumers served by a competitive or restructured utility who do not affirmatively choose a power supplier. They are served with power procured by the distribution utility under rules established by the regulator.

Demand

In theory, an instantaneous measurement of the rate at which power or natural gas is being consumed by a single customer, customer class, or the entirety of an electric or gas system. Demand is expressed in kW or MW for electricity or therms for natural gas. Demand is the load-side counterpart to an electric system's capacity. In practical terms, electricity demand is actually measured as the average rate of energy consumption over a short period of time, usually 15 minutes or an hour. For example, a 1,000-watt hair dryer run for the entirety of a 15-minute demand interval would cause a demand meter using a 15-minute demand interval to record 1 kW of demand. If that same hair dryer were only run for seven and a half minutes, however, the measured demand would only be 0.5 kW. Metering of demand requires the use of either a demand meter or a smart meter.
See Also: "Capacity," "Interval Meter," and "Demand Charge."

Demand Charge

A charge paid on the basis of metered demand. Demand charges are usually expressed in dollars per watt units, for example kW (usually expressed as $/kW). Demand charges are common for large (and sometimes small) commercial and industrial customers, but have not typically been used for residential customers because of the high cost of demand meters. The widespread deployment of smart meters would enable the use demand charges for any customer served by those meters.
See Also: "Capacity," "Interval Meter," and "Demand."

Demand Meter

A meter capable of measuring and recording a customer's demand. Demand meters include conventional meters with separate demand registers, interval meters and smart meters.
See Also: "Demand," "Interval Meter," and "Smart Meter."

Demand Ratchet

A demand charge pricing scheme that charges for demand based on the highest metered demand over multiple billing cycles, usually one year. Demand ratchets have been justified on the theory that the system must be built to meet the maximum demand placed on it and a ratchet causes customers to pay for their own contribution to that demand based on their own maximum demand. Demand ratchets fail to capture the effects of time diversity and non-coincident of a customer's peak demand with the peak usage of any portion of the system. The increased temporal and geographic granularity of customer usage patterns made possible by smart meters obviates the need for demand ratchets and traditional demand charges.
See Also: "Demand Charge."

Demand-Related Cost

Costs which are associated primarily with the maximum demand placed on the system, as opposed to costs, such as fuel, which are driven primarily by total energy consumed. The term "demand-related cost" is an artifact of the era when utilities did not have precise data on the use of each customer or customer class at different hours of the day, and a time when all generation equipment had similar capital costs. This term was often applied to either all capital and operating costs of all generation, transmission, and shared distribution plant, or else to that portion determined necessary to meet peak demand. In an era where usage can be precisely measured by time period, and costs allocated accordingly, it is a somewhat anachronistic measurement.
See Also: "Energy-Related Cost."

Demand Response (DR)

Reduction in energy use in response to either system reliability concerns or increased prices (where wholesale markets are involved) or generation costs (in the case of vertically integrated utilities). Demand response must generally be measurable and controllable to participate in wholesale markets or be relied upon by system operators.

Demand-Response Program

A formalized system under which participating customers agree to reduce their consumption when called upon to do so. The agreement may be with their local utility (most likely under a formal tariff) or with a third-party curtailment service provider. The collective effect of the customers' reduction can be utilized by system operators to balance supply and demand or recognized by wholesale markets as an energy resource, paid at the prevailing market rate for energy at that point in time. Most demand-response programs limit the number of hours a given customer can be called upon to reduce usage. Participating customers are paid an incentive payment, in addition to the savings on their utility bill caused by their reduction in metered usage.

Distributed Energy Resources/ Demand-Side Resources (DER)

Any resource or activity at or near customer loads that generates energy or reduces energy consumption. Distributed energy resources include customer-sited generation, such as solar photovoltaic systems and emergency backup generators, as well as energy efficiency and controllable loads.

Distributed Generation (DG)

Any electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation, such as solar photovoltaic systems, but may include utility-owned generation placed within the distribution system.
See Also: "Customer-Sited Generation."

Distribution
The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Distribution System
The portion of the electric system used to distribute energy to customers. The distribution system is usually distinguished from the transmission system on the basis of voltage. After energy is received from a generator's bus bar, its voltage is stepped up to very high levels where it is transported by the transmission system. Transmission system components carry energy at voltages as high 758 kW or higher and as low as 115 kV or lower. Different utilities use different voltage levels as the demarcation between transmission and distribution. Urban utilities may use a lower voltage because their systems quickly transition from long-distance transmission facilities to local distribution needs, while more rural utilities may treat higher voltage facilities as distribution because of the need to "distribute" energy over longer distances. Because energy losses increase with each passage through a transformer and as voltages decrease, there is a general design bias toward keeping energy at higher voltage levels as long as possible along the route between generation and load. Industrial customers may take service at transmission level voltages, in which case it would be inappropriate to allocated distribution system costs to them.
See Also: "Generation" and "Transmission."

