DRAFT FOR PUBLIC COMMENT

Smart Rate Design for Distributed Energy Resources

Regulatory Assistance Project for the Michigan Public Service Commission

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1. Introduction

The electricity system is evolving rapidly across the United States. Across many different dimensions, modern technology and data are expanding the capabilities of utilities, customers, and other participants in the energy system. These capabilities allow for new opportunities to lower system costs and new pathways to cost-effectively achieve policy goals, such as economic development, equity, resilience, and emissions reductions. In particular, the cost of distributed energy resources (DER), such as clean distributed generation, battery storage, and energy management technologies, have declined substantially over the past two decades and many jurisdictions have seen rapid development of DER technologies at customer sites, such as solar photovoltaic (solar PV) systems.

In order to harness these capabilities, regulatory structures have to keep up, including cost allocation and rate design. Many regulatory methods from the last century were choices of convenience because of limitations that may no longer hold, and even many best practices from the 20th century were based on assumptions about the electricity system that are no longer true. That includes the traditional methods for embedded cost allocation, such as spreading demand-related costs over a very small number of system peak hours. Furthermore, these demand-related costs are then typically converted into simple individual non-coincident peak (NCP) demand charges for many commercial and industrial (C&I) customers and simple volumetric kWh rates for residential customers. In both cases, the pricing mechanism disregards the underlying proposition that those costs are driven by shared system peaks and would be better reflected in time-differentiated pricing.[1] Historically, attempts to develop more sophisticated methods to allocate demand-related costs were limited by data availability and time-differentiated pricing required metering that was either unavailable or expensive. Neither of these limitations hold any longer.

Net metering, a simple rate design and associated billing mechanism for distributed generation, often primarily solar PV, has existed in some jurisdictions since the early 1980s. Net metering, as the term can be used generally, offers a simple metering and billing mechanism for distribution generation compensation that is understandable for customers and easily implementable for utilities. As long as the number of customers adopting net energy metering was small, the issues presented to utilities and other customers were necessarily small as well. However, as penetration rates grew, issues around fair pricing and cost allocation, as well as system design and operation, began to spring up in the jurisdictions with the highest levels of distributed solar PV adoption.[2] Furthermore, jurisdictions with high penetrations of any one resource type can face declining marginal benefits for that resource.[3] While some of these issues can addressed with

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[1] More generally, the rate design that best matches cost causation will not always precisely match the relevant cost allocator because of data, metering, and billing limitations.

[2] At the end of 2020, Michigan ranked 32nd out of 50 states in megawatts of distributed solar PV at 98.9 MW. https://www.eia.gov/electricity/data/eia861m/ (reported Michigan data for "net metering" projects includes the DG program).

[3] For example, while solar PV can help enormously with system constraints in the early afternoon, its value is much more limited in the evening. Relatively high levels of solar PV have in fact pushed net system peaks from afternoon times to the evening in Hawaii and California. For generation resource adequacy purposes, this effect is the same whether the solar PV is interconnected at the transmission or distribution level. However, with more balanced resource development, this may not occur and, in the long term, this could also be counteracted by new sources of load.

improved planning, evolving the compensation mechanisms for distributed energy resources, including net metering, is an important piece of the puzzle.[4]

In Michigan, net metering for distributed generation has already evolved into the inflow/outflow model as a part of the distributed generation program, first established in 2018 in Case No. U-18383 and then implemented in subsequent rate cases. While the inflow/outflow model has its virtues, including removing most reasonable arguments about significant cost shifting from participating DER customers to non-participating customers, further rate design reforms for DERs are almost certainly needed so that they can fulfill their promise as a key part of the grid of the future. Michigan has the advantage of having two major investor-owned electric utilities with advanced metering infrastructure for all residential and small commercial customers, which enables a wide range of potential reforms.

In October 2019, the Michigan Public Service Commission (MPSC) established the MI Power Grid Initiative, in conjunction with the office of Governor Gretchen Whitmer, seeking to help integrate new clean energy technologies and optimize grid investments for reliable, affordable electricity service.[5] MI Power Grid has proceeded on three tracks: (1) customer engagement, including innovative rate offerings, (2) integrating emerging technologies, and (3) optimizing grid investments and performance. On September 29, 2020, the Michigan Senate adopted Senate Resolution 142 "to encourage the Michigan Public Service Commission to undertake a study into alternative and innovative rate design options for Michigan's electric customers."[6] Senate Resolution 142 also specifies a list of rate design options to consider in this study, all of which are discussed further below.[7]

In the December 2020 order in the Consumers Energy rate case, the MPSC opined generally on the need to examine a more comprehensive set of rate design options for distributed energy resources.[8] In an order on February 4, 2021, the MPSC explained this background, created the Distributed Energy Resources Rate Design working group under the MI Power Grid Initiative, and described the process for this report.[9] A stakeholder meeting was held on March 9th, 2021 and outline for this report was issued on April 6th, 2021.[10]

Further reforms to rate design for distributed energy resources in Michigan will inevitably involve complex and sensitive tradeoffs, where no one solution will be optimal with respect to each and every ratemaking principle and policy goal. The highest-level principles of ratemaking,

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[4] Numerous reports on reforms to net metering and distributed generation compensation have been published in the last decade. Notable examples include *NARUC Manual on Distributed Energy Resource Rate Design and Compensation* (2016), Staff Subcommittee on Rate Design (https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0); and *Review of State Net Energy Metering and Successor Rate Designs* (2019), Stanton, Tom, National Regulatory Research Institute (https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B/).

[5] See generally https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93593---,00.html

[6] http://www.legislature.mi.gov/documents/2019-2020/resolutionadopted/Senate/pdf/2020-SAR-0142.pdf

[7] The non-exclusive list in Senate Resolution 142 includes customer charges, fixed system access charges, demand charges, standby charges and time of use rates.

[8] P. 324, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000HwkkyAAB

[9] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000J8TH5AAN

[10] Feedback on a draft outline and presentations from stakeholders were part of the March 9th stakeholder meeting. In addition, written comments on the draft outline were submitted by DTE Electric, Consumers Energy, Tom Stanton, and Alain Godeau.

including effective recovery of the revenue requirement, customer understanding, equitable cost allocation, and efficient pricing, and broader policy goals of utility regulation, including competition, societal equity, economic benefits and environmental protection, are informative, but do not provide specific answers to our modern issues with DER rate design. When we are trying to understand this complex area of policy, there are important linkages between concepts that are sometimes discussed separately: (1) electric system cost causation and efficient marginal cost pricing, (2) benefit-cost tests and (3) cost allocation frameworks. Many of these concepts involve two more fundamental questions: (1) what is a given resource worth? and (2) how are electric system costs fairly split among all electricity customers? Understanding these relationships in detail should help to illuminate stakeholders' concerns with existing rate structures and to chart a productive path to the future.

This report catalogs the key complexities to consider and then lays out the multitude of potential program structures and different rate design options, before sketching out high-level potential paths forward for residential customers.[11] Three high level paths are:

- Gradual evolution:
    - New customers who adopt distributed generation (DG) would be required to be on a year-round time-varying rate, but otherwise keep the key elements of current inflow/outflow model. These customers would be placed on a TOU rate by default but could opt into other year-round time-varying rates as well.
    - In the next rate case for each utility, the default TOU rate for these customers could be redesigned and tiered customer charge adders to recover site infrastructure costs could be introduced for all residential customers.
    - Incremental administrative costs and new processes would be minimal, although additional analyses and cost allocation reforms could be helpful to implement rate design improvements.
- Advanced residential rate design for DER customers:
    - A broad category of residential customers, including customers with DG, storage, EVs, and high usage, would be moved to an "advanced" marginal-cost-based rate design. Other residential customers would remain on a simpler "basic" rate.
    - The advanced residential rate would include a seasonally varying multi-period time-of-use rate with critical peak pricing, as well as a demand charge for site infrastructure[12] and a distribution flow charge[13] on all imports and exports.

[11] While this report focuses on residential customers, nearly identical recommendations would apply to small business customers. Larger commercial and industrial customers are different in some significant interrelated ways, notably with respect to increased sophistication, higher bills, and the ability to hire professional energy management. Individually, they make up a higher percentage of usage at different levels of the system such that their actions may pose additional risks to system planning and operation.

[12] The term "site infrastructure" encompasses the final equipment connecting customers to the broadly shared electric system, including service lines, line transformers, and secondary voltage lines.

[13] A symmetric kWh charge on both imports from and exports to the distribution grid, as further discussed in Sections 5.A and 6

  - For customers who elect to export to the grid, export credit structures would also be based on marginal cost, and the environmental component could vary by technology. The inflow/outflow structure would be replaced by netting within each pricing period.
  - Several different new analyses and processes would be necessary to set the different elements of the new rate and credit structures, as well as analysis to ensure a reasonable expectation that the revenue requirement can be recovered.
- Customer options and stability:
  - New DG customers would have a choice between two rate structures. Existing net metering and DG program customers would be grandfathered on their current rates but would have the ability to opt into one of the new options.
  - Choice A would be a buy-all/credit-all tariff.
    - A buy-all rate is the same as that which other, non-DER customers pay.
    - DG customers have a separate production meter, and all production is credited at a value-based flat rate that is locked in for 20 years.
  - Choice B would be a variation on traditional net metering.
    - Inflow/outflow structure would be replaced with monthly netting.
    - The rate for net imports would be same as the typical residential rate, with the credit for net generation set at same administrative values as Choice A above.
    - These customers would have a grid access charge based on installed capacity, the revenues of which would be split between public benefits programs and distribution system costs.
  - New processes and analyses would be necessary to set administrative credit values and the grid access charges.

These three paths are designed to illustrate how different tariff approaches perform relative to different regulatory principles and policy objectives, which will clarify key tradeoffs. This report provides a qualitative evaluation of these three pathways on four primary criteria:

- Fair cost allocation;
- Efficient customer price signals to use, generate, and store energy;
- Customer understanding and acceptance; and
- Administrative feasibility.

In the end, a new program structure and new rate design(s) for DER could be a blend of elements from each of these three pathways and different elements from each could be adopted over time.

2. Background and Regulatory Context in Michigan

A. Overview of Electricity Market Structure and Utility Regulation in Michigan

The current market structure and basic practices for electric utility regulation in Michigan form important context to understand the role of distributed resources generally, but also more specifically serve as important underlying factors in electric system cost causation – which in turn is important for both cost allocation and efficient pricing. Since 1909, the Michigan Public Service Commission (MPSC) -- originally the Michigan Railroad Commission and then the Michigan Public Utilities Commission -- has had authority to regulate electric rates and conditions of service for its jurisdictional investor-owned electric utilities (electric IOUs).[14] In the present day, this includes 7 electric IOUs.[15] While the MPSC has substantial regulatory authority over its jurisdictional electric utilities and their retail rates, the Midcontinent Independent System Operator (Midcontinent ISO or MISO) has certain responsibilities over wholesale energy markets, transmission, and certain aspects of reliability planning.[16] Michigan's seven electric IOUs do not directly own transmission assets, but rather use the transmission owned by independent transmission companies[17] that are overseen by MISO, which is regulated by the Federal Energy Regulatory Commission (FERC). The seven jurisdictional electric IOUs do own both generation and distribution assets. In the case of distribution assets, the MPSC has exclusive regulatory authority, but authority is shared in certain respects with MISO for generation. The MPSC does retain authority over generation resource adequacy, integrated resource planning, and certificates of necessity for large generation investments or purchased power agreements. When the MPSC exercises its authority over generation for the investor-owned utilities, several important statutory requirements should be kept in mind:

- The statutory renewable portfolio standard of 15% by 2021 and the statutory goal of 35% renewable energy and energy efficiency by 2025.[18]
- The integrated resource planning statute, which requires equal consideration of supply and demand side resources as well as a shared savings framework.

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[14] These are sometimes referred to as "rate-regulated electric utilities" to distinguish from cooperatives, where the MPSC has lesser regulatory authority, and municipal utilities, where the MPSC has very little regulatory oversight.

[15] Consumers Energy, DTE Electric, Alpena Power Company, Indiana Michigan Power Company (I & M), Upper Peninsula Power Company (UPPCO), Upper Michigan Energy Resources Corporation (UMERC) and Xcel Energy (Northern States Power Company – Wisconsin or NSP-W).

[16] I & M's service territory in southwest Michigan is covered by PJM instead of MISO.

[17] The corporate parents of two jurisdictional investor-owned utilities do own transmission assets in Michigan, American Electric Power (owners of I&M) and Xcel. Many of transmission assets in the rest of the state were previously owned by jurisdictional investor-owned electric utilities but were sold following restructuring.

[18] Governor Whitmer's MI Healthy Climate Plan executive orders also related goals pertaining to clean energy and reductions in electric sector greenhouse gas emissions. https://www.michigan.gov/climateandenergy/0,4580,7-364-98206---,00.html

- The energy waste reduction statute, which results in each utility having a 1% annual electric savings target.[19]

Under Public Act 286 passed in 2008, Michigan electric customers are allowed to choose an alternative electric supplier. These customers no longer pay the generation supply charge regulated by MPSC, but rather pay a rate agreed upon between the customer and alternative electric supplier. However, the overall customer choice program for each utility is capped at 10 percent of average retail sales, thus limiting the number of customers who can participate.[20] In addition, electric utilities are required to offer voluntary green pricing programs to customers.

Last, apart from state-jurisdictional net metering policies and retail rate designs, there are federally required compensation opportunities for certain kinds of energy resources in Michigan. The Public Utilities Regulatory Policies Act of 1978 (PURPA) requires utilities to sign long-term contracts with qualifying facilities (primarily small renewable and cogeneration units) at an avoided cost rate.[21] These PURPA contracts may include, but are not limited to, generation resources connected at the distribution level. Second, as issued in 2020 and clarified in 2021, FERC Order 2222 has created a framework for distributed energy resources to participate in organized wholesale markets, including MISO.[22]

B. History of DER Compensation Policies and Rate Design Reforms

In Michigan, net metering was first established by Public Act 295 of 2008.[23] For small distributed generation projects (20 kW or less), this meant monthly netting and credit rollover between billing periods at the full retail rate, referred to statutorily as "true net metering." Larger projects (above 20 kW) were instead eligible for "modified net metering," where credits were defined at the power supply portion of the retail rate.[24] In 2016, Public Acts 341 and 342 required the replacement of the legacy net metering frameworks with a new distributed generation program. The statutory requirements for the new DG program included a study by the MPSC on "an appropriate tariff reflecting the equitable cost of service for customers who participate in a net metering program or distributed generation program."[25]

[19] https://www.michigan.gov/mpsc/0,9535,7-395-93308_94792---,00.html

[20] https://www.michigan.gov/mpsc/0,9535,7-395-93308_93325_93423_93501_93509---,00.html

[21] https://www.michigan.gov/documents/lara/PURPA_Report_FINAL_04202020_with_appendices_688003_7.pdf

[22] The Order 2222 compliance approach for MISO is currently under development: https://www.misoenergy.org/stakeholder-engagement/issue-tracking/distributed-energy-resources/

[23] Prior to 2008, a "negotiated" net metering arrangement had been established by the utilities and MPSC.

[24] Since the creation of the new distributed generation program, the previous "true net metering" and "modified net metering" are collectively referred to as the "legacy net metering programs."

[25] MCL 460.6a(14)

The process for creation of the new DG program took multiple steps, including (1) an interim distributed generation program established shortly after the 2016 laws took effect,[26] (2) a MPSC staff report filed in February 2018,[27] (3) a framework order establishing the key aspects of the program in April 2018,[28] and (4) implementation in rate cases filed after June 2018.[29] The key feature of the new program is replacement of monthly netting with separate measurement and billing of "inflow," meaning kWh delivered *from* the distribution system, and "outflow," meaning kWh delivered *to* the distribution system.[30] Inflow is charged at the relevant retail rate, while outflow is only credited at the supply portion of the retail rate, excluding transmission costs for two of the four electric utilities with approved DG program tariffs.[31] At the end of the billing period, the total monetary value of credits earned from outflow are subtracted from the customer's retail rate charges (e.g., a customer charge and inflow charges and a demand charge for some classes) to determine the final bill amount. Outflow credits can typically only be applied to a portion of the bill,[32] and any unused credit value can be rolled over to the next billing period. The inflow/outflow framework has substantial flexibility and can be applied to nearly any rate structure. For example, residential DG program customers are allowed to opt into time-of-use rates just like any other residential customer.[33] Inflow and outflow are then measured and priced separately for each period in the time-of-use rate.

By statute, participation in the legacy net metering and distributed generation programs are limited to 1% of average in-state peak load for the preceding 5 years. However, the utilities who have approached or reach their limit have raised this cap, either through a rate case settlement with other parties or a voluntary agreement with MPSC.[34] Eligible technologies for these programs include solar PV, wind, hydroelectric projects, and methane digesters, although the

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[26] Case No. U-18383, https://mi-psc.force.com/s/filing/a00t0000005pUNMAA2/u183830022. The interim distributed generation program largely tracked the substance of the legacy net metering programs, with the limitation that the new customers may only remain on those rates for 10 years from their date of enrollment.

[27] Case No. U-18383, https://mi-psc.force.com/s/filing/a00t0000004ZOVtAAO/u183830024

[28] Case No. U-18383, https://mi-psc.force.com/s/filing/a00t0000004rpGlAAI/u183830076

[29] For DTE Electric and UPPCO, the commission rate case order approving the new DG program tariffs was issued in May 2019 and DG program enrollment began in the same month. For I&M, the approval order came in January 2020 and enrollment began in February 2020. For Consumers Energy, the approval order came in December 2020 and enrollment began in January 2021. Alpena Electric has recently filed a rate case that includes a DG program tariff and Xcel is expected to file a rate case in the fall of 2021. It is unknown when UMERC will file a rate case that includes a DG program tariff.

[30] This billing and pricing framework is sometimes referred to as "instantaneous netting." Generation consumed instantaneously on-site is effectively compensated at the full reduction in retail billing determinants. This is different than "buy-all/credit-all" arrangements where none of the gross generation is treated as a reduction in retail billing determinants. These alternative metering and billing frameworks will be discussed further in Section 4. In addition, for some utilities' larger C&I rates, customers with demand charges can be credited based on kW outflow, analogous to a reverse demand charge.

[31] When credit values are lower than import retail rates, the inflow/outflow model leads to higher bills for participating customers than monthly netting structures under traditional net metering.

[32] For most of the utilities, credits can only be applied to the generation portion of the bill. This restriction can either be thought of as part of the rollover rules, or else as a minimum bill defined by the distribution charges.

[33] There are utility implementations of the net metering program where participating customers could also opt into time-of-use rates but could only use credits earned in one time period in that same period in subsequent billing months (e.g., credits earned during an "on-peak" period can only be applied to usage in subsequent "on-peak" periods).

[34] UPPCO doubled its program size cap to 2% of its peak load as part of a rate case settlement agreement approved in May 2019 and further agreed to increase its program size to at least 3% as part of a settlement agreement in case No. U-20995. Consumers Energy notified the Commission that it would increase its program size cap to 2% on December 21, 2020.

vast majority of the installed capacity participating in the program has been solar PV to date. DG projects under these programs are categorized by size:

- Category 1: 20 kW and under
- Category 2: between 20 kW and 150 kW
- Category 3: Methane digesters over 150 kW and up to 550 kW

The program caps have been divided between these three categories, with Category 1 typically limited to 50% of the overall cap, 25% for Category 2 and the remaining 25% for Category 3.

In addition, the MPSC, along with Consumers Energy and DTE Electric, has been working to take advantage of the capabilities provided by advanced metering infrastructure with new rate design options. Starting in June 2021, residential customers for Consumers Energy no longer have a year-round flat kWh rate option and are placed on the Summer Peak Rate by default, with a higher on-peak rate from 2 pm to 7 pm on weekdays from June through September. Consumers Energy also provides other time-varying options for residential customers. DTE does still have a non-time-varying inclining block kWh rate for residential customers by default but provides several time-varying options to residential customers, including a relatively simple "time of day" rate and a more complex dynamic peak pricing rate.[35] These innovations are designed to better align rates with cost causation and have the additional benefit of fairer and more efficient cost allocation within rate classes. Only the generation supply portion of these rates varies by time and season, which may provide additional opportunities for rate design innovation with respect to the distribution rate.

C. Brief Survey and Statistics on DER by Technology Type and Tariff

[This section will be completed pending release of 2020 DG program report and data. This section will also include state-level comparisons using U.S. EIA data from Form 861-M.]

