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Rate-Making Principles and Net Metering Reform: Pathways for Wisconsin

Prepared for the Wisconsin Public Service Commission

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Distributed energy resources (DERs) such as solar photovoltaics (PV), wind turbines, electric vehicles and storage have proliferated in recent decades, coinciding with a decrease in price.[1] Customers who install distributed generation (DG) receive compensation from the utility for the value of the electricity they produce, through a policy known as net energy metering (NEM) or net metering. NEM has a long tradition in Wisconsin. The Wisconsin Public Service Commission (PSC) established rules in 1982 to require investor-owned and public utilities to offer net metering.[2] Rapid changes in technology, decreasing prices and the evolution of the electricity system since then make this an ideal time to reexamine NEM in Wisconsin.

In June 2020, the Wisconsin commission issued a notice of investigation to consider parallel generation purchase rates.[3] After receiving data, comment and staff memorandums, the commission issued an order in May 2021 requiring five utilities to file tariffs updating their avoided cost-based rates for parallel generation, consistent with the commission's order. Additionally, the commission directed further review of net metering

[1] Distributed solar cost approximately $12 per watt in 2000 and fell in 2019 to between $2.30 and $3.80 per watt, depending on the size and market. Barbose, G., Darghouth, N., O'Shaughnessy, E., & Forrester, S. (2020). *Distributed solar 2020 data update*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf

[2] Wisconsin Public Service Commission. (n.d.-a) *Net metering and buy-back tariffs.* https://psc.wi.gov/Pages/ForUtilities/Energy/NetMeteringandBuyBackTariffs.aspx

[3] Wisconsin Public Service Commission. (2020, June 11). *Notice of investigation and request for comments*. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=391581

practices by development of an informational paper to be issued for public comment.[4] This paper is provided in response to the commission's request.

Section I: Rate-Making Principles and Perspectives on Costs and Benefits

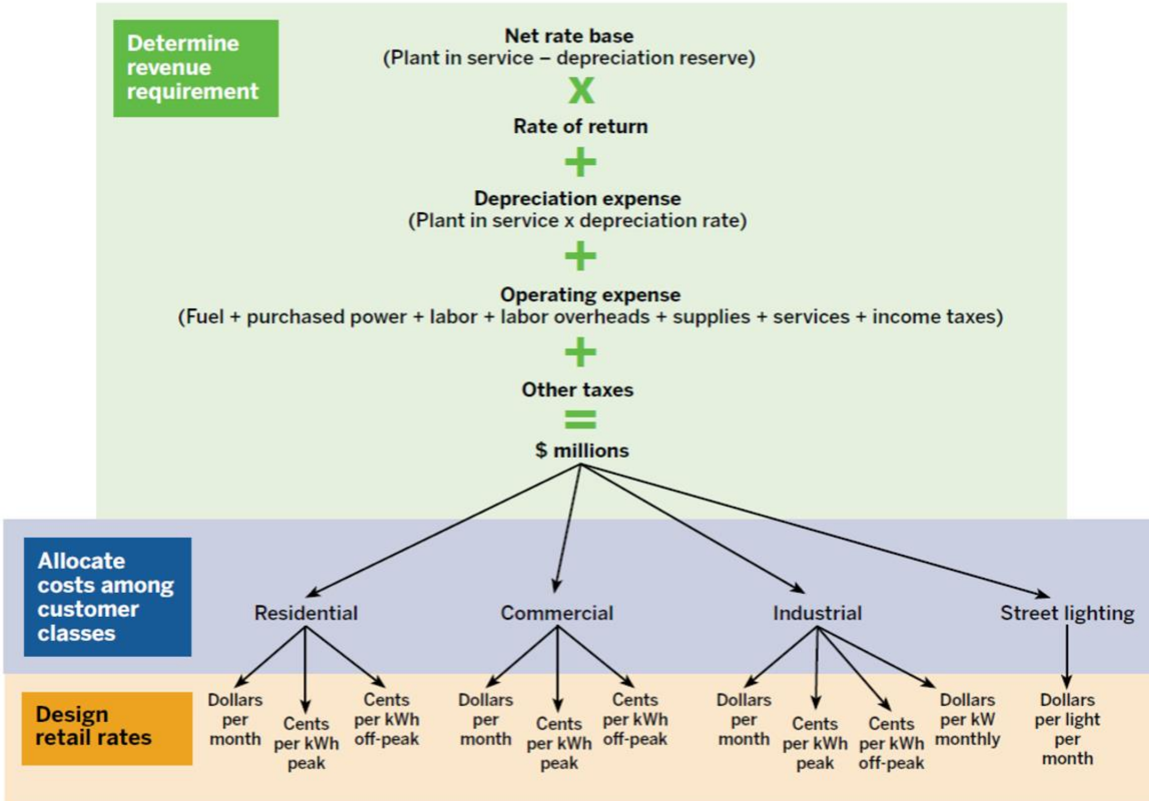
Before digging into the options for reform of DER rate design and related cost allocation reforms, it is worth reviewing basic rate-making principles that have been relied upon for decades, as well as historical and evolving ideas about electricity system costs and their proper allocation. It is also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

Traditional Rate-Making Principles

In traditional economic regulation of electric utilities, regulators review proposals for rates from 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, commercial and industrial, and street lighting. For many utilities, 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 in the service class pay the same prices. As shown in Figure 1 on the next page, 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.

[4] Wisconsin Public Service Commission, Docket 5-EI-157, Order on May 4, 2021, regarding investigation of parallel generation purchase rates. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=410850. The commission noted the issues addressed by this paper could include, but are not limited to, the differing size thresholds that different utilities set for net metering tariff eligibility, the practices for measuring capacity relative to the eligibility thresholds, different options for netting calculations, the potential effects of FERC Order 2222 and the potential application of minimum bill methods for net metering customers.

Figure 1. Simplified rate-making process 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) and taxes, as well as an explicit element for a rate of return on net rate base.[5]

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 past analysts.[6] Many of these principles are still useful today, though it is also worth asking how changing circumstances

[5] Costs of service can be determined in a rate case through a comprehensive cost of service study or by making adjustments to a previously determined revenue requirement without conducting a full cost of service study.

[6] The most famous of these are the Bonbright principles from Bonbright, J. C. (1961). *Principles of public utility rates.* Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/. Other examples include *Public Utility Economics* by Garfield & Lovejoy (1964) and *The Economics of Regulation* by Alfred Kahn (1970-71). On Page 291 of his treatise, Dr. Bonbright lists eight 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).

may affect them or even call into question their relevance. Generally accepted principles that remain helpful in today's debates regarding rate structure include:

- **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 economically efficient.
- **Customer understanding, acceptance and bill stability.** 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. A customer's bills should remain relatively stable from year to year if there is relatively little change in the customer's billing determinants.
- **Equitable allocation of costs and the avoidance of undue discrimination.** The apportionment of the total cost of service among different customers should be done fairly and equitably.
- **Effectiveness in yielding total revenue requirements.** The utility should have an expectation that it will have the opportunity to approximately recover its revenue requirement from customer rates, with a reasonable amount of stability from year to year, when it effectively manages its franchise obligations.

There will be trade-offs between these principles in many cases. For example, rates that make revenue recovery more certain for utilities could lead to less equitable cost allocation and less economically efficient rate design for customers. Similarly, more efficient forward-looking price signals may have consequences with respect to customer bill stability or, in extreme cases, overall revenue stability. The task of the regulator is to strike a balance in these objectives.

Broader Policy Goals

In addition to the traditionally recognized rate-making principles, 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 is 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 generation. Thus, broad discussions about public policy goals and objectives tend to surface in debates around DG rate design and compensation.

The highest-priority policy goal is to fulfill the commission's mission to ensure that utility services are safe, reliable, affordable and environmentally responsible.[7] A wide range

[7] Wisconsin Public Service Commission. (n.d.-b). *History & mission*. https://psc.wi.gov/Pages/AboutPSCW/HistoryAndMission.aspx

of other policy goals that elaborate on the commission's core mission have been firmly established by the Legislature and can be found in statutes, such as:

- The state energy policy goals and priorities in Wis. Stats § 1.12.
- The energy efficiency and renewable resource programs (i.e., Focus on Energy) described in Wis. Stats. § 196.374.
- The renewable portfolio standard in Wis. Stats § 196.378.

Wisconsin Clean Energy Plan

The objectives for the state's forthcoming Clean Energy Plan are also instructive for this inquiry, even though the plan was developed pursuant to an executive order and is not currently enacted in statute. Namely, the plan seeks to:[8]

- Put Wisconsin on a path for all electricity consumed within the state to be 100% carbon free by 2050.
- Ensure that Wisconsin is fulfilling the carbon reduction goals of the 2015 Paris Agreement.
- Reduce the disproportionate impacts of energy generation and use on low-income residents and communities of color and ensure these communities are prioritized in receiving clean energy economic and health benefits.
- Maximize the creation of, and equitable opportunities for, clean energy jobs, economic development and stimulus, and retention of energy investment dollars in Wisconsin.
- Improve the reliability and affordability of the energy system.
- Strengthen the clean energy workforce through training and education, while retraining workers affected by the transition from fossil fuel to clean sources of energy.
- Protect human and environmental health by reducing ecosystem pollution from fossil fuels.

Cost Causation in the Electric System

The concept of cost causation is a fundamental one for both cost allocation and rate design. While occasionally it is used as a backward-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 (2) prices are most efficient if they reflect how costs are caused. In both cases, these are forward-looking marginal cost concepts.[9]

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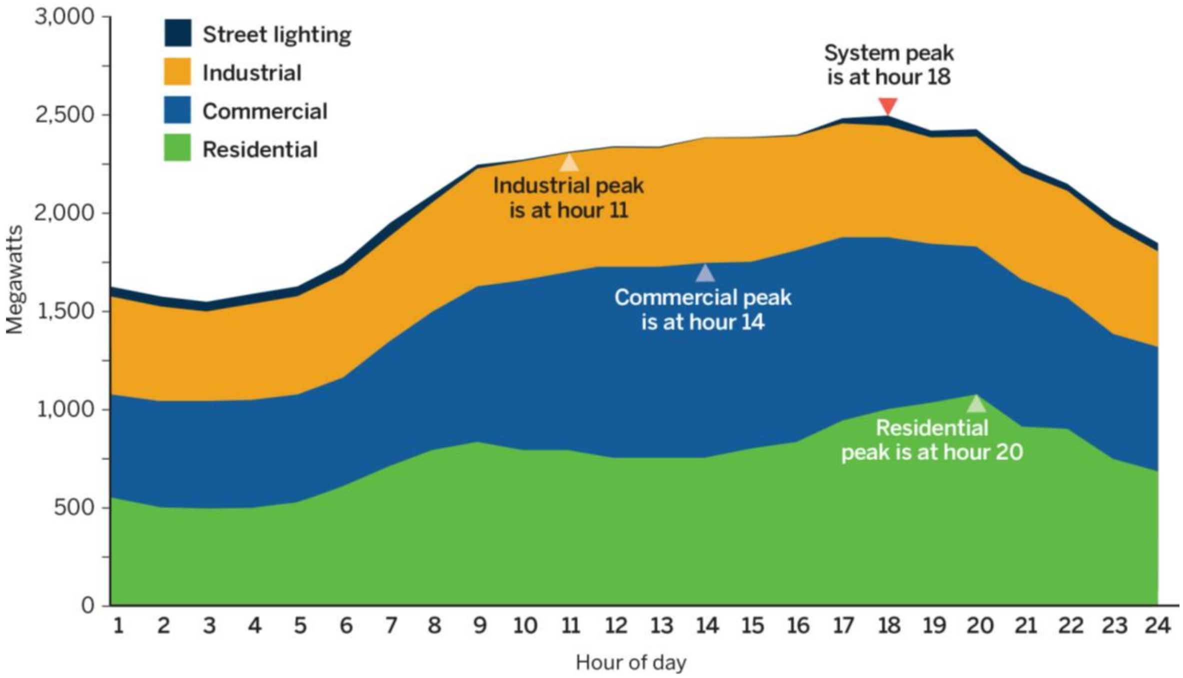
[8] State of Wisconsin, Office of Sustainability & Clean Energy. (n.d.). *Clean energy plan.* https://osce.wi.gov/pages/cleanenergyplan.aspx

[9] Readers should not infer from this explanation that all parties will agree on all aspects of cost causation or that there is one best or most accurate method for allocating costs. Indeed, in a case resolved by the U.S. Supreme Court in 1945, Justice William Douglas wrote for the majority, "A separation of properties is merely a step in the determination of costs properly allocable to the various classes of services rendered by a utility. But where as here several classes of services have a common use of the same property difficulties of separation are obvious. Allocation of costs is not a matter for the slide rule. It involves a judgment of a myriad of facts. It has no claim to an exact science." (Colorado Interstate Gas Co. v. Federal Power Commission, 324-US 581,589)

Many of the more contentious debates around cost causation tend to focus on the allocation and pricing of capacity investments for generation, transmission and distribution.[10] The 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 something less, often significantly so. This phenomenon is known as diversity of demand, and it 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 2 shows hypothetical 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 from any of the class peaks.

Figure 2. Diversity at the customer class level



[10] 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. The reasonableness of fixed charges, and their proper magnitude, turns on other issues.

When similar data are 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 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. In many respects, reliability concerns arise predominantly (but not exclusively) at peak system hours.[11] Achieving the objectives in a reasonable way requires detailed economic analysis of the different potential options that meet the relevant engineering criteria.[12] 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 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 and have reserves available on short notice throughout the year is much different from the capacity that one would build to generate year-round. To be economic, capacity that serves only short-term needs must have 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. Demand response programs also tend to have low upfront investment costs and are often employed to meet infrequent, short-term peak capacity needs.[13] In contrast, a larger 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 system investments 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 generator. In some situations, long transmission lines are needed to connect low-cost

[11] 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.

[12] The details of how this is achieved vary from one independent system operator (ISO) to another and from state to state.

[13] Demand response resources have proven to be a competitive option for meeting peak capacity needs in ISOs that procure capacity resources through an auction-based forward capacity market. For example, demand response provided more than 10% of the capacity procured in recent ISO New England auctions and more than 5% in PJM Interconnection auctions.

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 and should be classified on that basis. 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 for line losses.[14] 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.[15]

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. 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.

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. The purposes of advanced metering infrastructure and its related pricing and data collection capabilities, however, go far beyond what is necessary strictly for billing. As a result, advanced metering infrastructure should be fairly allocated and efficiently charged to customers in a manner that reflects these broader purposes.

Last but not least, administrative and general costs generally support all of a utility's functions and are in scale with the overall size of the enterprise. For example, an office building and parking lot are 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 penetration of distributed solar, such as Hawaii.[16] DG can affect the need for shared distribution

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[14] 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/

[15] Lazar & Baldwin, 2011, p. 1.

