

DISTRIBUTION SYSTEM PRICING WITH DISTRIBUTED ENERGY RESOURCES

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The work described in this technical report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in scale to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity on implications are common to both time periods. The U.S. Department of Energy (DOE) played a useful role during the 1990s discussion and debate by sponsoring a series of papers that illuminated and dug deeper on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues, with the aim to better inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of new and improved technologies, together with changing customer and societal desires and needs, both of which are coupled with possible structural changes in the electric industry and related changes in business organization and regulation. Some of the technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some of the technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To maintain effectiveness in providing reliable and affordable electricity and its services to the nation, power sector regulatory approaches may require reconsideration. Historically, major changes in the electricity industry came with changes in regulation at the local, state or federal levels.

The DOE, through its Office of Electricity Delivery and Energy Reliability's Electricity Policy Technical Assistance Program, is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policymakers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, works closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.



Acronyms

See Appendix A for a complete glossary of key terms used in the report.

AC	Alternating Current
AMI	Advanced Metering Infrastructure
DC	Direct Current
DERs	Distributed Energy Resources
DSO	Distribution System Operator
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GIWH	Grid-Integrated Water Heater
kW	Kilowatt
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
PUC	Public Utility Commission
PV	Photovoltaic System
RFP	Request for Proposals
TOU	Time of Use
VOST	Value of Solar Tariff



Executive Summary

Technological changes in the electric utility industry bring tremendous opportunities and significant challenges. Customers are installing clean sources of on-site generation such as rooftop solar photovoltaic (PV) systems. At the same time, smart appliances and control systems that can communicate with the grid are entering the retail market. Among the opportunities these changes create are a cleaner and more diverse power system, the ability to improve system reliability and system resilience, and the potential for lower total costs. Challenges include integrating these new resources in a way that maintains system reliability, provides an equitable sharing of system costs, and avoids unbalanced impacts on different groups of customers, including those who install distributed energy resources (DERs) and low-income households who may be the least able to afford the transition.

This report examines pricing issues related to the business relationship between electric distribution utilities and the owners of DERs. At a minimum, utilities will likely continue to supply most owners of DERs with backup and supplemental service and with various other grid services. Utilities will receive power from certain types of DERs and may be able to secure important grid reliability services from DERs as well.

The authors of this report have attempted to portray these issues from a perspective in the future, when these resources are assumed to be widespread, when there are “fleets” of thousands and millions of units that are already integrated into the distribution system. The report uses specific resources as examples, intended to illustrate the issues that utilities, regulators and consumers will face, not to exclude potential other resources that may have different impacts. Examples include:

- Grid-integrated water heaters
- Ice storage air conditioners
- PV systems with smart inverters
- Backup generators
- Battery and inverter-based storage systems

The pricing for services from the utility to customers with DERs, and for services DERs provide to the utility, can take many forms. This report examines four approaches to pricing these services:

1. **Granular Rates:** The pricing for services to and from customers with DERs is highly granular, with each service provided by each party separately priced.
2. **Buy/Sell:** The pricing for services to customers with DERs is in the form of a bundled traditional utility price. The pricing for services DERs provide to the utility is in the form of a resource-specific price reflecting the characteristics of the service.
3. **Procurement Model:** The pricing of services the utility provides customers with DERs is in the form of a bundled utility price. The services DERs provide to the utility are procured on a competitive basis, with third-party aggregators likely playing a role in



presenting a value proposition to both the utility and the DER owner/host that meets their financial and other criteria.

4. **DER-Specific Rates:** The utility applies separate rates to customers with DERs, both for supplying backup and supplemental service and for procurement of services from DERs. Each type of DER faces a different type of rate, based on the characteristics of the resource and technology.

Each of these options is examined based on multiple evaluation criteria. These criteria are inevitably somewhat subjective and will vary geographically and temporally and evolve with technology. Criteria include:

- **Economic Efficiency:** Does the DER provide a net economic benefit that should be able to be shared in a way that makes all parties better off?
- **Equity/Fairness:** Does the pricing scheme ensure that DER owners/hosts are fairly compensated and that other customers do not bear costs in excess of what they would face without these DERs?
- **Customer Satisfaction:** Do customers enjoy better electric service, lower costs, or the perception of a better overall package of values?
- **Utility Revenue Stability:** Does the utility receive a fair and predictable level of revenues that track the costs they face?
- **Customer Price/Bill Stability:** Do utility customers experience relatively stable electricity distribution bills, either as a result of stable prices or by operation of a regulatory framework that manages costs over time to produce stable bills?

The report ultimately presents two perspectives on the pricing models (see Section VI). While there is a great deal of consensus among the authors about the overall framework by which DERs should be evaluated and the options available for pricing of services to and from DER customers, there is not consensus on which framework provides the best balance of efficiency, equity, customer satisfaction, and stability for utilities and consumers. Ryan Hledik presents considerations from the perspective of the distribution utility, while Jim Lazar presents issues from the perspective of consumers. Their perspectives are distinct from one another and from their clients and should not be perceived to represent the viewpoint of any of their individual clients, their employer, Lawrence Berkeley National Laboratory or the U.S. Department of Energy. These views are intended to stimulate critical examination of emerging issues, to bring creative perspectives to a complex and rapidly evolving field, and to tee up issues for future study. The time-constrained reader may wish to concentrate on Section VI of the report.

The report concludes with recommendations for exploring ideas presented through field pilot testing and rigorous analysis. In a world of rapidly emerging technologies, challenging environmental constraints, evolving consumer preferences and political realities, these pilot efforts must produce useful data and replicable results and be carefully designed, faithfully executed and professionally evaluated.



I. Introduction

A. Why Is This Report Relevant?

There is no consistent standard for a “threshold” level of distributed energy resources (DERs) at which they become an operational challenge or major focus for system operators.¹

By almost any reasonable standard, however, high penetration of distributed generation is now evident in Hawaii and moving quickly in this direction in locations in California, Arizona, Texas and New Jersey. The Hawaii Public Utilities Commission (PUC) reports that solar photovoltaic (PV) capacity in Maui will soon equal more than half of the system peak demand.² Electric cooperatives in the Midwest are moving quickly to place significant portions of their load under active control and may approach this level soon.³ Time-varying pricing is stimulating smart customer and technology responses in locations across the United States.

Technological innovation is coming to the electric industry at a pace at which the industry is unaccustomed. These innovations have begun and are likely to continue to permeate all portions of the system, from the generator and the transmission system to the distribution system and customer loads. Smart grid technology allows system operators an unprecedented real-time or near real-time understanding of how the electric system is working. Sensors and controls will inform operators when and where the system is under stress or is experiencing operational anomalies and allow operators to tweak system conditions to maintain reliability and avoid system failures.

At the same time, smart appliances and control systems that can communicate with the grid, with third-party service providers or directly with customers are entering the retail market. These appliances and systems provide customers with greater control over their energy consumption and open up opportunities to provide valuable services to the system. From a system operator’s viewpoint, DERs such as smart appliances, distributed generation, and changes to customer loads are simply additional variables which can be manipulated to keep demand and supply in balance and to maintain a number of technical operating parameters required for a stable electric system.

There are other market drivers at work, as well. State mandates such as renewable portfolio standards and net metering, coupled with rapidly declining technology costs, have resulted in a burgeoning distributed solar PV industry. Customers are installing these systems at an increasing rate. Increasing DER penetration is partly due to fundamental economics and partly due to customers’ preferences for control over their energy supply.⁴ While the presence of PV systems presents a number of operational challenges, it also presents opportunities for new services to be provided by the customer to the local distribution system and to regional system operators, such as voltage support, frequency control and other ancillary services. On-site battery storage and grid-level battery storage are poised to follow in the footsteps of PV systems as their prices fall and their efficiencies increase.

¹ Corneli and Kihm (2015).

² Hawaii Public Utilities Commission, Decision and Order No. 33258, Oct. 12, 2015.

³ Flohr (2013).

⁴ Graffy and Kihm (2014).



Customers are increasingly driven by economic choices that are broader than the savings to be achieved on their electric bills. Just as the telephone industry transformed itself from “plain old telephone service” to the smartphone era, electric service will likely need to evolve as customers get more involved in energy consumption decisions and broaden their sense of values to be had from the system in the smart appliance era. For example, recent severe weather experiences, such as hurricanes Katrina and Sandy, have increased the perceived value of backup generation sources. Thus far, mostly fossil fuel-based systems have filled this need, but the advent of smart inverters allows PV systems to continue to function when the grid goes down, keeping the lights on for individual customers and, potentially, their neighbors. In addition, the convergence of telephone and Internet technologies and applications with communications-capable end-use appliances is giving customers increased control over their energy usage. For example, Nest thermostats allow customers to control their home heating and air-conditioning systems from smartphones. In the future, customers may be able to use their smartphones to see, for example, if they left the oven on.

A number of third-party services are also now available which provide bill savings to the customer and aggregated ancillary services to system operators, such as energy efficiency and curtailment service providers.⁵ As smart end-use appliances become more prevalent, these third-party providers will likely develop increasingly comprehensive and complex service offerings for both customers and system operators.

These are a just a few of the examples of technological and market drivers that are changing the relationship between the distribution utility, power suppliers, system operators, customers and third-party service providers. As market penetration of all of these innovations increases, the values at stake and the magnitude of change to the industry will become ever greater.

The smart grid-integrated water heater (GIWH) in a “threshold penetration scenario” is a good, and easily understood, proxy for exploring how these new technologies and services can fit together, and where stakeholders and regulators will need to focus their attention to accommodate them. By a threshold penetration, we mean sufficient numbers deployed that there are economies of scale in the supporting industry, and sufficient numbers that the combined load is meaningful for system planning and operation purposes.

We will use the GIWH to demonstrate the many opportunities and issues related to these changes in the industry. PV systems are also a good proxy for these issues, as they have the added characteristic of injecting energy into the system and are likely to increasingly integrate storage capacity, although they present dramatically different challenges depending on whether they include integrated, controllable storage. Storage options such as battery systems offer the ability to smooth load curves over the course of a day, as do thermal storage systems for air-conditioning. Backup generation may provide support to the grid and possibly help avoid brown-outs and blackouts.

⁵ See for example, Comverge’s case study providing demand response services for PEPCO.
<http://www.comverge.com/comverge/media/pdf/Case%20Studies/Pepco-Holdings,-Inc-Case-Study.pdf>.



WHAT ARE DISTRIBUTED ENERGY RESOURCES?

DERs are any resources or activities at or near customer loads that generate energy or reduce energy consumption. They include generation technologies such as solar PV systems and emergency backup generators, energy storage such as batteries, energy efficiency, and smart appliances or other controllable loads. DERs are central to the visions that many have for an overall smart grid evolution.

Some forms of DERs are dispatchable by the system operator, while others are not. For example, virtually all forms of energy efficiency are not dispatchable because they are essentially always “on.” To illustrate, a more efficient motor will always be more efficient any time it is in use, and space heating and cooling systems will consistently consume less total energy over the course of a day after the building envelope has been better insulated.

Likewise, solar PV, absent associated storage capacity, will produce energy when the sun shines but not otherwise, and the system operator has no control over its availability. On the other hand, smart appliances like a GIWH, battery systems and air-conditioning thermal storage can be directly controlled by the system operator (or a third party) and brought “online” (in a resource sense) by turning off the heating element, discharging the battery or drawing down the “chill” stored in water reserves, or taken “off line” by turning on the heating element, charging the battery or chilling water for later use.