D. History and Future Directions for the Electric System and Utility Regulation

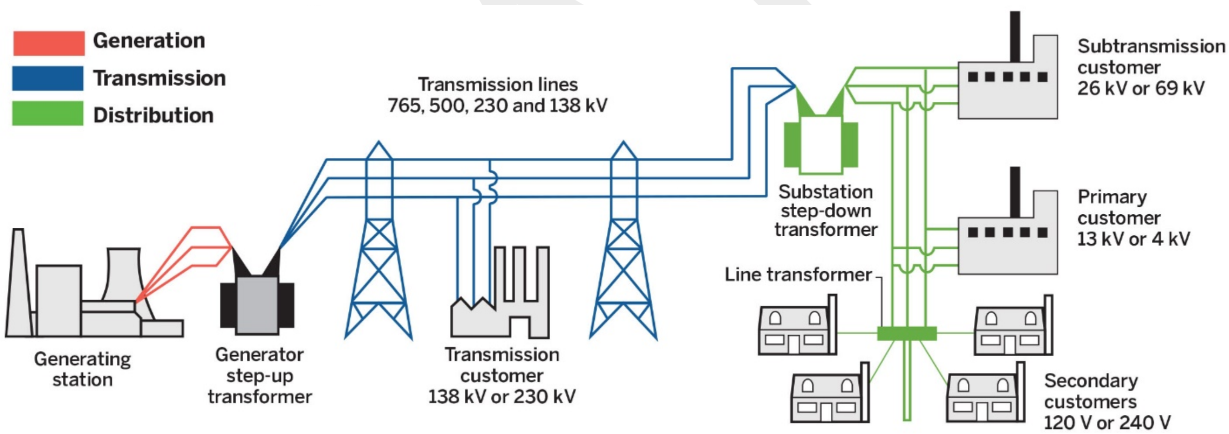
The evolution of the electric system is nothing new. In the United States, the electric system has undergone significant developments every few decades since it was first begun in the late 19th century. An initial period of unrestrained private utility development, primarily in cities, was followed by the establishment of state regulation of franchised monopolies in the 1910s and 1920s. In the 1930s and 1940s, the Federal Power Commission (now the Federal Energy Regulatory Commission) was granted new authority, the major interstate electric conglomerates were broken up and significant federal efforts were undertaken to ensure access to electricity service across the entire country. In the 1970s, escalating fuel prices due to international oil crises and the availability of new generation technologies sparked major new capital investments and introduced the possibility of competition at the wholesale level. In the 1980s and 1990s, PURPA implementation and integrated resource planning was followed by wholesale market

[35] DTE customers in the distributed generation program are not currently allowed to opt into the dynamic peak pricing rate.

development and restructuring of electric utilities in many parts of the country. In the 2000s, due to innovative drilling and extraction techniques, such as hydraulic fracturing, the cost of fossil gas declined and domestic production increased sharply, which in turn led to major increases in electricity generation from gas. These major trends shaped our electricity infrastructure and regulatory systems and, as change continues, learning and adaptation must be continuous to meet energy needs in an efficient and increasingly sustainable manner.

For much of the 20th century, the electric system was conceptualized in the way that is illustrated in Figure 1. Large central generators were the source of electric energy and connected to the transmission grid. While a few very large industrial customers took service directly at transmission voltages, nearly all customers were served at the lower voltages that defined the electric distribution system. On the distribution system, some customers took service at the primary voltage level and either used specialized equipment that operated at that voltage or owned their own transformers to convert the electricity to the correct voltage. However, all residential customers and nearly all small commercial customers took service at secondary voltage, where a line transformer may serve anywhere from one customer in extremely rural areas to dozens of customers in an apartment building.

Figure 1. Illustrative traditional electric system



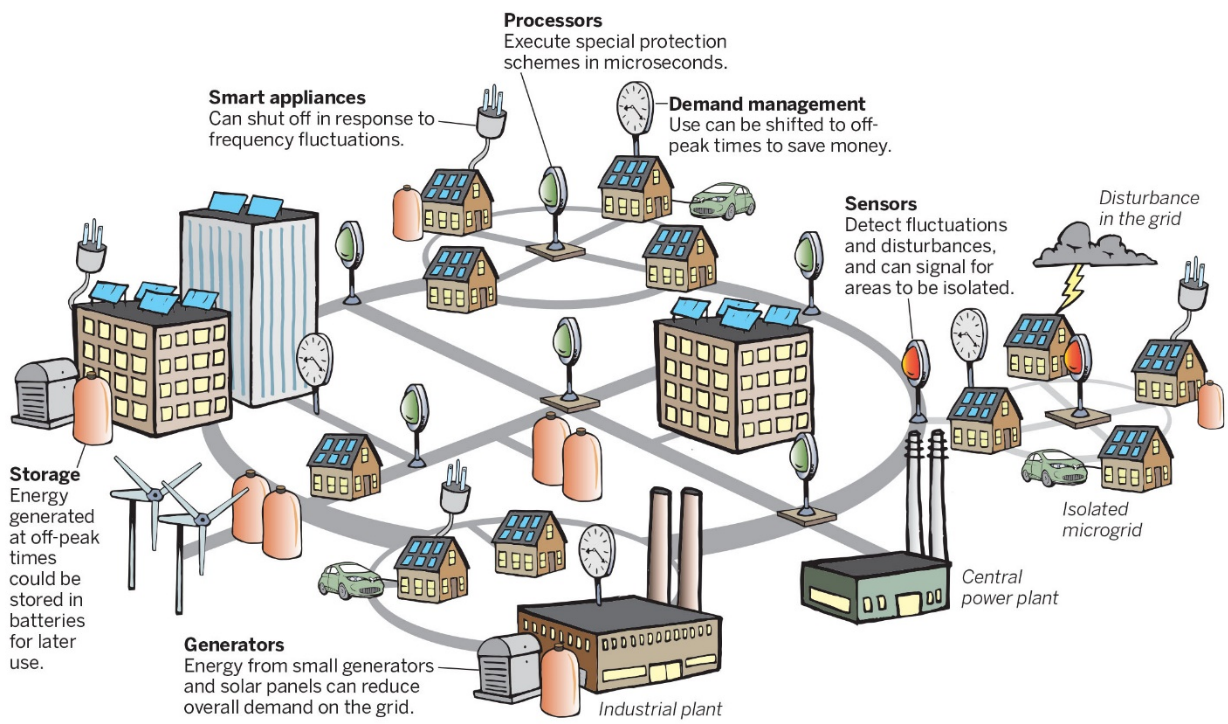
Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*

Cost allocation and rate design techniques developed in this context were based on certain assumptions, including:

- Reliability risks focused on generation resource adequacy issues driven by the highest hours of customer usage over the course of the year;
- Little visibility and control within the transmission and distribution systems;
- Metering technology could only handle simple forms of data recording and storage; and
- Little or no capability for customers to manage their usage or export energy back onto the grid.

In the 21st century, however, another fundamental set of changes has occurred. There have been major decreases in the cost of solar PV and energy storage, and major breakthroughs in other customer-side technologies. Advanced metering and smarter distribution system technologies provide better data and fine-grained control of the system. This new data can be used in a multitude of ways, including better planning and investment criteria – all the way down to more efficient transformer sizing. Furthermore, electrification of transportation and heating poses both challenges and opportunities for the electric sector.[36] The future electric grid may bear more resemblance to Figure 2, with generation and storage at consumer sites, two-directional power flows, and more sophisticated control equipment for customers and the grid itself.

Figure 2. Illustrative future electric system



Source: Adapted from U.S. Department of Energy. (2015). *United States Electricity Industry Primer*

While elements of this potential future for the electric system can be sketched out at a high level, there are many key uncertainties that will only be resolved by observing innovations as they develop, along with policy decisions at every level of government. One important example of this is how the generation resource mix will evolve over time. In several states with high levels of solar development, a distinctive new load shape has developed, as shown in Figure 3 for Hawaii.[37]

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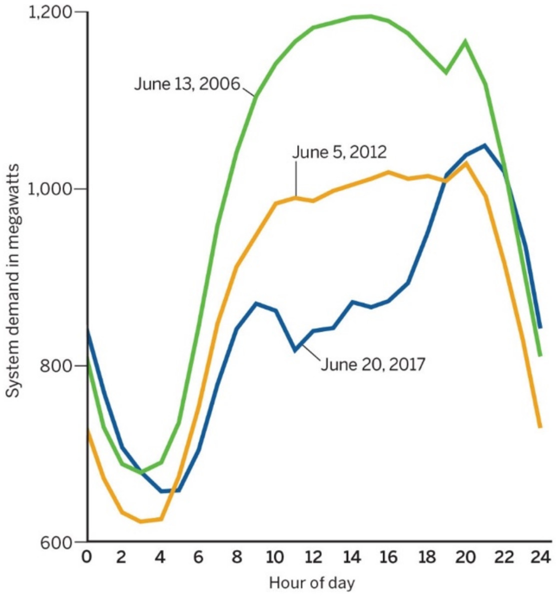
[36] See Farnsworth, D., J. Shipley, J. Lazar, and N. Seidman (June 2018), Beneficial Electrification: Ensuring Electrification in the Public Interest, Regulatory Assistance Project, https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

[37] This pattern for solar development is particularly distinctive if the vast majority of solar installations are all south-facing, thus increasing the correlation of production for these resources. A variety of policies in many jurisdictions incentivize the maximization of kWh production, which logically leads to south-facing panel orientations. Policies that better reflect system values could lead to different panel orientation choices, such as west or southwest orientation or panel tracking. This would lead to a somewhat different pattern of solar development.

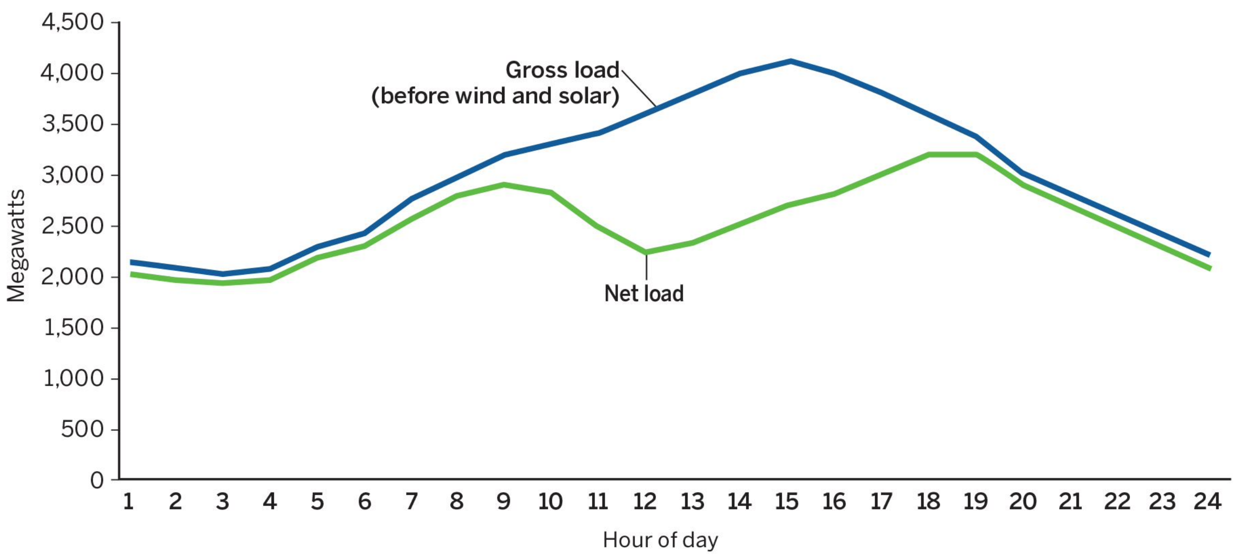
Figure 3. Evolution of system load in Hawaii on typical June weekday



Data source: Federal Energy Regulatory Commission. *Form No. 714 — Annual Balancing Authority Area and Planning Area Report*

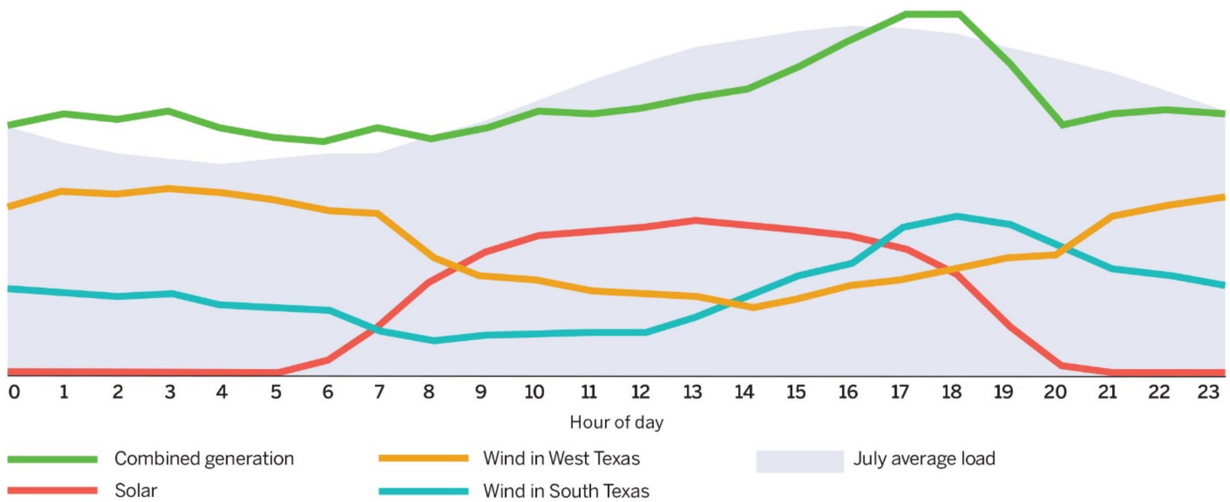
Changes like these have implications for how the electric system is planned, operated, and regulated, and this is discussed further below with respect to cost causation. One key planning implication is that generation resource adequacy risks may no longer be highest at the times of peak gross customer usage. Instead, as shown in Figure 4 the concept of "net load," which subtracts out nondispatchable resources, notably solar PV and wind but conceptually including some other resources as well, becomes key. In the case of generation resource adequacy, all nondispatchable resources connected to the system are relevant, not just nondispatchable technologies that are net metered or connected to the distribution system.

Figure 4. Illustrative net load curve



However, there are many other possible outcomes for the evolution of the generation resource mix. For example, it is possible that a balanced mix of wind and solar development could roughly match overall system load shape, as demonstrated in Figure 5.

Figure 5. Illustrative Texas wind and solar resource compared with load shape



Sources: Adapted from Slusarewicz, J., and Cohan, D. (2018). *Assessing Solar and Wind Complementarity in Texas* [Licensed under http://creativecommons.org/licenses/by/4.0]. Load data from Electric Reliability Council of Texas. (2019). *2018 ERCOT Hourly Load Data*

In contrast to Figure 3, this resource development pattern shown in Figure 5 would likely require fewer changes to grid operation and planning, at least in the near term.

In the last several years, states across the country have established regulatory initiatives to take advantage of these trends and avoid potential negative consequences by creating an electricity system that is more flexible, competitive, customer-friendly, and sustainable. With its MI Power Grid initiative, the Michigan Public Service Commission has taken several steps down this path as well and will have additional opportunities to harness these trends for the benefit of all of Michigan's citizens.

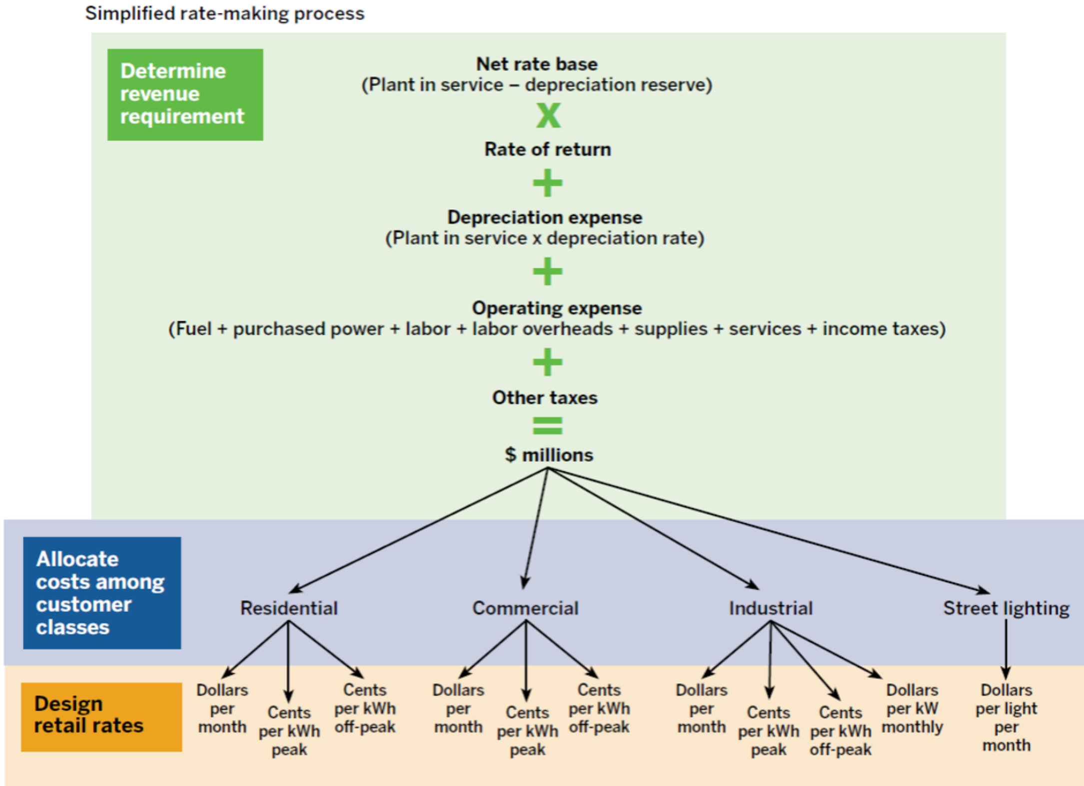
3. Ratemaking Practices and Perspectives on Costs and Benefits

Before digging into the options for reform of DER rate design, and related cost allocation reforms, it is worth reviewing basic ratemaking principles that have been relied upon for decades as well as historical and evolving ideas about electricity system costs and their proper allocation. It is also important to acknowledge the changing demands being placed on the electricity system and the evolving public policy goals that now influence utility actions and regulators' decisions, including in the areas of cost allocation and DER rate design.

A. Traditional Ratemaking Process and Principles

In traditional economic regulation of electric utilities, regulators review rates proposed by utilities and issue orders to determine just and reasonable rates. In the regulation of prices for utility service, the prevailing practice is to develop separate sets of prices for a small and easily identifiable number of customer classes. Examples of customer classes include residential, general service, and street lighting. For many utilities, general service (commercial and industrial) customers are divided into multiple classes, often based on size thresholds or the distinction between secondary voltage service and primary voltage service. For a given utility and its service territory, all customers in each class are typically eligible for the same set of default and optional tariffs, under which all customers pay the same prices. This is typically the same price for each customer within a class regardless of their location within a service territory, a practice known as postage stamp pricing. As shown in Figure 6, the prices for each class are typically developed in three high-level steps: (1) determination of the revenue requirement, (2) allocation of costs between customer classes, and (3) final design of the retail rates. For each step, data collection and tracking, with respect to utility costs of all kinds, customer usage and behavior, and energy resources, is an important foundational element of ratemaking.

Figure 6. Simplified ratemaking process diagram for electric utilities



The annual revenue requirement is set based on the cost of service, a technical term which typically includes operating expenses, depreciation expense (a measure of the annual loss in value of utility capital assets), taxes, as well as an explicit element for a rate of return on net rate base. Environmental and public health externalities are not directly included in the cost of service, although a range of compliance costs and program expenditures are motivated by these underlying concerns.

In the process of setting the rate structure, a term that combines the cost allocation and rate design steps, regulators and stakeholders refer to a wide range of principles or guidelines, many lists of which have been compiled by analysts of the past.[38] Many of these principles are still useful today, though it is also worth asking how changing circumstances may affect them. Some generally accepted principles that remain helpful in today's debates regarding rate structure include:

[38] The most famous of these is the "Bonbright principles" from Principles of Public Utility Rates by James C. Bonbright (1961). On page 291, Dr. Bonbright lists 8 frequently cited principles but immediately explains that "Lists of this nature are useful in reminding the rate maker of considerations that might otherwise escape his attention, and also useful in suggesting one important reason why problems of practical rate design do not readily yield to 'scientific' principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities… their overlapping character, and their failure to offer any rules of priority in the event of conflict." He goes on to discuss his preferred three criteria of "(a) the revenue-requirement or financial-need objective…(b) the fair-cost-apportionment objective…and (c) the optimum-use or consumer-rationing objective." (p. 292).