[16] 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 MW at 1 to 3 p.m. By 2017, with extensive deployment of customer-sited solar, the peak demand was 1,068 MW at 9 p.m.

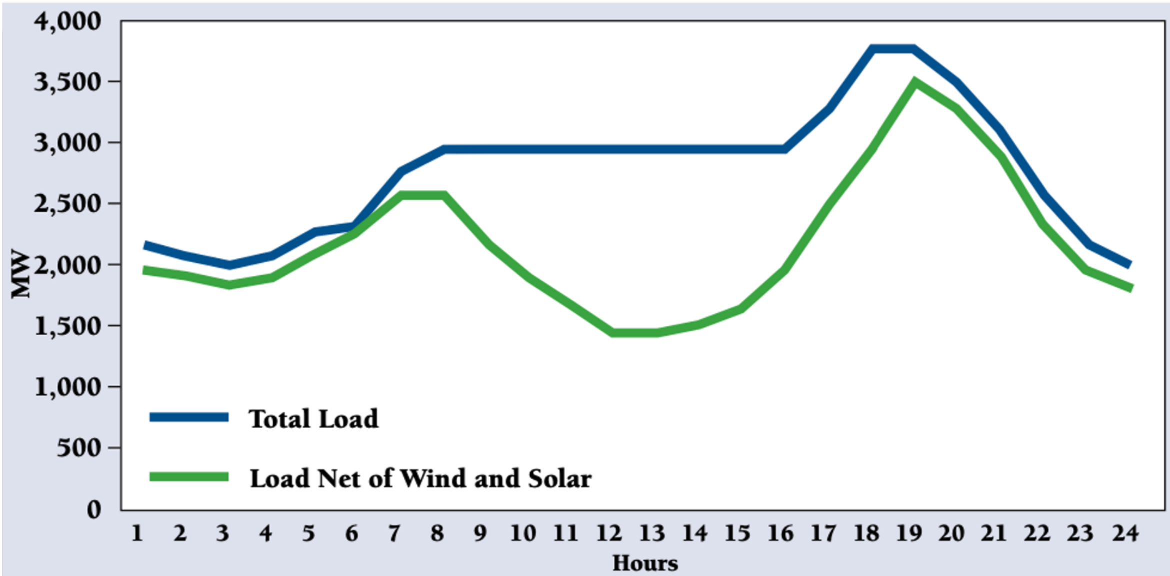
infrastructure by reducing certain distribution circuit peaks or by increasing infrastructure investment requirements for DG interconnection or substation investments to allow power to flow up from distribution circuits to the higher voltage distribution grid under certain conditions. Higher penetration of variable renewable resources (including utility-scale resources) generally may lead to the need for additional fast-ramping resources and other measures to "teach the duck to fly"[17] — that is, to smooth out what has become known as the duck curve to match fluctuations in renewable energy production. Extremely high penetration of certain technologies may require investments in a broader range of dispatchable resources, such as long-duration energy storage. Although some of these issues are no longer theoretical in some jurisdictions, they should be properly quantified to keep them in perspective.

California was the first jurisdiction to experience the duck curve, and subsequent analysis and experience highlights policies that can help avoid it. The California context is important. Aggressive adoption of utility-scale solar and distributed solar generation in 2012 and 2013 contributed to the duck curve. By 2013, utility-scale solar adoption was becoming significant in California and the neighboring states of Nevada and Arizona. The combination of distributed solar approaching its prescribed cap of 5% of peak load and the addition of thousands of megawatts of utility-scale solar contributed to the emergence of the duck curve at the California Independent System Operator.

The duck curve describes the shape of customer net load after significant quantities of solar are adopted. Comparing the gross load to the net load in the typical 24-hour day renders a pair of curves that together resemble a duck at rest. During the middle of the day, when solar production is greatest, total energy consumption less total solar production causes net load to sag. Before solar adoption, peak consumption in the summer happens in the afternoon when air conditioning and economic activities are peaking. After significant solar adoption, the middle of the day into the afternoon becomes a period of relatively low net consumption due to abundant solar output. The accompanying effects of solar are a shifting of the net peak from the late afternoon into the evening (the top of the duck's head) and a rapid ramp up (the duck's neck) as solar production begins declining and ceases in the early evening (see Figure 3 on the next page). Together, these challenges of shifting the peak and a rapid ramp up indicate a shift of system stress periods. Adoption of time-of-use (TOU) rates with adjusted peak periods becomes important to address system stress and limit any shifting of costs from one group of customers to another. (For more on the question of cost shifts, see the text box on Page 16.)

[17] Lazar, J. (2016). *Teaching the "duck" to fly* (2nd ed.). Regulatory Assistance Project. https://www.raponline.org/knowledge-center/teaching-the-duck-to-fly-second-edition/

Figure 3. Hypothetical example of the duck curve

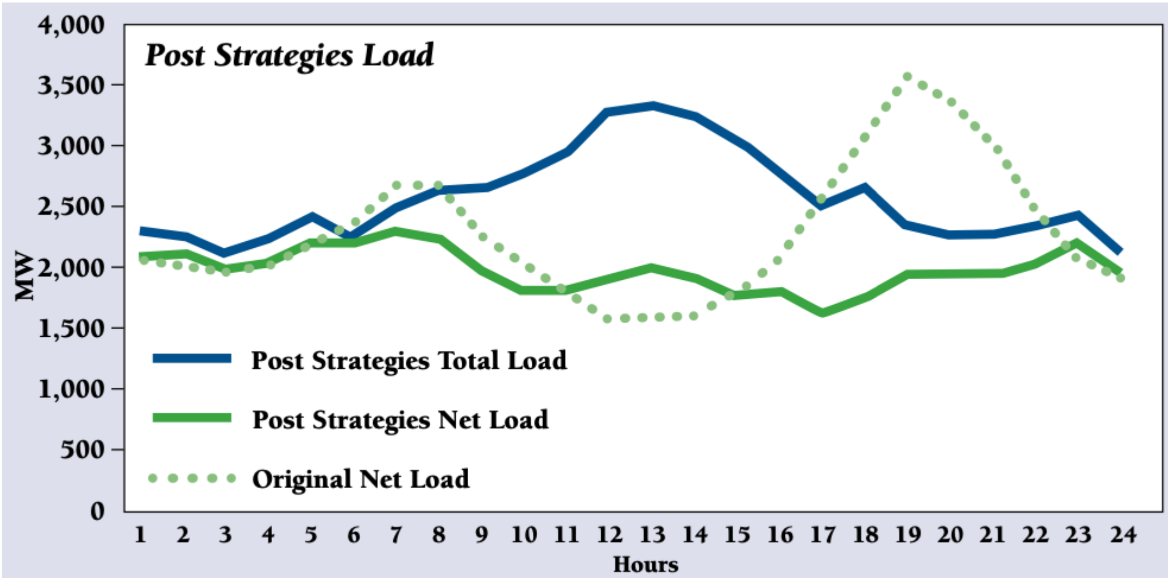


In California, for the first decade of solar DG adoption, the electric system peak coincided with hours of peak solar production, making solar production valuable in addressing increasing peak loads. However, utility-scale and distributed solar collectively surpassed 20% of annual peak load, with utility-scale solar reaching 4,495 MW in 2013, while distributed PV approached the 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, legislation mandated a reconsideration of the default NEM tariff, with the new default to become effective as the 5% cap was reached in the respective utility service territories.

As solar adoption has soared in the United States over the last 10 years, the possibility of duck curves in the highest-adoption states has emerged as an issue. Perhaps the first lesson that states need to learn from the California experience is that system needs will shift, with peak periods changing and periods with significant ramping emerging. Time-of-use rates and the redefinition of the peak period have proven to be important tools in California that help compensate for the impacts of higher solar production. A number of higher-adoption states are implementing these tools. Other strategies can provide more manageable load profiles. Figure 4 on the next page depicts a hypothetical example of the duck curve and how these strategies, some of which are discussed below, can provide more manageable load profiles.[18]

[18] Lazar, 2016.

Figure 4. Load after application of load management strategies



Jurisdictions with low levels of DG penetration, such as Wisconsin, may not need to act on these issues immediately, but it rarely hurts to be prepared for foreseeable issues. Additionally, many of the actions taken to avoid the duck curve are activities and programs that already exist in Wisconsin. The following actions can be incorporated to avoid the duck curve from large amounts of renewable generation, including DG:

- Target energy efficiency to the hours when load ramps up sharply.
- Orient fixed-axis solar panels to the west: Orienting solar panels to the west-southwest increases output during the afternoon and reduces morning output. This would produce a more valuable profile of power output, better suited to the shape of load to be served.
- Implement service standards allowing the grid operator to manage electric water-heating loads to shave peaks and optimize utilization of available resources.
- Retire inflexible generating plants with high off-peak must-run requirements.
- Deploy electric energy storage in targeted locations, including electric vehicle charging controls.
- Implement aggressive demand response programs.
- Use inter-regional power transactions to take advantage of diversity in loads and resources.[19]

[19] Lazar, J. (2014). *Teaching the "duck" to fly*. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-teachingducktofly-2014-jan.pdf

Cost-Benefit Tests

Jurisdictions in the United States that have implemented ratepayer-funded energy efficiency programs typically require that these programs and measures pass one or several cost-effectiveness tests before programs are included in rates. In some states, cost-effectiveness tests are also used to assess programs for other types of DERs, including distributed generation. Conducting a cost-effectiveness test requires a thorough evaluation of the costs associated with a DER, as well as the benefits (which mostly consist of *avoided* costs), and the results can inform rate designs and programs that support those resources.[20] However, it is essential to consider at the outset that the type of test selected has huge implications, as each test considers costs and benefits from a different perspective (see Table 1).[21]

Table 1. Summary of standard cost-effectiveness and rate impact tests

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

Source: National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

Regulators in some states have adopted modified versions of one of the standard tests or developed their own jurisdiction-specific test that accounts for the benefits and costs associated with achieving applicable policy goals. In Wisconsin, evaluations of the Focus on Energy program currently rely on a modified total resource cost (TRC) test. The Wisconsin test varies from a standard TRC test in that an assumed benefit is attributed to

[20] For example, in 2018, ICF prepared a meta-analysis for the U.S. Department of Energy of recent cost-benefit evaluations for distributed solar resources. ICF reviewed evaluations from 15 states that focused on the value of distributed solar resources and whether net metering tariffs are cost-effective or create a cost shift to customers without solar. ICF. (2018). *Review of recent cost-benefit studies related to net metering and distributed solar*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2020/06/f75/ICF%20NEM%20Meta%20Analysis_Formatted%20FINAL_Revised%208-27-18.pdf.

[21] National Energy Screening Project. (2020). *National standard practice manual for benefit-cost analysis of distributed energy resources,* p. E-2. https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf. For more on cost-benefit tests, refer to the National Energy Screening Project website (https://www.nationalenergyscreeningproject.org/).

avoided greenhouse gas emissions, even though that is a societal benefit rather than a utility system or participant benefit. The question of which cost-effectiveness test(s) to use normally arises as part of the quadrennial planning process mandated under Wis. Stat. § 196.374(3)(b)1.

Cost of Service Frameworks

Cost allocation is the method regulators use to determine how to equitably divide a set amount of costs among several broadly defined classes of ratepayers.[22] 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 partly overlapping principles to help guide the task of allocating costs efficiently and equitably:

1. Cost causation.
2. Costs follow benefits.

Two major quantitative frameworks are used around the United States for cost allocation: embedded cost of service studies and 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 planning period of perhaps five to 20 years and typically involve more substantial forward-looking analysis than embedded cost techniques.

Embedded cost of service studies, sometimes termed "fully allocated cost of service studies," are the most common form of utility cost allocation study. 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.

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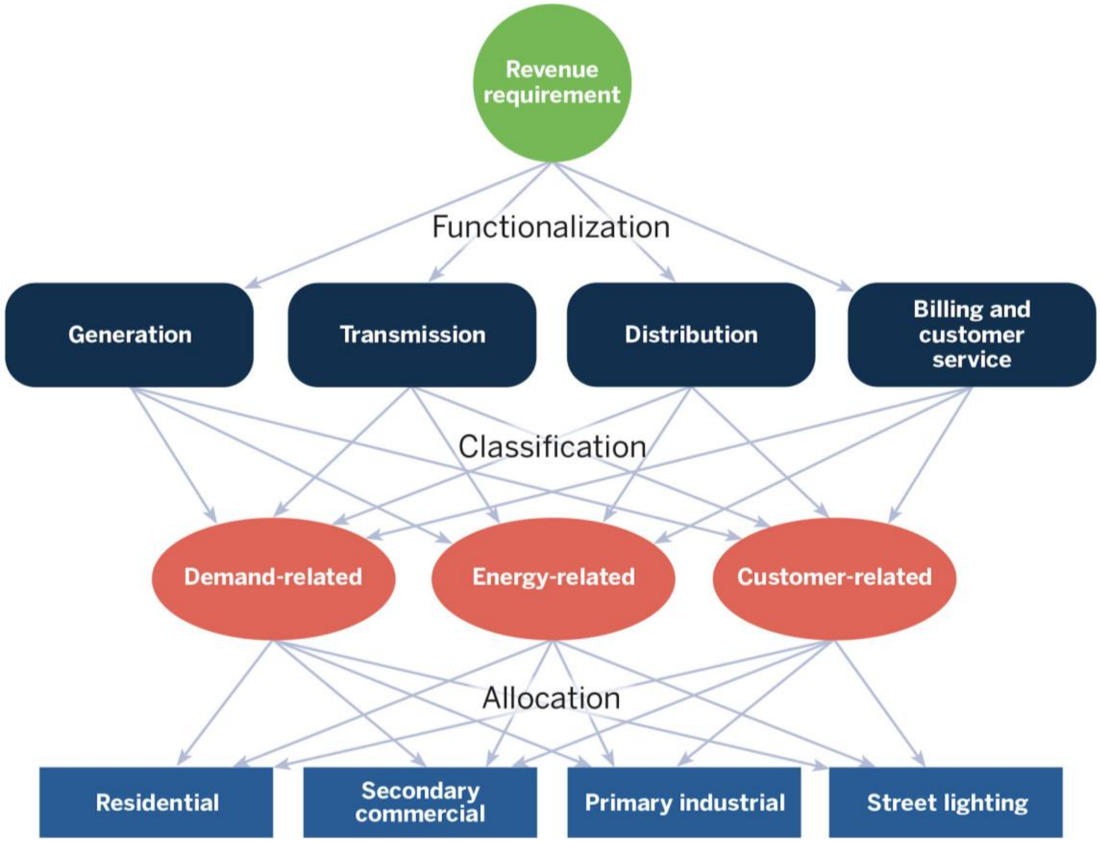
[22] For more information, see Lazar, J., Chernick, P., Marcus, B., & LeBel, M. (Ed.). (2019). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

Figure 5. Traditional embedded cost allocation approach



As shown in Figure 5, embedded cost allocation techniques follow three typical steps of functionalization, classification and 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.