Duration Curve
A graphic plot depicting, on a cumulative basis, the different prices (price duration curve), demand levels (load duration curve) or resource utilization (resource utilitzation duration curve) over the course of a specific time period.

Dynamic Pricing
Dynamic pricing creates changing prices for electricity that reflect actual wholesale electric market conditions. Examples of dynamic pricing include critical period pricing and real-time rates.

Economic Dispatch
The utilization of existing generating resources to serve load as inexpensively as possible.

Embedded Cost
A cost that has already been incurred or is unavoidable in the future. Rate cases based upon historical test years often use embedded cost-of-service studies that allocate the actual recorded historical investments (net of accumulated depreciation) and actual operating expenses among customer classes.
See Also: "Cost of Service Study" and "Marginal Cost."

Energy
A unit of demand consumed over a period of time. Energy is expressed in watt-time units, where the time units are usually one hour, such as 1 kilowatt-hour (kWh), 1 megawatt-hour (MWh), etc. An appliance placing 1 kW of demand on the system for one hour will consume 1 kWh of energy.

Energy Charge
A price component based on energy consumed. Energy charges are typically expressed in dollars per watt-hours, such as $/kWh or $/MWh.
See Also: "Energy," "Demand," and "Demand Charge."

Energy Conservation
The use of any device or activity that attempts to reduce energy, especially during times of system peaks. Energy conservation is usually meant to denote behavioral changes or changes in patterns of use. For example, increasing thermostat settings in the summer or decreasing them in the winter is a form of conservation. Energy conservation may last only so long as the associated behavior or usage pattern remains in effect.
See Also: "Energy Efficiency."

Energy Efficiency
The deployment of end-use appliances that achieve the same or greater end-use value while reducing the energy required to achieve that result. Higher-efficiency boilers and air conditioners, increased building insulation, and higher-energy-rated windows are all examples of energy efficiency. Energy efficiency implies a semi-permanent, longer-term reduction in the use of energy by the customer.
See Also: "Energy Conservation."

Energy Time-Shift
A process by which purchasing inexpensive electric energy, available during periods when price is low, to charge the storage plant so that the stored energy can be used or sold at a later time when the price is high. Entities that time-shift may be regulated utilities or nonutility merchants.

Energy-Related Cost
Any cost categorized as an energy cost in a cost of service study. Energy-related costs always include costs such as fuel and purchased power and may include other costs as well. The widespread deployment of smart meters may result in elimination of other cost categories, such as demand, in favor or more sophisticated time-of-use energy rates designs that would allocate all non-customer-related costs to energy.
See Also: "Fuel Cost," "Purchased Power," "Demand-Related Cost," and "Customer-Related Cost."

Externalities
Costs or benefits that are side effects of economic activities and are not reflected in the booked costs of the utility. Environmental impacts are the principal externalities caused by utilities (e.g., health-care costs as a result of air pollution).

Fixed Charge
Any fee or charge that does not vary consumption. Customer charges are a typical type of fixed charge. In some jurisdiction, customer are charged a connected load charge based on the size of their service panel or total expected maximum load. Minimum bills and straight/fixed variable rates are additional forms of fixed

charges.
See Also: "Minimum Bill," "Straight-Fixed/Variable Rate" and "Customer Charge."

Fixed Cost

An accounting term meant to denote costs that do not vary within a certain period of time, usually one year. This term is often misapplied to denote costs associated with plant and equipment (which are themselves denoted "fixed assets" in accounting terms) or other utility costs that cannot be changed in the short run. From a regulatory and economics perspective, the concept of fixed costs is irrelevant. For purposes of regulation, all utility costs are variable in the long run. The costs associated with seemingly fixed assets, such as the distribution system, are not fixed even in the short run. Utilities are constantly upgrading and replacing distribution facilities throughout their system as more customers are served and customer usage increases, and efforts to reduce demand can have immediate impacts on those costs.

Flat Rate

A rate design with a uniform price per kWh for all levels of consumption. A rate design that charges a single price for all consumption, typically used to denote that form of energy rate pricing.
See Also: "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate," and "Straight-Fixed/Variable Rate."

Frequency

The cycles per second of an alternating current electric system. In most of North America, the electric system operates at a nominal 60 cycles per second (expressed in "hertz" as 60 Hz), while most of the rest of the world operates at 50 Hz. All of the generators connected to a single interconnection are required to synchronize the cycles of their own equipment to that of the entire system. From a system operator's point of view, loads must be constantly and near-instantaneously matched to generation output in order to maintain system frequency within a narrow allowed band (e.g., 59.9 to 60.1 Hz). When the frequency exceeds allowed limits, many generators and loads are designed to automatically disconnect from the grid, which may cause serious disruptions to service, including brownouts and blackouts.