- **Effectiveness in yielding total revenue requirements**: The utility should have an expectation that it will approximately recover its revenue requirement from customer rates, with a reasonable amount of stability from year to year.
- **Customer understanding and acceptance**: Prices should not be overly complex or convoluted such that customers cannot understand how their bills are determined or how they should respond to manage their bills. Customers and the public should generally accept that the prices they are charged for electricity service are fair for the service they are receiving.
- **Equitable allocation of costs and the avoidance of undue discrimination**: The apportionment of total costs of service among the different customers should be done fairly and equitably.
- **Efficient price signals that encourage optimal customer behavior**: On a forward-looking basis, electricity prices should encourage customers to use, conserve, store and generate energy in ways that are most efficient.

It should be noted that there may be tradeoffs between these principles in many cases. For example, rates that make revenue recovery more certain could lead to less equitable cost allocation and less efficient rate design. Similarly, certain types of more efficient forward-looking price signals may be more difficult for a typical customer to understand or in extreme cases have consequences for overall revenue stability. Thus, the task of the regulator is to strike an overall balance in these objectives.

B. Policy Goals of Utility Regulation

In addition to the above ratemaking principles, utility regulation has always included important policy goals, such as the prevention of monopoly pricing and customer discrimination, promotion of economic development, and expansion of service. As one may expect, public policy goals are evolving and continue to add new expectations on utilities and regulators to accomplish an expanding set of objectives related to electricity service. The achievement of many of these goals and objectives can be directly influenced by the cost allocation and rate setting processes that utility commissions oversee. In addition, these goals and objectives often have direct or indirect links to deployment and utilization of distributed energy resources. Thus, broad discussions about public policy goals and objectives have a legitimate role in debates around DER rate design and compensation. Policy goals that have implications for DER deployment and compensation include:

1. **Competition across fuels and sectors**: One of the overarching goals of utility regulation is efficient choices of energy sources and, relatedly, allocation of resources across sectors. While the real world never perfectly matches ideal theoretical conditions, the goal that utilities should be regulated in order to mimic efficient market outcomes is a worthy one. In particular, utility management should be incentivized to operate and invest efficiently in order to maximize the long-run value of their company in a manner that is consistent with the public interest.
2. **Competition within the electric sector**: Many policymakers and stakeholders desire increased or enhanced competition within the electricity sector to drive costs down for customers and provide more choices. Desire for greater competition has been primarily

focused on electricity generation and supply in the last several decades. Independent power producers at the wholesale level can provide increased competition in generation, as can distributed energy resources. Going forward, many jurisdictions are exploring whether certain forms of competition are feasible for the delivery system, with the notable example of "non-wires" procurements for alternatives to traditional distribution system investments.

3. **Provision of reliable service**: Reliability of electricity service has always been important, but also, with the advent of DERs and microgrid capabilities, can now encompass a broader concept of customer resilience.
4. **Societal equity**: Historically, regulatory goals related to equity have universal access and affordability. In modern times, this has also evolved into the goal of equitable distribution of benefits for public policy programs.
5. **Administrative feasibility**: Modest refinements to existing rules, processes and programs are simpler to adopt. In some cases, larger changes are possible but require additional time, resources and attention from relevant policymakers and stakeholders. In other cases, some theoretically possible reforms may not be feasible, or may require other intermediate reforms or expenses before they could begin.
6. **Clean energy and DER-focused employment**: In many states there is increasing interest in promoting employment opportunities related to distributed resource deployment. Jobs in the solar industry, for example, are already robust in many states and have continued to grow in recent years with the exception of 2020 due to the COVID-19 pandemic. Jobs related to installation and construction of DERs may be a policy motivator for considering ways to promote growth in these industries including through DG compensation and rate design structures.
7. **Public health and environmental protection**: For the past several decades, there have been many state and federal standards and programs to protect public health and the natural environment. Dating back to the 1970s, that includes so-called "criteria" pollutants regulated under the federal Clean Air Act, which involves a mix of federal and state responsibilities within the electric sector. In the past two decades, many states have renewable or clean energy targets in statute that require utilities to deliver a certain percentage of clean energy by specific dates. More recently, more states are adopting goals and binding requirements for utilities and other emitters to reduce greenhouse gas emissions. All of these policy drivers implicate potential changes to regulatory approaches in order to require or incentivize certain actions by utilities and customers.

Gradualism, another frequently cited principle in utility regulation, is not a policy goal or end in itself but rather an approach to problem solving and a means to achieve other regulatory objectives. With respect to DER rate design, gradualism has a strong connection to the principle of customer understanding and acceptance, the goal of avoiding disruptions to DER companies and employment, and the ease of implementation administratively.

C. Cost Causation on the Electric System

The concept of cost causation is a fundamental one for both cost allocation and rate design.[39] While occasionally it is used as a backwards looking concept with respect to cost allocation, it primarily refers to how the characteristics of utility customers collectively affect costs on a forward-looking basis. Understanding how current behavior affects current and future costs requires an understanding of the economics and engineering of the electric system. But once it is understood how costs are caused, there are straightforward arguments that (1) costs are allocated most equitably to the customers who cause them and that (2) prices are most efficient if they reflect how costs are caused. In both cases, these are forward-looking marginal cost concepts.

The biggest debates around cost causation tend to focus on the allocation and pricing of capacity investments for generation, transmission, and distribution.[40] The vast majority of this capacity investment is shared by large numbers of customers, and each component of this shared system is sized to meet an expected peak coincident demand of the customers it serves. Peak coincident demand for the relevant group of customers is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as diversity of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might, or might not, coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads, through a shared transmission network. Figure 7 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

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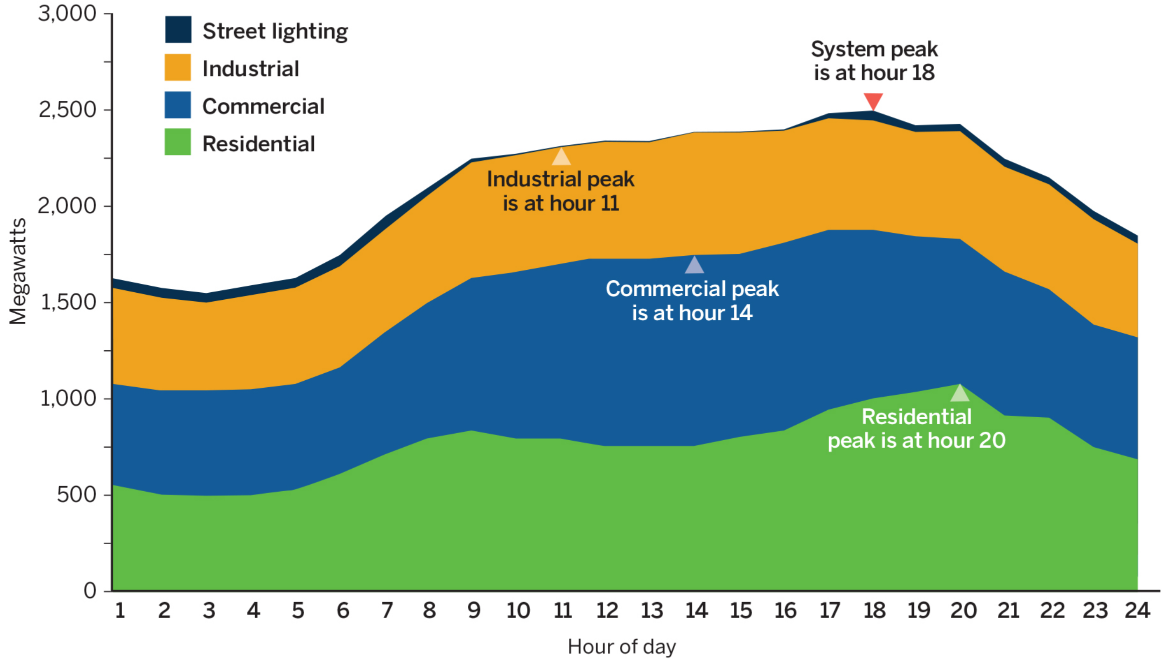
[39] For further discussion of these issues, see Section 5.1 in Lazar, J., P. Chernick, W. Marcus, M. LeBel (ed.), (January 2020), Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project, https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[40] There is a persistent fallacy that fixed capacity investments mean that pricing should properly be translated into fixed charges. This is easily disproven by looking at the numerous competitive industries that involve large capital investments but use unit prices. For example, oil refineries are massive capital investments, but gasoline is still sold by the gallon. Furthermore, the concept of "fixed" charges in this context is sometimes applied flexibly to include both customer charges but also different kinds of demand-based charges, which can vary from billing period to billing period. The reasonableness of fixed charges, customer charges, and demand-based charges (as well as their proper magnitude) turns on other issues.

Figure 7. Illustrative load diversity at the customer class level



When similar data is examined at the level of individual customers, metrics for diversity of load are even higher. Overall, the diversity of customer load is one major reason why it is less expensive to build a shared electric system, in addition to the historic economies of scale for generation technologies.

Given these patterns of customer load, utilities and system planners need to invest to meet two primary objectives: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. Historically, reliability concerns have risen predominantly (but not exclusively) at peak system load hours.[41] Achieving the objectives in a reasonable way requires detailed economic analysis of the different potential options that meet the relevant engineering criteria.[42] This can be seen with respect to analyzing the optimal mix of generation resources. Given multiple different types of generation technologies, storage, and demand response, the optimal mix depends on year-round load patterns. The different options have different capabilities and different cost characteristics and should not be blindly lumped together as “capacity” for system planning or even cost allocation and rate design purposes.

Because of these economic considerations, the kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the kind of capacity that one would build to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period)

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[41] Reliability can be thought of as having two dimensions, in terms of both system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[42] The details of how this is achieved vary from ISO to ISO and state to state.

can be much cheaper than building *any* kind of generation resource that is seldom used. In order to be economic, capacity built to serve only short-term needs generally has low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger upfront investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon. This means that not all generation capacity costs are caused by system peaks or even reliability needs more broadly. It is also relevant that the choice of some generation technologies is justified partly by ratepayer cost considerations and partly by policy requirements.

Many of these same considerations apply to the transmission and distribution system, and an analyst should look to the underlying purposes and benefits of investments to understand their role in system planning and to allocate and price them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. A transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In some situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy, rather than to meet peak demand, and should be classified on that basis. Similarly, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year. Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering options for transmission and distribution networks that have implications with respect to line losses.[43] For example, one of the reasons to choose higher voltage transmission is to carry the same power levels at a lower current, which can decrease line losses substantially. Average annual line losses typically are around 7% but marginal system losses at the time of peak can be 15-20% in many utility systems.[44]

It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. We collectively term these categories of costs as “site infrastructure.” Even at this level, there can be significant load diversity among the customers sharing a line transformer. But there are many residential customers (e.g., single family homes) with dedicated service lines and a fair number of secondary general service customers that have dedicated line transformers.

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[43] See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

[44] Lazar and Baldwin, 2011, p. 1.

Billing and customer service costs are directly related to the number of customers, although larger customers often have more sophisticated bills and other arrangements that add incremental costs in these categories. Traditionally, a simple meter was categorized as a billing cost and every customer needed a single meter. However, the purposes of advanced metering infrastructure, and its related pricing and data collection capabilities, goes far beyond what is necessary strictly for billing. As a result, advanced metering infrastructure can be fairly allocated and efficiently charged to customers in a manner that reflects these broader purposes.

Expenditures for public policy programs and requirements, such as energy efficiency or energy waste reduction programs, renewable portfolio standards, and discounts for low-income customers, senior citizens, or industrial customers, are driven by a wide range of motivations, including reductions in electric system costs, supporting innovation, public health and environmental benefits, and broader economic and societal goals. Some of these categories, particularly energy efficiency and energy waste reduction, can be thought of as part of the efficient least-cost operation and planning of the electric system and thus has a cost causation basis driven by usage and customer behavior. Expenditures that are more driven by broader societal goals, such as certain kinds of customer discounts, do not have a cost causation basis in the same way.

Last but not least, administrative and general costs generally support all of a utility's functions and scale with the overall size of the enterprise. For example, an office building and parking lot is built for the number of employees that use that location. Crucially, there are not customer characteristics that directly influence these costs.

Although all customer behavior influences these cost drivers in different ways, it is important to note how trends in DER adoption, and in some cases the adoption of solar PV distributed generation specifically, are changing the nature of the electric system and basic patterns of cost causation. DG customers may influence generation costs by causing a shift in peak time or level. This has occurred in states with high penetrations of distributed solar, such as Hawaii.[45] As discussed above in Section 2.D, system planners must dispatch plants to meet the "net load" curve, subtracting the generation from non-dispatchable resources interconnected at either the transmission or distribution level from gross load.

In addition, DG can affect the need for shared distribution infrastructure by reducing certain distribution circuit peaks or, conversely, by increasing infrastructure investment requirements for DG interconnection or substation investments to allow power to flow up from distribution circuits to the higher voltage distribution grid under certain conditions. Higher penetrations of variable renewable resources generally (including utility-scale resources) may lead to the need for additional fast ramping resources and other measures to "teach the duck to fly."[46] Extremely high penetrations of certain technologies may require investments in a broader range of dispatchable resources, such as long-duration energy storage. More localized distribution issues could be caused by clustering of adoption. While some of these issues are no longer theoretical in

[45] In Hawaii, June load shapes changed as increased levels of distributed solar were added to the system. In 2006, the system peak demand was approximately 1,200 MWs at 1 to 3 p.m. By 2017, with extensive deployment of customer-sited solar, the peak demand was 1,068 MWs at 9 p.m.

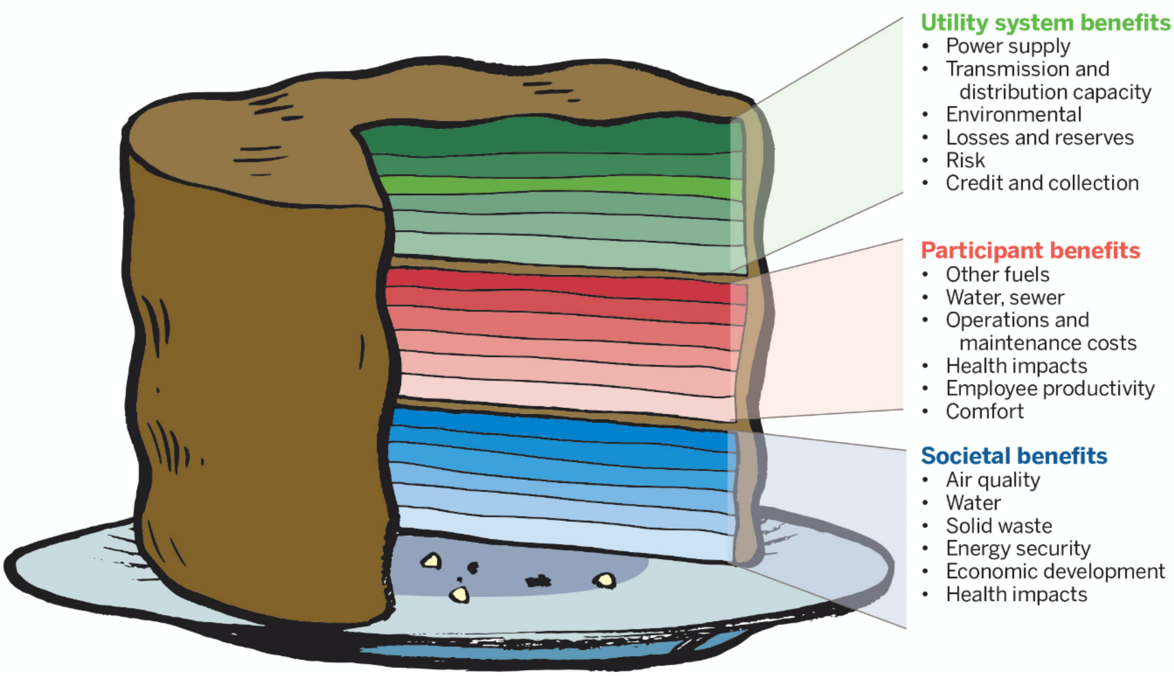
[46] Teach the Duck to Fly, Second Edition, Jim Lazar: https://www.raponline.org/knowledge-center/teaching-the-duck-to-fly-second-edition/

some jurisdictions, they should be properly quantified to keep them in perspective. Jurisdictions with low levels of DG penetration, such as Michigan, may not need to act on these issues in the near future but it rarely hurts to look out over the horizon for foreseeable issues.

D. Benefit-Cost Analyses

Jurisdictions in the United States that have implemented ratepayer-funded energy efficiency (EE) programs typically subject these programs to benefit-cost analyses to determine whether the investments are cost-effective. Regulators in these jurisdictions require that these programs and measures pass one or several cost-effectiveness tests before programs are included in rates.[47] In some states, cost-effectiveness tests are also used to assess programs for other types of distributed energy resources (DERs), including distributed generation. The type of test selected has huge implications for which programs pass, as different cost tests consider costs and benefits from differing perspectives (e.g., the utility system, program participants, or society as a whole). The breadth of the factors considered also varies among the tests and can further vary depending on the willingness of the jurisdiction to pursue a comprehensive assessment of the benefits of energy efficiency or other DERs. Figure 8 displays a comprehensive list of possible benefits to consider for distributed energy resources.