> "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."
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> J. C. Bonbright, *Principles of Public Utility Rates*[23]

Seeing the weaknesses in the historical embedded cost techniques, many regulators 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 account for how

[23] Bonbright, 1961, pp. 348-349.

costs change over time and which rate class characteristics are responsible for driving 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 has led to numerous stakeholder disputes. Many jurisdictions have migrated back to the 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. 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.[24] 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 technique and the inverse-elasticity technique to allocate these costs.[25]

For the most part, the presence of customers with distributed energy resources has not drastically changed cost allocation techniques, at least at this point. After utility costs are functionalized and classified, each type of cost is then allocated to customer classes based on the relevant allocators. For allocators based on energy and demand metrics, customers with DERs are not treated any differently. If a utility still uses load sampling, DER customers may or may not be a significant part of the sample. For utilities with advanced metering infrastructure (and thus full load data for all customers), DER customers are typically aggregated with the rest of their customer class. To the extent that a jurisdiction has a special cost recovery mechanism for either lost revenue from DER customers or the cost of net metering credits, these are typically allocated and priced in a simple manner (e.g., on a cents-per-kWh basis over all usage).[26]

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[24] This particular circumstance typically excludes externalities from the definition of marginal cost.

[25] For more information, see Lazar et al., 2019, section 27.3.

[26] As a part of the implementation of the value of distributed energy resources tariff in New York, a more refined approach has been taken, attempting to follow the "costs follow benefits" principle. For example, the cost recovery for credits valued for energy and capacity should be recovered from the same customers that benefit from reduced utility purchases of energy and capacity. See New York Public Service Commission, Case 15-E-0751, Order on March 9, 2017, on net energy metering transition, Phase One of value of distributed energy resources, and related matters, p. 52. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b5B69628E-2928-44A9-B83E-65CEA7326428%7d

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 across 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 they describe 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 time frame 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. 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 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, strongly overlaps 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 resources at least cost.

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

- **A residual cost definition** of a cost shift asks whether a group of customers contributes the same margin toward 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 question is similar to those that can be asked about the cost causation basis of embedded cost allocation and pricing techniques. This question is different from the marginal cost definition of cost shifting mentioned above, because residual costs are in *addition* to 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.

Section II: Applying Rate-Making Principles and Goals to Net Metering and Alternative Rate Design Options

Although many characteristics of the evolving electric grid argue for modernizing retail rate designs, the growth of DERs is unquestionably a key driver. The connections between DERs and rate design are dynamic and are increasingly significant as deployment levels grow. Stated simply: DER deployment affects utility sales and costs, utility sales and costs affect retail rates, and retail rates affect DER deployment. In this section we explain how different aspects of DER rate design conform to the rate-making principles and goals articulated in Section I. We pay particular attention to NEM tariff designs.[27] And, because 97% of the distributed generation on a net metering tariff uses solar PV technology, we will concentrate mostly on implications for solar PV.[28]

Traditional Net Metering

Utilities in the United States first began offering NEM tariffs in the early 1980s. In Wisconsin, the PSC issued an order in 1982 requiring all regulated utilities to file NEM tariffs available to customers with DG systems up to 20 kW in capacity.

In those early days, digital smart meters were not available. There were only two practical possibilities for metering DG installations for residential or small commercial customers:

- A second meter could be installed to monitor production from the DG system separate from the measurement of the customer's electricity consumption.
- Net energy consumption could be measured by a single analog meter that was capable of spinning forward (when consumption exceeded generation) or backward (when generation exceeded consumption).

Limitations in metering capabilities, paired with billing system challenges and the desire to keep tariffs simple enough for customers to easily understand, led to the design of what we will call traditional NEM tariffs. The key features of a traditional NEM tariff are as follows:

- Net energy consumption (in kWh) is measured for the entire billing period as a whole.
- If net energy consumption for the billing period is a positive number, the customer's net energy usage is billed at the otherwise applicable retail energy rate for that customer class.

[27] This paper uses "net energy metering" or "NEM" to refer to any tariff where a customer with a DER capable of injecting energy into the distribution system (i.e., a distributed generation or energy storage resource) is billed or receives bill credits based on the customer's net consumption of energy or net excess generation over defined netting periods. In Wisconsin, these kinds of tariffs are variously labeled net metering, NEM or net billing. Some parties make a distinction by using the term "net energy metering" to describe tariffs where credits for net excess generation are volumetric (kWh credits) and "net energy billing" for tariffs where credits are monetary (in the form of a fixed price in cents per kWh). We feel such distinctions are unnecessary and instead use "NEM" to describe both kinds of crediting mechanisms.

[28] Congressional Research Service (2019). *Net metering: In brief*. https://crsreports.congress.gov/product/pdf/R/R46010

- If net energy consumption for the billing period is a negative number, meaning that generation exceeded consumption, the customer receives a credit toward other charges on the bill or future bills at the full retail energy rate.[29]

Many U.S. utilities still offer traditional NEM tariffs today. However, smart meters are now widely available that are capable of monitoring net exports and net imports of energy in small time intervals for use in a variety of DG tariff designs, including those relying on time-varying rates. A growing number of utilities (and the public utility commissions and legislatures that regulate them) are considering alternatives to traditional NEM.

Why Distributed Generation Tariff Design Matters

As explained above, the value of DG can be looked at from different perspectives. From any perspective chosen, we find that tariff design strongly influences DG value. We examine the question first from the perspective of customers with DG, then from the utility system perspective and finally from the societal perspective. Decision-makers who examine DG value from all three perspectives will be better positioned to make smart choices about rate designs.

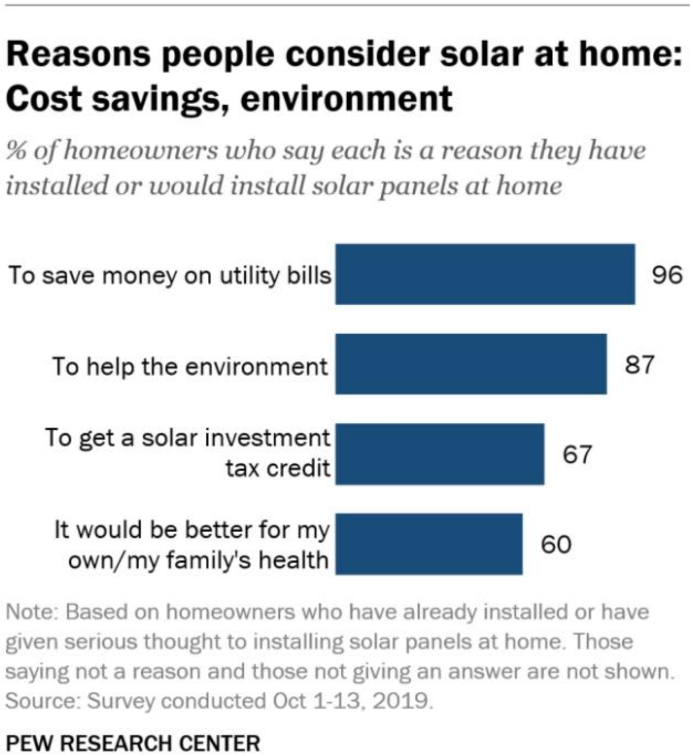
Customer Perspective

Customers install DG for multiple reasons, but numerous surveys indicate that the most common or important reason for a majority of customers is the opportunity to save money. For example, Figure 6 on the next page shows results from a recent survey by Pew Research Center[30] that is largely consistent with similar surveys of American public opinion.

[29] For this reason, traditional NEM is sometimes referrred to as "full retail rate NEM."

[30] "*More U.S. Homeowners Say They Are Considering Home Solar Panels*." Pew Research Center, Washington, D.C. (2019, December 17). https://www.pewresearch.org/fact-tank/2019/12/17/more-u-s-homeowners-say-they-are-considering-home-solar-panels/. See also Solar Simplified. (2020, December 29). *Consumer perceptions of the solar industry (2020)*. https://www.solarsimplified.com/media/consumer-perceptions-report-2020

Figure 6. Factors influencing potential solar adoption



Source: *"More U.S. Homeowners Say They Are Considering Home Solar Panels."* Pew Research Center, Washington, D.C. (2019, December 17).

The desire of customers to save money is central to explaining why DG tariff design matters. The various components of a DG tariff design will determine which utility costs the customer can and cannot avoid, and this, combined with the prices in the tariff, will determine the customer's payback period (i.e., how long it will take before the bill savings from installing DG pay for the initial investment and any ongoing costs).

A 2015 report from the Lawrence Berkeley National Laboratory explored the impacts of net metering and retail rate designs on customer adoption of distributed solar PV.[31] The authors reached several conclusions, including:

- "[R]etail rate design and PV compensation mechanisms can have a dramatic impact on the projected level of PV deployment. For example, wider adoption of time-varying rates is found to increase PV deployment in the medium term but reduce deployment in the longer term, relative to the reference scenario based on current rate offerings."
- "[W]e estimate that cumulative national PV deployment in 2050 could be ~14% lower with a $10/month residential fixed charge, ~61% lower with a $50/month residential fixed charge and ~31% lower with 'partial' net metering."

[31] Darghouth, N., Wiser, R., Barbose, G., & Mills, A. (2015, July). *Net metering and market feedback loops: Exploring the impact of retail rate design on distributed PV deployment* (LBNL-183185). Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/net-metering-and-market-feedback

In early 2021, the North Carolina Clean Energy Technology Center at North Carolina State University prepared a study for three California utilities that reviewed net metering reforms from across the country.[32] One aspect of the study looked at the impacts of reforms on solar adoption rates. In some cases, adoption rates were cut in half, while in others they increased or stayed roughly steady (see Table 2 for the results).[33] Details of the reforms adopted in each case are available in the study and offer insights as to why each case did or did not affect adoption rates, but the fact that some reforms had profound effects is sufficient to make the point that rate design affects customer decisions about solar adoption.

Table 2. Solar adoption rates before and after net metering reforms

Utility	NEM Reform Date	Avg. Monthly Capacity Additions Before NEM Reform (MW/Month for 12 Months Preceding Reform)	Avg. Monthly Capacity Additions After NEM Reform (MW/Month for 12 Months Following Reform)
Arizona Public Service	Sept. 2017	9.36	16.30
PacifiCorp (CA)	Mar. 2020	0.05	0.025*
HECO (CSS / CGS)	Oct. 2015	4.04	4.06
HECO (CGS+ / Smart Export)	Feb. 2018	0.97	0.43
NV Energy (Net Billing)	Jan. 2016	6.33	3.37
NV Energy (Net Metering)	Sept. 2017	0.96	3.36
National Grid (NY) – Phase One NEM / VDER	Mar. 2017	1.99	1.48
SMUD (TOU Rates)	Jan. 2018	1.40	1.54

* Average monthly capacity additions for Mar. – Nov. 2020

Source: North Carolina Clean Energy Technology Center. (2021, February). *A Review of Net Metering Reforms Across Select U.S. Jurisdictions*

More recently, researchers at The Brattle Group studied the effects of different rate designs on payback periods and distributed solar deployment using econometric demand models and data from 27 states. They concluded, "In terms of payback, we find that a one-year increase in the payback period drops solar installations by 6 per cent."[34, 35]

[32] North Carolina Clean Energy Technology Center. (2021-a, February). *A review of net metering reforms across select U.S. jurisdictions.* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M371/K711/371711892.PDF. The study was attached as Appendix 1 to a joint proposal of Pacific Gas and Electric Co., San Diego Gas & Electric Co. and Southern California Edison Co. filed March 15, 2021, in California Public Utilities Commission Docket R.20-08-020.

[33] North Carolina Clean Energy Technology Center, 2021-a, p. 4.

[34] Faruqui, A., Ros, A. J., & Kaiser, G. (2021, July). The battles over net energy metering. *Energy Regulation Quarterly, 9*(2). https://energyregulationquarterly.ca/articles/the-battles-over-net-energy-metering#sthash.X4Nbws5t.dpbs. A footnote in the article notes, "The results we cite in this sections is [sic] from consulting work performed to date as well as a working paper entitled, 'Residential Rooftop Solar Demand and the Impact of NEM Compensation and Residential Electricity Prices.' Please contact the author for a copy of the paper."

[35] Much of the cited article references the estimated impacts of NEM reforms proposed by California utilities on payback periods and solar adoption rates in that state, but the econometric analysis and the conclusions cited here are not specific to California.

The importance of rate design to DG customers has also been demonstrated in cases where utilities (or regulators) reduced the compensation rate in tariffs for customers who had already installed and interconnected a PV system. These actions, especially if they are not phased in over a long period of time, can reduce the economic value of existing investments and generate strong opposition. For example, when Nevada regulators reduced net metering compensation in 2015, an outcry by customers and solar installers eventually led to a reversal of the policy.

Utility Perspective

When customers generate electricity behind the meter, they reduce their utility's costs of service but also reduce the revenues the utility collects. No tariff design will perfectly balance reduced utility costs and reduced utility revenues in all circumstances and at all times. One of the arguments for traditional net metering, in addition to its simplicity, has historically been that crediting net generation at the full retail energy rate achieves "rough justice" in this difficult balancing act and avoids the need to precisely evaluate the impacts of DG on utility costs and revenues. So long as DG deployment is "low," any small imbalance created by the tariff will have minimal impact on utility cost recovery. But in many parts of the country, DG deployment is no longer considered "low" and utilities are increasingly concerned about cost recovery implications.

Customers on a net metering tariff can avoid the full retail energy rate for every kWh they self-supply (i.e., generate and consume instantaneously on site). They can also receive a bill credit from the utility for any net excess generation that they export to the grid. This has implications for utility cost recovery in the short term for at least two reasons. First, retail energy rates are established in rate cases based on *average* utility costs. The variable energy costs that a utility *actually* avoids when a customer with DG generates electricity can, depending on timing and location and other variables, be more than or less than the average energy cost reflected in retail rates. Second, rates are designed to recover some of the utility's short-run *fixed* costs through energy charges, but many of the utility's short-run fixed costs do not diminish when customers self-supply. This can lead to what is sometimes referred to as a lost contribution to fixed costs (LCFC).[36] The design details of a net metering tariff and the prices within the tariff will play a large role in determining the magnitude of any LCFC. If relatively few customers take service on the tariff, the LCFC (if it exists) will be relatively small and may have no noticeable impact on utility cost recovery. But if a significant amount of generation is covered by a net metering tariff and the LCFC grows big enough, it will eventually create pressure to increase prices. This leads to the frequently expressed concern that traditional NEM tariffs unjustly shift costs from customers with DG to all the other customers.[37]

The general concern about cost shifting is compounded by concerns about inequity. Researchers at Lawrence Berkeley National Laboratory found that customers who installed solar in 2018 spanned all income ranges, but only 30% had incomes below

[36] If the variable energy costs that a utility avoids because of customer generation exceed the average energy costs reflected in retail rates, this can partially or even fully offset any LCFC arising from the tariff.