While DERs can be viewed as energy resources used to balance the system in real time, they can also be viewed as capacity resources used in the planning process and to maintain reliability by assuring that loads will not exceed supply during the system peak. In addition, some types of DERs can provide ancillary services, such as voltage support and frequency control and other services, and do so at extremely low cost and higher efficiency than traditional supply-side options. At the same time, DERs, particularly those that inject power to the grid and are intermittent in nature, could potentially increase system costs if they are not coupled with technologies that allow for the management of their energy supply. Power quality issues may also need to be addressed as customer loads become more variable. This may be easiest where customer loads and resources can be controlled automatically by the customer and, with permission, the utility or a third party.

Some forms of traditional central-station generation have limited flexibility from a system operator’s perspective. Nuclear- and coal-fired steam generating plants are viewed as baseload resources. The combination of their economic characteristics (high capital cost, low fuel cost) and operational characteristics (not easily ramped up or down, long lead times to come online from a dead stop) means they are most efficiently utilized when run full-out all the time. Natural gas turbines, on the other hand, have relatively low capital costs and higher fuel costs compared to baseload power plants and can be brought online quickly. They are typically used to serve on-peak demand, running a limited number of hours. Hydroelectric power has high capital costs and low fuel costs, but usually a limited “fuel” supply due to limited water availability. Most hydro projects with lakes or reservoirs operate at relatively low capacity factors, with the limited water supply used to produce power when it is most valuable. Hydro can be brought online quickly and ramped up and down easily. It is often utilized to follow changes in load or to bridge periods when steam generation is being ramped up or down.

Some DERs also can be very flexible. Because DERs come in a variety of forms, and each form comes in relatively small increments (see Table 1), it may be possible to aggregate a variety of DERs into a virtual energy resource that can match system balancing needs more closely than traditional generating resources. For example, aggregated GIWHs could be matched with PV supplies and energy storage systems (battery and thermal) to potentially provide a more stable supply of and demand for energy over the course of a day. When a passing cloud reduces PV output, water heaters could be cycled off to match the decline in PV energy, resulting in a combined resource with constant impact on the system over time.*

*See NREL (2015), p. 6.



Table 1. Typical Installed Capacity by Technology

Technology	Range of Typical Installations
Residential PV	4–6 kilowatts (kW) (DC) ¹
Commercial PV	10 kW–500 kW
GIWH	4.4–5.5 kW
Electric Storage (Batteries)	Scalable
Other Thermal Storage	Scalable ²

¹ Bird et al. (2015)

² Ice Energy produces the Ice Bear storage air conditioner with 10–50 kilowatt-hours (kWh) of storage per unit; the Austin Energy district cooling system includes central ice storage for approximately 100,000 megawatt-hours (MWh) of energy.

B. Scope of This Paper

This paper explores options for pricing of distribution system services in a potential high DER future. It is not intended to address immediate pricing options that are necessarily appropriate for any current system or region.⁶ In other words, we are focused on a future state of the world that is at least 15 years out (2030 and beyond) with high adoption of DERs. While many changes in infrastructure may be needed to accommodate DERs, identification of those changes is beyond the scope of this report. Further, we are not commenting on the cost-effectiveness of DERs or pricing for energy and capacity from DERs — e.g., net metering and feed-in tariffs — topics which are, likewise, beyond the scope of this paper.⁷ Rather, we are focused on discussing distribution service pricing models that would provide the right incentives for efficient adoption of DERs in the future.

The report first identifies distribution system services today and changes that are likely in the future. It then discusses pricing alternatives for recovery of system costs, as well as payment for system services that could be deployed to assure that DERs both pay a fair share of system costs and are eligible to sell cost-effective services to the utility system. The report compares these alternatives from both a utility perspective and from a consumer perspective; the latter includes both the perspective of a DER-owning consumer and of a fully grid-dependent consumer.

C. Overview of Distribution Services Today and Likely Changes in a High-DER Future

In most parts of the United States today, distribution services are provided as a complete package by a state- or locally regulated electric utility, together with local control area operators and independent system operators.

This is changing slowly as a combined effect of multiple simultaneous changes. First, as more and more distributed generation — primarily solar PV — is added, the role of the local utility and the function of the distribution system is changing. Second, demand response programs have evolved to where a significant portion of system load can be controlled, either by system operators or by technology installed at the customer premises, to significantly alter the distribution system load from minute to minute and hour to hour. Third, distributed storage, both thermal and electrical, is being installed to add customer flexibility to respond to pricing

⁶ Report No. 5 in the Future Electric Utility Regulation series addresses pricing issues associated with recovery of fixed utility costs. See feur.lbl.gov.

⁷ For more information on these topics see, for example, American Public Power Association (2013) and NRECA (2013).



and reliability needs. Finally, as more granular rate designs are rolled out, the ability of customers to respond is being tested, and it is often found to be much more nimble than previously assumed.

Energy efficiency, which is effectively always on anytime the associated energy-consuming device is in use, has about the same load shape as the system load shape. It has about a 3-to-1 peak to off-peak ratio, assuming a 50 percent system load factor overall. So energy efficiency is more like a peaking generating unit than a baseload generating unit.

D. Overview of Unbundling, Packaging and Pricing Approaches

This report looks at several ways that the grid services used by and provided by DER customers can be packaged and priced. These include:

- **Granular retail rates:** Each service is discretely priced, with customers or aggregators free to purchase desired products, and the utility crediting DER customers for specific services provided. Each price is calculated so that expected sales will generate the overall revenue requirement determined by the regulator.
- **Retail Buy/Sell arrangement:** Customers pay retail prices for all services delivered by the utility system; they are paid separately for any discrete services they supply to the grid.
- **Procurement Model:** Third-party aggregators maintain the direct business relationship with DER customers, pricing services on a competitive basis.
- **DER-specific retail rates:** Customers with DERs pay separate tariffs for service, based on the unique service characteristics of their requirements. Standardized credits are calculated for services provided by DER customers on a technology-by-technology level.

E. Questions This Report Addresses

This report addresses only pricing issues, not underlying technology or cost-effectiveness evaluation issues. The report is concentrated on four elements of pricing:

1. What Are the Models for Pricing and Packaging These Services?

We examine four approaches, described above, to pricing and packaging for distribution services provided by and to DER customers. We believe these are representative of the range of reasonable approaches, but do not suggest that these are the only appropriate models to consider.

2. What Are the Advantages and Disadvantages of the Pricing Models?

We address the equity and efficiency elements of each of the pricing models we present. These elements are measured against traditional regulatory principles evolved over the history of utility regulation and against the technological opportunities and challenges that are before us.

3. How Should the Merits of These Pricing Models Be Evaluated?

The authors do not entirely agree on the merits of each of these pricing models. This report provides two perspectives on how costs and benefits should be measured and the subjective criteria that may be appropriate in evaluating desirability of a particular pricing approach.



4. What Are the Key Next Steps for Policymakers and State Regulators?

The role for policymakers and state regulators will depend in great part on three factors. First, does the jurisdiction have existing policy guidance to encourage DERs, or is the focus on short-run cost minimization? Second, are distribution services provided by integrated utilities with a power supply responsibility, or by a restructured market in which distribution system operators provide only energy delivery services? Third, are DERs presently being deployed rapidly or slowly?

In jurisdictions with rapid deployment and vertically integrated utilities, there is likely a need for more rapid movement toward some sort of discrete pricing for the distribution services needed by and provided by DERs. Regions with slow deployment may be able to learn from experiences in fast-deploying jurisdictions like Hawaii and California before adopting policies and pricing frameworks.

F. Report Organization

Section II: Provides an overview of distribution system functions. This includes a discussion of more than 20 discrete services that could conceivably be unbundled and priced on a granular basis.

Section III: Develops four options for packaging and pricing of distribution services provided to and provided by DER customers.

Section IV: Addresses the taxonomy of issues to be considered when unbundling and pricing distribution services. The primary purpose of this section is to ensure that the differing perspectives presented in Section VI involve consistent treatment of these issues, so that the reader can concentrate on the issues raised by the authors.

Section V: Examines the engineering issues, economic costs and cost evaluation, and equity issues associated with providing discrete DER services to, and acquiring these services from, DER customers.

Section VI: Presents the perspectives of the two authors of this report on the pricing options developed in Section III and examined in Sections IV and V. Ryan Hledik of The Brattle Group presents electric utility perspectives; Jim Lazar of The Regulatory Assistance Project presents consumer advocate and broader public interest perspectives.

Section VII: Presents conclusions and recommendations.



II. Distribution System Services Today and Likely Changes in the Future

This section summarizes the services provided by the distribution utility to customers (both those with DERs and those without) as well as services that could be provided by (or avoided by) customers with DERs. The role of the distribution utility in a potential future world of high DER adoption is uncertain and likely to vary from one jurisdiction to the next. That is the subject of detailed discussion in earlier reports in the Future Electric Utility Regulation series.⁸ This report focuses on new distribution system services that could be offered by customers with DERs and thus summarizes distribution utility functions and services at a high level.

A. Basic Functions of the Distribution Utility (Services That the Utility Provides to All Customers)

1. Traditional Core Services

For the vast majority of electric utility customers, their relationship with the utility has been fairly simple — that of an energy consumer, expecting a highly reliable service at a reasonably low cost. Besides basic energy delivery, consumers have also purchased an implicit capacity service, which in most cases assures that their highest rate of consumption would be served. Industrial customers and, often, commercial customers, have paid an explicit charge — the demand charge — which is intended to reflect capacity service. Additionally, the service package has included customer service, metering and billing, and perhaps energy consultations or energy audits. Virtually every other aspect of service, mostly what we now generally call ancillary services, has been bundled into these core services. Only customers with special needs, such as microchip manufacturers, were likely to deal with, much less explicitly pay for, higher levels of power quality such as frequency control, voltage control, harmonics control, transient spikes and dips in power — not to mention on-site, emergency backup energy supplies.

The “core services” provided by the distribution utility include:

- Grid connection
- Metering and billing services
- Power delivery
- Reliability
- Standby service of various types
- Supplemental service of various types
- Ancillary services of various types
- Power factor correction and other power quality services
- Access to markets for sale of supply and other specialized services

In the future, with potential high adoption of DERs, the distribution utility’s functions may need to expand to include additional planning, grid operation and market operation services. An example of additional planning functions is DER hosting capacity⁹ analysis. Historically, utilities may have viewed hosting capacity as a system constraint on the ability to add DERs to the system. In the future, the planning paradigm will need to view hosting capacity as a variable

⁸ See feur.lbl.gov, in particular, De Martini and Kristov (2015).

⁹ Hosting capacity is the amount of capacity on any given portion of the distribution system to accommodate additional DERs with existing and already planned facilities.



output and the addition of DERs, especially DER loads that can be scheduled or dispatched in real time, as a means for avoiding distribution investments and enhancing hosting capacity. Additional operational functions would include coordination of DER services at the interface between the transmission and distribution system and other functions to manage new two-way flows of power on the distribution system. Market operations would include, for example, optimal dispatch of DERs and clearing and settlements for DER transactions if such markets are created.¹⁰

Ultimately, the services provided by the distribution utility may be used in smaller or larger quantities by customers who adopt DERs, depending on the nature of the particular resource. For example, customers with controlled end uses will reduce their need for future capacity reservations, whereas customers with large exports to the grid may need additional capacity.