Figure 8. A "layer cake" of benefits from distributed energy resources

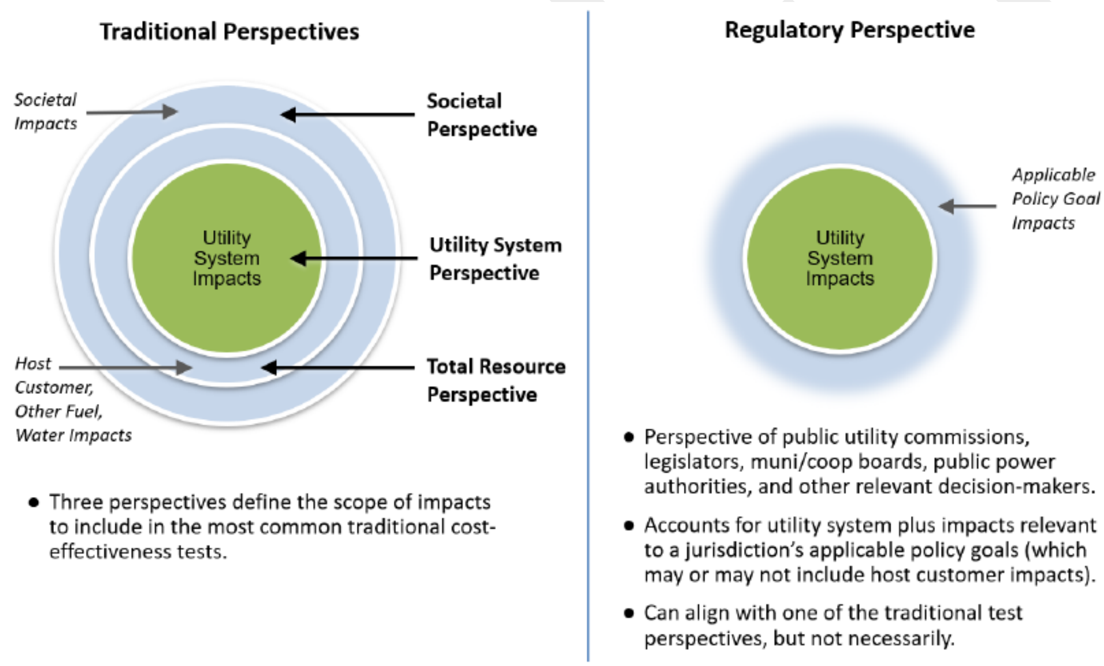


It is important to recognize that the different tests provide different types of information from different perspectives. While all of these different perspectives may be considered relevant and

[47] Lazar, J., and Colburn, K. (2013). Recognizing the Full Value of Energy Efficiency. The Regulatory Assistance Project. Montpelier, VT. Retrieved from: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburn-layercakepaper-2013-sept-09.pdf

important, and warrant consideration, states typically use one of these tests as the primary test to determine whether to invest ratepayer funds in DER programs.[48] For example, a state may require use of multiple tests but use one test as the primary test. The most commonly used tests are the Program Administrator Cost Test/Utility Cost Test, the Total Resource Cost Test and the Societal Cost Test. The Ratepayer Impact Measure Test and Participant Cost Test are less commonly used, and almost never used as primary tests.[49] Jurisdictional Cost Tests, originally described in the National Standard Practice Manual,[50] reflect a new approach to cost-effectiveness testing where each jurisdiction is encouraged to develop its own unique test. Figure 9 shows a graphical depiction of the differences between these tests.[51]

Figure 9. Graphical depiction of differences between cost-effectiveness tests



i. Program Administrator/Utility Cost Test

The Program Administrator Cost Test (PAC) – also called the Utility Cost Test (UCT) – looks at costs and benefits from the perspective of the utility offering the DER program. Generally, this test seeks to answer the question of whether the utility's revenue requirements will decrease as a result of the program. However, in states that allow retail competition in energy supply, it is more accurate to say this test measures whether utility system costs – i.e., the combination of the

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[48] https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-10.NEEP_.EMV-Screening.13-041.pdf

[49] https://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburn-layercakepaper-2013-sept-09.pdf

[50] National Efficiency Screening Project. (2020). National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

[51] National Efficiency Screening Project. (2020). National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources: Summary, (August 2020), P. V, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-Summary_08-24-2020.pdf

utility's delivery costs plus the costs of energy supply (regardless of the supplier) – will decrease. Using the UCT for DER program evaluation almost always makes sense because it reveals whether the benefits to a utility will exceed the cost to the utility (which will ultimately be recovered from its customers). This is always important information for a regulator to have and only rarely will it make sense to approve a program that fails the UCT. However, many jurisdictions have opted not to use the UCT as their *primary* cost-effectiveness test because it gives an incomplete picture of the costs and benefits of DERs. The picture is incomplete because, in most cases, DER programs do not cover the full cost of a DER investment. Instead, customers put their own money into the investment, supplemented by utility program incentives, and receive their own benefits that are additional to the utility's benefits. The TRC test, described below, is more commonly used than the UCT as a primary test because it can compare total costs and total benefits for all the parties investing in a DER (i.e., the utility and the customer).

ii. Total Resource Cost Test

The Total Resource Cost (TRC) Test seeks to answer the question of whether the total combined costs for the utility offering a DER program and the participating customers will decrease. This test includes the full costs of the measure, program administrative costs, and the benefits the measure provides not just to the utility but also to the participants, including operations and maintenance (O&M) savings, increased productivity, lowered absenteeism, and other non-energy benefits. Although most states specify the TRC test as the primary means for determining cost-effectiveness, very few actually require that all participant benefits be quantified.[52] As a consequence, the benefits of DERs are often severely underestimated in practice by this test. It is crucial that analysts and regulators take full account of resource related non-energy benefits in applying the TRC. Where these benefits cannot be easily quantified, the use of placeholders or default values may be necessary; otherwise, the value of these benefits is carried as zero, which is almost certainly the wrong number.[53] If the TRC is used as the primary cost-effectiveness test, the UCT can still be employed as a secondary test. In cases where a proposed program passes the TRC but fails the UCT, it may be possible to adjust the utility program incentives to ensure that the program will pass both tests.

iii. Societal Cost Test

The Societal Cost Test (SCT) includes all costs and benefits experienced by society as a whole. It seeks to answer the question of whether society is better off with the program. It includes all of the TRC costs and benefits, but it also includes the impacts on people who are not customers of the utility offering the DER program. In addition to the fact that the SCT looks at impacts outside of the utility's service territory, it also considers environmental externalities and other non-energy benefits that are not currently valued by the market.[54] The SCT may also include non-energy costs, such as a reduction in non-participant property values if a neighbor uses a DER

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[52] Lazar and Colburn, 2013

[53] Lazar and Colburn, 2013

[54] Lazar and Colburn, 2013

program to erect a small wind turbine.[55] In some cases, emissions costs are included in the market price used to determine avoided costs or are otherwise explicitly included in the TRC calculation. Emissions permit costs may already be included in the market price of electricity in some jurisdictions. In other jurisdictions, a variety of measures for the cost of emissions are included in the SCT.[56]

iv. Jurisdiction-Specific Test

The cost tests described above often do not address pertinent jurisdictional or state policies, and as a result are sometimes modified in an ad-hoc manner that varies across states. Additionally, different types of distributed energy resources (DERs) are frequently treated inconsistently in these modified tests, which could lead to over-investment in some DERs and under-investment in others.[57] Recognizing these deficiencies, the National Energy Screening Project developed a National Standard Practice Manual for DERs which describes a process and principles that each state can use to create its own Jurisdiction-Specific Test. The JST is calculated from the perspective of regulators or decision-makers. It seeks to answer whether the cost of meeting utility system needs, *while achieving the applicable policy goals of the jurisdiction in question*, will be reduced by the program or measure being analyzed. It includes the utility system impacts, plus those impacts associated with achieving applicable state policy goals.[58] So, for example, if a state has an established goal to deploy rooftop solar, a JST can be designed that reveals whether an electric utility DER program will reduce the total cost of serving customers' electric needs *and* achieving the rooftop solar goal. In this hypothetical scenario, a utility incentive program that increases utility costs could pass the JST if it is the best or only way to achieve the rooftop solar deployment goal. The process for developing a JST involves five steps shown in Figure 10.[59]

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[55] This is a hypothetical example included simply to illustrate the possibility of non-energy costs for non-participants. In fact, the Lawrence Berkeley National Laboratory collected data on almost 7,500 sales of homes situated within 10 miles of wind facilities. Their analysis found that "if property value impacts exist, they are too small and/or too infrequent to result in any widespread, statistically observable impact, although the possibility that individual homes or small numbers of homes have been or could be negatively impacted cannot be dismissed." See https://windexchange.energy.gov/projects/property-values.

[56] National Action Plan for Energy Efficiency (2008). Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers. Energy and Environmental Economics, Inc. and Regulatory Assistance Project. Retrieved from: https://19january2017snapshot.epa.gov/sites/production/files/2015-08/documents/understanding_cost-effectiveness_of_energy_efficiency_programs_best_practices_technical_methods_and_emerging_issues_for_policy-makers.pdf

[57] Michals, Julie (2021, February 25). Exploring Optimization Through Benefit-Cost Analysis. NCEP Special Session. Power Point. Retrieved from: https://pubs.naruc.org/pub/685F9A10-155D-0A36-31D1-C5B6E6012E03

[58] Better Buildings U.S. DOE (2021, February 11). Passing the Test: How are Residential Energy Efficiency Cost Effectiveness Tests Changing? Power Point. Retrieved from: https://www.energy.gov/sites/default/files/2021/03/f83/bbrn-peer-test-021121.pdf

[59] National Energy Screening Project. (2020). National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Figure 10. Illustrative steps to develop a jurisdiction-specific test

STEP 1 Articulate Applicable Policy Goals
Articulate the jurisdiction's applicable policy goals related to DERs.

STEP 2 Include All Utility System Impacts
Identify and include the full range of utility system impacts in the primary test, and all BCA tests.

STEP 3 Decide Which Non-Utility System Impacts to Include
Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1:

- Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.

STEP 4 Ensure that Benefits and Costs are Properly Addressed
Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where:

- Benefits and costs are treated symmetrically.
- Relevant and material impacts are included, even if hard to quantify.
- Benefits and costs are not double-counted.
- Benefits and costs are treated consistently across DER types.

STEP 5 Establish Comprehensive, Transparent Documentation
Establish comprehensive, transparent documentation and reporting, whereby:

- The process used to determine the primary test is fully documented.
- Reporting requirements and/or use of templates for presenting assumptions and results are developed.

Note: The 5-step process is not necessarily chronological in order and often requires iteration.

v. Ratepayer Impact Measure Test

The Ratepayer Impact Measure (RIM) Test examines the impact of utility-sponsored DER programs on future customer rates. The difference between the RIM test and the UCT is that the RIM test adds utility lost revenues (i.e., DER program participant bill savings) to the actual costs incurred by the utility. A reduction in utility revenues may eventually force the utility to raise rates to recover certain costs. Very few states have ever used the RIM test as the primary determinant of cost-effectiveness for their DER programs, in part because it doesn't really indicate whether a measure is inherently cost-effective. Instead, it indicates whether some of the utility's embedded costs might be shifted from DER program participants to non-participants. Although almost no utility regulators use this as a primary test for decision making, many regulators are appropriately concerned about cost-shifting and the potential magnitude of rate impacts and do consider the results of the RIM test.[60]

E. Cost Allocation Frameworks[61]

Cost allocation is the step in the ratemaking process where regulators determine how to equitably divide a set amount of costs among several broadly defined classes of ratepayers. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. In addition, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class. At the highest level, there are two partially overlapping principles to help guide the task of allocating costs efficiently and equitably:

1. Cost causation; and
2. Costs follow benefits.

There are two major quantitative frameworks used around the United States for cost allocation: (1) embedded cost of service studies and (2) marginal cost of service studies. Embedded cost studies use analytical methods, including historic load research data, to divide up existing costs making up the existing revenue requirement. Marginal cost studies look at changes in cost that will be driven by changes in customer requirements over a reasonable future planning period of perhaps five to 20 years, and typically involve more substantial forward-looking analysis than embedded cost techniques.[62]

Embedded cost of service studies are the most common form of utility cost allocation study, sometimes termed “fully allocated cost of service studies.” Most state regulators require them, and nearly all self-regulated utilities rely on embedded cost of service studies. The distinctive feature of these studies is that they are focused on the cost of service and usage patterns in a test year, typically either immediately before the filing of the rate case or the future year that begins when new rates are scheduled to take effect. This means there is very little that accounts for changes over time, so it is primarily a static snapshot approach. MPSC uses a projected test year in rate cases, typically one or two years in the future from the filing of a rate case.

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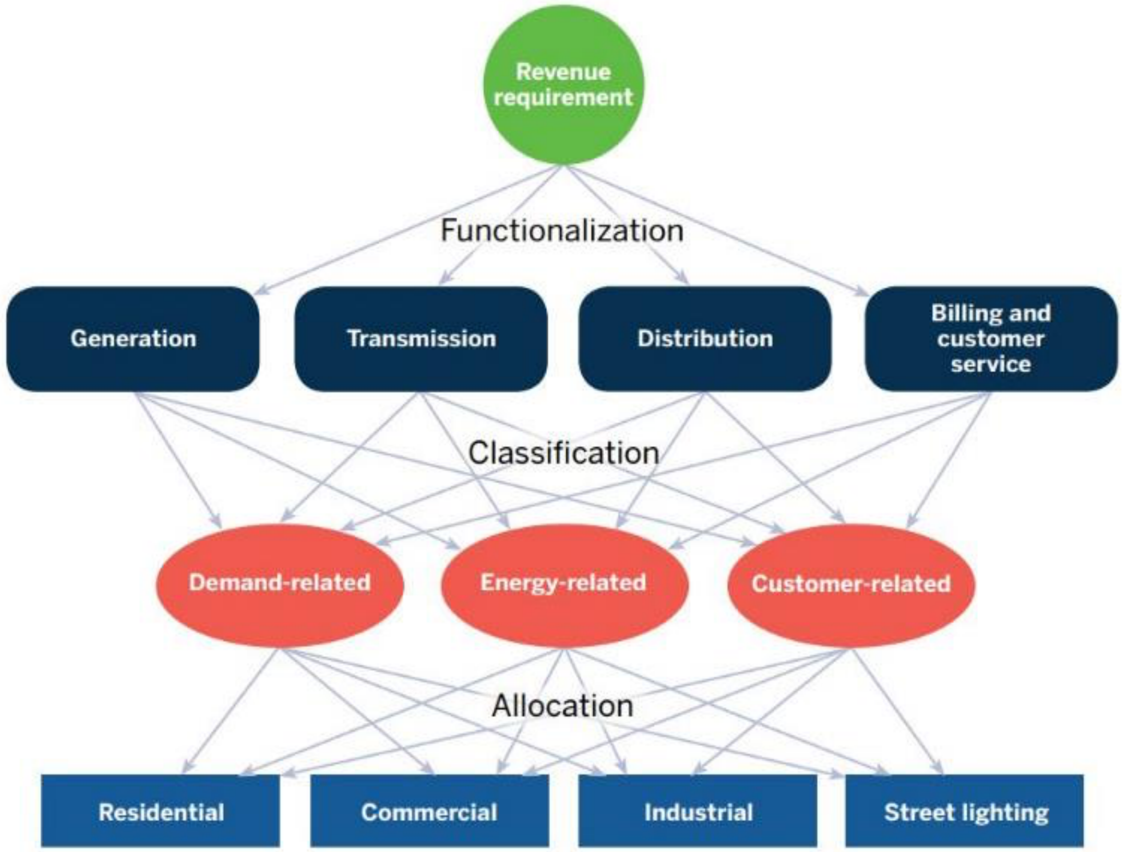
[60] Lazar and Colburn, 2013.

[61] This section is derived from much more comprehensive descriptions and analysis in Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project, https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[62] In many embedded cost jurisdictions, additional consideration of marginal costs can be incorporated at the rate design stage.

Figure 11. Diagram of traditional embedded cost allocation approach



As shown in Figure 11, embedded cost allocation techniques follow three typical steps of (1) functionalization, (2) classification, and (3) allocation. There can also be more than one way across the three steps to achieve a similar result in this framework. But as a general matter in this framework, a cost allocation analyst is forced to choose which of the three classifications (demand-related, energy-related, or customer-related) fits best for each category of costs, a process which has been long understood to have major flaws. In most cases, the allocation step contains more nuance and flexibility where many different allocators are used for different kinds of costs.

"But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion is that it belongs to none of them…. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that 'the sum of the parts equals the whole.' He is therefore under impelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories."

Bonbright, Principles of Public Utility Rates, 1961 edition, p. 348-49[63]

[63] https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

Seeing the weaknesses of the historical embedded cost allocation techniques, as well as typical rate design structures, regulators in many jurisdictions across the United States reformed cost allocation techniques in the 1970s and 1980s by adopting marginal cost of service techniques instead. In contrast to the static snapshot that is typical of embedded cost approaches, marginal cost of service studies explicitly account for how costs change over time and which rate class characteristics are responsible for driving those changes in cost. The fundamental principle of marginal cost pricing is that economic efficiency is served when prices reflect current or future costs — that is, the true value today of the resources that are being used to serve demand — rather than historical embedded costs. Importantly, marginal costs can be measured in the short run or long run. A true short-run marginal cost study will measure only a fraction of the cost of service, the portion that varies from hour to hour with usage assuming no changes in the capital stock. By contrast, a total service long-run marginal cost study measures the cost of replacing today's power system with a new, optimally designed and sized system that uses the newest technology. More typically, marginal cost of service studies used a variety of medium- to long-term values for different elements of the electric system and regulators used these results to inform both cost allocation and pricing. Despite the theoretical appeal of these marginal cost methods, the complexity of these estimates proved daunting over the past several decades and led to numerous stakeholder disputes as well. Many jurisdictions have migrated back to the relative simplicity of embedded cost allocation techniques.

However, one key insight of marginal cost allocation techniques is the idea that marginal cost pricing will almost never approximate the revenue requirement determined in a rate case using the embedded cost of service. As a result, it escapes the trap described by Bonbright above, because a round peg is never forced into a square hole. In some historical circumstances (e.g., high marginal fuel prices in the 1970s) marginal cost pricing may have collected more than the revenue requirement, but in most prevailing conditions it is thought that marginal cost pricing for electric utilities will collect less than the embedded cost of service.[64] The additional costs that need to be collected to meet the full revenue requirement are called "residual costs." There is no generally accepted way to allocate and price these costs, although jurisdictions have used both the "equal percentage of marginal cost" (EMPC) technique or the inverse-elasticity technique to allocate these costs.

[64] This particular circumstance often excludes externalities from the definition of "marginal cost."

What is a cost shift?

There can be numerous different definitions of "cost shift" and different stakeholders may use the term differently. Clarifying precisely the potential issue could be helpful to solving any problem, although the different definitions are partially overlapping. The first set of possibilities can be referred to as embedded cost definitions of cost shifts.

> Embedded cost definition among customer classes at the cost allocation stage – In between rate cases, a customer class that reduces its cost allocation determinants disproportionately compared to the other classes will reduce its revenue allocation in the next rate case, leading to higher revenue allocations to other customer classes.
>
> Embedded cost definition within a customer class at the rate design stage – In a rate case, if a given set of customers has reduced its billing determinants significantly, then a given *rate* must be higher to collect the same amount of revenue from that class.

Mechanically, these embedded cost definitions of a cost shift are straightforward, but whether this represents a problem that affirmatively needs to be solved can still be disputed. Possible disagreements are the reasonableness of current cost allocation and rate design techniques, as well as the lag between current day rates and the timeframe where long-run cost savings can be achieved. However, some parties may instead point to the ratepayer and societal benefits that are not explicitly considered in either cost allocation or rate design. Many of these benefits are typically considered more explicitly in the cost-benefit tests described above. This leads to a different marginal cost definition of a "cost shift."

> A marginal cost definition of a cost shift asks whether the value of the resource falls short of its compensation, or vice versa. For example, if a solar PV customer is effectively compensated at a retail rate of 12 cents per kWh but provides a value of 14 cents per kWh, then there is no cost shift under this marginal cost definition. However, if that solar PV customer provides a value of only 10 cents per kWh, then that would represent a "cost shift" under this definition.

Again, this is conceptually straightforward but subject to numerous different potential disputes. Parties may disagree about many different aspects of value, such as how to calculate long-run electric system values and whether to include societal benefits. Picking the relevant benefits to include in this analysis, as well as consideration of any relevant costs, is strongly overlapping with the choice of a benefit-cost analysis framework. Some stakeholders may also disagree with this framework, arguing instead that the way to maximize ratepayer benefits is to procure at least cost.

The last potential definition of a cost shift revolves around the issue of residual costs. This can be considered under either the embedded cost framework or the marginal cost framework, although marginal costs techniques wrestle with this more explicitly.

> A residual cost definition of a cost shift asks whether a group of customers contributes the same additional revenue above their marginal costs towards the utility's embedded cost of service, such that other customers are not asked to contribute more than they had previously.

Under the embedded cost framework, this is similar to questions that can be asked about the cost causation basis of embedded cost allocation and pricing techniques. This question is different than the above marginal cost definition of cost shifting because residual costs are *an additional cost* above and beyond marginal electric system costs that utilities had expected to collect from the relevant group of customers. However, calculated residual costs are likely to be much lower if societal benefits are included in the marginal cost calculation.

4. Overarching Program Parameters

Rate design for distributed energy resources occurs within the context of a utility tariff that specifies the terms and conditions of exchange between the DG resource owner and the utility. These tariffs often operate in the context of utility commission regulations and orders, as well as other statutory and regulatory frameworks, which can be described as a broader program for distributed energy resources. The tariff specifies how a customer will be billed by the utility, or in some cases compensated financially outside of their traditional utility bill. The tariff also specifies the obligations of the DER resource owner and the utility relative to the operation and use of the resource. Metering and billing are foundational to the terms and conditions of the transaction, and the regulator has options in defining how metering and billing will work. The first part of this section describes those options.

The second part of this section describes other terms and conditions that are typically included in a tariff for distributed generation or DERs more generally. Other terms and conditions often include customer eligibility requirements, interconnection requirements, renewable energy credit (REC) ownership requirements, data sharing and transparency requirements and specification of any program or nonbypassable charge obligations accepted by the DG resource owner. Tariffs are not static and over time the terms and conditions available to customers often change. The third part of this section describes how regulators address the transition of tariffs over time. This section concludes with a discussion of how underlying analyses are completed and reviewed by the PSC and introduces the role of pilots in testing new tariff possibilities.