[37] Net billing tariffs, where the credit for net excess generation is different from the full retail rate, can increase or decrease the concerns about cost shifting depending on whether generation is credited at a rate greater than or less than the retail energy rate.

120% of area median income. However, several states have adopted policies to make DG deployment more equitable, and the same report noted that there were three states where half the customers installing solar in 2018 had incomes below the area median for owner-occupied homes.[38]

Cost-shift concerns have been one motivator for efforts to redesign NEM tariffs or replace them with alternatives. Other revisions stem from a desire to compensate DG adopters fairly for the value they provide to the electric system, compensate the utility fairly for the grid services customers provide, and charge nonparticipating consumers fairly for the value of the services they receive.[39] In many cases, these efforts have been supported or opposed with benefit-cost analyses that seek to quantify the extent to which cost shifting is occurring or will occur. ICF, for its 2018 review of studies related to the costs and benefits of NEM and other distributed solar rate designs,[40] identified more than 40 relevant studies but selected a subset for review based on these criteria:

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

The studies that ICF reviewed varied widely in the conclusions they drew about avoided costs, value and cost shifting associated with DG tariffs, as indicated in Table 3 on the next page.

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38 Barbose, G., Forrester, S., Darghouth, N., & Hoen, B. (2020, February). *Income trends among U.S. residential rooftop solar adopters*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/income-trends-among-us-residential

39 Linvill, C., Shenot, J., & Lazar, J. (2013). *Designing distributed generation tariffs well: Fair compensation in a time of transition*. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/05/rap-linvillshenotlazar-faircompensation-2013-nov-27.pdf

40 ICF, 2018.

Table 3. Principal findings of studies on distributed solar rate designs

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

Source: ICF. (2018). *Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar*

ICF attempts to make sense of these widely varying findings by offering some key observations, excerpted here:

- Overall value depends substantially on which costs and benefits are included and monetized in a study. ... Three value categories, all on the wholesale power system, are included in all studies: avoided energy generation, avoided generation capacity, and avoided transmission capacity.
- Approaches to defining the value categories and methods for quantifying them vary across studies and affect the results.
- The perspective from which value is assessed affects which value categories are included and how they are quantified.
- Studies use a range of input assumptions for factors that influence results, such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates.

ICF did not attempt to identify the "right" way to assess DG tariffs but did reach some additional conclusions that may point in a helpful direction for rate design:

- "[T]he 15 studies analyzed in this paper converge on at least three common value categories, all at the wholesale or bulk power level: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Methodological approaches to calculating these common categories are generally well established, similar, and agreed upon, with the quantified result potentially differing based on a wide range of regional factors and assumptions."[41]
- "Given the relative newness of evaluating the cost, performance, and therefore net benefit to the distribution grid, the majority of differences between the studies occur in this area."
- "[I]ncorporating distribution system value components in a staged order, starting with values that are the largest and most readily quantifiable, is a practical approach to capturing near-term value. For example, distribution capacity deferral represents a value component with long-term and substantial value that may be a good first step, and several States, including New York and California, have quantified it. As a second step, States may look toward the additional value of increasingly complex components such as reliability, resilience, and voltage management."

Societal Perspective

Societal impacts are most relevant to discussions about DG tariffs in cases where a jurisdiction has adopted broad goals or requirements, and where the deployment of DG is thought to contribute to achievement of those goals. For example, Wisconsin has established some renewable energy goals and requirements in statutes. Wis. Stats. § 1.12(3)(b) states, "It is the goal of the state that, to the extent that it is cost-effective and technically feasible, all new installed capacity for electric generation in the state be based on renewable energy resources, including hydroelectric, wood, wind, solar, refuse, agricultural and biomass energy resources." The renewable portfolio standard in Wis. Stats. § 196.378 includes minimum targets for utility procurement of renewable energy. In addition to these statutory goals, there is an ongoing and vigorous debate about whether the state should adopt more ambitious goals for reducing greenhouse gas emissions, evidenced in preparations for the forthcoming Wisconsin Clean Energy Plan.

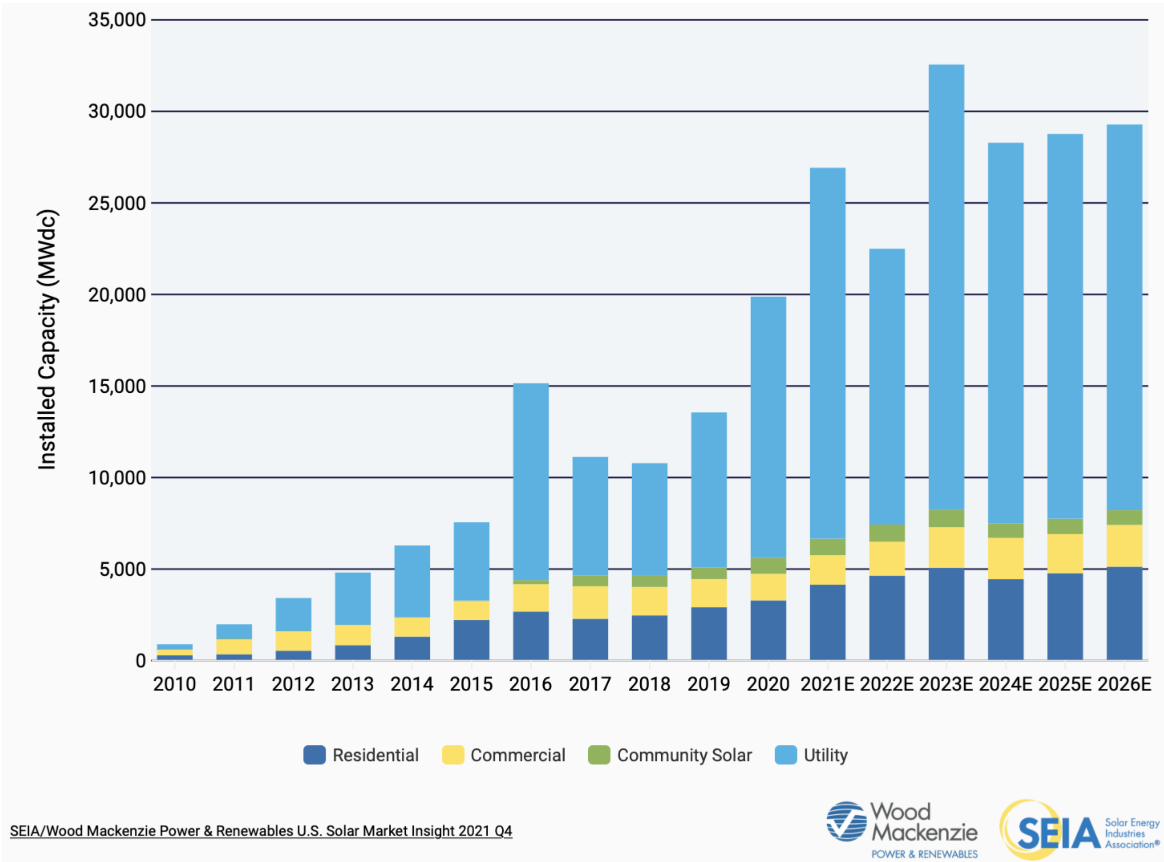
Solar energy can play a significant role in achieving these kinds of societal goals. According to the Solar Energy Industries Association (SEIA), "Solar has ranked first or second in new electric capacity additions in each of the last 8 years. In 2020, 43% of all new electric capacity added to the grid came from solar… the second year in a row that solar added the most generating capacity to the grid." [42] SEIA's data also suggest that customer-sited solar

[41] A brief summary of the methodological approaches for these three common value categories can be found in ICF, 2018, pp. 12-13 (for avoided energy and generation capacity) and pp. 14-15 (for avoided transmission capacity). ICF's assertion that the approaches are "well established, similar, and agreed upon" does not mean that the approaches taken in each study were identical in their details.

[42] Solar Energy Industries Association. (n.d.). *Solar industry research data*. https://www.seia.org/solar-industry-research-data

installations operating under NEM or other retail tariffs will continue to form a significant fraction of new solar capacity additions for years to come (see Figure 7).[43]

Figure 7. U.S. solar PV deployment forecast



Source: Solar Energy Industries Association. (n.d.). *Solar Industry Research Data*

In its *Annual Energy Outlook 2021*, the U.S. Energy Information Administration (EIA) echoes the solar deployment forecasts from SEIA, projecting over 220 GW of installed solar PV capacity by 2035 and 350 GW by 2050 — more than wind or any other renewable energy source.[44] And data U.S. utilities submitted to the EIA further reinforce the fact that DG is a big contributor to total solar generation, with 31% of the generation from solar facilities in 2020 coming from small-scale facilities (as opposed to utility-scale facilities).[45]

[43] Solar Energy Industries Association, n.d.

[44] U.S. Energy Information Administration. (2021, February). *Annual energy outlook 2021*. https://www.eia.gov/outlooks/aeo/

[45] U.S. Energy Information Administration. (2021-a, December). *Electric power monthly*. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_1_01

The EIA data also show how important NEM is for solar deployment. As of September 2021, more than 3 million customers and almost 32 GW of capacity in the United States were operating on some form of NEM tariff.[46] However, it is important to recognize that the uptake of solar and the percentage of customers on NEM tariffs varies widely from state to state, as shown in Table 4.[47] While more than 17% of customers in Hawaii were on NEM tariffs as of September 2021, only 0.3% of Wisconsin customers were. The reason this matters is that the impacts of NEM on utility cost recovery and potential cost shifting depend in large part on how many customers are on NEM tariffs.

Table 4. Net energy metering participation rates, by state, as of September 2021

State	Total customers	NEM customers	Percentage
Hawaii	509,156	89,435	17.6%
California	15,779,279	1,365,247	8.7%
Arizona	3,282,373	205,800	6.3%
Nevada	1,430,640	75,634	5.3%
Utah	1,302,282	53,923	4.1%
Connecticut	1,693,466	62,103	3.7%
Massachusetts	3,293,018	119,100	3.6%
New Jersey	4,211,331	144,467	3.4%
New Mexico	1,055,099	35,808	3.4%
Colorado	2,801,829	93,270	3.3%
District of Columbia	326,497	10,303	3.2%
Maryland	2,681,226	81,098	3.0%
Vermont	379,134	8,934	2.4%
New York	8,460,553	158,734	1.9%
Delaware	510,486	9,148	1.8%
New Hampshire	753,449	11,784	1.6%
Rhode Island	493,861	6,949	1.4%
Maine	837,155	10,852	1.3%
Oregon	2,084,366	24,984	1.2%
Idaho	954,453	10,620	1.1%
Louisiana	2,450,510	26,208	1.1%
Florida	11,181,540	98,649	0.9%

[46] U.S. Energy Information Administration. (2021-b, December). *Form EIA-861M (formerly EIA-826) detailed data*. https://www.eia.gov/electricity/data/eia861m/#netmeter. Note that the form the Energy Information Administration uses to collect NEM data asks utilities to report on all tariff arrangements that allow customers to sell (or obtain bill credits) for excess generation over their load requirements, "typically but not necessarily at a rate equivalent to the retail price of electricity."

[47] U.S. Energy Information Administration, 2021-b.

South Carolina	2,841,835	25,429	0.9%
Pennsylvania	6,214,765	41,058	0.7%
Washington	3,652,444	26,632	0.7%
Illinois	5,987,483	36,301	0.6%
Montana	659,068	4,272	0.6%
Alaska	352,149	1,932	0.5%
Iowa	1,679,198	7,833	0.5%
Missouri	3,231,916	16,075	0.5%
Virginia	4,015,431	22,061	0.5%
Wyoming	349,841	1,761	0.5%
North Carolina	5,566,607	24,929	0.4%
Michigan	5,027,615	12,714	0.3%
Minnesota	2,823,292	9,158	0.3%
Oklahoma	2,143,160	7,454	0.3%
Texas	13,868,560	44,520	0.3%
Wisconsin	**3,136,865**	**8,291**	**0.3%**
Arkansas	1,682,927	4,166	0.2%
Indiana	3,304,594	5,922	0.2%
Kansas	1,573,302	2,787	0.2%
Ohio	5,678,036	11,242	0.2%
West Virginia	1,022,112	1,598	0.2%
Kentucky	2,324,026	2,433	0.1%
Nebraska	1,098,739	942	0.1%
Alabama	2,696,173		0.0%
Georgia	5,204,001	519	0.0%
Mississippi	1,583,094	571	0.0%
North Dakota	476,897	79	0.0%
South Dakota	494,848	119	0.0%
Tennessee	3,489,730	51	0.0%
U.S. total	158,650,411	3,023,899	1.9%

Data source: U.S. Energy Information Administration. (2021, December). *Form EIA-861M (formerly EIA-826) Detailed Data*

The U.S. Department of Energy, in its recently published *Solar Futures Study*, modeled scenarios for achieving 95% decarbonization of the U.S. grid by 2035 and 100% decarbonization by 2050.[48] The department's modeling found that the most feasible and cost-effective means of achieving such goals requires adding huge amounts of new solar capacity, including huge amounts of new distributed solar PV: "In 2020, about 80 gigawatts (GW) of solar, on an alternating-current (AC) basis, powered around 3% of U.S. electricity demand. By 2035, the decarbonization scenarios envision cumulative deployment of 760-1,000 GW, serving 37%-42% of electricity demand. ... By 2050, those scenarios envision cumulative deployment of 1,050-1,570 GW, serving 44%-45% of electricity demand on an energy (MWh) basis. We estimate that roughly 80%-90% of that capacity will be utility-scale solar, with the remainder coming from smaller-scale distributed solar." In other words, the Energy Department estimates that about 100 to 200 GW of new distributed solar could be added to the grid in the next 30 years if the current administration's decarbonization goals are to be achieved.[49]

Applying Rate-Making Principles to Distributed Generation Tariff Design

A DG tariff comprises many details, and the choices made with respect to one tariff design element can influence and interact with the options available for other elements. Although none of the elements should be viewed in isolation, some are more important than others in shaping whether the tariff will result in unfair cost shifting and whether the customer will have a reasonable payback period. We will explain what those key elements are, how they implicate cost shifting and payback periods, and how various tariff design options comport with the cost allocation and rate-making principles described in Section I. Stated succinctly, the objective is to holistically design rates that:

- Are just and reasonable.
- Yield the total revenue requirement.
- Are simple enough to be understandable to customers.
- Reflect cost causation on a forward-looking, long-term, marginal cost basis.
- Send price signals that encourage economically efficient customer behavior.
- Ensure that utility services will be safe, reliable, affordable and environmentally responsible.
- Support the achievement of other public policy goals of the state of Wisconsin.
- Are based on a fair allocation among customers of all costs, including DG costs.