2. Ancillary Services

The Federal Energy Regulatory Commission (FERC) defines *ancillary services* as those services “necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.”¹¹ Of course, FERC’s jurisdiction, and therefore its frame of reference, is related to the interstate transmission system and not, generally, to the local distribution system. But, in functional terms, the FERC definition applies equally to the distribution system, although the aggregate need for ancillary services at the distribution level may be more varied geographically and temporally than at the transmission level.

The “traditional” ancillary services in FERC-approved tariffs that include prices are:

- Scheduling and dispatch
- Reactive power and voltage control
- Loss compensation
- Load following
- System protection
- Energy imbalance

A grid with high levels of DERs will meet one or more of these needs by controlling end-use loads and dispatching distributed storage and other resources, in addition to the historical approach of controlling the output of utility-scale generating units. These elements can include:

- Demand response/curtailment of loads
- Demand response/acceleration of loads
- Active load scheduling
- Dispatch of customer storage

¹⁰ See De Martini and Kristov (2015) for further detail. Whether these functions would be performed by a distribution utility or an independent distribution system operator or managed by a distribution platform provider is an issue that will need to be addressed.

¹¹ “Guide to Market Oversight. Glossary,” FERC, <http://www.ferc.gov/market-oversight/guide/glossary.asp>.



This report addresses pricing for distribution services, not for power supply services. While DERs can simultaneously provide both types of services, the compensation framework for the power supply component of these services is beyond the scope of this paper. However, as we note in the report's conclusion, the actual compensation framework needs to address both power supply and distribution system services.

B. Distribution System Services Utilities Provide to DER Customers (Additional Services for End-Use Customers With DERs)

Implicit in traditional utility sales to end users are a number of ancillary services, such as frequency control, voltage support, power factor control and other technical services. End users pay for these services only in the sense that they are implicitly bundled into energy, demand and power factor charges. The cost of providing these services is necessarily bundled into the tariff rates of utilities, which are based in a broad sense on the total cost of providing service to customers. However, most customers remain unaware of these ancillary services. Some large customers, such as microchip manufacturers, have special needs for extremely stable, high-quality power, and contract with utilities (or third parties) to provide additional equipment to assure that the power fed into their manufacturing facilities meet their exacting needs. The costs for these additional services are typically directly assigned to those customers and not allocated to others.

C. Types of Distribution System Services DER Customers May Provide to the Utility System in a High DER Future

The advent of so-called “smart inverters” which convert the direct current (DC) output from generation, such as solar PV and battery systems, to grid-compatible alternating current (AC) could allow DERs to provide a broad range of functions, some of which were not previously available to utilities. The most obvious of these is the ability to provide voltage support, frequency regulation and power factor correction, simply because whenever DC power is inverted to AC power, there is the opportunity to create a custom-crafted waveform of nearly any character.

The Electric Power Research Institute (EPRI), in a 2014 technical report, outlined 24 sets of functions that smart inverters may provide. Some are merely status reports on the operating condition of the inverter or its generating supply. But most are functions which are clearly ancillary services or which offer demand response control.¹² While the EPRI report was focused on functions provided by smart inverters, devices that do not have inverters could potentially provide many of these functions. Because the list of inverter functions includes the functions which might be supplied, for example, by a GIWH, we use them here as our starting reference and review them in the context of the economic issues related to these functions, an issue the EPRI paper does not address. Appendix B presents a more detailed explanation of these functions, including probable applications and economic considerations associated with each function. Table 2 categorizes the EPRI-identified functions.

¹² EPRI (2013).



Table 2. Categorized Functions

Category	Functions
Customer Emergency and Safety Constraints	Disconnect function; Maximum generation limit function
Grid Emergency and Safety Constraints	Connect/disconnect function; Maximum generation limit function; Multiple grid configuration management (including islanding) function; Load following function
System Maintenance and Outage Services	Connect/disconnect function; Maximum generation limit function; Multiple grid configuration management (including islanding) function
System Limitation Services	Maximum generation limit function; Peak power limiting function; Multiple grid configuration management (including islanding) function; Load following function
Reliability and System Stability Services	Low/high voltage ride-through function; Low/high frequency ride-through function; Fixed power factor function; Intelligent Volt-VAR function; Dynamic reactive current support function; Dynamic volt-watt function; Real power smoothing function; Maximum generation limit function; Peak power limiting function; Multiple grid configuration management (including islanding) function; Load and generation following function
Power Quality Services	Fixed power factor function; Intelligent Volt-VAR function; Volt-Watt function; Dynamic reactive current support function; Frequency-Watt function; Watt-power function; Dynamic volt-watt function; Real power smoothing function; Maximum generation limit function; Peak power limiting function
Grid Equipment Preservation Services and Customer Equipment Preservation Services	Fixed power factor function; Intelligent Volt-VAR function; Volt-Watt function; Dynamic reactive current support function; Frequency-Watt function; Watt-power function; Dynamic volt-watt function; Real power smoothing function; Maximum generation limit function; Peak power limiting function
User Preference and Value Services	Price driven functions; Temperature driven functions; Coordinated charge/discharge management function; Direct battery charge / discharge function; Load and generation following function
Efficiency and Economic Opportunity Services	Price-based charge / discharge function; Coordinated charge / discharge management function; Direct battery charge/discharge function; Price driven functions; Load and generation following function

Source: EPRI (2013).

Many of these functions raise new and interesting questions about which party has the duty to adapt to changing circumstances and who bears the economic consequences. In some cases — for example, overvoltage on the customer’s side of the distribution transformer — the argument may be strong that the customer should bear the physical and economic responsibility of addressing the problem. However, when the “problem” resides on the grid side of the



transformer, it is not apparent that the DER owner should bear the economic responsibility, even if it is most economical for the DER owner to bear the physical responsibility of addressing the problem.

From the utility's perspective, it may cure the problem by upgrading distribution grid assets or by limiting the output of the DER. If limiting the output of the DER comes at no cost to the utility because the DER is required to conform by utility or regulatory fiat, the DER will no doubt be compelled to provide the service. If, however, the utility is required to provide compensation for the DER owner's opportunity cost or to pay on the basis of the utility's avoided cost or on a value basis, then a more economically efficient solution to the problem will likely be chosen. An important consideration in developing pricing models for distribution services will be to determine the total system costs avoided by the DER customer.

D. Types of Distribution System Services DER Customers May No Longer Need

Several types of DER installations could make certain grid services unnecessary for DER owners. We illustrate this concept with a few examples.

While an interconnected solar PV system or backup generator will necessarily have an inverter, neither generator can provide all of the EPRI-identified functions in Table 2 above, such as direct battery charge and discharge functions. Even so, from a system operator's viewpoint, they may be able to emulate some of those functions (such as direct charge) through the disconnect function. For example, if an over-voltage or over-frequency condition is present, disconnection of the PV system may deliver the same solution as directly charging a battery, both of which may reduce voltage or frequency. This is more apropos for the PV system than the backup generator: The PV system will presumably be online whenever there is sufficient sunlight; the backup generator may typically be used only for emergencies or scheduled maintenance. While functionally equivalent in some circumstances, these two solutions are not completely identical. In one case — disconnection of the PV — the energy not generated while the disconnection continues is lost, while the energy used to charge a battery is partially recoverable at a later time. At the same time, some cost is incurred providing the energy to charge a battery, no fuel costs are avoided by not generating PV energy, and some costs are incurred to replace that energy.

It will be important to price distribution services in a way that gives utilities an incentive to pursue the most economic solutions. For utility distribution operators that are not subject to revenue regulation, the illustrative scenario above could present an incentive to sell more energy by disconnecting the customer-owned PV and charging the battery (regardless of who owns it). Thus, for customers and third-party aggregators, it is critical that the costs and prices facing the distribution operator be fully transparent to ensure that the operator is able to pursue the most cost-effective opportunities.¹³

1. Customers With a Backup Generator

A customer with a backup generator capable of meeting the customer's entire electricity needs does not require grid services at any particular moment in time. Grid services likely provide a

¹³ One approach that has been discussed to address this potential conflict is the introduction of an independent distribution system operator. See De Martini and Kristov (2015).



cost savings, a convenience, and avoid emissions, odors and fuel procurement. Almost without exception, customers installing these systems choose to use grid services, so long as they are provided at reasonable cost. As many as 12 million homes in the United States have backup generators.¹⁴ The more sophisticated of these include automatic transfer switches that isolate the property from the grid and start the generator when outages occur. Unlike PV systems with inverters, these backup systems are usually not capable of operating synchronized to the grid. Figure 1 is an example of such a system. The customer with a backup generator may be willing to accept a lower standard of reliability from the power supply and distribution utility system than other customers.



Source: Costco.com

Figure 1. Backup Generator With Automatic Transfer Switch

Residential backup generators are designed to provide reliable household backup when grid power or distribution services are unavailable.

2. Customers With a Battery and Inverter-based Energy Storage System

Because an inverter-based energy storage system has the characteristics of both generation and load (see Appendix B), it can provide all of these functions, limited only in their capacity to deliver or absorb energy.

3. Customers With a GIWH or Thermal Storage Air-Conditioning

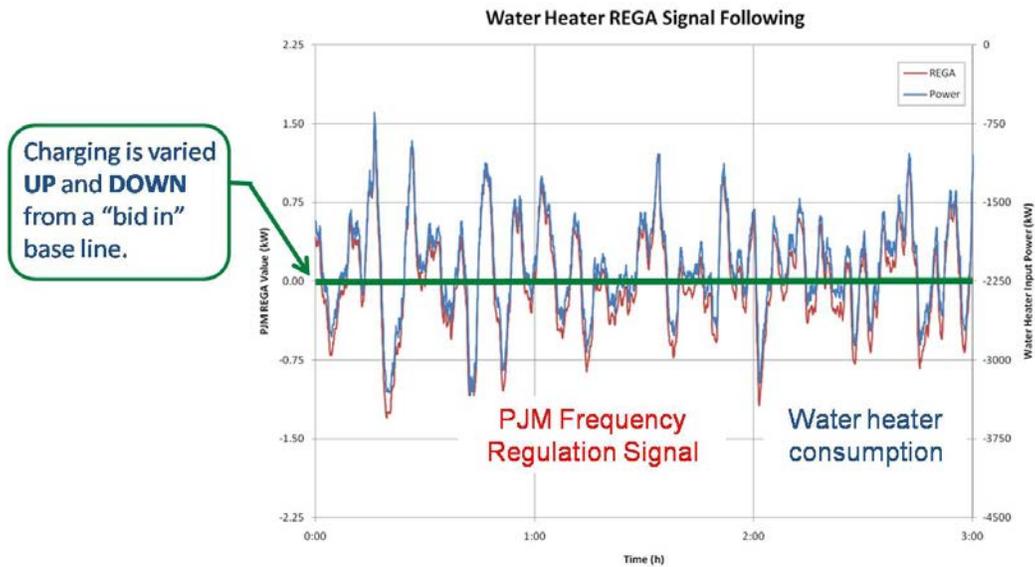
Physically, GIWHs and thermal storage air-conditioning are the inverse of a solar PV system or backup generator. From a system balancing perspective, turning a water heating element or chiller “on” is equivalent to turning a generator or other energy supply “off” and vice versa. Of course, because these resources do not actually produce energy, they cannot perform many of the functions that a PV system or other generator can. However, they can, in theory, provide services such as frequency and voltage control in addition to providing diurnal storage capacity, which is a supply function rather than a distribution function. We discuss the overlap of these functions in Section VI.