A. Metering and Billing Frameworks

The fundamental exchange between utility customers, including those with DERs, and the utility is captured in the specification of how their bills are calculated and designed. For customers with distributed energy resources, there are numerous options to consider which are described at a high level in this section.

i. Monthly Netting

The most typical metering setup for distributed generation customers across the country to date has been net energy metering with monthly netting. This setup measures net kWh consumption[65] each month to determine the customer's bill. Consumption offsets production from the DG resource over the course of the month and if there is a net consumption of energy for that month, the customer is assessed a charge for that net consumption based on the tariff rate design. If there is a net production for the month, then the customer is paid or credited based on the export credit structure specified in the tariff. While a common policy has been to define the export credit at the full retail rate for the customer class, there are now many different variations on this across the country. For months with net production, the resulting credits are typically applied toward future billing periods rather than resulting in a payment to the customer. Under monthly netting,

[65] Under the simplest version of this metering setup, a utility cannot tell any more details about how a customer is using the system. The kWh meter counts up as energy flows in, and reverses direction as energy flows out. In some jurisdictions however, monthly netting is calculated from more sophisticated metering data.

all hours of the month are fungible in the sense that net consumption in any hour is counted the same as net consumption in any other hour. In this framework, a customer minimizes their bill (or maximizes their credit value) by lowering their consumption and increasing their generation (to the extent that generation can be managed or influenced).

ii. Inflow/Outflow Measurement (aka Instantaneous Netting)

The metering setup either known as inflow/outflow (as it called in Michigan) or instantaneous netting, typically measures a customer's net consumption or net production in real time. At the end of the billing period, there is a separate billing determinant for kWh of inflow (imports or energy received from the grid) and outflow (exports or energy delivered to the grid). Several different metering setups are capable of billing on this basis. The simplest has two kWh registers, one that tracks kWh imported and another that tracks kWh exported. Advanced meters and interval metering arrangements may either track imports and exports separately for each time period, or else calculating net imports or net exports within a small (e.g., 5 minute) interval, which tends to produce a very similar result.[66] Under this framework, the customer is still billed every month but always has two non-zero kWh billing determinants if there are any exports to the grid. If the credit for exports is lower than the retail rate for imports, then a customer can minimize their bills by shifting consumption to times that they would otherwise be exporting energy because self-consumption is compensated at a higher rate than exports.

iii. Time-of-Use Netting

In time of use netting, net imports and net exports are aggregated for all hours within like time periods. For example, if there is an on-peak range of hours specified in the tariff (e.g., 2 pm to 7 pm on weekdays) then all on-peak hours are aggregated for the billing period to produce one billing determinant for those hours. In time of use netting, hourly net imports or exports are fungible only for hours within the same time of use period. Some jurisdictions and utilities have applied time of use netting in a rigid way, where kWh credits earned during one pricing period (e.g., summer on-peak) can only be used during that same window in subsequent billing periods. Monetary crediting, discussed further in Section 5.B, solves this issue, but there can be other ways to address it as well.

iv. Buy-All/Credit-All Metering and Billing

Monthly netting, inflow/outflow billing, and time of use netting contemplate compensation of a DG resource that exists behind the meter at a site where use of power from the grid, self-consumption of on-site generation, and exports to the grid are all structurally permissible. In the alternative, buy all/credit all metering can apply to behind the meter installations as well, but it is worth noting that it can also be appropriate for standalone DG resources that sit in front of the meter. In a buy all/credit all construct the customer buys all of the energy that they consume from the utility at the retail tariff and is compensated for all energy they produce at an export

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[66] This result would only be noticeably different if a customer switched from importing to exporting within the time intervals and managed to have significant netting of imports and exports within those interval windows.

tariff price. Buy all/credit all arrangements require metering that tracks production separately from consumption to preclude any self-consumption of DG production by the customer. This is often an incremental cost, although sometimes this utility billing framework can take advantage of a generation production meter required for another program or purpose.

One issue with this framework is that generation, storage, and consumption cannot all be optimized together. Depending on how the wiring and interconnection is required to be done, a customer could not use a single storage installation to manage both generation and usage, and otherwise it would defeat the purpose of separate billing of gross generation and gross consumption. However, both the retail consumption rate and the export credit structure can be managed independently and could be as simple or as sophisticated as desired in either case, as long as the relevant metering and billing systems can handle it.

v. Stand-Alone Distributed Energy Resources And Remote/Virtual Net Metering

Like buy-all/credit-all metering, where on-site projects are metered separately, some jurisdictions allow distributed energy resources to interconnect to the distribution system regardless of any particular arrangement with or proximity to specific electricity customers. These resources are then allowed to earn export credits, just like other DER exports, and allocate those credits to electric customers according to the rules of the particular jurisdiction. This type of arrangement goes by many different labels, such as remote or virtual net metering, but can more generically be referred to as stand-alone distributed energy resources. This is the predominant model for community solar programs in many states. Since there is no presumption that these projects are located near any other customers, each stand-alone distributed energy resource requires its own metering. Many different compensation structures are possible depending on the metering for these projects.

vi. Options That Require Advanced Metering and Advanced Inverters

With advanced metering infrastructure, the options for netting methods expand enormously. Netting periods could be based on the smallest interval that the metering and billing system can handle or any aggregation of those time periods. That can include hourly netting or inflow/outflow measurement within each hourly period. However, these more complex structures would likely only be appropriate for more sophisticated customers or would need to wait for the availability of reasonably affordable automated energy management technology.

In addition, DER resources with advanced inverter functionality can offer additional services like voltage and frequency regulation. DERs may also become part of a non-wires solution that addresses local grid congestion or mitigates local grid stress. In that case the DER is providing a specific service under specified terms and is separately compensated for those capabilities. Compensation for the functionalities delivered by advanced capabilities can be specified as options within a tariff or they may exist in a separate tariff that is targeted at acquiring these additional services. While these granular options for compensating DG resources for services other than energy alone are rare today, they are technically feasible but will only become common when utility distribution information systems evolve to integrate best practice digital technologies that exist today and that will likely become prevalent in the coming decade.

B. Other Program and Tariff Design Features

Billing and metering specifications are the central feature of a DG resource tariff, but tariffs include other provisions that clarify eligibility and obligations of participating customers and the utility. This section describes some of these features.

i. Tariff Eligibility by Customer Class and Resource Specification

Customers who own and operate DER are not homogenous. All customers must interconnect their resource to the utility distribution system in compliance with adopted interconnection requirements, but the interconnection requirements can vary. Customers differ based on their energy requirements, on the size of their resource, on the combination of resources they operate and on how the resource is interconnected to the grid. For example, larger systems are likely to require more significant interconnection study and may well include certain dedicated facilities that a smaller installation would not require. Another example where customer difference matters fall with customers that adopt solar and storage facilities may present different interconnection requirements and offer a different range of grid services. And, of course, larger commercial and industrial customers are adopting resources in a far different context than your average residential customer. For a given set of customers, there can be restrictions on the size or other features of the distributed energy resource that they are allowed to adopt or the manner in which they operate their resources. This can also be for reasons that are unrelated to the electric system impacts, such as U.S. Internal Revenue Service restrictions on the applicability of tax credits. For all of these reasons, more than one tariff may be required and eligibility for the tariff would align with the customer and situational context contemplated in the given tariff. Beyond the requirements that apply to a specific customer, many states, including Michigan, have put limits on the overall participation in the program. Sometimes referred to as “net metering” caps, these may be arbitrary from an electric system perspective but can serve as a check-in for evaluation of the relevant policies.

ii. Tariff Requirements Addressing Information Transparency and Control of the Resource

DER owners and operators benefit from transparent information on grid conditions and grid resource needs so that the operation of the facilities can be optimized. Utilities benefit from transparent information on the use of customer facilities so that the utility can plan for an optimized system that accommodates all resources and loads within the necessary system parameters. Each DER has value on multiple domains: behind the meter, on the distribution system domain and on the wholesale system domain and realizing value across multiple domains requires transparent information sharing. Sometimes, utilities or a third-party service provider may require control of a DER in exchange for compensating the owner or operator for certain capabilities.

Information sharing, transparency and DG resource control are complex and potentially controversial on both sides of this relationship so the information architecture specified in the tariff can be a difficult negotiation. That being said, there is public benefit to finding the right balance and the tariff should specify that balance point for the tariff in question. Different tariffs may require different information and control requirements but every tariff benefit from being clear about the information, privacy and control terms.

iii. Renewable Energy Credit Ownership

In some states, production from renewable generation resources are recognized as generating renewable energy credits in proportion to the renewable production from the facility. In some tariffs the REC is retained by the resource owner while in others it automatically transfers to the utility administering the tariffs. RECs have value so specifying the ownership terms and conditions in the tariff is essential. Under a variety of different certification schemes, it is generally thought that ownership of the RECs represents the claim to the "environmental" attributes of that generation. As a result, specific compensation for the environmental values of a resource can be reasonably tied to transfer of REC ownership.

iv. Nonbypassable Charges and Program Costs

Certain costs incurred by the utility on behalf of DER customers or on behalf of all customers may be deemed to be partially or wholly the responsibility of DG resource owners. For example, program administration costs associated with operating a DER program that aligns with a given tariff may be assigned to DER customers operating under that tariff. Other costs, like energy efficiency program costs, may be deemed to be the responsibility of all customers and the tariff may need to specify the obligations of the DER customer to continue to contribute to these costs after they migrate to a new tariff. This latter category of costs is called nonbypassable charges. Other typical costs included in nonbypassable charges might be associated with decommissioning nuclear facilities, the securitized cost of retired plants, or operating other public purpose programs, like programs that explicitly support low- and moderate-income customers or utility EV charging programs. Tariffs specify how program costs and nonbypassable charges will be collected for tariff participating customers.

C. Treatment of Pre-Existing Net Metering and DG Program Customers

When a default DER tariff changes the regulator needs to decide how customers served under the pre-existing tariff will be treated. In most states the pre-existing customers keep their default tariff for some period of time and new customers are enrolled in the new default tariff. The treatment of pre-existing customers is sometimes specified in the enabling legislation that caused the original tariff and sometimes the regulator specified an implicit or explicit expectation of the duration of the tariff. By statute, Michigan has specified that 10 years is an appropriate timeframe for grandfathering but many other jurisdictions have adopted longer timeframes, in some cases as long as 20 years.[67] In this typical treatment the pre-existing DER customers are said to be "grandfathered" into the original tariff. The economic justification for grandfathering is often founded in changing fundamentals of DER ownership over the last decade. Pre-existing customers entered into a tariff that was created based on those fundamentals with certain economic expectations. However, the fundamentals have changed. The cost of solar has declined significantly so new customers face a lower cost of ownership and the value of solar to the system may have changed over time as the penetration of solar expanded (e.g., the value of afternoon energy may have declined as the amount of solar increased). In addition, the emergence of less expensive storage has changed the options open to customers who adopt certain DERs today.

If new and existing DG customers are treated differently based on differences in fundamentals and based on specifications in law, then the creation of a new rate structure with significantly different economics may be more feasible. If existing customers are not grandfathered, then severe customer and political backlash has been observed from major reforms. For example, the Nevada legislature passed AB 405 in 2017, which reversed a Nevada Public Utilities Commission decision to take away grandfathered tariffs as a part of net metering reform. However, in some places existing customers do have portions of their tariff changed when new tariffs are introduced. See the California NEM discussion in the Appendix for a brief discussion of that transition. In other words, gradualism in transitions may be a reasonable substitute for grandfathering of pre-existing DER customers.

D. Process, Analysis and Pilots

The traditional process for utility ratemaking has an established structure, where a public utility commission sets the rules and parameters in advance (e.g., the uniform system of accounts) and then the utility presents their affirmative case in a proposal to the commission, along with the required testimony and analysis. Other parties, including Commission staff under the MPSC structure, scrutinize the utility's testimony and analysis through discovery and file testimony and analysis of their own. The analysis from those other parties may either follow the same general parameters as the analysis presented by the utility, or else parties may choose to file analysis that they believe is more relevant and persuasive on the issues in question. Further discovery, cross-examination at a hearing, and formal briefs from all parties round out the litigation before the commission decides on the relevant issues.

While this process works reasonably well on some issues, alternative procedural approaches can serve to level the playing field and give more opportunities to parties that do not have funding to participate from either ratepayers or the state. Collaborative working groups, intervenor funding, and hiring independent experts to do the relevant analysis with stakeholder input are all methods used in many jurisdictions to help make well-informed public policy decisions. The MPSC, or potentially other state agencies, could form a partnership to analyze key questions with the

[67] Nevada and Arizona established 20-year grandfathering. The Nevada legislature passed AB 405 in 2017, which established 20-year grandfathering for each of the four tariffs specified (see https://puc.nv.gov/Renewable_Energy/Net_Metering/ for a description of these four tariffs). The Arizona Corporation Commission instituted 20-year grandfathering in its 2017 decision as reflected in Arizona Public Service tariffs (see https://www.aps.com/en/Residential/Service-Plans/Understanding-Solar for a description of the APS tariff terms including grandfathering).

national labs under the United States Department of Energy or one of Michigan's universities. Different processes could even be used for different parts of a DER rate design proceeding.

In addition, pilots for new rate designs and programs can be used in order to collect data and create a shared understanding of the potential results and implications of certain reforms. Piloting also has the advantage of offering the opportunity to experiment with more than one tariff design. For example, a more moderate reform can be implemented as a default structure while more complex rates can be tested in pilots.

5. Designing Rates and Credits

When designing retail rates for electric customers, as well as credit structures for customers with export capabilities, the options are nearly limitless.[68] Much like the colors of the rainbow, they can be grouped for convenience but when examined closely there are infinite shades of each color, and one color gradually transforms into the next. For example, a demand charge with an annual ratchet shares many properties with typical monthly demand charges, and peak-time rebates share many properties with critical peak pricing – just as purple blends into blue and orange into red.

A. Designing Retail Rates

i. Fixed Charges

Fixed charges do not change from month to month based on the amount or timing of usage and are generally based on some permanent (or infrequently changed) characteristic of the customer. Because they are fixed from month to month regardless of customer behavior, customers generally have no way to reduce the fixed portions of their bills other than cancelling service all together. There are several types.

1. Monthly Customer Charges

Customer charges are per-month fixed charges that apply to each customer in a tariff class, regardless of usage. Under a typical flat monthly customer charge, higher customer charges impose larger burdens on the customers with lower usage within that customer class. For residential customer classes in many jurisdictions, this often means higher bills for low-income households and apartment residents, which all tend to have lower-than-average usage. Ideally, the customer charge should not exceed the customer-specific costs that are attributable to an incremental customer being added to the system (i.e., a service line, billing, collection, simple metering, and a share of customer service).

It is most common to have a monthly customer charge that is the same for all customers in a class, but there are variations worth noting. In Nevada, for instance, residential customers are effectively split into two classes: (1) single-family with a customer charge of $12.50 per month and (2) multi-family with a customer charge of $7.70 per month.[69] In several jurisdictions, there are a variety of tiered customer charges and subscription-style customer charges. In Burbank, CA, for one, the municipal electric utility has a base residential customer charge of around $9 with a three tiered system of service size charges depending on the type of customer: an additional $1.40 per month for multifamily customers, an additional $2.80 per month for a single family building customer with a panel size less than or equal to 200 amps, or an additional $8.40 per month for a customer with a panel size over 200 amps.[70] Electricite de France (EdF)

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[68] A previous RAP publication on rate design generally is Lazar, J. and Gonzalez, W. (2015). Smart Rate Design for a Smart Future. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7680

[69] https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/np_res_rate.pdf

[70] https://www.burbankwaterandpower.com/electric/rates-and-charges

has residential tariffs with customer charges based on a kVA subscription level that starts at approximately 9 euros per month for 3 kVA and escalates to nearly 40 euros per month for a 36 kVA subscription.[71] In the case of Burbank, these customer charge levels will typically not change over time, unless a customer installs a different service panel. But in the case of EdF, customers can choose different subscription levels, making this more akin to a subscription or contract demand charge.

2. System Access Charges

System access charges, sometimes called grid access charges, are essentially fees charged to DG customers each month for the privilege of being connected to the grid.[72] These are often defined as a fixed fee per kW of installed capacity, meaning that the charge a customer sees on each monthly bill varies depending on the size of the DG unit. The NY PSC decided that a monthly "customer benefit contribution" charge of approximately $1 per kW DC of installed PV generation would be applied to new residential installations beginning in 2022. Part of the rationale for such a charge was that NY has still operated under traditional retail rate net metering for residential customers, and that rate design reforms were waiting for full rollout of advanced metering infrastructure. Revenue from this new charge will to be directed towards NY's low-income discounts as well as energy efficiency and clean energy programs.

3. Minimum Bills

Minimum bills impose a minimum charge to a customer if their bill as otherwise calculated does not meet a minimum threshold level. If a customer otherwise has a bill higher than the minimum threshold level, it does not impact them. A customer with on-site generation, storage, efficiency, and other DERs could be affected by the minimum bill if their metered usage (because of netting or other reasons) is very low, and this could decrease the value proposition for DERs. Other features of a rate structure for DER customers can have similar impacts to a minimum bill. As noted previously, a rollover policy that prohibits credits from being applied to certain portions of the bill can be thought of like a minimum bill as well.

ii. Energy (Per-kWh) Charges

1. Flat kWh Rate

The simplest form of energy charge is the flat kWh rate, which is derived by simply dividing the relevant portion of the revenue requirement for a given class of customers by the kilowatt-hour sales and charges a purely volumetric price. Since price doesn't vary based on time for the customer, homeowners and businesses have no real incentive to minimize their use of electricity during peak demand hours. In many jurisdictions historically, flat rates have had either inclining block – where the rate goes up over a certain kWh threshold – or declining block – where the rate goes down over a certain kWh threshold – features.

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[71] https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grille_prix_Tarif_Bleu.pdf

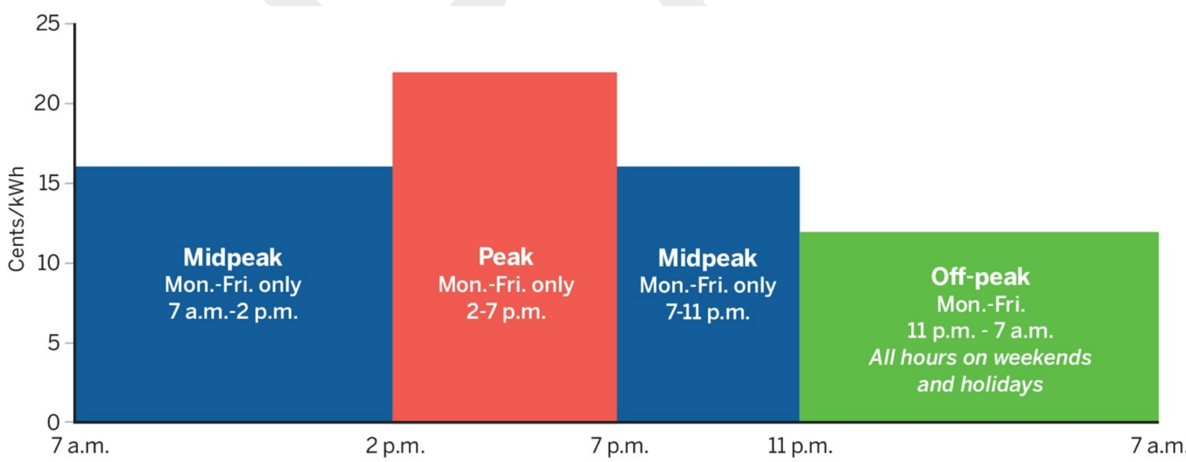
[72] In Michigan, at least one utility has labeled a traditional monthly customer charge as a "system access charge."

2. Time-of-Use Rates

Time of use (TOU) or time of day (TOD) rates vary depending on the time of day according to a regular pre-determined schedule. These rates recognize that the utilities cost to generate and deliver the electricity can vary at different times of the day and year. For example, it is more expensive to generate electricity on a hot summer afternoon when everyone is running their air conditioners. So many people calling for increased electricity demand requires utilities to run less efficient, more expensive power plants to meet this increased demand, and also sets a major portion of capacity costs for generation resource adequacy. By contrast, mild spring or fall weekends when demand for heating and cooling is low, may have a surplus of capacity. Well-designed TOU rates are a cost causation improvement over flat or block rates because they offer some correlation between the temporally changing costs of providing energy and the customer's actual consumption of energy. Of course, as the characteristics of the electric system and customers change over time, the structure of TOU rates will continually need to be updated to match cost causation patterns.

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 an "on-peak" period, during which prices are higher than during "off-peak" hours. In most cases, on-peak periods are limited to weekdays. The simplest TOU rates are only defined by two pricing periods within each billing period. However, three pricing periods are fairly common (see Figure 12), and four or more are possible. Simple TOU rates can be implemented with relatively cheap meters (e.g., two registers and a programmable timer), but more advanced TOU rates may require interval meters or full advanced metering infrastructure.