Fuel Cost

The cost of fuel, typically burned, used to create electricity. Fuel types include nuclear, coal, natural gas, diesel, biomass, bagasse, wood, and fuel oil. Some generators, such as wind turbines and solar photovoltaic and solar thermal generators, use no fuel or, in the case of hydroelectric generation, virtually cost-free fuel.

Future Test Year/Projected Test Year

A regulatory accounting period that estimates the rate base and operating expenses a utility will incur to provide service in a future year, typically the first full year during which rates determined in that rate case will be in effect.
See Also: "Adjusted Test Year" and "Historical Test Year."

Generation

Any equipment or device that supplies energy to the electric system. Generation is often classified by fuel source (i.e., nuclear, coal, gas, solar, etc.) or by operational or economic characteristics ("must-run," baseload, intermediate, peaking, intermittment, load following, etc.).

Green Power

An offering of environmentally preferred power by a utility to its consumers, typically at a premium above the regular rate.

Grid

The electric system as a whole or as a reference to the non-generation portion of the system.

Grid Integration

The management of the variable power flows from generating units, maintaining power quality, and managing voltage and frequency stability. Variable renewable resources create different challenges for grid integration than conventional generating units, including minute-to-minute variations in output, periods of large wind generation shortfall, and power quality issues created by wind gusts.

Historical Test Year

A regulatory accounting period that measures the actual costs that a utility incurred to provide service in a 12-month period, typically adjusted for known and measurable changes that have occurred or are expected to occur afterward.
See Also: "Adjusted Test Year" and "Historical Test Year."

IEEE 1547

A industry standard governing the engineering and performance criteria for interconnection of customer-sited generation to the electric system. When a proposed interconnection meets certain criteria, it is usually allowed to proceed without any further review or approval of the utility, except for the execution of a required interconnection agreement. This is the case unless the interconnection would cause the total capacity of customer-sited generation on local parts of the distribution system to exceed certain threshold or would be expected to create a situation-specific safety or reliability hazard to the system or the public. Generally, under the terms of the original IEEE 1547, a customer-sited generator would be required to automatically disconnect from the system and the customer's load in the event the grid fails or becomes unstable. An updated version, IEEE 1547.8, is currently being drafted for "smart inverters" to enable smart grid functions that allow system operators to communicate with the inverter, dispatch it for certain ancillary services, and allow the PV unit to continue to serve the customer's load in the event the grid becomes unstable or unavailable.
See Also: "Distributed Generation."

Incentive Regulation/Performance-Based Regulation (PBR)
A form of regulation in which the utility is given specific performance targets or benchmarks to achieve and is rewarded financially for meeting or exceeding them and, optionally, penalized for failing to meet them. In a sense, all regulation is incentive regulation, but, as a term of art, this refers specifically to the formal system of establishing rewards and penalties for specific performance criteria such as cost controls, reliability and customer service.
See Also: "Decoupling" and "Revenue Regulation."

Inclining Block Rate
A form of rate design in which blocks of energy usage have increasing prices as the amount of usage increases. Inclining block rates appropriately, if crudely, reflect the fact that increased costs are associated with greater usage. They enhance the economics of energy efficiency and renewable energy by increasing the savings a customer can achieve by reducing energy purchases from the utility.
See Also: "Flat Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Incremental Cost
A cost of study method based on the short-run cost of augmenting an existing system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deploying the next unit of capacity in the form of generation, transmission or distribution.

Independent Power Plant (IPP)/Merchant Power Plant
A power plant that operates in a competitive market and is not directly included in the rates of a regulated utility or subject to general utility regulation.

Integrated Resource Planning (IRP)
A public planning process and framework within which the costs and benefits of both demand and supply-side resources are evaluated to develop the least total-cost mix of utility resource options. Also known as least-cost planning.

Interconnection Agreement
A contract between a utility and a customer governing the connection and operation of customer-sited generation which is operated synchronously with the electric system.
See Also: "Distributed Generation," "Net Energy Metering" and "IEEE 1547."

Interval Meter
A meter capable of measuring and recording a customer's usage over a defined period of time.

Intervenor
An individual, group, or institution that is officially involved in a rate case.

Kilowatt (kW)
A kilowatt is equal to 1,000 watts.
See Also: "Watt."

Kilowatt-hour (kWh)
A kilowatt-hour is equal to 1,000 watt-hours.
See Also: "Watt-hour."