When networked together in groups of thousands of water heaters, it is possible to ensure that some units are always “on,” providing the ability to reduce load instantaneously, and some units are always “off,” providing the ability to increase load instantaneously. Operating in this

¹⁴ Pentland (2013).



framework, these systems can provide both upward and downward support at all times. Analysis by PJM (Figure 2) illustrates how quickly GIWHs can respond to a system frequency regulation signal, outperforming any generating resource.



Source: Steffes Corp.

Figure 2. Load Following Precision of a Grid-Integrated Water Heating Network. This figure shows how a control system applied to a group of water heaters can closely follow the frequency regulation signal — much more accurately than a generating resource.

This section shows that different types of DER customers can respond in different ways to distribution services pricing and can potentially provide valuable services to the distribution system operator. At the same time, by virtue of using the grid in new ways, some DER customers may impose new costs on the grid. Both of these potential effects on the economics of the distribution system highlight the need to develop new models for pricing distribution services. We discuss in Section III different approaches to pricing that might be used, and then in the later sections explain how this pricing might affect both utilities and DER owners.



III. Options for Unbundling, Packaging and Pricing Distribution Services for DER Customers

Distribution services can be unbundled, packaged, priced and presented to customers in a variety of ways. In this section, we present four possible pricing models for DER customers. In some cases, discrete pricing elements could be appropriately extended to customers without DERs. Each pricing model has its own relative advantages and disadvantages.

The four pricing models are not mutually exclusive in their applicability to a utility’s customer base. One model may be best suited for a certain customer class, while a different model may be a better fit for another customer class.

Table 3 summarizes the four pricing models. Each detailed description presents a general framework for how the pricing model would be established and implemented. These are not the only possible conceptual frameworks for pricing distribution services. The four models illustrate a few distinctly different approaches to pricing distribution services, in order to establish a framework for discussing their relative advantages and disadvantages. In Section VI we discuss the advantages and disadvantages of these pricing models from the perspective of both the utility and the customer.

Table 3. Summary of the Four Pricing Models

Pricing Model	Description
Granular Rate	A detailed, disaggregated rate in which each distribution service is priced separately and avoided through self-supply or otherwise paid for by the DER customer
Buy/Sell Arrangement	A bifurcated rate in which the DER customer pays a simple, bundled price for use of the distribution system and is separately paid for distribution services provided to the utility under a different pricing structure
Procurement Model	Utilities procure distribution services from non-regulated third parties who aggregate the services provided by individual DER customers and compensate those customers accordingly
DER-Specific Rates	A different rate is offered to each class of DER customer to reflect the costs of serving that type of customer as well as the value of the services that the specific class of DER customers provide

A. Model #1: The Granular Rate

The Granular Rate is a highly disaggregated retail rate that prices each major distribution service separately. Customers are billed based on the amount of each individual distribution service they use.



For a DER customer, the cost of distribution services could be avoided through self-supply. For example, to the extent that a customer participating in a demand response program can reduce its need for distribution capacity through a reduction in demand, the customer would simply avoid paying for a portion of the demand-related distribution capacity cost. Alternatively, some DERs may increase a customer's need for certain services. For instance, if a customer installs a large, uncontrolled rooftop PV system in a location of the grid where there is already a high level of PV adoption, the amount of energy being pushed on to the system when the sun is shining may be enough to require upgrades to the distribution system to handle reverse flows. In this case, the associated costs would be apportioned to all customers sharing this responsibility and reflected on the bill as a "purchase" of additional distribution capacity by the customers.

A well-designed Granular Rate could be coupled with a net metering policy without creating the concerns about cost recovery and equity that are often raised when net metering policies are largely coupled with simple volumetric rates. To the extent that the DER customer produces more of any given service than is consumed on-site, the customer would be paid the same price by the distribution utility for this excess self-supply as the customer would pay for the service it otherwise would purchase from the utility if the DER did not provide the service. If the prices are set to reflect the cost of each service as accurately as possible, the price should roughly represent the value of the excess supply to the utility.

In addition to pricing distribution services individually, the Granular Rate is also disaggregated in the sense that prices can vary by time and location. For instance, DER (and, ideally, all) customers located in parts of the distribution system with a near-term need for a transformer capacity upgrade may pay a distribution capacity reservation charge, and therefore would also avoid this higher price through peak demand reductions. Customers in parts of the grid with significant excess distribution capacity could pay less for that service.

The notion of a highly granular retail rate was recently presented by the Rocky Mountain Institute in its paper "Rate Design for the Distribution Edge."¹⁵ The paper discusses the potential benefits of unbundling rates across various attributes and introducing temporal and spatial granularity into the rate's design. The notion of a distribution locational marginal price has also begun to garner attention in jurisdictions that are confronting the issue of how to integrate high levels of DERs into the distribution system.¹⁶ This concept, which essentially extends the notion of transmission-level nodal pricing down to the distribution level, could be considered one form of the Granular Rate model.

Taken to its extreme, the Granular Rate could result in a different price for virtually every customer. Further, it could include a disaggregated list of services and charges that would be many pages long. For practical purposes, it will likely be necessary to make simplifying approximations in the rate's design. As is always the case in rate design, designing the Granular Rate will be both art and science. Decisions will need to be made as to the appropriate type of charge for pricing each distribution service. For instance, are capacity costs most appropriately

¹⁵ Rocky Mountain Institute (2014).

¹⁶ Several academic papers have been published on this topic. See, for example, Li, Wu and Oren (2013).



collected through a fixed charge, a demand charge, a dynamic volumetric rate such as a critical peak pricing rate, or some other type of charge?¹⁷

To illustrate how the Granular Rate approach would work, we have developed examples of a hypothetical customer’s bill on the rate. Given the broad range of ways in which the Granular Rate could be designed, and different views on which types of charges are the most appropriate for recovering distribution costs, we have provided illustrations of two plausible designs. One uses demand charges to recover distribution capacity costs and the other uses time-varying volumetric charges. We use a GIWH combined with central air-conditioning with a smart thermostat as the example DERs owned by the hypothetical customer. Table 4 is a simplified illustration of the hypothetical customer’s bill under the current rate, before implementation of the Granular Rate.

Table 4. Summer Month Distribution Bill for a Residential DER Customer on Current Rate

	Total Rate [A]	Amount Used [B]	Total Charge [A] x [B]
Variable charge (\$/kWh)	\$0.0330	1,000	\$33.01
Customer charge (\$/month)	\$6.00	—	\$6.00
Sales tax (%)	3%		\$0.99
Grand Total:			\$40.00

In the first illustrative example of the Granular Rate approach, distribution capacity costs are recovered through demand charges. Different costs could be recovered through different measurements of demand. For example, for the given hypothetical utility, if distribution substation capacity costs are largely driven by system peak-coincident demand, they could be collected through a system peak-coincident demand charge. Other aspects of the distribution system that are more local in nature, such as distribution feeder capacity, would be collected through a demand charge that is based on class peak-coincident demand or the individual customer’s maximum demand.¹⁸ Power quality and reliability services, such as frequency control, are billed on a volumetric (cents per kilowatt-hour) basis. Exports to the grid, if in large quantities and in a location where upgrades are needed to handle reverse power flows, would be billed based on the customer’s contribution to the need for new capacity, as measured by the maximum output of the distributed generation system (net of on-site consumption) at various times.¹⁹

Control of the heating element in the GIWH and of the air-conditioner through the smart thermostat allows the customer’s load to be curtailed at times when the customer’s total demand (peak coincident or non-coincident) is high, in order to reduce the customer’s long-run

¹⁷ For a thorough description of rate design options, see Lazar and Gonzalez (2015).

¹⁸ Demand could be measured in a variety of ways. For example, system peak-coincident demand could use the “XCP” method, in which the customer’s demand is measured during the X highest system load hours of the year. Or it could be based on the customer’s maximum demand during peak hours of the day (e.g., 2 p.m. to 6 p.m.) over the course of a month.

¹⁹ In an alternative approach, the maximum of the customer’s demand or generation could be used to set a single capacity reservation price. The two have been priced separately in this example to account for the fact that the nature of distribution system upgrades needed to handle two-way flows may be different than investments needed only to handle growth in demand.



need for distribution capacity. Smoothing of load also leads to less wear and tear on the distribution system, which reduces maintenance costs.²⁰ The result is a summer month bill that is perhaps \$5 or \$10 lower than it would otherwise have been if the customer did not have DERs. Table 5 shows the hypothetical customer’s bill under this new rate structure. The table highlights in red the specific line items in the bill impacted by the customer’s use of DERs.

Table 5. Summer Month Distribution Bill for a Residential DER Customer on a Granular Rate With Demand Charges

	Systemwide Average Rate [A]	Locational Rate Adjustment [B]	Total Rate [C]=[A]+[B]	Amount Used [D]	Total Charge [C] x [D]
Capacity Need for Consumption					
System Peak Charge (\$/kW)	\$3.50	\$0.50	\$4.00	2.0	\$8.00
Class Peak Charge (\$/kW)	\$2.00	\$0.10	\$2.10	3.0	\$6.30
Individual Peak Charge (\$/kW)	\$1.00	\$0.00	\$1.00	5.5	\$5.50
Capacity Need for Net Excess Generation					
System Peak Charge (\$/kW)	\$0.00	\$0.00	\$0.00	0	0
Local Distributed Generation Coincident	\$0.00	\$1.50	\$1.50	0	0
Peak Export Charge (\$/kW)					
Power Quality and Reliability					
Frequency Control (\$/kWh)	\$0.0003	\$0.00	\$0.0003	1,000	\$0.50
Voltage Support (\$/kWh)	\$0.0005	\$0.00	\$0.0005	1,000	\$0.30
Power Factor Control (\$/kWh)	\$0.0010	\$0.00	\$0.0010	1,000	\$1.00
Other Power Quality Services (\$/kWh)	\$0.0002	\$0.00	\$0.0002	1,000	\$0.20
Other Services					
Maintenance (\$/kWh)	\$0.0005	N/A	\$0.0005	950	\$4.75
Metering and Billing (\$/Month)	\$5.00	N/A	\$5.00	--	\$5.00
Other Administrative (\$/Month)	\$1.00	N/A	\$1.00	--	\$1.00
Taxes and Fees					
Sales Tax (%)	3.0%				\$0.98
Total					\$33.53

Alternatively, the Granular Rate could be designed to recover capacity costs through time-varying volumetric charges, as illustrated in our second example. The volumetric rate could be a time-of-use (TOU) rate in which the price is higher during peak periods and lower during off-peak periods on each day. A critical peak pricing structure could be overlaid on the TOU rate to reflect the notion that a portion of distribution capacity costs are driven by critical period requirements. In this second conceptualization of the Granular Rate approach, the hypothetical DER customer’s bill is roughly the same, but recovered through different types of charges. Table 6 illustrates this second option for designing the Granular Rate.²¹ How to design a

²⁰ Note that, in this specific illustrative example, we have not assumed that the GIWH is providing frequency regulation, though that is a service that could be provided in certain applications. Rather, the GIWH assumed to be providing only peak reductions and a reduction in distribution maintenance costs.