Figure 12. Illustrative three-period summer residential time-of-use rate



There are many different choices that go into the design of a time-of-use rate.[73] Moving from two to three pricing periods provides extra flexibility at the cost of some additional complexity for both customers and the utility. In addition, having an on-peak period that is too narrow risks missing or shifting the actual peak without reducing it. Conversely, a broad on-peak period

[73] See generally Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates, Colgan, J. et al. (July 2017), https://uspirg.org/reports/usp/guidance-utilities-commissions-time-use-rates

makes shifting load outside of that window more difficult and may penalize those without options to shift load. Additional options like “feathering,” where customers are allowed to choose between different 3-hour peak periods (e.g., 2 pm to 5 pm, 3 pm to 6 pm, or 4 pm to 7 pm), are also possible.

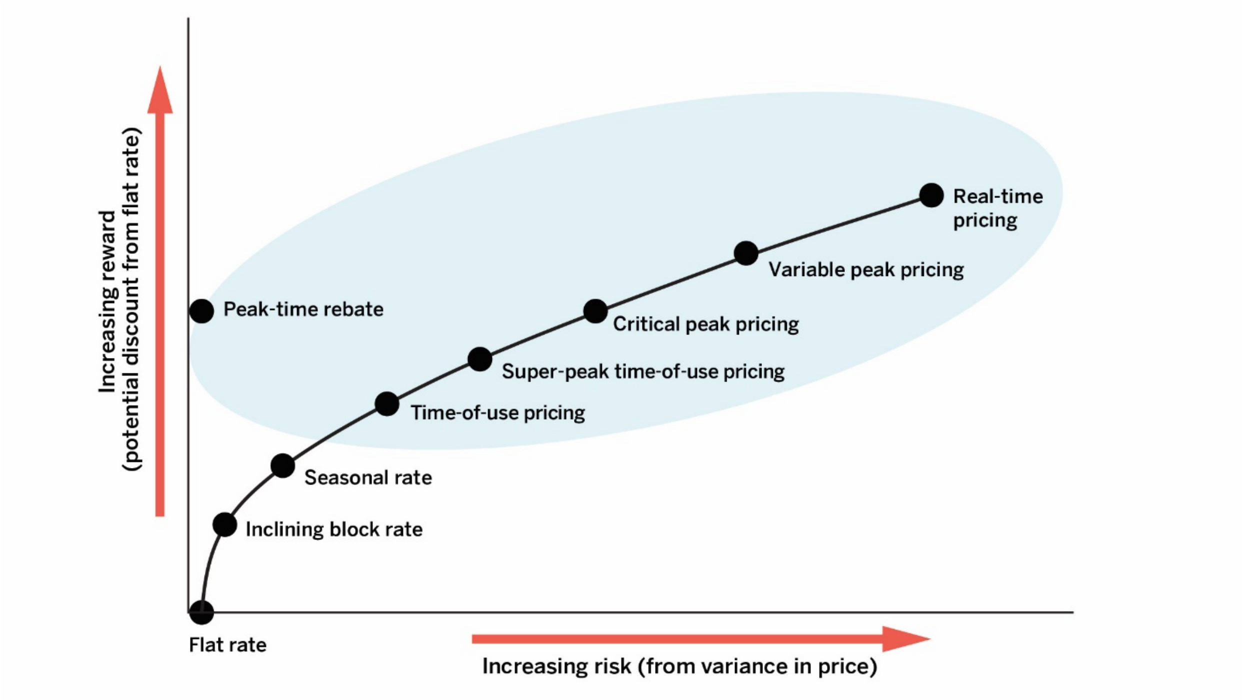
3. Critical Peak Pricing, Variable Peak Pricing, Peak-Time Rebates and Real-Time Pricing

Critical peak pricing (CPP), variable peak pricing (VPP) and peak-time rebates (PTR) can be considered refinements to the TOU concept but are determined based on day-to-day electric system needs. 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. Variable peak pricing, as it is currently being implemented for Oklahoma Gas & Electric, allows the utility to choose between four different daily peak prices depending on wholesale market conditions: (1) low, (2) standard, (3) high, and (4) critical.[74] This provides an additional element of discretion beyond just the critical peak designation. Under the PTR concept, rather than charging customers a high critical peak price, customers are given a credit on their bills if they can reduce usage during a peak-time event. Most versions of CPP, VPP and PTR require advanced metering infrastructure.

Real-time pricing goes further than the previous three options by charging the customer prices that vary by hour or even smaller time increments. This can be the actual prices set in wholesale markets, or the wholesale price could be adjusted. As more technologies become available that enable customers to respond to electricity prices more dynamically, various forms of real-time pricing may become more widely available. With technologies like smart appliances and energy storage, customers can automatically monitor and respond to prices as they change and monetize the potential benefits through bill savings. Furthermore, by ensuring that these customer price signals are directly linked to electric system market conditions, it can be a significant improvement in the value of a customer’s response. However, this can represent additional risk to a consumer and almost certainly lowers overall bill stability. This can be conceptualized as a risk-reward tradeoff for customers as depicted in Figure 13.

[74] https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

Figure 13. Representation of customer risk-reward trade-off in time-varying tariffs



Source: Faruqui, A., Hledik, R., and Palmer, J. (2012). *Time-varying and dynamic rate design.*

While this risk to the customers adopting the rate needs to be accounted for, there are also broader ratepayer benefits from least-cost system planning and operation if customers are able to respond appropriately to more sophisticated price signals.

4. Bidirectional kWh Rates or "Distribution Flow" Charge

A "bidirectional" kWh rate to ensure that DER customers pay for usage of the grid is an approach that has been less frequently discussed than other options.[75] Customers with distributed energy resources are able to self-supply some of their energy needs but also typically export energy to the grid. With some exceptions, kWh rates historically have only applied to imported energy, but they can also be applied as a charge on exports. The concept is that the DER customer taking power from the grid needs the grid in order to have reliable service. This same customer, however, also needs the grid when the DER customer is in an exporting condition and thus pays a charge when feeding power to the grid. Under the simpler versions of this concept, this would show up as a reduced credit for exports[76] and shares many similarities with "asymmetric" import rate and export credit schemes.

[75] For a longer discussion, see *Designing Distributed Generation Tariffs Well: Fair Compensation for a Time of Transition* (2013). Linvill, Carl, John Shenot and Jim Lazar, Regulatory Assistance Project (http://www.raponline.org/wp-content/uploads/2016/05/rap-linvillshenotlazar-faircompensation-2013-nov-27.pdf).

[76] It is technically possible that the combination of a credit value and an export charge could combine to be net charge to the DER customer for exporting energy.

One specific version of this concept would set up a separate "distribution flow" charge that is the same whether a customer is taking a kWh from the grid or exporting kWh onto the grid. The distribution flow charge corresponds directly to a broader conception of how DER customers will be using the grid in the future, as well as a reasonably intuitive metric of the "size" of a customer. Other key features of this concept are that it does not result in any significant rate structure change for customers who do not export energy, that it avoids undue discrimination because the rate is the same across all customers within the class, and that it applies both to imports and exports. Such a distribution flow charge could be limited to certain categories of costs that are unambiguously relied upon by the DER customer when exporting, as well as any nonbypassable charges and a portion of administrative and general costs. Importantly, the rate necessary to recover the relevant categories of costs would be lower than a rate applied just to imports, because this new billing determinant (imports plus exports) would be higher and the costs would be spread over a larger denominator. As a result, customers without DER would actually experience a reduced charge per unit for these costs and thus lower bills.

iii. Demand-Based Charges: Individual Maximum kW Charges and Other Forms of kW Charges

A customer's instantaneous demand for power, denoted in kW, is a measure of the capacity needed to serve its combined end-uses in that moment. Most demand charges are based on a customer's maximum call for power in a specified period, typically a month (i.e., a billing period). These rate designs have been around system nearly the beginning of the electric system in the late 1800s. As a practical matter, the charges are not based on the customer's highest instantaneous demand in a period, but rather on its highest short-term usage (typically 15, 30 or 60 minutes) in that time.[77] Demand charges come in a variety of forms, ostensibly to address particular needs, but there have long been questions about whether they are an efficient form of pricing.[78] The following subsections describe five types of demand charges seen in the US.

1. Traditional Billing Period Individual Non-Coincident Peak (NCP) Demand Charge

The most common form of demand charge is one that is assigned to a customer's individual peak demand during a billing period, which is referred to as the customer's non-coincident peak. This customer NCP might or, more likely, might not coincide with the overall system peak or any other time that drives shared system costs. This is illustrated for a residential customer in Figure 14.

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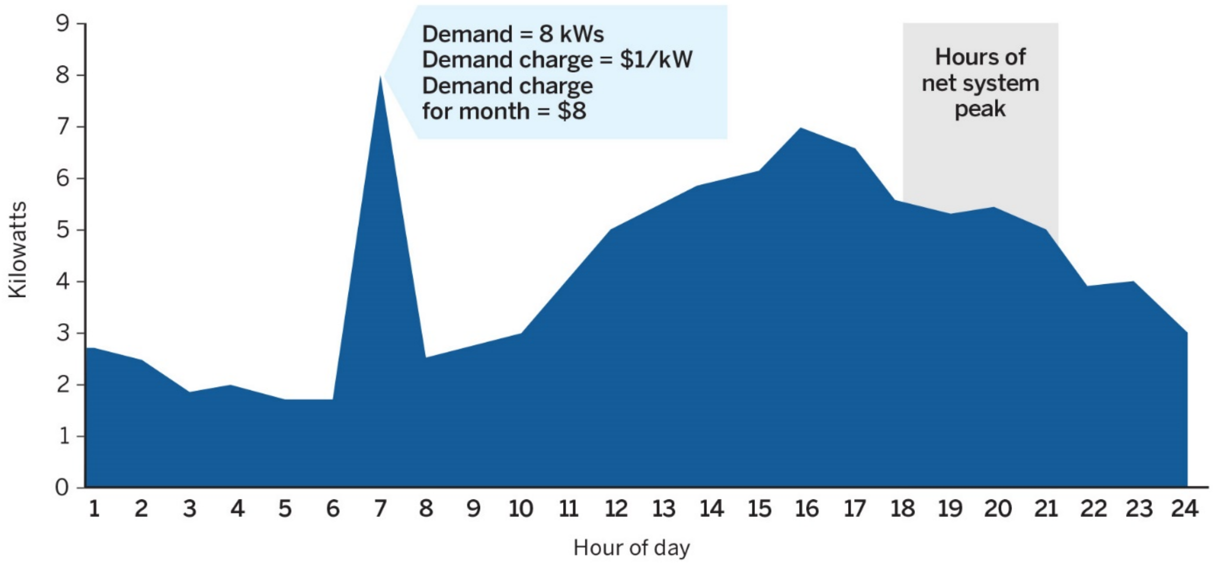
[77] This means that demand charges are priced on a "kWh per hour" basis instead of a true kW measurement.

[78] See LeBel, Mark, and Frederick Weston, "Demand Charges: What Are They Good For?" https://www.raponline.org/knowledge-center/demand-charges-what-are-they-good-for/

Figure 14. Illustrative monthly noncoincident peak demand charge for an individual residential customer



Because of the lack of clear correlation between individual customer peaks and the hours when usage drives system costs, demand charges have a relatively weak cost causation basis in the modern grid where the costs of load shifting are declining, and advanced metering enables numerous other options. However, demand charges have a better cost causation case for the elements of the system with little or no load diversity.[79] As mentioned previously, shared line transformers and other local distribution infrastructure will have less diversity of load than distribution substations, transmission systems and the regional generation system. Furthermore, dedicated transformers and dedicated service lines are naturally sized for individual customers, which can be impacted by that customer's NCP. For residential customers and small business customers, there are also significant questions about demand charges are sufficiently understandable and whether these customers can respond in an effective manner to manage their bills.[80]

Many monthly demand charges for large industrial customer classes are characterized by *ratchets* across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. 80% ratchets are quite typical, for instance: billing demand will be the greater of this month's noncoincident maximum load or 80% of the maximum in any of the previous 11 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to the hours that drive system costs, there remains little incentive to minimize usage at the times it would be most beneficial to the system.

[79] In addition, there can be more general benefits of limiting customer variability to the extent that a customer is able to respond in this manner.

[80] See Chernick, P. et al. (July 2016). Charge without a Cause? Assessing Electric Utility Demand Charges on Small Consumers, https://acadiacenter.org/resource/charge-without-a-cause/

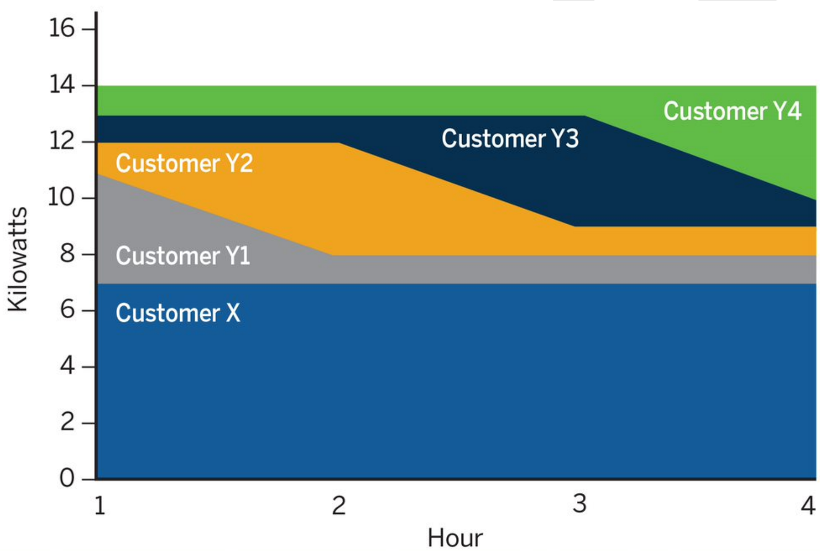
2. "Peak Window" NCP Demand Charge

A "peak window" demand charge is based on an individual customer's NCP within a defined multi-hour interval, similar to the on-peak period for a time-of-use (TOU) rate. Peak window demand charges are an improvement over their traditional counterpart, insofar as they do a better job of relating the contribution of a customer's demand to system peaks and allocating costs accordingly to it, but they nevertheless do not solve some of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are typically more efficient—and fair—than peak window demand charges for shared system costs for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period unless individual customer peaks are strongly correlated with the hours that drive costs.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

This latter point can be illustrated with a hypothetical case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Such a case is shown in Figure 15 for a four-hour on-peak period.

Figure 15. Customer load comparison illustrating ability to share capacity



Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as Customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, Customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that Customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Furthermore, incentivizing the Y customers to flatten their load within this time period does not necessarily lower the combined peak of these customers, although it could remove the cost allocation differential between customer X and the Y customers.

3. Contract Demand Charge

A contract demand charge shares much in common with a subscription-based fixed charge. The most common form involves large industrial customers contracting with the utility for certain levels of maximum demand for a fixed price. Historically, some contract demand charges have been higher if they are expected to be incurred at peak demand time, with an appropriate discount for individual peak demand that occurs at off-peak times. As noted previously, EdF provides a residential rate that includes a kVa subscription charge that strongly resembles a contract demand charge, although the categories of costs involved in this EdF rate are much narrower than a typical industrial contract demand charge.

4. Daily-as-Used Demand Charge

Daily-as-used demand charges are, as the name implies, a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges (which is to say that it is, at most, a 23-hour ratchet). In New York, daily-as-used demand charges are used as a part of standby rates.[81] Daily as-used demand charges applied to peak windows could be a further improvement on peak window demand charges for some purposes, and they could fluctuate according to system conditions. However, as such further refinements are made, such a system of narrowly applied demand charges converges on a system of time-varying energy (kWh) rates.

5. Standby Charge

A standby charge is typically an umbrella term for demand charges that are specially applied to commercial and industrial customers with distributed generation, sometimes termed "partial requirements" customers. Historically, many of these customers had large combined-heat-and-power (CHP) facilities. These customers were typically on rates that applied a traditional monthly demand charge, or additionally included an annual ratchet. If these CHP facilities underwent maintenance for a single day, they would trigger a substantial demand charge for the month or even set their demand ratchet for the coming year, a result that is both inefficient and unfair. A number of jurisdictions have tried to address this by adjusting standby demand charges for the lower probabilities of coincidence with system peaks. The charges themselves are either reduced in some way or the instances in which they are applied are more narrowly circumscribed. One example is the use of daily-as-used demand charges as an alternative to monthly standby charges, as described above. This approach recognizes that different combined heat and power customers are likely to have scheduled and forced outages on different days and therefore can share the capacity to provide their standby service. It also rewards customers for maintaining their on-site facilities and limiting outages.

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[81] https://cdn.ymaws.com/ny-best.org/resource/resmgr/energystorageresources/rider_q_pdf_final.pdf

B. Designing Credits

While debates over rate designs for electric utilities go back to the early 20th century, defining export credit structures for DG customers, or DER customers more generally, is a much newer topic. From the inception of "net metering", simply defined credit structures have been most common, but the potential variations and complexities are nearly endless once again.

i. Volumetric Versus Monetary Crediting

When defining an export credit scheme, there is a threshold choice about how to define the relevant unit for a "credit." When net metering was first established, many jurisdictions defined the credit by the number of kWhs, which can be called "volumetric crediting." If a customer had net excess generation of 100 kWhs in May, those kWh credits would roll over and could be used to reduce billed kWh in subsequent months, if that customer had net consumption. This would generally be true regardless of whether the *price* of kWhs changed in subsequent months, whether that was because of seasonal rates or other factors. While this simplicity had its virtues, many jurisdictions have subsequently found volumetric crediting to be inflexible in many situations. For example, it can be difficult to change the value of the credit if it is directly pegged to a kWh number[82] and thorny questions are also raised when using volumetric crediting in the context of TOU rates.

As a result, many jurisdictions, including Michigan in its transition from legacy net metering to the DG program, have necessarily gone from a volumetric crediting scheme to "monetary crediting." Under monetary crediting, any credits at the end of the billing period are defined by their dollar value in that period and can either be applied to other billing determinants within that same billing period (e.g., a customer charge) or rolled over to be applied in subsequent billing periods. There are often additional rules about whether and how monetary credits can be applied within the same billing period and how they get rolled over. The monetary value in the same billing period can also be different than the value that would be rolled over into subsequent months. Because of this additional flexibility, our following discussion of credit design in this section and potential pathways in Section 6 assumes that a monetary crediting framework will be used.

ii. Methods for Setting Monetary Export Credits

A simple starting point for the definition of monetary credit value is a direct link to the retail rate. From an administrative perspective, this provides an easy reference for every customer class. As noted previously, Michigan is currently taking this approach by defining credit value at the supply kWh rate, with or without transmission costs depending on the utility. Other jurisdictions have linked credit value to retail rates in numerous different ways. Projects of different sizes in Massachusetts have long been eligible for different portions of the retail rate. Small DG installations were eligible for the full kWh retail rate, albeit excluding energy efficiency surcharges, but larger installations only received the supply kWh rate and the transmission kWh

[82] Technically, a volumetric credit could be redefined as a percentage of a kWh to adjust its value. We are not aware of any jurisdictions that have attempted this approach.

rate. Reforms implemented in New Hampshire several years ago set the residential credit value at the sum of the supply kWh rate, the transmission kWh rate, and 25% of the distribution kWh rate.

Linking credit values to retail rate structures can also be done with time-varying rates as well as rate design elements besides kWh charges. When DG program customers are allowed to opt into time-varying rates under the DG program, they have time-varying supply credits that follow the underlying time-varying supply rate. Several other jurisdictions have used this approach as well. Under the DG program, MPSC is also defining a demand-based credit in reference to generation demand charges for some utilities' C&I rate classes.

Beyond the methods for setting export credit value in reference to retail rates, many jurisdictions have used a variety of methods for independently setting credit value. Historically, this included methods that were directly linked to wholesale market energy prices, such as a simple average wholesale price applied to credits generated in that month. A very different approach was started nearly a decade ago by Austin Energy, a municipal utility in Texas. Under a buy-all/credit-all structure, gross solar generation is credited at an administratively determined "value of solar" flat kWh rate, which included wholesale energy market value, generation capacity savings, T&D capacity savings, reduction in line losses, fuel price hedge value, and environmental benefits.[83] Shortly thereafter, Minnesota adopted a similar flat kWh value of solar tariff structure, which has only been applied to community solar projects to date.[84] Under Minnesota's structure, renewable energy credits are transferred from the customer to the utility because of the rationale that environmental benefits, represented by the REC, are part of the value-based compensation.