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48 U.S. Department of Energy. (2021, September). *Solar futures study*. https://www.energy.gov/sites/default/files/2021-09/Solar%20Futures%20Study.pdf

49 The Energy Department primarily used the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model for this study. But because ReEDS is a bulk power system model, projections for distributed PV adoption were developed exogenously using a customer adoption model and the results were imported into ReEDS. Three scenarios were developed for distributed PV adoption, based on three different projections of future cost trajectories. This accounts for the range in the projected levels of distributed PV.

Eligibility

DG tariffs usually start with a description of the types of customers and installations that are eligible to receive service under the tariff. Virtually all such tariffs place limits on the size of the individual installations eligible for the tariff, expressed as either a cap on the installed capacity or a limit comparing the expected annual generation of the system and the customer's preinstallation annual energy usage. DG tariffs sometimes also include caps on participation (e.g., limiting the availability of the tariff to a specific number of customers or MW of installed capacity). To the extent that the other details of a DG tariff might lead to cost shifts, eligibility caps can limit the impact and reduce the likelihood that the lost contribution to fixed costs will necessitate noticeably higher prices for other customers.

The key rate-making principle to consider in defining eligibility for DG tariffs is whether the tariff is nondiscriminatory. Is there a rate-making principle that justifies constraining eligibility for a particular tariff (e.g., one with a more favorable buyback rate) to only certain customers or certain sizes of installations? Is there a justification for capping participation?

Metering

Some tariff designs, such as a "buy-all/credit-all" tariff, require two meters.[50] Some utilities have also required multiple meters in cases where customers are eligible for special incentives or special rates that require metering of gross renewable generation or the amount of energy stored in or discharged from on-site storage devices.[51] The cost of installing a second electric meter is normally hundreds of dollars and can exceed $1,000. This adds significantly to the costs the customer will need to recoup, and thus to the payback period, which presents a strong argument against such a tariff. In addition, adopting this kind of tariff essentially requires the regulator to accept the premise that customers should be forced to sell a commodity they produce (energy) at a rate which they have little or no ability to negotiate to a specific buyer they cannot choose. It is comparable to a policy that says the customer must sell all the tomatoes they grow in their garden to the nearest grocery store at a price the store chooses and then buy all the tomatoes the customer wants to eat from the same store at a different price the store chooses. For this reason, some customers and solar advocates may argue that buy-all/credit-all tariffs are unjust and unreasonable, regardless of whether they conform to other rate design principles, unless the customer also has a net energy metering or net billing tariff option.

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[50] For clarification on what we mean by a buy-all/credit-all tariff, see the discussion of "buy all, sell all" tariffs in Zinaman, O., Aznar, A., Linvill, C., Darghouth, N. R., Dubbeling, T., & Bianco, E. (2017, October). *Grid-connected distributed generation: Compensation mechanism basics*. National Renewable Energy Laboratory. https://emp.lbl.gov/publications/grid-connected-distributed-generation. We use the term "credit" rather than "sell" because in the United States utilities typically give the customer a bill credit rather than writing a check for the customer's generated energy.

[51] For example, two or, in some cases, three meters could be required under the Solar Massachusetts Renewable Target program. Metering of DG generation is needed because utilities are allowed to take credit for the gross amount of renewable energy generated and not merely the net amount exported to the grid when demonstrating compliance with the state's renewable portfolio standard, and metering of energy storage is needed because there are special incentive adders for storage devices. See Massachusetts Solar Program. (2021). *Solar Massachusetts Renewable Target (SMART) program*. https://masmartsolar.com/

Their opposition isn't necessarily based on cost allocation or rate design principles, but rather on the principle that they should be able to consume energy that they produce.

Instead of requiring more than one meter, a tariff could require DG customers to have a single "smart" meter (advanced metering infrastructure, or AMI) even in service territories where AMI is not the default technology for all customers. Smart meters are essential for enabling some of the rate design options discussed below.

Netting Intervals

Any NEM or net billing tariff needs to clearly describe how the billing determinants will be measured. One of the most crucial decisions is the netting interval or netting frequency. This is the time period for which DG production and customer electricity consumption are summed and measured for billing purposes. There are three basic approaches to netting.

First, in traditional NEM tariffs, especially those instituted prior to the widespread availability of digital meters, the netting interval is equal to the billing period. The customer's net consumption of electricity for the entire billing period is used to determine the charges or credits that appear on the bill.

Smart meters now allow for the use of shorter netting intervals, and shorter intervals allow closer examination of when and to what extent the customer is a net consumer (importer) of electricity, and when a net generation (exporter). This is useful and in fact necessary if one wants to design a net billing tariff that is based on time-varying prices.

In the second approach to netting, net consumption can be measured during shorter intervals — for example, the peak and off-peak periods in a time-of-use rate — aggregated for the entire billing period and then billed or credited separately at the applicable rates for those intervals. In this example, at the end of the billing period the utility could separately calculate the customer's net consumption during the peak and off-peak periods, apply the applicable price or credit rate to each, and add those two calculated values to get the total charge or credit for the billing period.

The third approach is called an inflow/outflow model or instantaneous netting.[52] In this approach, the amount of energy that flows across the meter in either direction is measured for the billing period as a whole or in shorter TOU intervals. Time-varying rates (or credits) can be applied to every interval based on whether the customer is importing or exporting, and different values can be applied to inflows and outflows. An example of this approach is shown in Table 5 on the next page.

[52] Section III describes examples of this approach from Arizona and Michigan.

Table 5. Illustrative calculation of net metering using inflow/outflow method

	kWh	Price/credit rate (per kWh)	Charge/credit
Peak inflow	77	$0.26	$20.02
Off-peak inflow	235	$0.07	$16.45
Peak outflow	-23	$0.24	$(5.52)
Off-peak outflow	-274	$0.06	$(16.44)
Total			$14.51

The importance of netting intervals for customer payback period and utility cost recovery can be illustrated by comparing the example in Table 5 to how the same customer might have been billed under the other two approaches. Under the first approach, only the net total consumption for the billing period would be used, and the price or credit would be a flat rate for all peak and off-peak hours:

	kWh	Price/credit rate (per kWh)	Charge/credit
Net consumption	15	$0.12	$1.80

And under the second approach, the net consumption values for peak and off-peak periods would be used:

	kWh	Price/credit rate (per kWh)	Charge/credit
Peak	54	$0.26	$14.04
Off-peak	-39	$0.06	$(2.34)
Total			$11.70

Shorter netting intervals can be used with more-complex tariffs that more closely reflect the time-varying costs of electricity service as well as the avoided utility costs resulting from DG exports. However, there are obvious trade-offs that regulators will want to consider. Using shorter netting intervals also complicates the bill calculation in ways that might require billing system modifications and might confuse customers. As a reminder, one of the most-cited rate-making principles is that prices should not be overly complex or convoluted such that customers cannot understand how their bills are determined.

Many of the NEM tariffs that Wisconsin utilities offer rely on monthly netting. Many utilities in Wisconsin employ TOU netting for customers on an underlying time-varying rate design, but because relatively few customers in Wisconsin today are on time-varying rates, there are relatively few customers on an NEM tariff that uses TOU netting.

Customer Charges and Other Fixed Monthly Charges

In an attempt to reduce any lost contribution to fixed costs associated with DG, one approach that many utilities have considered is to increase the basic customer charge in DG tariffs above the charge applied to comparable customers without DG. Because this charge does not change regardless of how much or how little the customer generates, it is one of the most reliable ways to ensure the utility will recover its costs of service and avoid cost shifts to customers without DG. In terms of our rate-making principles, it can be very effective in yielding the total revenue requirements.

On the other side of the ledger, this approach diminishes the amount of energy costs the customer with DG can avoid and thus increases the payback period for DG. Raising the customer charge to recover LCFC also conflicts with some of the rate-making principles noted in Section I.

To begin with, recovering LCFC by raising the customer charge is not grounded in the traditional approach to cost allocation, in which only customer-related costs (i.e., those that vary based on the number of customers) would normally be recovered through a customer charge. The essence of the LCFC dilemma is that in some (not all) cases, fixed costs may not be fully recovered because of changes in energy consumption and possibly, to a lesser extent, changes in demand. The LCFC problem, where it exists, is primarily energy related, not customer related. Cost allocation principles would suggest that the proper way to address the problem is through changes in energy prices and credit rates, if possible. A second problem is that customers may perceive this solution as discriminatory because a customer with DG pays a higher customer charge than one without DG, regardless of how much the DG installation generates in any given month. The third major problem with this approach is that raising the customer charge diminishes the price signals embedded in energy and demand charges that can encourage economically efficient consumer behavior with respect to timing of consumption, investments in energy efficiency or battery storage and the like.

Some parties to proceedings in other states have suggested that creating a separate customer class for DG customers and demonstrating, through a cost of service study, that the customer-related costs are different for this class is more consistent with rate-making principles. This approach may be worth exploring. 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 heating, electric water heating, electric 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, and to minimize the number of customer classes. 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 among the customer types and that there will be little controversy in reflecting those differences in the rate designs and levels.

Another alternative that is similar in some ways is to apply a minimum bill to customers with DG instead of raising the customer charge or creating a new customer class.[53] Instead of adding $10 a month to the customer charge, for example, the utility can institute

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[53] This is one feature of the DG tariff example from South Carolina that is described in Section III.

a $10 minimum bill. The key difference between a minimum bill and raising the customer charge can be seen in a hypothetical example. In a month when the customer is a net exporter of electricity, the two approaches both collect an extra $10 from the customer and reduce the LCFC problem. But in months when the customer's energy charges are more than $10, the minimum bill approach adds nothing to their bill.

Some utilities have imposed a grid access charge in their DG tariff as a way to partly address possible LCFC problems. The charge is a fixed monthly cost per kW of installed DG capacity. The premise behind such a charge is that the cost of serving these customers varies based on the installed capacity of their DG system. Because the capacity of a system doesn't change from month to month, this appears on the customer's bill as a fixed monthly charge. The impact of this kind of charge is effectively the same as the impact of raising the fixed charge an equivalent amount and can be quite significant. The previously cited Brattle analysis of California's proposed NEM reforms found that the proposed grid access charge affected customer payback periods more than the proposed changes to the customer charge and minimum bill.[54] Grid access charges may be a better reflection of cost causation than customer charges and can be equally effective at yielding the total revenue requirement. They also avoid the problem of pushing energy-related costs into the customer charge. But here again, the connection to cost causation is not terribly strong. The impact of a 5 kW DG system on utility costs might be no different than the impact of a 10 kW DG system, or it could be higher or lower depending on where each system is installed. To further complicate this question, DG systems usually can't interconnect to the grid if grid enhancements are needed to accommodate them, unless the installer pays for the enhancements. So, to be clear, grid access charges can be an effective tool for addressing LCFC, where such a problem exists, but they represent a deviation from traditional cost of service rate-making. Once again, we see trade-offs in rate design.

Energy Charges and Buyback/Credit Rates

In Wisconsin and other U.S. states, tariffs for customers with DERs are typically linked to energy charges (and for nonresidential customers, demand charges) described in a tariff that is broadly available to other customers in the same customer class. For example, residential customers on a net energy metering tariff who are net consumers of utility-supplied electricity in a given billing period almost always pay a retail rate for their net energy consumption that is the same as the energy rate other residential customers pay. Consequently, to design smart DG tariffs it may be necessary or at least helpful to examine whether the linked or underlying rate design is also smart.

Perhaps the most important aspect of NEM tariff design is the credit rate applied to net excess generation. Traditional NEM tariffs use billing period netting and provide credit at the customer's full retail energy rate. This is the simplest approach to implement and probably the simplest approach for customers to understand. The alternative to traditional NEM is to apply a credit rate that is different from the customer's retail energy rate. This can be done while maintaining billing period netting, or, for tariffs that employ a TOU or instantaneous netting method, varying credit rates can be applied to different time

[54] The researchers' conclusions for the proposed California NEM reforms would not be universally true; the impacts of each type of reform on payback periods would depend on the prices associated with each reform. See Faruqui et al., 2021.

periods. U.S. utilities are now using a variety of approaches to determining credit rates for excess generation:

Credit rates based on utility avoided costs. This approach, which many utilities in Wisconsin and elsewhere have adopted, offers NEM customers a credit for net generation that is based on an estimate of the energy and capacity costs that the utility will avoid because excess power from the NEM customer can be used to serve other customers. Crediting net generation at an avoided cost rate can be more consistent with rate-making principles than a traditional NEM tariff. An avoided cost credit rate can also be identical to or similar to power purchase (buyback) rates established for qualifying facilities under the federal Public Utility Regulatory Policies Act (PURPA).[55] However, it must be understood that a variety of methods can be used to estimate utility avoided costs and some methods will be more consistent with the rate-making principles than others. For example, basing utility avoided costs on recent average historical prices in an organized wholesale electricity market like the one that Midcontinent Independent System Operator (MISO) administers could be a good way to ensure rates will yield the revenue requirement and a good way to send accurate price signals to customers regarding the short-run costs of the existing power system.[56] Wholesale market prices, however, are not meant to, and in fact don't, reflect forward-looking, long-run marginal costs. A different approach, such as developing an independent forecast of forward-looking avoided utility costs (as happens routinely in energy efficiency program evaluation, for example), might better reflect long-run costs.[57] Regulators might also consider whether the avoided energy value takes into consideration avoided line losses and reserves. Because of line losses, a kWh generated by a customer on the distribution system will typically allow the utility to avoid generating or purchasing more than one kWh (a typical value might be 1.06 kWh) at the wholesale market level.

Credit rates based on a broader estimate of the "value" produced by distributed generation resources. This approach builds on the basic avoided cost methodology described above but estimates a value that encompasses more components than just the utility's avoided costs of energy and capacity. The best-known examples of this approach can be found in New York, where the PSC ordered utilities to offer "value of DER" tariffs;[58] in Austin, Texas, where a large municipal utility offers a "value of solar"

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[55] PURPA established the right of qualifying small power production facilities and qualifying cogeneration facilities, which are typically independent power producers or large customers, to sell energy to their local utility if they don't have nondiscriminatory access to an organized wholesale electricity market. Current FERC rules (18 C.F.R. §§CFR 292.309(e)) create a rebuttable presumption that qualifying small power production facilities with a capacity less than 5 MW do not have nondiscriminatory access to the MISO market. However, under separate provisions of PURPA, state regulators may not require utilities to purchase energy from qualifying facilities at rates in excess of the utility's "avoided costs" (i.e., "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source").