²¹ The totals are not exactly equal to avoid presenting granular rate designs with more than four decimal places, which would only confuse the underlying purpose: to show that granular rates can be structured on either a capacity or TOU-energy basis.



Granular Rate to achieve various objectives, and which charges are most appropriate for recovering distribution system costs, are discussed in Section VI.

Table 6. Summer Month Distribution Bill for a Residential DER Customer on a Granular Rate With Time-Varying Volumetric Charges

	Systemwide Average Rate	Locational Rate Adjustment	Total Rate	Amount Used	Total Charge
	[A]	[B]	[C]=[A]+[B]	[D]	[C] x [D]
Capacity Need for Consumption					
System Peak Charge (\$/kWh)	\$0.0108	\$0.0100	\$0.0208	300	\$6.24
System Off-Peak (\$/kWh)	\$0.0020	\$0.00	\$0.0020	700	\$1.40
Class Peak Charge (\$/kWh)	\$0.0064	\$0.01	\$0.0164	400	\$6.56
Class Off-Peak Charge (\$/kWh)	\$0.0010	\$0.00	\$0.0010	600	\$0.60
Grid Connection Charge (\$/kWh)	\$0.0050	\$0.00	\$0.0050	1,000	\$5.00
Capacity Need for Net Excess Generation					
System Peak Charge (\$/kW)	\$0.00	\$0.00	\$0.00	0	0
Local Distributed Generation Coincident Peak Export Charge (\$/kW)	\$0.00	\$1.50	\$1.50	0	0
Power Quality and Reliability					
Frequency Control (\$/kWh)	\$0.0005	\$0.00	\$0.0005	1,000	\$0.50
Voltage Support (\$/kWh)	\$0.0003	\$0.00	\$0.0003	1,000	\$0.30
Power Factor Control (\$/kWh)	\$0.0010	\$0.00	\$0.0010	1,000	\$1.00
Other Power Quality Services (\$/kWh)	\$0.0002	\$0.00	\$0.0002	1,000	\$0.20
Other Services					
Maintenance (\$/kWh)	\$0.0005	N/A	\$0.0005	950	\$4.75
Metering and Billing (\$/Month)	\$5.00	N/A	\$5.00	--	\$5.00
Other Administrative (\$/Month)	\$1.00	N/A	\$1.00	--	\$1.00
Taxes and Fees					
Sales Tax (%)	3.0%				\$0.98
Total					\$33.53

Of course, these are not the only ways in which the Granular Rate could be designed. Instead, the Granular Rate could allocate capacity costs on an hourly or even sub-hourly basis according to loss of load expectancy (LOLE) or some other metric.²² Prices could vary seasonally (e.g., only summer prices are shown in the example tables here). With all of these options, the overall philosophy of the Granular Rate approach remains: It is a single, unbundled and disaggregated rate structure with prices that reflect the amount both that DER customers pay to the utility and the utility pays DER customers for services they use and provide.

B. Model #2: The Buy/Sell Arrangement

In the Buy/Sell Arrangement, the DER customer’s transaction with the utility is bifurcated into two parts. In the first part (the “buy” transaction), each customer pays for its use of the distribution system through a simple, bundled rate that does not account for services provided

²² LOLE is a measurement of the extent to which the system is projected to be unable to meet all demands for service over a defined period of time.



by the DERs. That rate structure could be consistent with the largely volumetric rate that is in place for most utilities today. In the second part (the “sell” transaction), the utility pays the customer for distribution services provided by the DERs. These payments could be in the form of bill credits or direct payments and based on a structure that looks very different than the rate that the customer is paying.

The Buy/Sell Arrangement is not a new concept. In fact, many utilities across the United States already offer this pricing model in the form of demand response programs such as direct load control. For example, in a typical direct load control program for residential air-conditioning, the customer is likely paying a two-part rate with a flat volumetric charge for all energy consumed. Separately, in return for allowing the utility to cycle the compressor on the customer’s air-conditioning unit or increase the thermostat set-point by a couple of degrees, the customer is given a bill credit. The bill credit, also referred to as the incentive payment, reflects some portion of the capacity value that the load reduction provides to the utility. There could also be a “pay for performance” component to the incentive payment, in which customers receive an additional payment when a demand response event is actually called.

The federal Public Utility Regulatory Policies Act originally established the Buy/Sell Arrangement as a permissible method (called simultaneous purchase and sale) for compensating eligible generators (combined heat and power and small renewable energy facilities) and was the basis for feed-in tariffs in the United States.²³

With the Buy/Sell Arrangement, the approach described above for direct load control programs could be extended to all distribution services provided by DERs. For example, a customer with rooftop PV and a smart inverter may be able to sell various power quality services to the utility. As with all of the pricing models discussed in this report, the payment for various services could be location-specific and higher in locations of the grid where there is a more immediate need for the service.

Table 7 illustrates how the Buy/Sell Arrangement could work for a customer with a GIWH, compared to the same customer without any type of DER. In both cases, the customer pays for the same “use” of the distribution system through the standard two-part tariff (a volumetric rate and a fixed monthly customer charge). The amount paid is not affected by the presence or absence of the GIWH. The customer with the GIWH, however, has a lower overall bill due to bill credits for the provision of frequency control and voltage support, as well as a reduction in capacity needs due to reduced system peak-coincident demand.

²³ PURPA, Pub.L. 95–617, Nov. 9, 1978. § 292.304(b)(4).



Table 7. Summer Month Distribution Bill for Residential DER Customer With Buy/Sell Arrangement

Distribution System Use Charges			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.03	1,000	\$30.00
Customer charge (\$/month)	\$10.00	--	\$10.00
		Total Charges	\$40.00
Location-Specific Distribution Services Payments			
			Credit
Capacity services (\$/month)			(\$3.00)
Power quality services (\$/month)			(\$2.00)
		Total Credits	(\$5.00)
Total Bill			\$35.00

In this example, the customer would have paid a distribution bill of \$40 in the absence of any DERs. The payments for distribution services that were enabled by installing a GIWH resulted in a bill credit of \$5, reducing the bill to \$35. Credits would vary depending on the type of DERs installed by the customer and could also vary by season and location. The amount of the payments would be based on an estimate of the value of each of the services that the DER is offering.

C. Model #3: The Procurement Model

With the Procurement Model, utilities hold auctions or publish requests for proposals (RFPs) to procure distribution services from DERs. Third parties submit bids to the utility and, if selected, aggregate the services of individual DER customers to fulfill the requirements of the bid.²⁴ The utility pays the third parties for these services rather than procuring them from other (non-DER) resources. The structure of the distribution rates paid by individual customers would not necessarily be changed with this approach. Compensation to the customer would be based on a contract established between the customer and the third party. Products procured through an auction or an RFP need to be well defined in order to provide participating parties with the certainty necessary to construct a meaningful bid.

²⁴ It would also be possible to allow registered customers to bid directly into the market. For simplicity, in this discussion we have assumed that participation in the market happens through third parties.



Figure 3 shows that the Procurement Model can be broken into six fairly sequential steps.

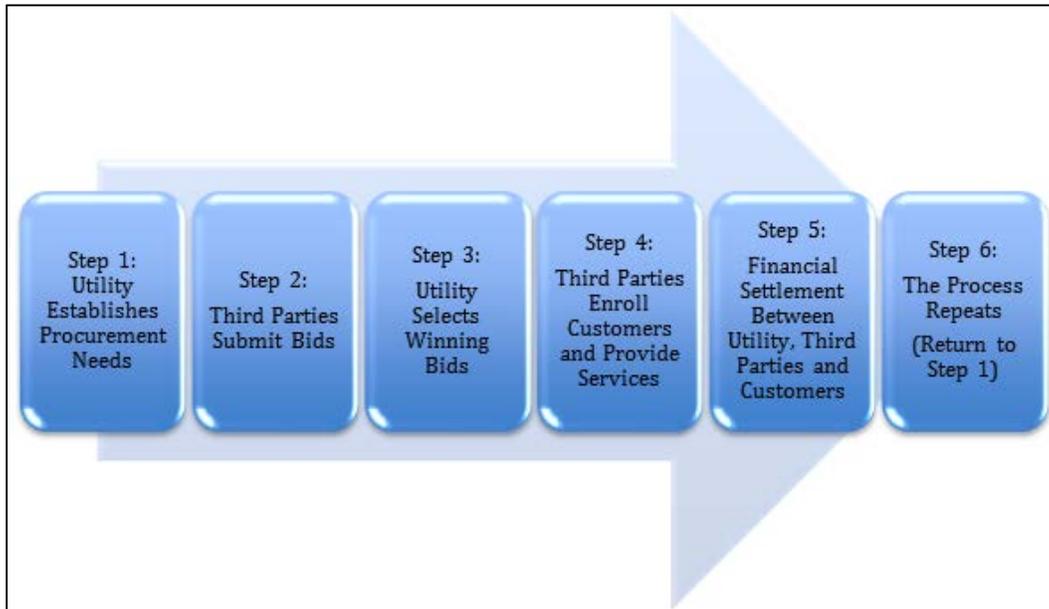


Figure 3. The Six Steps of the Procurement Model

The Procurement Model involves six sequential steps. The process begins at the left side of the figure, with the establishment of procurement needs, moves through submission and selection of bids, then provision of services, and concludes at the right side of the figure, with financial settlement between parties and a repeat of the six-step process. Note, though, that financial settlement does not necessarily have to happen at the end of the process.

Step 1: The utility establishes distribution services procurement needs. The first step is for the utility to determine the types and quantities of the distribution services that are optimal to procure. This could be done through the development of a detailed distribution system resource plan.²⁵ Then, the utility establishes a mechanism through which the services can be procured from DERs. One possible approach would be to set up an auction with predefined products. The product definitions would specify the specific characteristics of each service being procured, the time period over which the service is to be provided, and any eligibility requirements for participating in the market. An alternative approach would be to publish an RFP which describes the distribution services being solicited. Definitions of the services in the RFP could potentially be less prescriptive than in the auction, leaving some flexibility for bidders to propose the specific approaches that they consider to be most feasible and valuable to the system. This more open-ended RFP approach may be useful particularly early in the development of the market if it is not yet clear exactly how to define needs relative to the capabilities of the providers.

²⁵ Recently, utilities in some states have begun to develop detailed distribution system plans. In California, these are called Distribution Resource Plans. In New York, they are referred to as Distributed System Implementation Plans.



Step 2: Third parties submit bids to provide services. Based on expectations around customer enrollment and an understanding of the capabilities of the market, third parties submit bids to aggregate services of DER customers.²⁶ If participating in an auction, the bids could simply consist of one or more quantities of any given service and the price associated with each nominated quantity. If responding to an RFP, a more detailed proposal describing the services and contractual terms would likely be needed.

Step 3: Utility selects winning bids. There are a variety of ways in which the utility could select the winning bids. One important issue is how to determine the quantity of each service to procure. This could be a predetermined amount based on the utility's projected system needs. The utility could procure up to this amount, with a cap on the price it is willing to pay based on the cost of procuring the service from alternative (non-DER) sources.²⁷ A more sophisticated and complex approach would be to establish a "demand curve" in which the price paid for a service varies with the total quantity procured and the duration of the period over which it is available. For instance, it may be the case that certain ancillary services are very valuable but only needed in small quantities, in which case the demand curve would pay a high price for small quantities of the product and significantly lower prices when procuring beyond a certain level. A second issue is how to differentiate the bids and determine which ones to accept. With an auction the bids for a given product in a given location would be uniform other than the price and would therefore likely be procured based purely on cost, with lowest-cost resources being procured first. With an RFP there may be other value-added aspects of the offer that would justify a different approach than simply procuring the lowest cost resources.