More recently, New York has implemented a sophisticated time-varying "value of distributed energy resources" crediting structure for larger distributed generation and certain kinds of energy storage installations.[85] This general "VDER" framework has evolved gradually since its creation in 2017. The following value-based credit structure is applied to hourly exports to the grid:

- Hourly wholesale energy market value;
- Generation capacity value, with alternative credit structures depending on the capabilities of a given technology;
- A general delivery avoided cost value and a location-specific adder for projects in areas with identified constraints;
- Environmental value for eligible technologies; and
- A "market transition credit" has now been transitioned to a "community credit" for community distributed generation.

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[83] Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator, Rabago, K., L. Libby, T. Harvey, B. Norris and T. Hoff, http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergysSolarTariff.pdf

[84] Further information on Minnesota's value of solar tariffs can be found in Appendix A.

[85] See https://www.nyserda.ny.gov/all-programs/programs/ny-sun/contractors/value-of-distributed-energy-resources Mandatory application of the VDER tariff structure was initially applied to onsite projects for C&I classes with demand rates and two different categories of stand-alone projects connected directly to the distribution system, known as "remote net metering" and "community distributed generation." Other customers are allowed to opt into this tariff.

Several of these VDER credit elements are time-varying, namely the hourly wholesale energy market value as well as the generation capacity value and delivery values for certain technologies. Other elements of the VDER structure are flat per-kWh credits, including the environmental value for eligible technologies.

As may be evident from the preceding descriptions, many of the credit structures developed independently from retail rates have focused only avoided costs or value-based methods. However, one component of the NY VDER structure has taken a notably different approach, with the original market transition credit and now community credit. The market transition credit was originally created to ensure that a category of projects that had a particular policy importance, namely community solar projects intended to provide an equitable distribution of solar program benefits, could continue without disruption and it was structured to step down compensation gradually over time. As this market transition credit phased down over time and other issues with its implementation details became evident, the NY PSC replaced it with the community credit as a more stable way to meet these important policy goals.[86] This shows more generally how it is possible in many circumstances to incorporate other policy goals in the design of export credits.

iii. Application of Credit Value and Rollover Provisions

There are a wide variety of rules in different jurisdictions regarding how credit value can be applied to bills and even allocated across customers. The most permissive set of rules may be in Massachusetts where nearly any customer that generates credits can file a form with the utility specifying how those credits should be applied to other customer accounts. New York also has permissive rules on this topic under the VDER tariff. The general theory is that the value of the credits does not change, and it is immaterial to other ratepayers how that value is applied to other customer accounts. Furthermore, this is a helpful way to provide flexibility for community solar programs to spread benefits to residential customers who cannot install solar on-site, or even certain kinds of commercial and industrial customers.

However, most jurisdictions do have a variety of limitations on how credit value can be used over time or across customers. A common feature of many early net metering programs is known as an annual "cash out" where any balance of credits is paid off to the customer, sometimes at a lower rate per kWh than the normal retail rate credit value. In other jurisdictions, credits may simply expire with no compensation to a customer instead of annual compensation. As Michigan policies in this area to date have shown, there are numerous other potential kinds of limitations, including the previous prohibition under legacy net metering from applying on-peak credits to off-peak consumption as well as limitations on whether generation supply credits can be applied to the distribution portion of the bill or the customer charge. Last, the value of credits can be different when used in the same billing period than its rollover value. This is part of the Duke Energy settlement in North and South Carolina, as further described in the Appendix.

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[86] See NY Public Service Commission, Order Regarding Value Stack Compensation (April 2019), Case 15-E-0751, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={06B07A5A-893A-48CB-BB0E-E8B3ABF4A7C6}

6. Reforms to Consider and Evaluation of Potential Pathways for DER Rate Design

A. Defining the Key Issues

With at least four important ratemaking principles and numerous additional policy goals for utility regulation, sorting through the key issues can be a challenge. We suggest four primary criteria, derived from long-standing regulatory principles, by which to evaluate DER rate designs:

- Fair cost allocation;
- Efficient customer price signals;
- Customer understanding and acceptance; and
- Administrative feasibility.

This is not because other principles and goals are unimportant, but rather that other goals are less directly impacted by DER rate design (e.g., revenue stability would likely only be impacted significantly in extreme cases) or require further quantitative analysis to determine (e.g., impact on DER-related jobs and industries). See the callout box on equitable distribution of program benefits and community solar. The easiest point of comparison for our three alternative pathways below is the current parameters of the DG program.

Equitable distribution of program benefits and community solar

In some places with higher levels of distributed solar PV adoption, concerns have arisen that the customers adopting solar were primarily homeowners with above-average incomes and broader demographic characteristics that were not representative of the entire population. In particular, renters and other residents of multifamily buildings cannot generally install solar on their rooftops. While these concerns should be evaluated fairly, there are two ways of resolving them. One is to shut down program participation, but the other is to try to open up the programs to broader public participation. This can be done through additional incentives, but can also be achieved through more structural reforms. Community solar, where larger solar projects are separately interconnected to the distribution system and subscribing customers are credited by the utility, is one such structural reform. Community solar customers enjoy a lower electricity bill but also make a monthly payment to the owner or operator of the community solar project, often having substantial overall net bill savings. Of course, if there are concerns about the crediting mechanism and levels for community solar projects, that raises another set of potential concerns, which was one of the significant motivations for the NY VDER tariff reforms.

In addition, it has been the case in many jurisdictions that commercial and industrial customers were also effectively prevented from meaningful participation in net metering programs, either because of size restrictions on projects or the fact that substantial demand charges for these classes meant significantly lower compensation through net metering. Reforming crediting mechanisms and other program rules to allow for comparable adoption levels by C&I customers is another way to promote an equitable distribution of program benefits overall.

i. Fair Cost Allocation

The concept of fair cost allocation typically goes back to the foundation principles mentioned earlier: (1) cost causation and (2) cost follows benefits. While these two principles are often applied at the stage of a rate case where costs are being divided up among customer classes, they apply equally to dividing up costs between customers within a class, sometimes called "intraclass cost allocation." As may be evident, the principle of cost causation is typically linked to efficient marginal cost pricing and will be discussed further below.

The broader principle of "costs follow benefits" is typically applied to categories of costs that do not have a direct cost causation basis related to customer usage or other characteristics. At a minimum, this includes A&G costs and any program costs primarily motivated by societal benefits (e.g., low-income discounts), albeit under two slightly different theories. A&G costs literally benefit all customers because none of the services provided by the utility could be carried out without those costs. Programs justified by societal benefits are somewhat different because the benefits are not directly related to utility service provided to customers. Instead, broad allocation of these costs, across and within customer classes, is about shared responsibility.[87] In both of these cases, there is not an economically correct division of costs.

A more complex case is presented by elements of the electric system that do not necessarily have a direct cost-causation link to customer behavior, such as the "minimum-sized distribution system" referenced in the Bonbright quote on pages 31-32 of this report. These costs vary most directly with the area covered by the system or length of the lines, a factor that is not simple to include in rates and generally prohibited by the practice of postage stamp rates. However, there is an important sense in which different customers benefit from this distribution system backbone in proportion to their usage. With the further development of distributed energy resources and more customers exporting to the grid, the best way to think about this may be changing in the modern grid. In other words, the distribution system may no longer be built simply to ensure deliveries and sales, but rather may also be built to support bidirectional flows.

ii. Efficient Customer Price Signals

The principle of efficient customer price signals has long applied to customer usage, and in a modern grid, this concept must be extended to a customer's ability to store and generate electricity as well. According to microeconomic theory, prices are most efficient if they reflect marginal costs, although there are many theoretical difficulties and practical disputes that this statement glosses over. For example, some analysts prefer to only consider short-run marginal costs, particularly locational marginal prices in wholesale energy markets. However, the better perspective is to include long-run marginal costs of generation, transmission, and distribution capacity as these costs are ultimately caused and justified by continued customer usage, generation and storage optimization choices. It is also generally the case that maximizing societal well-being requires the inclusion of externalities as a marginal cost. This can justify a higher assignment of residual embedded costs to certain pricing elements, or the overall assessment of

[87] For this reason, some analysts and academics prefer that many costs should be paid for through the tax system – although this answer is frequently unrealistic and may have other downsides.

program costs and benefits using the societal cost test. Of course, externalities are not included directly in the cost of service, except as motivation for certain programs and various costs actually incurred by the utility. Furthermore, there are other practical consequences to the consideration of externalities in pricing, including distributional impacts.

The customer behavior factors that underlie marginal cost are often referred to as “cost causation,” as discussed previously. From the perspective of the electric system, an additional unit of energy exported from a customer has largely the same impacts as an additional unit of reduced consumption or an additional unit of generation consumed behind the meter that reduces imports, at least until the point of substantial reverse flows on elements of the grid. However, the marginal emissions impact, with associated environmental and public health consequences, can be different depending on the emissions profile of the distributed generation. REC policy is one way of accounting for these distinctions, which can be incorporated into DER rate design.

Cost causation, and the associated optimal marginal cost price structure, can be different for different elements of the electric system. Sending a monthly bill (either physically or electronically) has associated recurring costs every month that arguably fit into a customer charge. The broadly shared electric system fits well into a time-varying kWh pricing framework, although there are numerous disputes about how best to draw the connection between cost causation and workable pricing schemes. Service lines, secondary voltage lines, and line transformers are mixed cases where the best proxy is subject to significant uncertainty. Depending on one’s assumptions about cost causation at this part of the system and tradeoffs with other ratemaking principles, these costs could be best recovered through customer charges, demand charges, or kWh rates.

All deviations from efficient marginal cost pricing produce “inefficient” behavior, and any real-world pricing scheme will reflect such deviations for at least two reasons: (1) marginal cost pricing, regardless of someone’s preferred definition of marginal cost, virtually never matches the cost-of-service revenue requirement and (2) in most cases, proxies for marginal cost are often necessary instead of more precise and accurate pricing schemes, particularly for smaller and less sophisticated customers. In either case, deviation of pricing from marginal costs will cause distortionary behavior from customers, at least compared to the theoretical optimum. This is true regardless of the pricing element where a deviation is applied. For example, customer charges that are higher than marginal cost provide an inefficient incentive for customers to avoid paying that charge, either through formal or informal master metering or outright disconnection from the electric system. The latter possibility, also known as grid defection, was traditionally held to be an unlikely possibility, but continued cost declines for solar and storage, along with the availability of other backup generation options, may make it economically feasible for some customers in the near future. Extremely rural customers and other, specialized end-uses (e.g., crosswalk lights and highway signs) that used to be connected to the grid have already “defected” to solar and storage in many places.

iii. Customer Understanding and Acceptance

The principle of customer understanding and acceptance for residential customers covers several related issues. To begin, basic principles of fair play in a modern marketplace dictate that customers understand what they are paying for and why. Any differences in what they are paying from their friends and neighbors should be intuitive and explainable without recourse to jargon impenetrable to the public. Furthermore, many customers are making choices within an overall budget and would like to understand their choices to save on electricity or other utility bills.

There is also a meaningful sense in which customer understanding impacts the effectiveness of price signals built into electricity rates. Price signals can only work as intended if customers are able to respond to those incentives. Customer education, gradual introduction of reforms that build on each other, and understandable rules of thumbs (e.g., consume less on hot summer afternoons) are all helpful tools to improve customer response. More sophisticated tools and efforts are possible as well. Online data provision, automated energy management technology and storage, and the availability of 3rd party aggregators or other energy management companies can all help augment a customer's capabilities.

iv. Administrative Feasibility

Typical utility ratemaking practices across the United States today are already fairly lengthy and resource intensive affairs, with significant administrative costs throughout the process. Introducing new reforms into this process can be resource intensive as well, including the cost of new types of proceedings and new analytical requirements. Smaller reforms that make gradual changes to existing process are likely easier to manage with little incremental costs once a clear decision has been made. However, major reforms that make serious improvement to the efficiency and equity of programs or rate structures can have benefits that justify the administrative costs. In any case, weighing these implementation concerns is important to make sure that reforms are implemented well and are not solely an unnecessary and unfair burden on implementing agencies or any of the impacted stakeholders.

B. Data Collection, Customer Class Definitions and Cost Allocation Reforms[88]

Reforms to cost allocation processes can be important in their own right, but smarter and more robust analysis used in the cost allocation step can be carried over into rate design. There are two preliminary issues before major cost allocation and rate design decisions can be made: (1) the availability of relevant data on customer load, system load, and costs and (2) the definitions of the relevant customer classes and subclasses.

The customer load and system usage data available to a utility with advanced metering infrastructure goes far beyond what was possible a generation ago. Utilities previously had to sample customers with more sophisticated metering to create class level estimates. Similarly, utilities could put different kinds of metering on different elements of the system, but gathering more information always came at a cost. Now the bigger challenge is to store, process, and protect the vast quantities of customer and system data that are available. Investor-owned utilities in the United States generally follow the FERC Uniform System of Accounts to track their costs, but many cost allocation methods and rate designs benefit from refinements to this general

[88] Significant portions of Section 5.B are derived from Lazar et al., (Jan. 2020), Electric Cost Allocation for a New Era: A Manual.

framework. MPSC could consider working with the electric utilities to collect and track different kinds of expenses and investments in a disaggregated manner, including by voltage level and, where relevant, customer class.[89]

Another area for potential exploration is the definition of customer classes. Some utilities have more than one residential rate class or, alternatively, multiple residential subclasses, and the distinctions are often based on technology-driven class usage characteristics caused by end-uses such as electric space heat, water heat, vehicles, and solar installations. However, singling out customers based on technology adoption has serious practical and theoretical downsides. Furthermore, addressing one minor cost distinction is likely not fair or efficient if several other major cost distinctions are not addressed. It is wiser to consider multiple customer and service characteristics simultaneously to create technology-neutral classes for both cost allocation and rate design purposes. There are cases where separate residential classes or subclasses have been established based on significantly different cost profiles, such as customers with and without electric heat in some jurisdictions. In many cases, these cost distinctions could also be addressed through rate design reforms. To continue with the example of electric heating, the distinction between residential customers with and without electric heat could be captured through seasonal rates, thus lowering or eliminating what could otherwise be an intraclass cross-subsidy without separating these customers into two different classes or subclasses. Dividing up customers by class can also have rate design implications because different rate structures are used for different customer classes. For example, residential customer classes generally do not have demand charges today, but most large industrial classes do.

While improved cost distinctions from additional customer classes is a laudable goal, there are countervailing considerations that may dictate keeping the number of customer classes on the smaller side. First, there are administrative and substantive concerns around adding rate classes, both in litigation at state regulatory commissions and in real-world implementation. Some potential distinctions among customers may be difficult to implement because they involve subjective and potentially controversial determinations by on-the-ground utility personnel. In creating new distinctions, regulators, utilities, and stakeholders must all have confidence that there are true cost differences between the customer types and that there will be little controversy in reflecting those differences in the rate designs and levels. Some analysts object to customer classes based on adoption of particular end uses, although this may serve as a proxy for significantly different usage and cost profiles. Furthermore, some utilities and parties in a rate case may propose rate classes that effectively allow undue discrimination. If the proper data aren't available to scrutinize such claims, either publicly or for parties in a rate case, then this may allow an end run around one of the significant motivations for utility regulation: preventing price discrimination.

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[89] For example, the Missouri Public Service Commission has included exploration of better cost tracking methods as a stipulation in rate case settlements with electric utilities. See Corrected Non-Unanimous Stipulation and Agreement in Ameren Missouri Rate Case (Feb. 2020). MO PSC Docket No. ER-2019-0035, p. 16, https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=ER-2019-0335&attach_id=2020013839

Elsewhere, RAP has made comprehensive recommendations to modernize cost allocation practices.[90] Since MPSC currently uses an embedded cost allocation framework, it is a reasonable choice to remain in this basic framework. However, key insights from the marginal cost approach can be helpful to understand productive reforms for both cost allocation and the following step of rate design. Starting at the functionalization step, the best practice is to avoid collapsing costs into a narrow number of functions,[91] which risks losing crucial information that is needed in later steps of the process. A&G costs, billing and customer service, and public policy programs should be tracked separately from electric system costs. Any utility expenses and investments that provide benefits across multiple functions (e.g., DER program costs, certain utility-owned energy storage, and smart grid technologies) can be functionalized at this step, but often detailed information on those costs will be needed at later steps in the process as well.

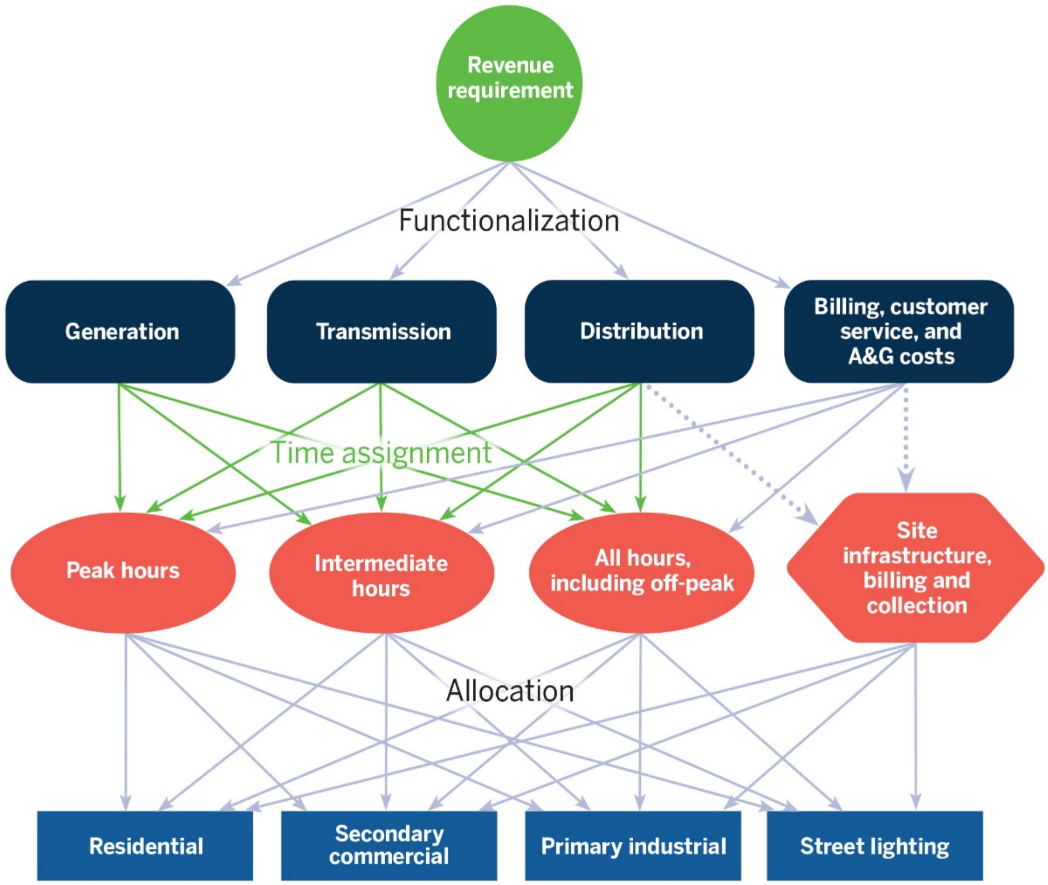
At the classification step, with improved information about class loads, and with a range of new technologies, it may be appropriate to move past the traditional energy and demand classifications to create new more granular distinctions.[92] Instead of dividing up shared system costs between the demand-related classification (generally intended to reflect system peak hours) and the energy-related classification (generally intended to reflect year-round energy usage), more granular time-based classification methods could be adopted. A simple version of this is displayed in Figure 16.

[90] Lazar et al. (2020).

[91] In some sense, the functionalization and classification steps of cost allocation have lost some of their importance compared to the past because modern analytical tools (e.g., spreadsheets) can just continue to use the most detailed data available without any summary shortcuts. However, these steps still are relevant for other regulatory purposes, such as retail supply choice and thinking about cost causation.

[92] By statute, MPSC has a presumption of treating production-related costs as 75% demand-related and 25% energy-related and treating transmission-related costs as 100% demand-related. This statute provides that MPSC may modify this method if it is determined that it does not follow the cost of service. Section 460.11 of the Michigan Compiled Laws.

Figure 16. Modern embedded cost of service flowchart



The demand and energy classifications are replaced by a three-period time assignment scheme, although more sophisticated versions of this are also possible. Site infrastructure, billing and collection costs, and A&G costs would be handled outside of this time-based framework. More specific recommendations include:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the basic customer method;
- Recognize that advanced metering no longer provides just customer billing but rather a broader array of system planning and operational benefits;
- Collect and track distribution system cost data in a way that ensures reasonable calculation of class-level responsibility for site infrastructure;
- Allocate any peak- or demand-related costs for generation and transmission using a broad resource adequacy measure, such as the highest 100 hours or an hourly weighting based on a loss-of-energy expectation study;

- Ensure broad sharing of administrative and general (A&G) costs across all classes and customers; and
- Allocate the costs of public policy programs that benefit the electric system according to those benefits (i.e., who benefits and in which ways), but share broadly across all ratepayers other program costs justified by broader policy objectives.