Line Transformer
A transformer directly providing service to a customer, either on a dedicated basis or among a small number of customers.

Load
The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system, or in a more specific sense to denote the customer demand at a specific point in time.

Load Following
The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as the load following resources at any given point in time. Baseload and intermediate generation is generally excluded from this category except in extraordinary circumstances.

Load Management
Active control of customer usage levels for the purpose of avoiding the use of high-cost supply resources or in response to system reliability needs.

Long-Run Marginal Costs
The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Losses/Energy Losses/Technical Losses/ Non-Technical Losses
The energy (kWh) and power (kW) lost or unaccounted for in the operation of an electric system. Losses are usually in the form of energy lost to heat, sometimes referred to as "technical losses"; however, energy theft from illegal connections or tampered meters, sometimes referred to as "non-technical losses," will also contribute to losses.
See Also: "Energy" and "Lost Revenue Adjustment Mechanism."

Lost Revenue Adjustment Mechanism (LRAM)
A mechanism by which a regulator allows a utility to recovery the sales margins that are lost when customers participate in utility-sponsored energy efficiency or renewable energy programs.
See Also "Decoupling."

Marginal Cost
The long-run costs of the next unit of electricity producted, including the cost of a new power plant, additional transmission and distribution, reserves, marginal line losses, and administrative and environmental costs. Long-run marginal costs should look at the cost of building a new utility system, not just the costs of augmenting output from an existing system. Also called long-run incremental costs (LRIC) or total system long-run incremental costs (TSLRIC).

Megawatt (MW)
A megawatt is equal to one million watts or 1,000 kilowatts.
See Also: "Watt."

Megawatt-Hour (MWh)
A megawatt-hour is equal to one million watt-hours or 1,000 kilowatt-hours.
See Also: "Watt-hour."

Meter Data Management System (MDMS)
A computer and control system which gathers metering information from smart meters, makes it available to the utility and, optionally, to the customer. A meter data management system is part of the suite of smart technologies and is integral to the smart grid concept.
See Also: "Smart Grid" and "Smart Meter."

Microgrid
A localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate.

Minimum Bill
A rate design that charges a minimum amount of money in return for a designated amount of energy, which must be paid even if they customer's actual usage is less that amount of energy.

Minimum Charge
A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Municipal Utility (Muni)
A utility owned by a unit of government, and operated under the control of a publicly elected body. About 15% of Americans are served by munis.

Net Energy Metering (NEM)/Net Metering
A rate design which allows a customer with distributed generation, typically solar photovoltaic systems, to receive a bill credit at the full retail rate for all energy injected into the electric system.

Non-Coincident Demand (NCD)/Non-Coincident Peak Load
A customer's maximum energy demand during a billing period or a year, even if it is different from the time of the system peak demand.
See Also: "Coincident Peak" and "System Peak."

Off-Peak
The period of time that is not on-peak. During off-peak periods, system costs are generally lower and system reliability is not an issue. Time-of-use rates typically have off-peak prices which are lower than on-peak prices.
See Also: "On-Peak."

On-Peak
The period of time when customer demand is higher than normal. During on-peak periods, system costs are higher than average and reliability issues may be present. Many rate designs and utility "programs" are oriented to reducing on-peak usage. Planning and investment decisions are often driven by expectations about the timing and magnitude peak demands during on-peak period. Time-of-use rates typically have on-peak prices that are higher than off-peak prices.
See Also: "Off-Peak."

Opt-In
A way of determining whether customers will be placed on an alternative or new rate schedule. In an opt-in approach, customers will only be placed on the rate schedule if they actively choose that option. The opt-in approach assures that customers are not placed on a rate schedule without their express permission, but will typically result in fewer customers taking the new rate.
See Also: "Opt-Out."

Opt-Out
A way of determining whether customers will be placed on an alternative or new rate schedule. In an opt-out approach, customers will automatically be placed on the rate schedule unless they actively to choose to stay on their existing rate schedule. The opt-out approach results in a participation rate on the new rate schedule, but risks placing customers on a rate without their knowledge and consent.
See Also: "Opt-In."

Payback Period
The amount of time required for the net revenues of an investment to return its costs. This metric is often employed as a simple tool for evaluating energy efficiency measures.

Peak Demand
The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, all of the customers in a class, or all of a utility's customers during a specific period of time — hour, day, month, season or year.

Peak Load
The maximum total demand on a utility system during a period of time.

Peaking Resource/Peaking Generation/Peaker
Generation that is used to serve load during periods of high demand. Peaking generation typically has high fuel costs or limited availability (e.g., pumped storage hydro generation), but often has low capital costs. Peaking generation is used a limited number of hours, especially as compared baseload generation. Peaking resources may connote non-generation resources such as storage or demand-side resources.
See Also: "Baseload Generation."