Step 4: Third parties enroll customers and provide services. When a given third party's bid has been selected, it must enroll customers (i.e., those DER customers who can provide the services). The third party may have already established a contract with customers, contingent on the bid being selected. Otherwise, customers would be recruited into the program by offering various incentives, and the third party would develop a portfolio of participants necessary to fulfill the requirements of its bid. This is entirely an agreement between the third party and the customer. Beyond meeting any pre-established eligibility requirements that may exist for participating in the market, this would not be a regulated activity; it would be up to the third party to determine how to go about establishing its portfolio of participants.

Step 5: Financial settlement between the utility, third parties and customers. Payment from the utility to third parties is based on the market clearing price of the auction or the terms of agreement in the bilateral contract which followed the RFP. Payment from the third party to participating DER customers is determined by the separate arrangement between those parties. Note that the financial settlement between the parties does not necessarily need to happen at the end of the process. Depending on how the process is structured, payments may be made in advance of delivering the services.

²⁶ As an alternative to submitting bids, it would be possible to have an "open season" for a certain quantity of various services. DER providers could receive a pre-specified payment for providing those services for the total quantity needed.

²⁷ For instance, if a utility determines that it will need to expand the capacity of a distribution substation by 5 MW at an annualized cost of \$30,000/MW-year, it might be willing to procure up to 5 MW of peak demand reduction from the customers served by that substation at a price below \$30,000/MW per year.



Step 6: The process repeats. As the utility's need for distribution services evolves, it can simply repeat the procurement process by hosting another round of the auction or issuing a new RFP.

Markets for various energy, capacity, reliability and balancing products already exist in wholesale transmission-level markets. Similarly, utilities regularly issue RFPs for services. The concept of the Procurement Model is to bring this framework down to the level of distribution services from DERs. A version of the Procurement Model approach for distribution services has been discussed in the context of New York's Reforming the Energy Vision proceedings, both in the form of RFPs for capacity displacement services as well as, in the longer term, an auction-based process.²⁸ The California Public Utilities Commission is considering a pilot program using a solicitation process — an all-source Request for Offers — and an incentive (based on the difference between the utility's return on equity and its cost of equity) — for utilities to adopt cost-effective DERs for displacing or deferring traditional distribution system investments.²⁹

D. Model #4: DER-Specific Rates

With the DER-Specific Rates model, a different distribution rate is offered to each major type of DER customer. The rates are designed to reflect the specific costs of serving those customers, as well as the value of the distribution services provided by those customers.

To implement the DER-Specific Rates model, it is first necessary to define subclasses of DER customers. For example, within the residential class there could be customers with uncontrolled rooftop PV, customers with PV and a smart inverter, customers participating in demand response programs focused on peak demand reductions, customers participating in demand response programs that provide around-the-clock fast response to balance load, and customers with behind-the-meter energy storage. To the extent that these customers appear in numbers sufficient to warrant the creation of a subclass, a cost-of-service study would be conducted for each subclass. The study would determine the net cost that the subclass contributes to total distribution system costs.³⁰ The net cost would account for the value of self-supplied distribution services from the DERs.

With the DER-Specific Rates approach, the structure of the new DER rates does not necessarily need to differ from that of the standard class rate. If desired, price levels could simply be adjusted up or down to better reflect the average cost of serving the DER customer subclass.

To illustrate this concept, consider a customer with an electric resistance water heater. In the absence of DER-Specific Rates, the customer would simply pay the standard residential tariff. To the extent that the electric water heater has a load profile that peaks at the same time as the distribution system, this customer may be underpaying for his or her use of the distribution grid

²⁸ From the New York Public Service Commission's February 2015 "Order Adopting Regulatory Policy Framework and Implementation Plan," p. 33: "The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives. Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP [distributed system platform] capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach."

²⁹ California Public Utilities Commission (2014).

³⁰ To fully capture the range of distribution costs and services considered in this pricing model, it may be necessary to conduct a new cost of service study that accounts for the marginal costs and benefits associated with the DER customer.



if the standard residential rate is based on a flat volumetric price that does not reflect the time-varying nature of distribution costs. In other words, the customer’s water heater may contribute disproportionately to distribution system capacity costs, and this contribution to costs would not be fully captured by the flat rate design.

With the DER-Specific Rate approach, two additional distribution rates might be offered. One of the rates could be a mandatory rate for all customers with uncontrolled electric heating. If designed with a flat volumetric charge, the volumetric price would need to be increased to reflect the higher average cost of serving these customers (as described above). The second rate would be available to customers with controlled electric water heaters. The price paid would be lower than in the electric water heating tariff described above and, depending on the distribution benefits of controlling the water heater, could be lower than the standard residential tariff. Table 8 illustrates what the DER-Specific Rate model could look like for this hypothetical customer with electric water heating.

Table 8. Illustrative Monthly Distribution Bills for a Customer With Electric Water Heating Under the Standard Residential Rate and the DER-Specific Rates Approach

Standard Residential Rate			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.03	1,000	\$30.00
Customer charge (fixed \$/month)	\$10.00	—	\$10.00
		Total Bill:	\$40.00
Rate for Customers With Uncontrolled Electric Water Heating			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.04	1,000	\$40.00
Customer charge (fixed \$/month)	\$10.00	—	\$10.00
		Total Bill:	\$50.00
Rates for Customers With Controlled Electric Water Heating			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.025	1,000	\$25.00
Customer charge (fixed \$/month)	\$10.00	—	\$10.00
		Total Bill:	\$35.00



The DER-Specific Rates approach is applied at its most basic level already by most utilities. For example, utilities distinguish commercial and industrial customers by size and voltage service levels. Utilities also have “partial requirements” tariffs for large customers with on-site generation who wish to produce some or all of their own electricity but rely on the utility for backup and supplemental services. In addition, within the residential class, utilities may distinguish tariffs for multifamily versus single-family residential customers as well as customers with and without electric space heat. Some utilities have begun to introduce separate rates for residential customers with distributed generation. For example, Salt River Project recently created a rate for residential customers with new on-site generation, called the Customer Generation Price Plan.³¹

³¹ Salt River Project Agricultural Improvement and Power District (2015a).



IV. Issues to Consider for Unbundling and Pricing Distribution Services

There are important practical issues to consider when exploring one or more of the pricing models discussed in Section III. The issues fall under four broad categories: design considerations, deployment options, interactions with existing policy objectives, and other implementation issues.

A. Design Considerations

Section III described a range of ways to design each conceptual pricing model for distribution services. The design of the pricing model will have important implications for customers, the utility, the regulator and other stakeholders. Following are key design questions to consider.

How much complexity is acceptable to customers? One key design consideration is the amount of complexity that customers are willing to tolerate. Studies have found that residential customers spend little time thinking about their energy bill. A pricing model that is simple and transparent may facilitate a more robust and economically efficient response from these customers. On the other hand, rising adoption of emerging technologies such as smart thermostats and rooftop PV is a possible indicator that customers are becoming increasingly interested in energy management. The knowledge and sophistication of certain segments within a customer class, and therefore their tolerance for a more complex pricing structure, may be higher than in the past.

Should the price vary by time of day, month of year or location on the grid? Most residential rates and demand-side program offerings today are not location specific. Customers are typically charged one price or offered one incentive payment level regardless of where they are located on the system.³² However, as recent studies have highlighted, location-specific price signals are needed to encourage adoption of DERs in a way that benefits the distribution system.³³ Variation in prices by season is very common in existing rates, and some rates also vary by time of day, typically in the form of a TOU rate for residential customers and a TOU or real-time pricing rate for commercial and industrial customers. Movement toward time-varying pricing is accelerating, and evidence suggests that consumers do respond constructively to time-varying pricing.³⁴ Any of the pricing models described in Section III could be designed to vary across all of these dimensions and with a much higher degree of granularity than existing offerings. Time-varying elements can include both the distribution charges and power supply charges, as we discuss in Section VI.

What is the appropriate structure of charges for pricing distribution services? The pricing of distribution services could be based on a fixed charge (\$ per customer per month), a variable charge (\$ per kilowatt-hour), a demand charge (\$ per kilowatt), or some combination of these. Which of these are the appropriate charges, and at what level, is an ongoing source of debate among utilities and industry stakeholders. Some argue that distribution system costs are largely fixed and should therefore be collected through a fixed monthly charge. Others argue that, in the long run, distribution costs vary with the amount of electricity consumed and are therefore

³² ConEd's DLRP demand response program is an exception to this and provides location-specific incentives for participation.

³³ Cappers et al. (2015).

³⁴ Faruqui and Hledik (2012).



best recovered through a variable charge. And some argue that, with the appropriate metering technology in place, demand charges best reflect the peak-driven nature of distribution system investment, while others argue that these are best reflected in time-varying charges. Assuming a more granular approach to distribution services pricing, as discussed in this report, it is likely that a combination of these types of charges will be needed, depending on the specific distribution service that is being priced.

B. Deployment Options

Beyond issues in designing the new pricing model, there are also different options for rolling it out to customers. These decisions have a significant impact on eligibility and participation.

Should DER customers be considered a separate class with a separate rate? If the new pricing model involves a change to the underlying rate structure (e.g., the Granular Rate model), it will be necessary to decide whether to offer the new rate only to DER customers or to make the rate change for all customers regardless of whether they have DERs. This is a topic of ongoing debate, particularly as it relates to rooftop PV.

Should the new pricing models be offered on a mandatory, opt-out, or opt-in basis? With any new rate offering, a key consideration is whether participation should be mandatory. If participation is voluntary, a decision must be made as to whether to offer it on an opt-out basis (where customers are automatically enrolled in the rate with the option to revert to a different rate option) or an opt-in basis (where customers must proactively sign up for the new rate in order to enroll). Participation in some pricing models, such as the Procurement Model discussed in this report, would realistically only happen on an opt-in basis.

C. Interactions With Existing Policy Objectives

When developing the new pricing model, it will be important to be aware of its potential implications for achieving existing policy objectives.

How do the objectives for the pricing model align with broader policy objectives? New pricing models are typically introduced to improve economic efficiency in some way, through more accurate price signals or a structure that otherwise provides incentives for cost-effective investments. In this way, the new distribution services pricing model could encourage investment in DERs. Alternatively, to the extent that the pricing model removes an unintended subsidy in the existing rate, this could reduce the incentive for certain investments. The likely outcome of the effect of the pricing model should be estimated and compared to other policy objectives, such as promoting clean energy or improving system reliability. There are also distributional impacts to consider. Policy objectives to protect certain vulnerable customer classes from large bill increases will need to be taken into consideration.

What are the interactions with revenue decoupling policies? In states with some form of revenue decoupling,³⁵ it will be important to consider the extent to which the introduction of the pricing

³⁵ Revenue decoupling refers to a regulatory mechanism through which a utility's allowed revenue requirement recovery is separated (or "decoupled") from the amount of electricity that it sells. For an in-depth discussion, see Shirley, Weston and Lazar (2011).



model either increases or decreases the need for that decoupling policy to remain in place, or requires changes to the decoupling mechanism.