[56] For example, current FERC rules create another rebuttable presumption that state regulators in the MISO footprint *may* use locational marginal price as the basis for a rate for qualifying facility energy sales to electric utilities located in the market (18 C.F.R. §§CFR 292.304(b)(6)).

[57] The current FERC rules do not specify whether rates based on locational marginal price should be based on historical or forecast locational marginal prices. Note that we are summarizing FERC rules only to illustrate one way to base avoided cost rates on market prices, while emphasizing that the FERC rules don't require the use of locational marginal price, nor do they dictate how an avoided cost rate could or should or must be established for customers on a retail NEM tariff.

[58] See NY-Sun. (2022). *The value stack*. https://www.nyserda.ny.gov/all-programs/programs/ny-sun/contractors/value-of-distributed-energy-resources

(VOS) tariff;[59] and in Minnesota, where a VOS tariff was developed pursuant to state law and is currently utilized for community solar projects.[60] (Refer to Section III for more details about the Minnesota and New York examples.) The values that are included in the credit rate will depend on the perspective that is used to determine value (i.e., the cost-benefit test perspectives explained in Section I).

- If a utility cost test is used, the credit rate can include utility avoided costs other than energy and capacity — for example, avoided line losses, avoided ancillary service costs or avoided costs of complying with environmental or renewable portfolio standards. This would provide a more complete estimate of value than the energy-and-capacity-only approach of a PURPA-based method.
- If a TRC, modified TRC or societal cost test approach is used, the credit rate can reflect additional value to participating customers or to society, such as an estimate of resilience value for critical infrastructure facilities or a climate change value based on the social cost of carbon.

Credit rates that are set at an arbitrarily high value specifically to promote and encourage customer adoption of distributed generation. The advanced renewable tariffs that many Wisconsin electric utilities offered a decade ago (some of which are still on the books) fit this description. This approach can be an effective way to achieve public policy goals in places that want to encourage distributed generation, but it conflicts with the fundamental principle that rates should reflect marginal utility costs and send price signals to customers that encourage economically efficient behavior.

Regardless of the approach to crediting net generation, utilities could see some lost contribution to fixed costs, based on the fact that NEM customers consume some portion of the energy they generate instantaneously on site. The amount of energy purchased from the utility does decline, and so long as some energy-related fixed costs are recovered through the energy charge there may be some LCFC.

The portion of any potential LCFC problem that is energy-related can be partly addressed by making underlying energy rates as reflective as possible of energy-related costs. This can be done by building the DG tariff around an underlying time-varying energy rate and then using TOU or instantaneous netting. Utilities in several states, including some of the examples cited in Section III, have adopted this basic framework. The shorter the netting intervals, the more the billing determinants will reflect that DG customers are using the grid and the better the chance to bill or credit them based on something closely resembling actual utility costs of service or avoided costs. As we've previously noted, however, this complicates the bill and makes it harder for customers to understand what they are paying for and whether DG can lower their bills.

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[59] See Austin Energy. (2021, November). *Value of solar (VoS) rates*. https://austinenergy.com/ae/rates/residential-rates/value-of-solar-rate. Minnesota has also determined a VOS rate for its investor-owned utilities, and those utilities are authorized to offer a VOS tariff as an alternative to offering traditional NEM tariffs. But because the determined VOS rates have thus far been higher than retail energy rates, Minnesota's utilities currently are sticking with NEM tariffs.

[60] For the updated tariff, see Xcel Energy. (2021, September 1). *2022 VOS calculation, community solar gardens program*. Minnesota Public Utilities Commission Docket No. E002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={6015A37B-0000-C710-AEC4-7CABA59FDC59}&documentTitle=20219-177646-01

Any “solution” that makes the potential for LCFC go away entirely will inevitably raise other problems and conflict with other rate-making principles. There are and always will be trade-offs in rate-making.

Demand Charges

Residential customers typically are not assessed demand charges. This historical truth stems from the belief that demand charges would be hard for many residential customers to understand and manage. If a customer doesn’t understand how to manage their demand, in whatever form it is billed, then even a charge that perfectly reflects cost causation will not prompt economically efficient behavior by that customer. It will merely confuse them.

Nonresidential customers, especially large commercial and industrial customers, commonly do see demand charges on their bills. The billing determinant in most cases is based on the customer’s noncoincident peak (NCP) demand — that is, their highest demand at any moment during the billing period.[61] A “ratchet” may also be employed, whereby the customer is billed based on the *greater* of their NCP demand in the billing period or some fraction (e.g., 80%) of their highest NCP demand over the preceding year.

Coincident peak (CP) demand — the customer’s contribution to systemwide demand during systemwide peak hours — is less frequently used for billing purposes. CP demand charges are based on the customer’s demand during one or more actual systemwide peak demand hours over the preceding year. This kind of demand charge is sometimes expressed as xCP where x is the number of hours considered in calculating the customer’s peak demand. A 1CP demand charge is based on the customer’s contribution to systemwide demand in the single highest-demand hour of the previous year, while a 5CP charge would consider the customer’s highest demand in any of the five highest systemwide demand hours of the year.

As a variation on the CP demand charge concept, some utilities bill demand on a TOU or peak window basis. The customer’s bill shows their peak demand during established peak periods and assigns a demand charge based on those values. In some cases, additional values are recorded for the customer’s peak demand during off-peak periods, with a lower demand charge applied to those off-peak periods. TOU demand charges can be more complicated than either a CP or NCP demand charge when there are two billing determinants. Even if a single billing determinant is used, the cost allocation process has to identify demand-related costs during peak and off-peak periods separately. TOU demand charges may not reflect cost causation as accurately as CP demand charges, but they ensure some contribution toward demand-related cost recovery even for customers that use little power during system peaks.

The use of NCP demand as a billing determinant is commonly thought to be easier to explain to customers than CP or TOU demand because it doesn’t require any explanation of what the systemwide peak period is. NCP demand may also be characterized as something customers can more readily control, since the customers don’t have to know

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[61] Some Wisconsin utilities refer to NCP demand as “customer maximum demand” or a similar phrase.

when the systemwide peak demand or peak window hours will occur but instead can focus on reducing their own NCP demand. NCP is also somewhat easier to meter, at least where older analog metering technologies remain in use. However, NCP demand charges convey no useful information about shared utility system capacity costs. A customer who affirmatively seeks to reduce their own NCP may do nothing to reduce shared capacity costs and could even, unwittingly, increase them. Where rate designs rely on demand charges to recover shared utility system capacity costs, CP or TOU demand charges will almost always reflect cost causation more accurately than NCP demand charges and will thus send price signals that encourage more economically efficient customer behavior.

The impact of distributed generation on demand charges will depend on whether the customer typically generates energy at times of their own peak electricity usage, if they are on an underlying tariff that bills based on NCP demand. A solar PV installation will not lower the demand charges of a customer whose peak demand happens in the middle of the night. Even if the customer's peak demand routinely happens in the daytime, the impact of a PV system on their demand charges will probably be far less than the impact on their energy charges because their peak demand may be nearly the same as before on cloudy days, or days when the PV panels are covered by snow, or in the early morning or evening. The corollary to this truth is that the LCFC and potential for cost shifting attributable to avoided demand charges will also be lower than that attributable to avoided energy charges.

Customers on a tariff that bills based on CP or TOU demand may see more significant impacts but only if the customer's generation coincides with the system peak periods used for billing demand. If the system peak periods come after the sun sets or before it rises, a customer might see no change in their CP or TOU demand after installing a PV system and there might be no demand-charge-related LCFC or cost shifting.

Demand charges are not the only way to send price signals to customers about demand-related utility costs. Time-varying energy rates, particularly when they include a critical peak price, can serve as an alternative to demand charges for recovering shared utility system capacity costs. This approach has the advantage of sending simple and efficient price signals that simultaneously reflect the time-varying nature of energy supply costs and the high cost of capacity resources that serve demand primarily during peak periods. Furthermore, the use of time-varying rates does not preclude utilities from recovering capacity costs that are not shared but are necessary to serve the needs of a specific customer, through a "site infrastructure" charge based on the customer's NCP demand.[62]

Credit Rollover

The final aspect of NEM tariffs that has a big impact on payback periods and LCFC is the treatment of credits between billing periods. Credits can be volumetric (kWh) or monetary (dollars). A typical approach is one where a customer who has net credits in one billing period can apply those credits to subsequent bills. Most commonly, credits can roll over

[62] For a more thorough critique of when and how to apply demand charges, and an explanation of how time-varying rates can serve as an alternative, see LeBel, M., & Weston, F. (2020). *Demand charges: What are they good for?* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/demand-charges-what-are-they-good-for/

for up to 12 months or roll over indefinitely, but there are examples at the other extreme where credits do not roll over at all. The impact is significant. If a customer with solar is a net generator in summer months when the sun is out for most of the day, but a net consumer during darker winter months, credits from the summertime can lessen their bills in winter. This explains why credit rollover policies have a significant impact on the customer's payback period.

If the credit that rolls over is volumetric, this is akin to saying that every kWh has the same value — whether imported or exported, and regardless of when it is generated or consumed. This is not terribly consistent with the idea that rates should reflect cost causation or send economically efficient price signals. Monetary credits can reduce this problem because the amount of the credit can be adjusted to reflect time-varying and seasonally varying price signals, including costs of service, utility avoided costs or estimates of value.

Section III: Key State Examples

Net metering is a concept that has wide application across the United States. According to North Carolina Clean Energy Technology Center data, as of August 2021, 39 states plus the District of Columbia had mandatory net metering rules.[63] Other states allow utilities to offer voluntary net metering programs. While the concept of net metering is widely used, the application across states varies quite a bit. The following case studies illustrate how different states have approached net metering or a similar policy and the unique design of these tariffs that has evolved in each jurisdiction.

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)[64] and North Carolina's House Bill 589 (passed in 2017)[65] which required revised tariffs and renewable energy procurement. Specifically, the South Carolina bill required the utility commission "to establish solar choice metering requirements that fairly allocate costs and benefits to eliminate any cost shift or subsidization associated with net metering to the greatest extent practicable."[66]

In May 2021, the South Carolina Public Service Commission unanimously approved the settlement. The new compensation mechanism, called solar choice metering, applies to all new residential customers on or after January 1, 2022. South Carolina had a net energy metering program, and the solar choice metering settlement contained some transition

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[63] North Carolina Clean Energy Technology Center. (2021-b, August). *Net metering map*. https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/08/DSIRE_Net_Metering_August2021.pptx

[64] South Carolina General Assembly, Bill H3659, 2019-2020. https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm

[65] General Assembly of North Carolina, House Bill 589, 2017. https://www.ncleg.gov/Sessions/2017/Bills/House/PDF/H589v6.pdf

[66] South Carolina General Assembly, Bill H3659, 2019-2020. https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm

elements for existing NEM customers. In particular, these customers can maintain service under their existing NEM program until December 31, 2025, or May 31, 2029, depending on their applicable sunset date. If NEM customers wish to transfer to the solar choice tariff, they can do so with written notice, assuming they meet eligibility requirements. For customers who reach the applicable sunset date and do not wish to take service under the solar choice tariffs, the utilities are directed to propose a transition tariff for those customers to the commission prior to the sunset dates.

The solar choice tariff program has the following elements:[67]

- The tariff utilizes monthly netting within TOU periods and credits excess energy at avoided cost. Customers are able to net energy sent to the utility against the energy supplied by the utility over the monthly billing period.
- Participants are charged a monthly grid access fee that is intended to recover distribution costs for customers with system sizes greater than 15 kW-dc. To design the fee, the average maximum demand for customers with systems greater than 15 kW-dc was determined and the distribution unit cost applied to estimate the total distribution cost. The grid access fee was then set to the level that would recover this cost minus the portion already recovered through the minimum bill. The fee would be applied to the nameplate capacity in excess of 15 kW-dc. The monthly grid access fee until the implementation of any future rate cases in South Carolina will be $5.86 per kW-dc for Duke Energy Carolinas and $3.95 per kW-dc for Duke Energy Progress.
- In addition to the grid access fee, participating customers pay a monthly minimum bill that recovers customer and distribution costs applied after riders but before the grid access fee, any nonbypassable charges or excess energy credit. The monthly minimum would be $30 to ensure recovery of customer and distribution costs from solar choice customers. The $30 is reduced by the basic facilities charge and the portion of the customer's monthly volumetric energy charges specific to customer and distribution costs. If the combination of the basic facilities charge, specific volumetric energy charges and bypassable riders is less than $30, then the monthly minimum bill charge is equal to the difference. Any avoided cost bill credits for net excess energy can be used to reduce a customer's bill after the minimum bill has been applied. Current basic facilities charges will be $13.09 for Duke Energy Carolinas and $14.63 for Duke Energy Progress and will change in accordance with any future changes in the basic facilities charge for the residential TOU rate schedules.
- Monthly excess net exports are credited at an annualized rate (weighted average rate for all hours, assuming a fixed block of energy) for avoided energy cost. The utilities will maintain the fixed block of energy methodology that is used in a rider, but they reserve the right to use a solar energy profile instead. They will also maintain the practice of using an annualized rate but reserve the right to use different rates for each month instead.

[67] South Carolina Public Service Commission, Docket Nos. 2020-264-E and 2020-265-E, Order No. 2021-390 on May 30, 2021, approving stipulations, approving interim riders, and establishing solar choice tariffs. https://dms.psc.sc.gov/Attachments/Order/823ec8b8-881b-4cba-82f9-1b5b5c6d7a50

- All costs related to demand-side management, energy efficiency, storm cost recovery and cyber security are nonbypassable with the option of proposing new components to the nonbypassable list of charges with no direct link to customer kWh usage. Inclusion of additional possible solar choice program costs would be handled in separate proceedings and rate cases.
- Imports and exports will be netted within each TOU pricing period initially, and net exports during that pricing period are credited at avoided cost as explained above. Critical peak pricing applies to all imports during the critical peak pricing hours. Any energy exports during the critical peak pricing hours will be netted against peak imports, not the critical peak imports. The designation of critical peak pricing days and hours will be set daily and will be posted daily on the utility's website.[68]
- Renewable energy certificate for all solar generation will be transferred to the utility upon being placed on the rate for the length of time the customer enrolls in a permanent tariff.
- The settlement also included a new incentive for qualifying 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. These proposals are under consideration in a separate energy efficiency docket.