Peak-Time Rebate (PTR)
A rate design which provides a bill credit to a customer who reduces usage below a baseline level during a period of high peak demand or when system reliability may be at risk. Peak-time rebates are an alternative to critical peak pricing rate designs.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Photovoltaic (PV) Systems
An electric generating system utilitzing photovoltaic cells to generate electricity from sunlight. PV systems may be either used in off-grid, stand-alone applications, or operated synchronously with the electric system by interconnecting through a power inverter which converts their output to system quality, AC power, which is synchronized with the AC cycles of the electric system. In the United States, synchronous operation requires the use of an inverter that meets the standards of IEEE 1547, in addition to possible additional requirements of the local utility.

Power Factor
The fraction of power actually used by a customer's electrical equipment compared with the total apparent power supplied, usually expressed as a percentage. A power factor indicates the extent to which a customer's electrical equipment causes the electric current delivered at the customer's site to be out of phase with system voltage.

Power Quality
Technical metrics applied to the voltage stability, frequency, waveform, and other details of electricity supply. These include power factor (reactive power), harmonic distortion, and other factors that affect the performance of electrical and electronic equipment connected to the grid.

Price Cap
The highest price allowed in the wholesale market and is a price mitigation tool. An "offer cap" is the highest price that a resource, including DR, can offer to the wholesale market. "DR" means the demand response treatment in the market.

Prudence Review
The process by which a regulator determines the prudence of utility resource decisions. If a cost is found imprudent, it may be disallowed from rates. While retrospective, prudence reviews are typically determined on the basis of the information available to decision-makers at the time the decision was made.

Purchased Power Cost
The cost incurred by a utility to purchase energy from another entity. Purchased power costs are usually collected through a utility's fuel and purchased power adjustment clause and typically have no markup or profit-adder for the utility. Power may be purchased in organized markets at the market clearing price or through bilateral contracts, which may specify resource, prices, timing and other terms and have reservation or demand charges in addition to energy charges.

Rate Base
The appropriate value for ratemaking purposes of the utility's investment in utility plant and other assets, including working capital, that is "used and useful" in providing service to the public.
See Also: "Used and Useful."

Rate Case
A proceeding, usually before a regulatory commission, involving the rates and policies of a public utility.

Rate Design
Specification of prices for each component of a rate schedule for each class of customers, which are calculated to produce the revenue requirement allocated to the class. In simple terms, prices are equal to revenues divided by billing units, based on historical or assumed usage levels. Total costs are allocated across the different price components such as customer charges, energy charges, demand charges and each price component is then set at the level required to generate sufficient revenues to cover those costs.

Rate of Return
A percentage value which is multiplied by rate base to determine a portion of the revenue requirement. The rate of return is equal to the utility's weighted cost of capital.
See Also: "Cost of Capital," "Cost of Equity," "Cost of Debt," and "Weighted Cost of Capital."

Reactive Power
In an energized electric system, a portion of the energy injected into the system is initially diverted into magnetic fields. In a perfectly designed and operated system, this is a one-time injection of energy and all additional energy injected into the system is delivered to end-use appliances or lost as heat. When the system is de-energized, the energy use to create the magnetic field is recovered. In reality, some end-use appliances, typically motors as they commence operation, can draw some of their energy requirements from the magnetic field, rather than from the

intended flow of energy, causing the customer's load to become out of phase with the system. Additional energy must then be injected into the system to maintain the magnetic field. This energy is termed reactive power. Customers whose equipment draws reactive power from the system are typically charged a power factor adjustment to account for this phenomenon.
See Also: "Power Factor."

Real-Time Pricing (RTP)/Dynamic Pricing
Establishing rates that adjust as frequently as hourly, based on wholesale electricity costs or actual generation costs.

Reliability
A measure of the ability of the electric system to provide continuous service to customers over time. Reliability is often measure in terms of "loss of load probability" (LOLP). The US-Canadian-Mexican interconnections generally experience extremely high reliability. Reliability standards are set and maintained by the North American Electric Reliability Corporation and its regional counterparts, as well as by RTOs/ISOs and electric utilities. Compliance with reliability standards is compulsory.

Renewable Energy Certificate (REC)/ Renewable Energy Credit/ Green Certificate/Green Tag/ Tradable Renewable Certificate
Documentation of energy produced by a renewable energy resource. RECs can be severed from the energy produced and separately traded. Utilities that must comply with a renewable portfolio standard usually are required to document their compliance by possessing RECs, through their own generation or by purchasing RECs from third-parties, to document the production of energy from renewable resources.
See Also: "Renewable Resources" and "Renewable Portfolio Standard."