C. Potential Pathways for New Rate Designs for Distributed Energy Resources

In Sections 4 and 5, a wide range of options for overall program structure, rate and credit design were discussed. These different options can be combined into even more overall reform packages. We present three illustrative potential pathways in this section:

- **Gradual evolution pathway** — modest improvements to the efficiency of pricing for new DG customers and overall rate design, along with associated cost allocation improvements, with a minimal need for new customer education efforts, process reforms, or administrative burdens.
- **Advanced residential rate design for DER pathway** — an aggressive effort to enlist a large segment of residential customers to optimize their usage, storage, and generation patterns to lower overall system costs while ensuring fair cost recovery with new rate structures. May require significant new analysis and process reforms, as well as customer education and assistance with energy management.
- **Customer choice and stability pathway —** a simple and understandable set of options to customers that are fair to non-participating ratepayers, with stable payment schemes that may lower barriers for both customers and DER companies. Requires significant administrative efforts to determine and update value-based credits and set grid access charge.

These three potential pathways are not exhaustive, and do not even use all of the program elements discussed in Section 4 or every single rate design and credit option discussed in Section 5. However, they do present coherent frameworks to illustrate key principles and tradeoffs. As policymakers and stakeholders consider the best path forward for DER rate design, and electric system reform more generally, we hope illustrates key choices and how to think about constructing overall reforms.

Gradual Evolution Pathway — Description

Customer Population Treatment

New residential distributed generation customers, as well as customers with storage or EVs with vehicle-to-grid (V2G) capabilities who wish to export to grid,[93] are placed by default onto year-round time-of-use rates that are generally available to all residential customers. These customers cannot opt back into traditional volumetric kWh rates but may choose from other options. Other customers (with or without DG) are allowed to opt into this rate.

Legacy net metering and previous DG program customers are allowed to remain on their pre-existing rate structures for 10 years from time of interconnection. However, this baseline rate design may continue to evolve as well.

Metering and Billing Framework

Primary features of current DG program model are maintained. Within each time-of-use period, inflow and outflow is billed and/or credited separately.

Key Rate and Credit Design Features

Import rates for these customers would be redesigned to be time-varying for both supply and distribution. Export credit value is set at time-varying supply rate.

All residential customers have a monthly customer charge based on basic customer method, with tiered adders to recover incremental service line, secondary network and line transformer costs by type of customer: (1) multifamily building customers, (2) single family building customers with panel sizes of 200 amps or lower, and (3) single family building customers with panel sizes over 200 amps.

Process Reforms

Process changes under this pathway would be minimal. Details of rate design would be improved by supportive analysis and cost allocation reforms. Implementation of tiered customer charge would require additional data collection to identify appropriate category for each customer.

[93] Customers with storage or V2G capabilities are only allowed to export to grid with appropriate interconnection approvals.

Gradual Evolution Pathway — Evaluation

Fair Cost Allocation

Continuation of the inflow/outflow framework ensures that customers contribute to all of the costs built into the retail rate for inflow, including public policy programs, A&G costs, and all elements of the shared electric system.

The tiered customer charges for site infrastructure begin to reflect cost differences between customers with respect to the local elements of the distribution system and improvements to time-varying rates improve allocation of costs of shared system.

Efficient Customer Price Signals

Improvements to time-varying rates for new DG customers encourage more efficient customer behavior for broadly shared system. Tiered customer charges for site infrastructure provide modest signal for certain long-term customer choices (e.g., panel size) and remove those costs from the kWh rates.

Customer Understanding and Acceptance

Only impacts small subset of customers with modestly more complex time-varying rates. Introducing tiered customer charge for all residential customers is simple mathematically but may require customer education regarding its purpose and cooperation to identify the right category for each customer.

Administrative Feasibility

The process for this option is relatively simple, with a potential exception for categorization of tiered customer charge. Details of new rate design reforms would require stakeholder discussion and potential litigation of details in rate case.

Advanced Residential Rate Design for DER Pathway — Description

Customer Population Treatment

The residential customer class will be divided into two subclasses: (1) advanced and (2) basic. All customers with DG, EVs, storage, or higher than 75th percentile in usage levels are required to take service in the advanced residential subclass.[94] Customers with relevant resources (DG, battery storage, and EVs with vehicle-to-grid capabilities) can elect whether or not they wish to export to the grid with appropriate interconnection approvals.

Metering and Billing Framework

Eliminate inflow/outflow billing within time periods and instead net imports and exports within each pricing time period for customers that export.

Key Rate and Credit Design Features

A system of time-varying marginal cost kWh charges and credits is paired with three rate elements for cost recovery only. The time-varying charges and credits for generation, transmission, and distribution should vary by season and include at least three TOU periods and critical peak pricing in all months with an expectation of potential resource adequacy issues. Customers with eligible generation technologies can receive an environmental value for exported energy, contingent on transferring RECs to the utility.

The three cost recovery elements are (1) a customer charge defined by the basic customer method, (2) an individual NCP demand charge to recover site infrastructure costs (service lines, secondary networks, and line transformers), and (3) a distribution flow charge on both imports and exports to recover a portion of shared distribution system costs, nonbypassable charges, and a share of A&G costs.

Process Reforms

Significant process reforms and additional analyses would be necessary to implement this option, including new time-varying marginal cost studies for transmission and distribution, setting environmental values in exchange for RECs, and stakeholder discussions to properly define a demand charge for site infrastructure and a distribution flow charge.

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[94] Low-income customers are placed in the basic subclass by default, and all customers in basic subclass can opt into the advanced subclass. Rate structures for the basic subclass should remain simpler than the rate design described for the advanced subclass.

Advanced Residential Rate Design for DER Pathway — Evaluation

Fair Cost Allocation

Moving away from inflow/outflow framework is justified by two new cost recovery mechanisms to ensure equitable contributions from these customers: the demand charge to cover site infrastructure and the distribution flow charge for nonbypassable charges, a portion of distribution system costs, and a share of A&G costs.

Price signal built into demand charge serves as a proxy to fairly split the costs of site infrastructure, and granular time-varying rate spreads the costs of the shared electric system.

Efficient Customer Price Signals

This option presents a big jump forward in the efficiency of the price signals sent to a significant portion of residential customers, enabling more efficiency in the electric system and potentially significant long-term cost savings. The demand charge for site infrastructure provides a proxy to help manage local distribution costs, and may result in modest additional benefits from encouraging customers to lower short-term load spikes and overall variability.

Customer Understanding and Acceptance

The complexity of this option and its application to a significant number of residential customers likely requires a substantial customer education effort, as well as clear explanations regarding the purpose of the new rates.

Administrative Feasibility

This option requires significant new analysis and process reforms that would require time and resources from relevant stakeholders and MPSC. More complex rates also do raise the risks of implementation difficulties for the utilities.

Customer Options and Stability Pathway — Description

Customer Population Treatment

New distributed generation customers have a choice between two rate options: Choice A is a buy-all/credit-all structure and Choice B is a significantly modified version of traditional net metering. Pre-existing customers with DG are allowed to opt into one of the new choices but are not allowed to switch back.

Metering and Billing Framework

Under Choice A, all gross generation is metered and credited separately from consumption. Under Choice B, inflow/outflow measurement is eliminated, and monthly netting is used instead.

Key Rate and Credit Design Features

Under Choice A, customers receive a value-based credit on all gross generation, set as described below and retail rate design may be changed separately from generation credits. Under Choice B, customers receive a value-based credit for net excess generation as determined by monthly netting. In addition to other retail rate charges, Choice B also includes a grid access charge defined by installed capacity to recover an equitable portion of nonbypassable costs and a share of distribution system costs.

For both choices, flat kWh credit values for solar PV and other nondispatchable technologies are set administratively every two years based on an estimated long-term value of the resource. Customers can elect to lock in their credit levels for 20 years or have their credit value updated over time. Customers only receive the environmental compensation values if they transfer the RECs to the utility.

Process Reforms

The primary process reform necessary for this pathway is adoption of an administrative structure to determine the value-based credits for distributed solar PV and potentially other technologies. In addition, significant stakeholder discussion may be necessary to define the grid access charge for Choice B.

Customer Options and Stability Pathway — Evaluation

Fair Cost Allocation

Under both choices, moving away from the inflow/outflow framework is justified by different changes to the framework. Under Choice A, it is inarguable that a customer is paying for all of the costs built into their retail rate, which is separate from the credit for gross generation. Under Choice B, the grid access charge is intended as a proxy for an equitable contribution to nonbypassable charges and the costs of the distribution grid.

Efficient Customer Price Signals

Flat kWh value-based credits provide a reasonable rationale for whether a customer investment is worthwhile to the system, but this option provides little improvement for customer load management or storage operation directly. There is no barrier to the application of new retail rate structures for these customers over time, however.

Customer Understanding and Acceptance

Customer understanding under this option should be straightforward, but acceptance of the options and potential differences between customers may need to be justified.

Administrative Feasibility

A significant administrative effort is required to set and update credit values. Practical details, such as treatment of storage, also need to be sorted out in this framework.

Appendix: Key State Examples

Duke Energy Settlement in North and South Carolina

In September 2020, Duke Energy Carolinas and Duke Energy Progress reached an agreement with solar and environmental advocates in North and South Carolina to revise the tariffs offered to residential solar customers. The development of the agreement was largely in response to South Carolina's Energy Freedom Act (Act 62 passed in 2019) and North Carolina's House Bill 589 (passed in 2017). In May 2021, the South Carolina Public Service Commission unanimously approved the settlement agreement. The new compensation mechanism, called "Solar Choice Metering," is scheduled to apply to all new residential customers on or after January 1, 2022.

The agreement includes several key elements:

1. A minimum monthly bill of $30.00 for each Solar Choice Metering customer will be assessed. The agreement states that this is to ensure the utilities can recover estimated customer and distribution costs.
2. Time-varying pricing, including time-of-use periods and critical peak pricing, which will encourage DG customers to reduce consumption when prices are high. Customer energy imports and exports are netted within each TOU pricing tier and monthly net exports are given a bill credit at the approved avoided cost rate. This credit can be used to reduce a customer's bill after the minimum bill has been applied. Critical peak pricing applies to imports during the CPP hours, and any energy exports during the CPP hours are netted against peak imports.
3. A monthly grid access fee for facilities larger than 15 kW.
4. Nonbypassable charges for demand-side management / energy efficiency programs, storm cost recovery, and cyber security costs.
5. A new incentive for qualifying Solar choice Metering customers to enroll in the proposed smart winter thermostat program. The agreement also includes a commitment on the part of the utilities to file a broader incentive program by June 1, 2022, that includes other peak load reduction technologies that can be paired with solar.

Utility proponents of the agreement note that cost recovery from solar customers will be fairer under this structure – Duke Energy estimated that 92% or more of the current "cost shift" from solar owners to non-solar-owners would be eliminated by this structure, and the utility will be able to charge solar customers more during peak demand times when most customers are drawing a lot of power from the grid. Solar proponents note that customers whose panels can send energy to the grid during peak hours will be properly compensated, and solar customers will also be able to save money by participating in the peak load reduction aspects of the program.

California – From NEM 2.0 Toward NEM 3.0

California utilities have been obligated to offer a Net Energy Metering tariff to its residential and commercial customers since the passage of SB 656 (Alquist, 1995).[95] From the first tariffs in 1996 up through 2016, NEM was priced at the full retail rate with an annual true up. Rate design in California during this period was an increasing block rate with TOU tariffs offered as an option. Each utility was obligated to offer the NEM rate to all customers on a first come, first served basis up until a prescribed cap was met. The cap was initially set at 0.1 percent of peak load but was raised several times before settling at 5% of peak load. The maximum size of NEM eligible systems settled at 1 MW.

By 2013 utility scale solar adoption was becoming significant in California and the neighboring states to California's southwest, Nevada and Arizona. The combination of distributed solar approaching its 5% cap and the emergence of thousands of megawatts of utility scale solar contributed to the emergence of the "duck curve" at the California ISO. Assembly Bill 327 (Perea) passed in the 2013 legislative session to address a perceived disconnect between the compensation being provided to solar DG adopters and the value of solar DG on California's electric system.[96] For the first decade of solar DG adoption, the electric system peak coincided with hours of peak solar production, making solar production valuable in addressing increasing peak loads. However, utility scale and distributed solar collectively surpassed 20% of annual peak load with utility scale solar reaching 4,495 MW in 2013 while distributed PV approached its 5% cap. This dramatic increase in production from solar introduced a shift in utility system and California ISO peak from the afternoon into the very late afternoon and early evening. With solar's production no longer coinciding with the electric system's peak and net peak, a reconsideration of the default NEM tariff was mandated by AB 327 with the new default to become effective as the 5% cap was reached in the respective utility service territories.

The California Public Utility Commission (CPUC) issued Decision 16-01-044 in January 2016 to implement the NEM successor tariff, commonly referred to as NEM 2.0. AB 327 specified some parameters for the revised NEM tariff while others arose as the CPUC considered testimony and data from proceeding participants. AB 327 was concerned that NEM customers pay their share of "nonbypassable" expenses. These expenses largely encompass public purpose programs that cause costs borne by utility ratepayers. These include programs like energy efficiency and low-income support programs. The issue of ensuring that solar adopting customers paying their share of system costs was addressed partly with this mandated feature and partially through additional features of the revised tariff including:

- A mandatory interconnection fee;
- A minimum bill provision; and,
- The phase in of mandatory time of use rates.

95 The text of SB 656 is available at http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

96 The decision adopting the successor tariff is at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

NEM 1.0 customers were grandfathered into the NEM 1.0 tariff and NEM 2.0 customers were given a guarantee that their NEM 2.0 tariff would be available for 20 years.

Solar in California has continued to grow rapidly in California since 2016. By 2020, utility scale solar has grown past 15,000 MW and distributed solar has surpassed 10,000 MW. The California ISO peak load is a bit less than 50,000 MW, so the 25,000 MW of solar is quite significant. The CPUC commissioned a "Solar Lookback Study" in 2020 to assess the performance of the NEM 2.0 tariff.[97] The lookback study indicates that further changes in the NEM framework will be needed to address persistent cost shifting. While commercial customers do not impose a cost shift, residential customers do appear to significant underpay for their share of system costs. NEM 3.0 has been launched by the CPUC to consider additional changes in rate and tariff design to address the cost shift and to better align rate design with cost causation.[98]

Minnesota Value of Solar Tariff

Minnesota passed legislation[99] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production. To date, the VOS tariff has only been used for Xcel's community solar gardens and no utility has opted in to use it for rooftop solar PV projects.

The MN Department of Commerce (MN-DOC) was directed[100] to establish a calculation methodology to quantify the value of distributed photovoltaics (PV). The MN-DOC submitted the draft methodology to the MN Public Utilities Commission (PUC) in January 2014.[101] The PUC approved[102] the methodology at a hearing on March 12, 2014, and posted the written order approving the methodology with MN- DOC approved modifications on April 1, 2014.[103]

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97 The evaluation of NEM 2.0, including a link to the Lookback Study is available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering/net-energy-meeting-nem-2-evaluation

98 To see the current status of NEM 3.0 visit https://www.cpuc.ca.gov/nemrevisit/

99 MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

100 Minn. Stat. § 216B.164, subd. 10(e)

101 Minnesota Department of Commerce (2014, April 1) Minnesota Value of Solar: Methodology. Retrieved from: https://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

102 In its order, the Commission noted that unlike most Commission proceedings arising under its jurisdiction, in this case the Commission could not substitute its judgment for that of the Department. Per statute, the Commission could only approve the Department's proposal, modify it with the Department's consent, or reject it. The Commission limited it's review to whether MN-DOC fulfilled its statutory obligations and reasonably justified the proposed methodology with regard to the public interest and in light of specific objections raised before the Commission.

103 MN PUC (2014) Order approving distributed solar value methodology. Docket No. E-999/M-14-65.

VOS Methodology and Formula

To calculate a utility's Value of Solar Figure, a set of avoided cost "components" are each multiplied by a "load match factor," if one is appropriate, and a "loss savings factor." Adding the results of these separate component calculations produces the utility's Value of Solar Figure. As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first-year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.[104]

There are eight components of value in the tariff as follows:

- Avoided Fuel Cost
- Avoided Plant Operation and Maintenance – Fixed
- Avoided Plant Operation and Maintenance – Variable
- Avoided Generation Capacity Cost
- Avoided Reserve Capacity Cost
- Avoided Transmission Capacity Cost
- Avoided Distribution Capacity Cost
- Avoided Environmental Cost

There are two placeholder components: Avoided Voltage Control Cost and Solar Integration Cost. These components are not part of the Value of Solar calculation at this time, but MN DOC anticipates that these categories of costs and benefits will be known and measurable in the future.[105]

Some key characteristics of the MN VOS policy include:[106]

- Investor-owned utilities may voluntarily apply to the MN PUC to enact a program in lieu of net energy metering. Thus far VOS has only been used in Xcel's Community Solar Gardens, as no other utility has voluntarily adopted it.
- PV systems must be under 1 MW in size. Additionally, on-site production cannot exceed 120% of annual on-site consumption.
- Customer electricity usage is separate from production.
    - Customers are billed for their total electricity consumption at the retail rate.
    - Compensation for the solar system is through a bill credit, at the value of solar tariff rate. Net excess generation is forfeit to the utility. Utility automatically obtains the solar renewable energy credit.

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[104] MN PUC (2014) Order approving distributed solar value methodology. Docket No. E-999/M-14-65.

[105] Id.

[106] Key characteristics derived from Cory, Karlynn (2013). Minnesota Values Solar Generation with new "Value of Solar" tariff. Blog. Retrieved from: https://www.nrel.gov/state-local-tribal/blog/posts/vos-series-minnesota.html and Farrell, J. (2014, April). Minnesota's Value of Solar: Can a Northern State's New Solar Policy Defuse Distributed Generation Battles? Retrieved from: https://ilsr.org/wp-content/uploads/2014/04/MN-Value-of-Solar-from-ILSR.pdf

- Value calculation:
    - Production based. It is expressed in $/kWh, levelized over 25 years.
    - It is estimated as the combined value to the utility, its customers and society.
    - Value calculation process:
        - Once the VOS is established in any one year, that VOS is held constant for participating customers who install solar PV in that year.
        - The valuation will be updated annually for new VOS participants to incorporate utility inputs for the value of PV in the year of installation.
        - A utility-specific VOS input assumption table is part of the utility's application and made publicly available.
        - A utility-specific VOS output calculation table will break out the value of components and the computation of total levelized value and be made public.
    - A tariff not an incentive, and it is not intended to replace or prevent incentives.
- Utility automatically obtains SREC, with zero compensation to customer.

Evolution in VOS Methodology Components

In 2019 the Commission updated the VOS methodology for the avoided distribution capacity cost component. Since 2017, the VOS has been used as the basis for the bill credit in Xcel's community solar garden (CSG) program. In its May 1 compliance filing and its petition, Xcel argued that the current VOS methodology produces a VOS rate that is "unreasonable, unrepresentative, and clearly falls outside of the public interest." Xcel pointed to the avoided-distribution-capacity-cost component of the methodology as the cause for volatility in the VOS rate, because the component used peak demand data to arrive at the capacity cost, and peak demand is volatile year to year due to variables such as customer requirements and weather. Xcel argued that a volatile VOS rate is confusing to customers and inaccurately represents the value of distributed solar to the system, which does not significantly change from year to year.

The Commission approved Xcel's proposal to move to a five-year average of per-kW distribution spending to calculate the avoided distribution cost for the 2020 VOS rate applied to the CSG program. The PUC also directed Xcel to file a framework showing how specific types of distribution projects will be categorized for future calculations of the VOS avoided-distribution-capacity-cost component. Finally, the PUC directed Xcel to discuss with the Department and other stakeholders how the following could improve the VOS methodology: (1) long-term load growth assumptions, (2) sensitivity analysis of different time periods for system-wide calculation, and (3) methods to de-average avoided distribution costs to account for location differences.[107]

[107] MN PUC (2019). Order approving changes to distributed solar value methodology and requiring further filings. Dockets E-002/M-13-867/ E-999/M-14-65.