Cost shift was a critical issue in this discussion, and the commission noted that it was the only material disagreement in the proceeding. Act 62 in South Carolina specifically required consideration of cost shifts by stating that the solar choice tariffs "must fairly align costs and benefits of service customer-generators in a way that eliminates cost shift to the extent such elimination can be achieved while also continuing the successful deployment of DER under Act 236 and avoiding disruption to the solar industry." As the commission noted, the solar choice tariffs must eliminate cost shift "to the greatest extent practicable," but that concept is informed by whether it would avoid disruption to the growing market for customer-scale DERs and allow for the continued private investment in on-site DERs, such as rooftop solar, under Act 62. In approving the settlement, the commission noted that elimination in potential cost shift is primarily achieved through an alignment of the costs and benefits of innovative rate mechanisms such as time-varying pricing. Specifically, the commission found that when taken together, the rate-making structures reduced cost shift for residential customers by 84% and 100% for Duke Energy Carolinas and Duke Energy Progress, respectively, from an embedded cost perspective. From a marginal cost perspective, the solar choice tariffs reduce cost shift for residential customers by 88% and 53% for Duke Energy Carolinas and Duke Energy Progress, respectively. The commission found that the tariff permits access to customer generator

[68] For a discussion of critical peak pricing, see South Carolina Public Service Commission, 2021, pp. 92-94.

options, while enabling customers to produce meaningful bill savings and ensuring a broader public good, and does so without penalizing solar choice customers given that customer generators may continue to offset energy required from the utility on a 1:1 basis through self-consumption.[69]

California: From NEM 2.0 Toward NEM 3.0

California utilities have been obligated to offer a net energy metering tariff to their residential and commercial customers since the passage of SB 656 in 1995.[70] 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 until a prescribed cap was met. The cap was initially set at 0.1% 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.

As noted above, by 2013 utility-scale solar adoption was becoming significant in California. The combination of distributed solar approaching its 5% cap and the presence of thousands of MW of utility-scale solar contributed to the emergence of the duck curve at the California ISO.

Assembly Bill 327 was passed in 2013 to address duck curve issues, including a perceived disconnect between the compensation being provided to solar DG adopters and the value of solar DG to California's electric system. 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 solar production caused the peak to shift from the afternoon to the very late afternoon and early evening. With solar production no longer coinciding with the electric system's peak and net peak, AB 327 mandated a reconsideration of the default NEM tariff, with the new default to become effective as the 5% cap was reached in the respective utility service territories.

The California Public Utilities Commission issued Decision 16-01-044 in 2016 to implement the NEM successor tariff, commonly referred to as NEM 2.0.[71] AB 327 specified some parameters for the revised NEM tariff, while others arose as the commission considered testimony and data from proceeding participants. AB 327 was concerned that NEM customers pay their share of nonbypassable expenses, which largely arise from public purpose programs incurring costs that utility ratepayers bear. These include programs like energy efficiency and low-income support. The issue of ensuring that

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69 South Carolina Public Service Commission, 2021. Discussion of cost-shift methodology starts on p. 63.

70 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

71 California Public Utilities Commission, Rulemaking 14-07-002, Decision 16-01-044 on January 28, 2016, adopting successor to net energy metering tariff. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

solar-adopting customers pay their share of system costs was addressed partly with this mandated feature and partly through additional features of the revised tariff, including:

- A mandatory interconnection fee.
- A minimum bill provision.
- The phase-in of mandatory TOU rates.[72, 73]

NEM 1.0 customers were allowed to remain on that tariff, and NEM 2.0 customers were given a guarantee that their NEM 2.0 tariff would be available for 20 years.

Since 2016, solar has grown rapidly in California. By 2020, utility-scale solar had grown past 15,000 MW and distributed solar had 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 significant. In 2020, California utility regulators commissioned the *Net-Energy Metering 2.0 Lookback Study* to assess the performance of the NEM 2.0 tariff.[74] The study assesses the costs and benefits of NEM 2.0 using four tests: the TRC test, the participant cost test, the utility cost test and the rate impact measure. The study presents results for all tests but focuses on the TRC results and a comparison of the first-year cost of service with first-year bill payment for new NEM 2.0 customers. The TRC test estimates total benefits and total costs associated with solar adoption and finds that while nonresidential systems produce more benefits than costs, the residential systems produce fewer benefits than costs (with a benefit-to-cost ratio ranging from 0.69 at PG&E to 0.8 at Southern California Edison).[75] A comparison of first-year costs to serve NEM 2.0 residential customers versus the total bill payments of these customers finds a large gap, with these customers in aggregate paying approximately $600 million less than the cost to serve them.

Thus the study indicates that further changes in the net energy metering framework will be needed to address the deficiencies of NEM 2.0. Although commercial customers do not impose a cost shift, residential customers do appear to significantly underpay for their share of system costs. The California commission has launched NEM 3.0 to consider additional changes in rate and tariff design to better align rate design with cost causation.[76] Final positions in the NEM 3.0 proceeding were submitted on September 14, 2021, and a proposed decision was issued in December 2021.[77] Proposals included in the September 14 positions range from a utility proposal to implement instantaneous netting and implement a grid benefits charge on all distributed solar customers to solar industry proposals that

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[72] For a description of the commission's analysis and rationale, see the Findings of Fact starting on Page 106 of California Public Utilities Commission, 2016.

[73] For a sample bill at one utility for NEM 2.0, see Pacific Gas & Electric Co. (n.d.) *Monthly NEM energy statement*. https://www.pge.com/includes/docs/pdfs/myhome/saveenergymoney/solarenergy/billing-callouts-nem-monthly.pdf

[74] For an evaluation of NEM 2.0, including a link to the study, see California Public Utilities Commission. (n.d.-a). *Net energy metering (NEM) 2.0 evaluation*. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering/net-energy-meeting-nem-2-evaluation

[75] Verdant. (2021). *Net-energy metering 2.0 lookback study,* Table 1.5. California Public Utilities Commission. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nemrevisit/nem-2_lookback_study.pdf

[76] To see the current status of NEM 3.0, visit California Public Utilities Commission. (n.d.-b). *Net energy metering revisit — rulemaking (R.) 20-08-202*. https://www.cpuc.ca.gov/nemrevisit/

[77] See the proposed decision at California Public Utilities Commission. (2021). *CPUC proposal aims to modernize state's decarbonization incentive efforts* [Press release]. https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-proposal-aims-to-modernize-state-decarbonization-incentive-efforts

modestly adjust the current NEM 2.0 mechanism. The simple solar DG payback period ranges from 4.3 years for the most generous proposals to 20 years for the most punitive.[78] The proposed decision is far closer to the utility proposal than many expected, and it targets a tariff that delivers a 10-year payback to customers installing new systems. NEM 1.0 and NEM 2.0 customers would be allowed to continue at their current rates and terms with a transition toward NEM 3.0 being required for these customers in about 10 years. This proposed decision proved highly contentious, with many parties seeking significant changes. Action on the proposed decision has been deferred indefinitely, and how the decision may be amended is uncertain. The commission has not published a procedural schedule for resuming discussion of the proposed decision as of the date of publication of this report.

Arizona Distributed Solar Tariff With the Resource Comparison Proxy

The Arizona Corporation Commission directed its staff to begin rulemaking to develop net energy metering rules in 2007.[79] The commission adopted NEM rules in 2008 that provided for annual netting where any end-of-year net kWh sales would be compensated at an avoided cost rate.[80] The avoided cost rate was defined to be "the incremental cost to an electric utility for electric energy or capacity or both, which, but for the purchase from the NEM facility, such utility would generate itself or purchase from another source."[81] On December 3, 2013, the commission issued Decision No. 74022, which ordered the opening of a generic docket on net energy metering issues.

Docket E-00000J-14-0023 was opened in early 2014 to consider these issues. The commission issued Decision No. 75859 on January 3, 2017, finding that NEM should be replaced with an instantaneous netting mechanism, sometimes known as the inflow/outflow model, that compensates DG exports at the "actual value of DG."[82] NEM customers with an interconnection request that was filed before the effective date of the export credit tariff could remain with NEM for 20 years.

The commission determined that the value of DG should be set at an administratively determined avoided cost, and it advanced two methodologies: the staff's avoided cost methodology and the staff's resource comparison methodology as modified by the commission. The commission chose two methodologies to allow experience to be gathered in implementing each and in recognition that the methodologies have relative strengths that merit further consideration.

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78 For a summary of the submitted testimony and expected decision date, see Trabish, H. (2021, October 1). *As California's solar net metering battle goes to regulators, a focus on reliability may be the best answer*. Utility Dive. https://www.utilitydive.com/news/as-californias-solar-net-metering-battle-goes-to-regulators-a-focus-on-re/606816/

79 Pursuant to the federal Energy Policy Act of 2005, amendments to the Public Utilities Regulatory Policies Act of 1978, the Arizona Corporation Commission began this proceeding to consider NEM as a so-called PURPA standard.

80 Arizona Administrative Code, R 14-2-2301 through 2308.

81 Arizona Administrative Code, R 14-2-2302(1).

82 Arizona Corporation Commission, Decision No. 75859, Order on January 3, 2017, at ordering paragraph 133, p. 170.

The staff's avoided cost methodology specifies energy, generation capacity, transmission capacity and distribution capacity, line losses and environmental costs at specified levels for five years.[83] The resource comparison proxy methodology uses the five-year rolling weighted average of a utility's solar power purchase agreement and utility-owned solar generating resources with additions for the benefits of avoided transmission and distribution capacity investment and avoided line losses. The commission specified that the inputs to the avoided cost methodology be updated every year and that the methodology be considered in full with each new rate case. The five-year duration was selected to reflect an expectation that a new rate case would occur approximately every five years.

Arizona Public Service implemented the resource comparison proxy methodology through its RCP rate rider.[84] The rate rider specifies a 10-year rate (exceeding the initial five-year duration contemplated in the originating commission order) and carries the provision that the proxy will not decline by more than 10% per year. With utility-scale solar prices declining rapidly over the last five years, the 10% protection has proven important. For solar DG installed in 2017, the resource comparison proxy is 12.9 cents per kWh. By 2021, it declined to 9.405 cents per kWh.

Residential solar customers at Arizona Public Service have had three TOU rate design options, two of which include a demand charge for the last few years. Nonsolar customers have the same TOU options and two options that are not TOU.

On October 26 and 27 of 2021, the Arizona Corporation Commission ordered a decrease in Arizona Public Service rates and included significant changes to the solar tariffs. A grid access charge that had existed for solar customers for 10 years (predating the tariffs described above) was repealed and the TOU periods were narrowed. Arizona Public Service is challenging in court certain cost disallowances the commission ordered, and it is unclear if this challenge will delay the implementation of the solar tariff changes.[85]

Minnesota Value of Solar Tariff

Minnesota passed legislation[86] in 2013 that allows investor-owned utilities to apply to the Public Utilities Commission for a value of solar 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

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[83] Arizona Corporation Commission, Decision No. 75859, Order on January 3, 2017, at Appendix A.

[84] Arizona Public Service. (2020, October). *Rate rider RCP partial requirements service for new on-site solar distributed generation resource comparison proxy export rate*. https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Renewable-Plans-and-Riders/rcp_RateSchedule.ashx?la=en

[85] For a summary of the decision, see Van Voorhis, S. (2021, November 3). *APS vows legal action after Arizona regulators deny cost recovery for $215.5M coal plant upgrades*. Utility Dive. https://www.utilitydive.com/news/arizona-public-service-threatens-lawsuit-over-proposed-172m-rate-cut/609007/

[86] Minnesota Session Laws, Chapter 85 HF 729, Article 9, Section 10, 2013.

electricity production. To date, the VOS tariff has only been used for Xcel's community solar gardens, and no utility has opted to use it for rooftop solar PV projects.

The Minnesota Department of Commerce was directed[87] to establish a calculation methodology to quantify the value of distributed PV. The department submitted the draft methodology to the Minnesota commission in January 2014.[88] The commission approved[89] the methodology at a hearing on March 12, 2014, and posted the written order approving the methodology, with modifications the Department of Commerce had approved, on April 1, 2014.[90]

VOS Methodology and Formula

To calculate a utility's VOS figure, several 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 VOS 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 data.[91]

There are eight components of value in the tariff:

- 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 VOS calculation at this time, but the Minnesota Department of Commerce anticipates that these categories of costs and benefits will be known and measurable in the future.[92]

[87] Minnesota Statutes, Section 216B.164, subdivision 10(e).

[88] Norris, B. L., Putnam, M. C., & Hoff, T. E. (2014, April 1). *Minnesota value of solar: Methodology.* Minnesota Department of Commerce. https://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

[89] In its order, the commission noted that unlike most 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 its review to whether the department 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.

[90] Minnesota Public Utilities Commission, Docket No. E-999/M-14-65, Order on April 1, 2014, approving distributed solar value methodology. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bFC0357B5-FBE2-4E99-9E3B-5CCFCF48F822%7d&documentTitle=20144-97879-01

[91] Minnesota Public Utilities Commission, 2014.

[92] Minnesota Public Utilities Commission, 2014.

Key characteristics of the Minnesota VOS policy include:[93]

- Investor-owned utilities may voluntarily apply to the Public Utilities Commission to enact a program in lieu of net energy metering.
- 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 VOS tariff rate. Net excess generation is forfeited to the utility.
- Value calculation:
    - It is production based and expressed in dollars per 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 is 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 will be made public.
    - A tariff is not an incentive, and it is not intended to replace or prevent incentives.
- The utility automatically obtains the solar renewable energy credit with zero compensation to the 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 program. In its May 1, 2019, 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

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[93] Key characteristics derived from Cory, K. (2014, October). *Minnesota values solar generation with new "value of solar" tariff.* National Renewable Energy Laboratory. 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?* Institute for Local Self-Reliance. https://ilsr.org/wp-content/uploads/2014/04/MN-Value-of-Solar-from-ILSR.pdf

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 community solar garden program. Commissioners 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 commission directed Xcel to discuss with stakeholders how the following could improve the VOS methodology: (1) long-term load growth assumptions, (2) sensitivity analysis of different time periods for systemwide calculation and (3) methods to de-average avoided distribution costs to account for specific location differences.[94]

New York Value of Distributed Energy Resources Tariff

The New York Department of Public Service (DPS) started the Reforming the Energy Vision (REV) initiative in the spring of 2014 as an ambitious effort to rethink many aspects of state utility regulation from the ground up.[95] Proceedings under the initiative were wide-ranging and encompassed many topics. However, key strands included both a major expansion of clean distributed energy resources and a range of reforms intended to maximize the benefits of customer-side resources. An important section of an early REV initiative order included extensive discussion and directions to reform rate design and methods for accurately valuing distributed energy resources.[96] Another important early REV reform was the establishment of a new benefit-cost framework.[97]

[94] Minnesota Public Utilities Commission, Dockets No. E-002/M-13-867 and E-999/M-14-65, Order on December 3, 2019, approving changes to distributed solar value methodology as modified and requiring further filings. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30D2CC6E-0000-CA1D-A52B-274566AF32CF}&documentTitle=201912-157987-01

[95] New York Public Service Commission, Case 14-M-0101, proceeding on motion of the commission in regard to Reforming the Energy Vision, Order on April 25, 2014, instituting proceeding. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9CF883CB-E8F1-4887-B218-99DC329DB311}

[96] New York Public Service Commission, Case 14-M-0101, Order on May 19, 2016, adopting a rate-making and utility revenue model policy framework, pp. 109-125. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D

[97] New York Public Service Commission, Case 14-M-0101, Order on January 21, 2016, establishing the benefit cost analysis framework. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F8C835E1-EDB5-47FF-BD78-73EB5B3B177A}

In 2015, the New York DPS established a community distributed generation program[98] and effectively suspended the limits on aggregated DG capacity for each utility.[99] In conjunction with the broader scope of REV reforms, this led to the initiation of a proceeding to consider net metering reforms in December 2015, titled "*In the Matter of the Value of Distributed Energy Resources*."[100] The initial stakeholder questions and discussions in this proceeding were wide-ranging but, after a series of stakeholder meetings, they were narrowed down to high-priority topic areas, many of which were linked to a fast-expanding queue for community solar projects. That included interconnection reform and changes to the net metering framework for larger distributed generation projects. This meant that more traditional net metering for small rooftop projects would be maintained, but this would be considered for reforms in the next phase of the proceeding.