Renewable Portfolio Standard (RPS)
A regulatory requirement that utilities meet a specified percentage of their power supply using qualified renewable resources.
See Also: "Renewable Resources" and "Renewable Energy Certificate."

Renewable Resources
Power generating facilities that use wind, solar, hydro, biomass, or other non-depleting fuel sources. In some states, qualified renewable resources exclude large hydro stations or some other types of generation.

Reserve Account
An allowed accumulation of revenues in excess of regularly occurring costs of service that may be drawn down in the event the utilities revenues are less than expected or its expenses are greater than expected.

Reserve Capacity/Reserve Margin/Reserves
The amount of capacity that a system must be able to supply, beyond what is required to meet demand, in order to assure reliability when one or more generating units or transmission lines are out of service. Traditionally, a reserve capacity of 15–20 percent was thought to be needed for good reliability. In recent years, the accepted value in some areas has declined to 10 percent or even lower.

Reserves Shortage Pricing
Pricing and penalties that are invoked by a system operator in cases of reduced power reserves to ensure sufficient generation is available when needed.

Restructured State/Restructured Market
Replacement of the traditional vertically integrated electric utility with some form of competitive market. In some cases, the generation and transmission components of service are purchased by the customer-serving distribution utility in a wholesale competitive market. In other cases, retail customers are allowed to choose their generation suppliers directly in a competitive market.
See Also: "Retail Choice."

Retail Choice/Retail Competition
A restructured market in which customers are allowed or must choose their own competitive supplier of generation and transmission services. In most states with retail choice, the incumbent utility or some other identified entity is designated as a default service provider for customers who, through inaction, do not choose another supplier. In Texas, there is no default service provider and all customers must make a choice.

Return on Equity
The profit rate allowed to the shareholders of an investor-owned utility, expressed as a percentage of the equity capital invested.

Revenue per Customer/Revenue per Customer Adjustment (RPC)
A form of revenue decoupling. RPC allows the target revenue for revenue decoupling to be adjusted based on the number of customers being served. In it's usual application, at the end of a rate case the allowed revenue to be collected from each billing component (i.e., customer charge, energy charge, demand charge, etc.) is divided by the adjusted test year billing units to derive an RPC value. In subsequent periods, the allowed revenue is recomputed by multiplying the actual number of customers being served by the RPC values for each rate component. That revenue value is then divided by the actual billing units for that period to derive the new price to be charged customers.
See Also: "Decoupling" and "Adjusted Test Year."

Revenue Regulation
A regulator approach which allows a utility to collect a target revenue level, regardless of its sales volume. The target revenue may be fixed between rate cases or may be allowed to change formulaically between rate cases.
See Also: "Decoupling" and "Lost Revenue Adjustment Mechanism."

Revenue Requirement
The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.

Seasonal Rate
A rate that is higher during the peak-usage months of the year. Seasonal rates are intended to reflect differences in the underlying costs of providing service associated with different times of the year.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak Time Rebate" and "Straight-Fixed/Variable Rate."

Service Drop
A transformer, conductor, pole, or underground facilities connecting a single customer to the electric system.

Smart Appliance
An appliance which is capable of communicating with a customer- or utility-owned data acquisition and control system.
See Also: "Smart Grid," "Smart Meter," and "Smart Technology."

Smart Grid
An integrated network of sophisticated meters, computer controls, information exchange, automation, and information processing, data management, and pricing options that can create opportunities for improved reliability, increased consumer control over energy costs, and more efficient utilization of utility generation and transmission resources.
See Also: "Smart Appliance," "Smart Meter," and "Smart Technology."

Smart Meter
An electric meter with electronics that enable recording of customer usage in short time intervals and two-way communication of data between the utility and the meter (and, optionally, the customer).
See Also: "Smart Appliance," "Smart Grid," and "Smart Technology."

Smart Technology
The collection of smart meters, smart appliances, system control and data acquisition systems and meter data management systems, which together enable utilities, system operators and customer to monitor current conditions and control one or more portions of the electric grid and connected appliances to optimize costs and reliability.
See Also: "Smart Appliance," "Smart Grid," and "Smart Meter."

Spinning Reserve
Any energy resource which can be called upon within a designated period of time which system operators may use to balance loads and resources. Spinning reserves may be in the form of generators, energy storage or demand response. Spinning reserves may be designated by how quickly they can be made available, from instantaneously up to some short period of time.

Standby Service
Support service that is available, as needed, to supplement supply for a consumer, a utility system, or another utility if normally scheduled power becomes unavailable. The unavailable source may be a third party provider or a customer-owned generator.

Straight-Fixed/Variable Rate (SFV)
A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," and "Peak-Time Rebate."