What is the interaction between pricing models for distribution services, pricing models for transmission service and pricing models for supply/commodity services? The pricing models presented in this report focus only on distribution services. However, customer bills also include charges for energy production and transmission costs. To the extent practical, it will be beneficial to coordinate distribution rate design charges in a way that is not confusing to customers.

We discuss in Section VI the types of DERs that provide most of their benefit at the supply level, and why it is therefore important to ensure that all benefit streams flow to the party making the investment in the DER.

D. Other Implementation Issues

How does implementation of the pricing models differ in vertically integrated versus restructured markets? Market structure could affect the development of the pricing model. For instance, in markets with retail competition, there will be less ability to coordinate the pricing of distribution services (offered by a regulated utility) with the pricing of supply (offered by a competitive retailer).³⁶ There may also be restrictions on the types of pricing structures that can be offered by the incumbent utility in restructured markets, due to concerns about their effect on competition. In vertically integrated markets, it may not make sense to develop a distribution-only pricing model when transmission-level services could be included as well.

Can the pricing model be feasibly implemented? The pricing models discussed in this report represent a significant departure from the way distribution services have traditionally been priced, in some cases introducing a significant amount of complexity. A key consideration will be how much complexity utilities are able to handle from an implementation perspective. For instance, a Granular Rate approach with distribution-level LMPs would introduce a set of implementation challenges that would be entirely new to the distribution utility. It will be equally important to consider the amount of complexity that regulators and stakeholders are willing to tolerate, as transparency is an important attribute of regulated pricing structures. The infrastructure requirements of offering more complex pricing models, and the associated cost of the infrastructure, are also important considerations, particularly given that distribution charges represent only a portion of the customer's bill. Developing a business case may be helpful in determining if the financial benefits outweigh the costs of introducing the new distribution pricing model, although some of the benefits may be qualitative and non-monetary in nature (e.g., improving fairness in cost recovery). We consider this a critical threshold issue.

How should recovery of prudently incurred costs be examined by regulators, including those of assets that may no longer be economic after widespread market adoption of DERs? Utilities are making long-term investments in distribution system assets to ensure that electricity can be reliably delivered to customers. If adoption of DERs becomes widespread, some of those assets may no longer be economic. The pricing model will need to address who pays for those

³⁶ Allowing the retailer to present a complete bill to the end customer, with distribution charges being settled between the distribution utility and the retailer, could help to resolve this issue. At the same time, it could prevent important distribution-related price signals from reaching the customer.



investments and the means through which the costs are recovered. A related question is if procurement of distribution services from DERs by the utility should have an associated time commitment (e.g., a 10-year capacity deferral commitment with penalties for non-compliance), or if this should be priced identically to how procurement of distribution services from the utility is priced — on an as-used basis. This would facilitate more effective distribution system planning but may restrict participation among DERs.³⁷

³⁷ See report No. 2 (De Martini and Kristov, 2015) in the Future Electric Utility Regulation series at feur.lbl.gov.



V. Criteria for Evaluating the Distribution Services Pricing Models

Each of the pricing models has its advantages and disadvantages. To develop a useful comparison, the pricing models can be evaluated based on their ability to satisfy basic principles of ratemaking. These principles are derived from the academic literature on the topic and updated for the purposes of this report to apply to a future scenario with widespread adoption of DERs.

There is an extensive library of academic literature on principles of rate design. Perhaps the most often cited and well-known text is Dr. James Bonbright's *Principles of Public Utility Rates*.³⁸ Bonbright established 10 basic principles of rate design and explained that there are trade-offs that prevent each from being perfectly satisfied without sacrificing others. Paul Garfield and Wallace Lovejoy, in *Public Utility Economics*, focused primarily on cost causation and the allocation of infrastructure costs to all consumers based partly on contributions to capacity needs when the system is constrained.³⁹ Alfred Kahn, in *The Economics of Regulation*, explored the role of pricing in regulated versus competitive markets.⁴⁰ Charles Chicchetti, in *The Marginal Cost of Pricing of Electricity*, argues for basing prices on long-run marginal costs. These are but a few of the important works on the basic principles of rate design.⁴¹

The literature on ratemaking principles is similar in its agreement that rates should reflect costs and recover those costs from customers in a way that accurately represents their use of the system. The literature varies in its emphasis on specifics. Some focus largely on the most appropriate way to reflect costs through rates, while others — particularly Bonbright — account for additional considerations in ratemaking, such as simplicity, stability and public acceptability.

The principles established in the academic literature, despite in some instances having been developed decades ago, are still applicable when considering distribution pricing in an environment with high adoption of DERs. For instance, the principle of cost causation is highly relevant regardless of the extent to which the generation resources in a particular energy market are centralized or distributed.⁴² Similarly, the notion that rates should be fair and understandable to customers is relevant in any market environment.

However, the relative emphasis on the importance of the ratemaking principles is likely to change in a future environment of widespread adoption of DERs. Simplicity, while certainly important for customer acceptance and understanding, may be less relevant if there is a market for third parties to manage a customer's energy, removing the need for customers to understand each line of their bill. Additionally, some price stability may need to be sacrificed to accommodate certain pricing models that introduce a high degree of variation across time and geographical location.

Our review of the literature leads us to five specific principles against which to evaluate the various approaches to unbundling, pricing and packaging distribution services in an environment

³⁸ Bonbright (1961). The text was later updated, with expanded discussion of ratemaking principles. See Bonbright, Danielsen and Kamerschen (1988).

³⁹ Garfield and Lovejoy (1964).

⁴⁰ Khan (1970).

⁴¹ Chicchetti (1977).

⁴² One interpretation of the cost causation principle includes basing prices on long-run marginal costs.



of widespread adoption of DERs: economic efficiency, equity/fairness, customer satisfaction, utility revenue stability and customer bill stability.

A. Economic Efficiency

The price of electricity should convey to the customer the cost of producing and delivering it, ensuring that resources consumed in the delivery of electricity are not wasted. In other words, costs should be recovered in proportion to their causation. If the price is set equal to the incremental cost of delivering a kilowatt-hour, customers who value the kilowatt-hour more than the cost of producing it will use it, and customers who value it less will not. This concept can be extended to suggest that prices should reflect intraday price differences, seasonal price differences and variation across geographic locations. The availability of interval consumption data, demand response and price-dispatched consumption greatly broadens the metric against which economic efficiency can be measured. A general view is that economically efficient prices reflect long-run marginal costs.

B. Equity/Fairness

No customer should unintentionally subsidize another customer. A classic example of the violation of this principle occurs under flat rate pricing. Since customers have different load profiles, “peaky” customers, who use more electricity when it is most expensive, are subsidized by less “peaky” customers who overpay for cheap off-peak electricity. Similarly, where all residential customers are served on a single tariff, subsidies exist between single-family and multifamily customers, and between customers served with overhead and underground distribution systems.

Note that equity is not the same as social justice. Some level of inter-customer subsidy is unavoidable with simple tariffs that apply to very different customers. To the extent that there is a policy objective to provide subsidies for certain customer segments (e.g., low-income customers or those with distributed generation), that is ideally accomplished with payments outside the rate itself in order to avoid providing customers with an incentive to consume inefficient amounts of any given service.

C. Customer Satisfaction

Pricing models should be designed to enhance customer satisfaction. Because most residential customers devote relatively little time to reading their electricity bills, rates should be relatively easy to understand and to respond to. This can depend as much on the way the pricing structure is presented as on how it is designed (i.e., a simple rate design can be presented on the bill in a way that is hard to understand, and vice versa). Simplicity is also a relative concept, since the presence of automating technologies or partnerships with energy managers can simplify the transaction for customers even with a fairly complex rate. Giving choices to customers can also help enhance customer satisfaction, since risk tolerances for price volatility versus stability vary across customers.

D. Utility Revenue Stability

Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-



recovering or over-recovering costs when rates are not cost reflective. Revenue regulation, or “decoupling,” is one mechanism that has been used to address the revenue stability issue independently of the pricing design.⁴³

E. Customer Price/Bill Stability

As suggested by Bonbright, cost causation is not the only criterion for fair rate design.⁴⁴ Prices for distribution services also should be stable and predictable. While transitioning to a new pricing model inherently includes a level of unpredictability and uncertainty, this means that there should be gradualism in the transition to avoid sudden unexpected changes in bills for DER (or other) customers.

There will be trade-offs in a given pricing model’s ability to satisfy all of these criteria. For example, fully satisfying the principle of economic efficiency and cost causation may require a more detailed pricing structure, risking customer confusion. Conversely, developing a rate that is geared toward customer bill stability may require making some simplifying decisions about the level of granularity that can be reflected in the pricing model. The relative importance of each criterion is subject to interpretation and debate. In Section VI of this report, we explore the extent to which the pricing models could satisfy these criteria, from the perspective of the utility, from that of the aggregator or sophisticated large-volume consumer, and from the perspective of the individual residential consumer.

⁴³ Shirley, Weston and Lazar (2011).

⁴⁴ Bonbright (1961).



VI. Perspectives on Unbundling and Pricing Distribution Services

This section describes the advantages and disadvantages of the distribution services pricing models from two perspectives: Ryan Hledik was assigned the utility perspective and Jim Lazar was assigned the customer perspective. While the authors draw from their experience to present general themes that are consistent with these two perspectives, this section of the report does not necessarily reflect the views of the authors' firms or clients.

The pricing models discussed in this report generally fall under the description of a "distribution operational market" described in Report No. 2 by De Martini and Kristov in the Future Electric Utility Regulation series.⁴⁵ In a sense, the four pricing models we describe in our report could each be considered different ways in which utilities would procure distribution services. However, the pricing models go beyond just the procurement of distribution services to also address the means through which customers are charged or are paid for these services.

A. Electric Utility Perspectives on the Distribution Pricing Models by Ryan Hledik

There is no "typical" electric utility. Utilities across the United States are highly heterogeneous, ranging from small public utilities that serve just a few thousand customers to massive investor-owned utilities that serve millions. Some utilities are vertically integrated, owning generation, transmission and distribution assets, with an obligation to ensure that each customer's demand for electricity is met. Other utilities own only the "wires," with a primary responsibility to ensure that electricity is reliably delivered to customers. The utilities vary in their resource mix and customer mix. Regulatory priorities and policy drivers differ considerably from one state to the next and sometimes even within a state. Due to these differences, there is not one single "right" approach to pricing distribution services. Different pricing models will be better suited to some circumstances than others.

The discussion of the advantages and disadvantages of the pricing models presented in this section is intended to provide a general overview of the issues that many utilities will grapple with when confronting the challenges of pricing distribution services in a high DER environment. The conclusions in this section are derived from the author's experience assisting utilities with a range of pricing issues and are his interpretation of the extent to which the pricing models would be suited for utilities. However, given the diversity of the utility industry and variation in the corporate objectives of those utilities, the views presented in this section are virtually guaranteed not to be applicable to the circumstances of all utilities.

As discussed earlier in this report, widespread adoption of DERs may present opportunities for utilities to reduce distribution system costs while maintaining adequate levels of reliability. However, adoption of DERs could also increase the cost of operating the distribution system, particularly as it relates to managing two-way flows of electricity and accounting for rapid fluctuations in supply, demand and power quality. Well-designed pricing models will not only need to compensate DER customers for the services that they provide, but importantly, to accurately collect from those customers the costs that they impose on the system.

⁴⁵ See feur.lbl.gov.