The DPS issued its Phase One order on March 9, 2017.[101] The key innovation in this order was the "value stack" credit structure for community distributed generation, remote net metering projects, and large on-site distributed generation projects.[102] 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.[103]
- Originally, a "market transition credit" for community distributed generation, which has subsequently been transitioned to a "community credit."[104]

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[98] New York Public Service Commission, Case 15-E-0082, Order on July 17, 2015, establishing a community distributed generation program and making other findings. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={76520435-25ED-4B84-8477-6433CE88DA86}

[99] New York Public Service Commission, Order on October 16, 2015, establishing interim ceilings on the interconnection of net metered generation. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6D51E352-B4C8-48F9-9354-2B64B14546DC}

[100] New York Department of Public Service, Case 15-E-0751, in the matter of the value of distributed energy resources. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751

[101] New York Public Service Commission, 2017.

[102] Large on-site projects were originally defined by the customer class, but subsequently certain projects under 750 kW became an exception if several criteria were met.

[103] This environmental value is vintaged by year and the floor for its value is the social cost of carbon (less the carbon allowance price for the Regional Greenhouse Gas Initiative). If renewable energy credit (REC) procurement costs are higher than the floor in a given year, then the REC procurement cost is used for the environmental value. Only REC-eligible technologies receive the environmental value and must agree to turn over their RECs to receive this value.

[104] The specifics of the market transition credit and the newer community credit have been adjusted over time in order to ensure gradual transitions as well as public policy goals related to the diversity of solar project types and project beneficiaries.

Several of these 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 value of distributed energy resources structure are flat per-kWh credits, including the environmental value for eligible technologies.

Phase Two of the proceeding began in late 2017 to address a wide range of issues coming out of Phase One, including rate design issues, continued improvements to the value stack credit structures, eligibility of stand-alone storage and low- and moderate-income participation. On July 16, 2020, the DPS issued an order establishing that retail rate net metering would continue for new mass market distributed generation projects, but that a new customer benefit contribution charge would be imposed on customers with new DG projects.[105] This charge would be priced on the basis of dollars per kW of installed capacity, and would be intended to collect the amount of revenue those customers otherwise would have contributed to utility low-income programs, energy efficiency programs and the New York State Energy Research and Development Authority clean energy fund. This charge would be calculated separately for different technologies and customer classes but has been estimated to range from $0.69 to $1.09 per kW of installed PV. The implementation date for this new charge was delayed from January 1, 2021, to January 1, 2022, as a result of the COVID-19 pandemic.[106] Final rates for the customer benefit contribution charge were filed in mid-December 2021 and range from $0.72 to $1.33 per kW.

Michigan Inflow/Outflow Model

In Michigan, net metering was first established by Public Act 295 of 2008.[107] For small DG 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 as the power supply portion of the retail rate.[108] In 2016, Public Acts 341 and 342 required the replacement of the legacy net metering frameworks with a new DG program. The statutory requirements for the new DG program included a study by the Michigan Public Service Commission staff on "an appropriate tariff reflecting the equitable cost of service for customers who participate in a net metering program or distributed generation program."[109]

The process for creation of the new DG program in Michigan took multiple steps, including (1) an interim distributed generation program established shortly after the 2016

[105] New York Public Service Commission, Case 15-E-0751, Order on July 16, 2020, establishing net metering successor tariff. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={E5A4CFD8-BD26-4287-B3F1-C1A72A3540BA}

[106] New York Public Service Commission, Case 15-E-0751, Order on August 13, 2021, adopting net metering successor tariff filings with modifications. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8E4FAF00-6CE5-460F-B0F6-CF67E3D04B3B}

[107] Prior to 2008, the utilities and the Michigan Public Service Commission had established a "negotiated" net metering arrangement.

[108] 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.

[109] Michigan Compiled Laws, Section 460.6a(14). Although the inflow/outflow billing method was chosen under this legal standard, it is possible that other billing methods and rate structures could meet this standard.

laws took effect,[110] (2) a staff report filed in February 2018,[111] (3) a framework order establishing the key aspects of the program in April 2018[112] and (4) implementation in rate cases filed after June 2018.

The key feature of the new DG 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.[113] 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. 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,[114] and any unused credit value can be rolled over to the next billing period. The inflow/outflow framework has substantial flexibility to be applied to nearly any rate structure. For example, residential DG program customers in Michigan are allowed to opt in to TOU rates just like any other residential customer. Inflow and outflow are then measured and priced separately for each period in the TOU rate.

By statute, participation in the legacy net metering and distributed generation programs is limited to 1% of average in-state peak load for the preceding five years. However, the utilities that have approached or reached their limit have raised this cap, either through a rate case settlement with other parties or a voluntary agreement with the Michigan PSC.[115] Eligible technologies for these programs include solar PV, wind, hydroelectric projects and methane digesters, although the 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.

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110 Michigan Public Service Commission, Case No. U-18383, Order on July 12, 2017. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UYJbAAO. 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.

111 Michigan Public Service Commission Staff. (2018, February 21). *Report on the MPSC staff study to develop a cost of service-based distributed generation program tariff* (Case No. U-18383). https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE

112 Michigan Public Service Commission, Case No. U-18383, Order on April 18, 2018. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000022KiuAAE

113 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 from buy-all/credit-all arrangements, where none of the gross generation is treated as a reduction in retail billing determinants.

114 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 as a minimum bill defined by the distribution charges.

115 Upper Peninsula Power Co. doubled its program size cap to 2% of its peak load as part of a rate case settlement approved in May 2019 and further agreed to increase its program size to at least 3% as part of a settlement in Case No. U-20995. Consumers Energy notified the commission that it would increase its program size cap to 2% on December 21, 2020.

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 Michigan PSC, along with the state's two largest electric utilities, Consumers Energy and DTE Electric, has been working to take advantage of the capabilities provided by advanced metering infrastructure with new rate design options, particularly for residential customers. 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 and a monthly customer charge of $8. 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, with a monthly customer charge of $7.50 per month. However, DTE provides several time-varying options to residential customers, including a relatively simple time-of-day rate and a more complex dynamic peak pricing rate.[116] 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.

Conclusion

As the deployment of distributed generation, and solar PV in particular, grows in Wisconsin and around the world, greater attention is being paid to the rate designs applicable to those customers. The most common approach historically used in the United States — full retail rate net metering — presents a simple option that is reasonably easy to explain to customers but can lead to cost shifts. Where few customers are on NEM tariffs, the potential for cost shifts will have little impact on total utility revenues and is unlikely to result in a need to immediately or significantly raise retail rates for other customers. But that potential grows as more customers install DG, and reforms to the traditional approach to NEM have been proposed and adopted in many jurisdictions.

According to the North Carolina Clean Energy Technology Center, more than half of the U.S. states have considered significant net metering reforms through legislation or regulatory proceedings. Notwithstanding this activity, the majority of states continue to offer traditional, full-retail-rate net metering that nets production and consumption over the monthly billing period. Arkansas, Connecticut, Indiana, Kentucky, Louisiana, New York, South Carolina and Utah have all modified their net metering programs since 2019.[117] California, Illinois, Hawaii, Michigan and Mississippi are evaluating programs. With all of these changes there will be a lot of examples to look to, but it is too early to know how all of those new changes are affecting solar value, deployment and cost shifting.

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

[117] DSIRE Insight Team. (2021, May 25) *Status of state net metering reforms*. https://www.dsireinsight.com/blog/2021/5/25/status-of-state-net-metering-reforms

Also, notably, some states adopted successor tariffs to net metering and subsequently returned to traditional net metering and monthly netting. These states include Nevada, Maine and Kansas.[118]

Debates about net metering reforms can easily devolve into outcome-based positioning by the parties that appear before a utility commission. Solar advocates and environmental organizations may argue for policies and rate designs that improve the value proposition for customers who install solar, even if those options are detrimental to customers without solar. Utilities may advocate for policies and rate designs that slow the adoption of distributed solar, as a way to minimize lost sales and earnings opportunities, even if those options inadequately compensate customers with DG.

Given the variety of changes occurring across the United States and the world on net metering and increased deployment of DG amid dropping prices, reliance on long-standing rate-making principles will be key to prudent decision-making. Long-standing and evolving rate-making principles should guide the decisions. A balancing of priorities is always necessary — for example, balancing the desire for rates that accurately reflect cost causation with the desire for rates that are simple for customers to understand.

Table 6 on the next two pages summarizes some of the key rate design elements for DG tariffs, the most common options applicable to each element and examples where each option has been adopted.[119] It also captures some of the biggest challenges and most salient points for applying rate-making principles to each option. It should be understood, however, that a principled approach to NEM reform must consider not just the options for each individual element of rate design but also the way those pieces fit together. The combination of options selected will ultimately determine customer value, rates of adoption and the potential for cost shifting.

[118] For example, in Nevada, regulators adopted a tariff with avoided cost compensation for excess generation in 2015, but legislation restored traditional net metering in 2017. Similarly, in 2017, Maine regulators approved a tariff to replace net metering, but the Legislature restored traditional net metering in 2019. DSIRE Insight Team, 2021.

[119] State data sources: net metering summary tables at DSIRE. (n.d.). *Programs*. North Carolina Clean Energy Technology Center. https://programs.dsireusa.org/system/program?type=37&category=2&; and DSIRE Insight Team, 2021. More states may be included in the categories listed.

Table 6. Key rate design elements for distributed generation tariffs

Rate design element	Options	Examples	Issues, rate-making principles implicated and trade-offs
Eligibility	System size caps	AZ, MI, NM, NY, NV, DC, GA, MD, ND, MS, FL, AK, IN, KY, WY, PA	Can reduce magnitude of any cost shifts that may occur
	Program/tariff caps	GA, MD, MS, AK, IN, KY, NV	If rate design minimizes potential for cost shifts, is there a rate-making principle that justifies program caps?
Netting intervals for DG customers	Monthly	AR, CT, KY, NH, NY, VT, ND, NM, FL, AZ, AK, IN, KY, WY, PA, NV, DC,	Simple to understand and necessary for customers without advanced metering infrastructure, but incompatible with any net billing tariff that is based on time-varying prices, which thus reduces the chance to minimize cost shifts
	TOU periods	CA, SC	More complex than monthly netting, probably understandable for customers on an underlying time-varying rate, can enable rate designs that better reflect average time-varying costs
	Instantaneous	AZ, IN, MI, MS	Even more complex and difficult for customers to understand than TOU netting
Customer charge in underlying rate design	(Standard)	(Most U.S. utilities)	Which costs are considered customer-related in cost allocation? Should costs that are not customer related be recovered this way?
Additional or different fixed charges for DG customers	None	HI, IN, KY, LA, MI, MS, UT, VT	Treats customers with and without DG identically in terms of nonbypassable charges but does not address LCFC concerns
	Additional fixed charge	SC	Can address LCFC concerns in a direct and easy-to-understand manner but prolongs DG payback periods; usually isn't based on increased *customer-related* costs of service
	Minimum bill	SC	Can address LCFC concerns without creating the possibility of DG customers paying more than their "fair share" toward short-term fixed utility costs
	Grid access charge	AR (larger customers), NY, SC[120]	Also addresses LCFC in a direct and simple way; better reflection of cost causation than additional fixed charge and avoids the problem of pushing energy-related costs into the customer charge, but the connection to cost causation is not strong
Energy charges in underlying rate design	Flat		Simplest for customers to understand but doesn't reflect time-varying nature of utility costs or send accurate price signals for economic efficiency; when paired with DG, more likely to result in cost shifts
	Time-varying		Harder to understand but more accurate price signals and less likely to result in cost shifts

[120] Grid access fee applies to system sizes greater than 15 kW-dc.

Buyback/ credit rates for DG customers	Retail rate	MD, NY, IN, KY, PA, NV, DC	Simplest and most familiar NEM approach for small customers but incompatible with time-varying rates (or ceases to be simple) and most likely of the options to result in cost shifts
	Avoided utility costs	ND, NM, MS, FL, WY	Closer match to most of the traditional cost recovery principles than retail rate credit, and puts DG customers on comparable footing to PURPA customers, but many challenges around appropriate methods for setting the rate especially with respect to using historic/short-term or projected/long-term avoided costs
	Value	MN	Need to agree on perspective/cost test and methods for quantifying costs and benefits; most of the same challenges as avoided cost method; more compatible with achieving policy goals that aren't reflected in utility costs (e.g., climate goals)
	Promotional rate		Not grounded in rate-making principles and likely to lead to cost shifts but can be a direct and simple approach for meeting policy goals
Demand charges	None	IN, MD, ND, NM, MS, FL, AK, NY, PA, WY, NV, DC	Historically, demand charges have been considered too complex for residential customers and/or unnecessary
	NCP		Easier than CP or TOU for customers to understand, easier for customers to manage their own costs but less reflective of cost causation for shared utility capacity
	CP		Harder to understand and manage than NCP or TOU but potentially more reflective of cost causation for shared utility capacity
	TOU	AZ	More complicated than NCP and typically not as reflective of cost causation as CP but ensures some contribution toward demand-related cost recovery even for customers that use little power during system peaks
Credit rollover[121]	Monetary ($)	AZ	Can be set at levels that accurately approximate average avoided costs or value but more complex than volumetric credits
	Volumetric (kWh)	MD, NM, AK, IN, WY, PA	Simple but less reflective of avoided costs or value
	Time-limited		Can reduce magnitude of any potential cost shifts but possibly unnecessary or unfair if credit rate is reflective of avoided costs or value

State data sources: DSIRE. (n.d.). *Programs*; DSIRE Insight Team. (2021, May 25). *Status of State Net Metering Reforms*

[121] Not all descriptions of net metering tariffs reflect this information. States reflected explicitly call out this information. Other states may have it, but this is not reflected in the summary.

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