Substation
A facility with a transformer that steps voltage down from a portion of the system which transports energy in greater bulk and to which one or more circuits or customers may be connected.

Supervisory Control and Data Acquisition (SCADA)
A collection of sensors, meters, communications equipment and computers that monitors the status of any portion of the electric system, reports that status to system operators, utilities, and optionally, customers and provides for control of system equipment and, optionally, end-use appliances to optimize costs and reliability.

System Peak Demand
The maximum demand placed on the electric system at a single point in time. System peak demand may be measure for an entire interconnection, for sub-regions within an interconnection or for individual utilities or service areas.

Tariff
A listing of the rates, charges, and other terms of service for a utility customer class, as approved by the regulator.

Therm
A unit of natural gas equal to 100,000 Btu. The quantity is approximately 100 cubic feet, depending on the exact chemical composition of the natural gas.

Time-of-Use Rate/Time-Differentiated Rate (TOU)
Rates that vary by time of day and day of the week. TOU rates are intended to reflect differences underlying costs incurred to provide service at different times of the day or week.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Tracker
A rate schedule provision giving the utility company the ability to change its rates at different points in time, to recognize changes in specific costs of service items without the usual suspension period of a rate filing.
See Also: "Adjustment Clause."

Transformer
A device that raises ("steps up") or lowers ("steps down") the voltage in an electric system. Electricity coming out a generator is often stepped up to very high voltages (345 kW or higher) for injection into the transmission system and then repeatedly stepped down to lower voltages as the distribution system fans out to connect to end-use customers. Some energy loss occurs with every voltage change. Generally, higher voltages can transport energy for longer distances with fewer energy losses.

Transmission Voltage
Voltage levels used to in the transmission system for transport of power to substations. Transmission voltages are generally above 50kV.
See Also: "Transmission."

Transmission/Transmission System
That portion of the electric system designed to carry energy in bulk. The transmission system is operated at the highest voltage of any portion of the system. It usually designed to either connect remote generation to local distribution facilities or to interconnect two or more utility's systems to facilitate exchanges of energy between systems.
See Also: "Distribution" and "Generation."

Unit Cost
The costs allocated to a specific function, such as demand or energy, divided by the billing units for function (billed demand or billed energy). The result is expressed in dollars per unit, as in $/kW or $/kWh.

Used and Useful
A regulatory concept — often triggered when plant is first placed in service, but applicable throughout the life of the plant — for determining whether utility plant is eligible for inclusion in a utility's rate base. While different state courts have interpreted the concept differently, utility plant is generally considered "used" if it is actually used or is available for use in providing service to the public. This includes reserve inventories available to replace failed equipment or for upgrades and expansions anticipated in the near future, as well reasonable levels of generation "reserves" in excess of that needed to serve the utility's anticipated peak load. Utility plant is generally considered "useful" if it is the appropriate kind of plant to be used in providing service and is available at a reasonable cost. To be included in a utility's rate base or expenses, plant must satisfied both of these conditions. For example, a combined-cycle gas turbine might be both used and useful, while a highly inefficient oil-fired plant that cannot meet emissions requirements would not, even though they might both be actually used to generate electricity during a rate case test year. Alternatively, that same combined-cycle plant might be useful, but unused because the utility has sufficient other resources to provide service.

Value of Solar Tariff (VOST)
A tariff that pays for the injection of solar generated power into the electric system at a price based on its value. The valuation of solar is usually based on some or all of the following: avoided energy costs, avoided capital costs, avoided O&M expenses, avoided system losses, avoided spinning and other reserves, avoided social costs, any other avoided costs, less any increased costs incurred on account of the presence of solar resources, such as backup resources, spinning reserves, transmission or distribution system upgrades or other identifiable costs. A VOST is an alternative to net energy metering and non-value-based feed-in tariffs.
See Also: "Net Energy Metering" and "Feed-In Tariff."

Vehicle-to-Grid (V2G)
The process of treating elecric vehicles as a distributed resource for the electric grid and allowing system operators to withdraw power from them or store energy in them or later use, with the constraint that they will be adequately charged for use when needed by the EV driver.

Volt
A unit of measurement of electromotive force. Typical transmission level voltages are 115 kV, 230 kV and 500 kV. Typical distribution voltages are 4 kV, 13 kV, and 34 kV.

Voltage Support
An ancillary service in which the provider's equipment is used to maintain system voltage within a specified range.
See Also: "Ancillary Service."

Watt
The electric unit used to measure power, capacity or demand. Equivalent to one joule per second and equal to the power in a circuit in which a current of one ampere flows across a potential difference of one volt. One kilowatt = 1,000 watts. One megawatt = one million watts or 1,000 kilowatts.

Watt-Hour
The amount energy generated or consumed with one watt of power over the course of one hour. One kWh equals 1,000 watts consumed or delivered for one hour. One MWh equals one million watts consumed or delivered for one hour. The W is capitalized in the acronym in recognition of electrical pioneer James Watt.

Weather Normalization
An adjustment made to test year sales to remove the effects of abnormal weather. Because many end uses, especially air conditioning and heating, vary with temperature, there is a direct correlation between weather conditions and energy sales. The

objective in weather normalization is characterize the sales a utility would have is the weather experienced during a specific period had been the same as the average weather over some sufficiently long period of time, usually 20 to 30 years.
See Also: "Adjustment Clause" and "Decoupling."

Weatherization
A process or program for increasing a building's thermal efficiency. Examples include caulking windows, weather stripping, and adding insulation to the wall, ceilings, and floors.

Weighted Cost of Capital
A composite cost rate that reflects the cost of debt and cost of equity in proportion to their respective share of the utility's capital structure. The weighted cost of capital is sometimes expressed in after-tax terms, so that income taxes on the cost of equity and tax savings on the cost of debt are accounted for. The weighted cost of capital is the rate of return normally applied to rate base in the computation of a utility's revenue requirement.
See Also: "Cost of Capital," "Cost of Equity," "Cost of Debt," "Capital Structure" and "Rate of Return."

Related Resources

Electricity Regulation in the United States: A Guide

http://www.raponline.org/document/download/id/645

This 120-page guide offers a broad look at utility regulation in the US. Its intended audience includes anyone involved in the regulatory process, from regulators to industry to advocates and consumers. The chapters briefly touch on most topics that affect utility regulation, but do not go into depth on each topic as the discussion is intended to be short and understandable. A lengthy glossary appears at the end of this guide to explain utility sector terms.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

http://www.raponline.org/document/download/id/6516

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run costs associated with production and usage. While new technology is enabling innovations in rate design that carry some promise of better capturing opportunities for more responsive load, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change.

Time-Varying and Dynamic Rate Design

http://www.raponline.org/document/download/id/5131

This report discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.

Designing Distributed Generation Tariffs Well

http://www.raponline.org/document/download/id/6898

Improvements in distributed generation economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in distributed generation adoption in the United States. Regulators are looking for the well-designed tariff that compensates distributed generation adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive. This paper offers regulatory options for dealing with distributed generation. The authors outline current tariffs and ponder what regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole. The paper highlights the importance of deciding upon a valuation methodology so that the presence or absence of cross-subsidies can be determined. Finally, the paper offers rate design and ratemaking options for regulators to consider, and includes recommendations for fairly implementing tariffs and ratemaking treatments to promote the public interest and ensure fair compensation.

Revenue Regulation and Decoupling: A Guide to Theory and Application

http://www.raponline.org/document/download/id/902

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as decoupling and the policy issues associated with its use. This would include public utility commissioners and staff, utility management, advocates and others with a stake in the regulated energy system. While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide includes a detailed case study that demonstrates the impacts of decoupling using different pricing structures (rate designs) and usage patterns.

Decoupling Case Studies: Revenue Regulation Implementation in Six States

http://www.raponline.org/document/download/id/7209

This paper examines revenue regulation, popularly known as decoupling, and the various elements of revenue regulation that can be assembled in numerous ways based on state priorities and preferences to eliminate the throughput incentive. This publication focuses on six utilities: Pacific Gas and Electric Company, Idaho Power Company, Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid-Massachusetts, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented. These examples examine the details of revenue regulation and provide a range of options on how to implement revenue regulation. These specific utilities were chosen in order to represent a range of mechanisms used throughout the US and to contrast differences to provide a broader overview of the options available in designing decoupling mechanisms and to describe how they have worked to assist state regulators and utilities considering implementing revenue regulation.

Charging for Distribution Utility Services: Issues in Rate Design

http://www.raponline.org/document/download/id/412

In this report, we evaluate rate structures for electric distribution services, including embedded and marginal cost valuation methods, approaches and principles of rate design, and interactions with competitive markets.

Pricing Do's and Don'ts: Designing Retail Rates as if Efficiency Counts

http://www.raponline.org/document/download/id/939

Rate design is a crucial element of an overall regulatory strategy that fosters energy efficiency and sends appropriate signals about efficient system investment and operations. Rate design is also fully under the control of state regulators. Progressive rate design elements can guide consumers to participate in energy efficiency programs and reduce peak demand, yet relatively few utilities and commissions have implemented many of these elements. This RAP paper identifies some best practices. Because pricing issues tie closely to utility growth incentives, we also address revenue decoupling.

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