In discussing the advantages and disadvantages of the pricing models, it is helpful to first understand the utility's goals for pricing distribution services. Specifically, what do utilities want to accomplish when redesigning rates or introducing new pricing models? In an increasingly competitive market, what are the objectives that will define a utility's pricing of distribution services? Broadly speaking, a utility's ratemaking objectives are likely to align closely with the five principles described in Section V of this report.

Customer satisfaction is a critical consideration for utilities as they develop pricing structures. Utilities, as a business, want their customers to be satisfied with their product. And customer satisfaction is of course an issue that the utility's regulators are acutely aware of, as their phone will ring anytime customers are displeased with the utility. For this reason, it is no surprise that utility executive compensation packages are sometimes tied to customer satisfaction metrics.

Revenue stability and, in particular, revenue adequacy, is a primary issue for utilities. Distribution utilities are required to reliably deliver electricity to all customers. Looking forward, even with the widespread adoption of DERs there will still be a need for an extensive and robust grid.⁴⁶ Utilities will continue to need to make long-term infrastructure investments in order to fulfill this commitment. Having access to capital necessary to finance these investments requires that the utilities have some certainty in the revenue that is needed to cover the costs. Pricing structures that are designed to fully recover costs with some degree of certainty are critical to the utility's ability to reliably serve its customers.

Fairness and equity are also key considerations for utilities, and this has become increasingly apparent as the industry has confronted ratemaking challenges associated with the growing adoption of DERs — solar PV in particular. Whereas concerns about net metering and volumetric rates initially gravitated toward talk of the “utility death spiral” and an inability to recover costs, the conversation has more recently shifted to one of fairness in rate design. Specifically, utilities have begun to make a concerted effort to reform rates in a way that ensures that those who use the grid also pay for its use. In other words, the debate has shifted from a question of *how much* cost will be recovered to a question of *from whom* it will be recovered.

Bill stability is of interest to utilities in the same way that they are focused on maintaining a high level of customer satisfaction. With any proposed rate change, utilities evaluate the expected distributional impacts on customer bills. Virtually any revenue-neutral⁴⁷ change to a rate's design will produce customers whose bills automatically decrease and customers whose bills automatically increase. It is inevitably the customers with bill increases who become the focus of stakeholder concerns during rate case proceedings, particularly those in vulnerable customer segments, such as low-income households or the elderly.⁴⁸ Utilities often include, as features of their new pricing proposals, strategies and tools to ease the burden of the bill increase for these

⁴⁶ Corneli and Kihm (2015).

⁴⁷ Revenue neutrality means that the new rate will produce the same revenue as the old rate, absent any change in customers' electricity consumption patterns.

⁴⁸ These concerns are perhaps why peak time rebates have, thus far, been the preferred default dynamic pricing option (retail rates that change in response to electricity demand by hour or day) for residential customers. While the rate design has its advantages and disadvantages, it presents a no-lose proposition to participants, who face only the upside of potentially reducing their bills, with no financial downside.



customers.⁴⁹ But even in the absence of specific transition tools, new pricing models can help to address potential bill increases for vulnerable customers. If the new pricing model includes financial incentives for, say, participation in a distribution-level demand response program, this would present customers with a bill savings opportunity. Additionally, to the extent that the new pricing model removes the cross-subsidy currently embedded in existing rates, where customers who have certain DERs are subsidized by those who cannot necessarily afford them, this is also likely to benefit vulnerable customers.

Intersecting all of these objectives is that of **economic efficiency**. The need to develop pricing structures that reflect incremental costs is a principle that has guided utility ratemaking for decades and is a key determinant of equity in rate design. The tension for utilities and their stakeholders is typically the extent to which economic efficiency will be sacrificed for the achievement of the other objectives.

With this review of the basic utility objectives for distribution pricing as a backdrop, the following is a discussion from a utility's perspective of the advantages and disadvantages of each of the four pricing models presented in Section III of this report.

1. Granular Rate

The Granular Rate model is a detailed and highly unbundled distribution rate with prices that are intended to reflect the cost of each distribution service, varying by time, season and location.

Advantages

From the utility's perspective, the Granular Rate model has a number of potential advantages. First, if well designed, by virtue of aligning rates closely with underlying costs, the rate would provide significant improvements in equity and fairness.⁵⁰ A customer whose net load is high during peak hours would contribute more to distribution capacity cost recovery by paying a higher price during those hours (either through a peak period surcharge or a peak-coincident demand charge). This would reduce or remove a significant unintended subsidy embedded in today's rates. At the same time, this would give the customer a financial incentive to reduce peak demand in the locations of the grid where the reductions are needed most, which should lead to a reduction in costs for the utility in the long run.

Second, the Granular Pricing model is the only one of the four pricing models that presents an opportunity to improve distribution pricing for all customers, not just those with DERs. Looking forward, as is often the case with market disruption, it is difficult to anticipate the types of new distributed technologies that will emerge and the services that they will provide. Developing a granular and robust rate for all customers will reduce the need to continually refine and develop new pricing packages to respond to technological changes in the market.

⁴⁹ For example, some utilities offer discounted rates to customers with qualifying incomes. The California Alternate Rates for Energy (CARE) program is one such example. For a discussion of possible rate transition strategies, see Faruqui and Hledik (2009).

⁵⁰ The principle of cost causation is typically interpreted to mean that prices should be based on long run marginal costs. This principle will need to be balanced with considerations for the recovery of prudent fixed/sunk costs and the other principles discussed in this report.



Third, while the Granular Pricing model is inherently complex, there is an attractive simplicity to representing the price of all distribution services on a single sheet, through a single tariff structure. Not only does the single bi-directional price for each distribution service (i.e., from the utility to the DER customer, and from the DER customer to the utility) have the benefit of transparency, it could also be perceived by DER customers to be fair in the sense that they would avoid the confusion of paying one price for the delivery of electricity but being paid a different price by the utility for the provision of distribution services.

Disadvantages

Depending on the level of detail incorporated into the rate, implementation of the Granular Pricing model could be very complex. For instance, taken to its extreme, the distribution locational marginal price approach discussed earlier in this report could require that *billions* of location-specific prices be computed in a given market each *month*.⁵¹ Further, measuring the amount of each individual service that is consumed or provided by an individual customer will pose significant implementation challenges. For example, how does one measure the amount of voltage support required by or provided by a given customer at a given time? In addition to advanced metering capability, utilities will need significant upgrades to billing and information technology systems to support these more complex computations.

Customer understanding is also a potential disadvantage of the Granular Pricing model. For instance, some industry stakeholders express skepticism that residential customers will be able to understand even the concept of a demand charge.⁵² While that is a hurdle that can likely be overcome through proactive messaging and education, it nevertheless emphasizes significant industry concern about a customer's ability or willingness to tolerate a very complex rate structure.

If the Granular Pricing model is poorly designed, with prices that do not closely reflect the long-run marginal cost of distribution services, there is the potential to introduce significant net revenue risk to the utility. For instance, customers are expected to shift their electricity consumption away from times when the price is high in order to reduce their bills. If those load reductions do not lead to deferred or avoided investments that are commensurate with the bill savings due to a misalignment of costs and prices, the utility's net revenues will decrease. There is also a short-run versus long-run dilemma. Even if costs decrease in the long run, there is still the challenge of dealing with the short-run revenue shortfall. This short-run issue can be addressed in a number of ways — for example, by accounting for the expected change in load patterns when setting the price levels to meet the revenue requirement, or through revenue decoupling.

From a procurement perspective, the Granular Pricing model gives the utility very little control over the quantity of distribution services it can purchase. While prices of the distribution services can be adjusted up or down to reflect their value, this is not likely something that can be done quickly and frequently due to regulatory lag in reviewing the proposed price changes. Further, it will take time for the utility to develop an understanding of the extent to which the

⁵¹ De Martini and Kristov (2015).

⁵² Alexander (2013).



prices would affect the provision of distribution services when accounting for these services in distribution resource plans.

The pricing model works well for utilities if...

The Granular Pricing model could be effective where there is a robust and competitive market for energy management firms who act as the interface between the customer and his or her bill. This would reduce perceived complexity for the customer. In a similar manner, the model could work for customers who have a high degree of load automation.

A prerequisite for implementing the Granular Pricing model is that utilities have advanced metering capability. Even in its simplest forms, the model will require time-varying volumetric charges or demand charges, and both of these options require interval meters (see the text box for a discussion of residential demand charges). More sophisticated offerings are likely to require even more advanced systems.

From a design perspective, the Granular Pricing model will likely be most effective in situations where simplifications can be made to the rate's design. For example, if the majority of a given utility's distribution resource needs are projected to be in system peak-driven capacity additions, the Granular Pricing rate could be designed to reflect these higher system peak costs while bundling other operational costs into a single charge. Customer demand response to the higher peak period price should lead to reductions in future capacity needs from the utility's perspective and would provide the most meaningful opportunities for bill savings from the customer's perspective.

The Granular Pricing model may be better suited for markets with retail competition where the distribution tariff is a transaction between retailers and the distribution utility. In this case, retailers make the decision as to how to pass the cost on to customers. Not only would this potentially help with simplifying the distribution bill for customers in a meaningful way, it could also help to address the challenge of coordinating distribution pricing with the transmission and generation charges that customers also must pay. In this case, the retailer could package these with the distribution prices in whatever way is most appealing to its target market.

Finally, the Granular Pricing model is best suited for environments in which the utility's chief concern is in improving equity and fairness in cost recovery. The primary benefit of the Granular Pricing model is that it charges customers precisely for their use of the distribution system, resolving inequities and cross-subsidies that are embedded in simpler rate designs.

One example of a Granular Rate being offered to residential customers is ComEd's Residential Real-Time Pricing (RRTP) program.⁵³ Customers pay electricity prices that vary on an hourly basis each day of the year. Participants in the program receive advance notification when high prices are expected and are encouraged to also participate in ComEd's direct load control program in order to maximize bill savings on the rate. Online tools and mobile apps provide additional information to facilitate demand management and bill reductions. While the program includes supply costs and is not focused specifically on distribution costs, it is an example of a Granular

⁵³ For more information, see ComEd (2014).



Rate offered to residential customers.⁵⁴ Figure 4 illustrates typical hourly prices faced by participants in the RRTP program.

TRANSITIONING TO RESIDENTIAL DEMAND CHARGES

Residential demand charges have recently been discussed as an attractive approach to pricing certain distribution services, such as the reservation of capacity on distribution substations or local transformers. A demand charge would recover some portion of the utility's costs through a price that is based on a measure of the customer's maximum instantaneous demand for electricity (kilowatts) rather than on his or her total monthly consumption (kilowatt-hours). There are a variety of ways in which "maximum demand" could be defined for the purposes of billing a demand charge, such as maximum demand during a period that is coincident with the system peak, maximum demand during a period that is coincident with the customer class peak, or maximum demand based on the customer's own peak over the course of the month.

The potential benefits of this approach are numerous if the demand charge is well-designed and carefully implemented. It would improve fairness and equity in cost recovery, by reflecting the peak demand-driven nature of distribution capacity investment. It would also provide an incentive for customers to improve their load factors and for the adoption of emerging energy management technologies such as battery storage and smart appliances. With a well-designed rate, the resulting changes in electricity consumption patterns would reduce system resource costs and customer bills in the long run. And while there are certainly differences between residential and commercial and industrial customers, a practical advantage is that there is already a regulatory precedent for demand charges, which have been offered to commercial and industrial customers for decades.

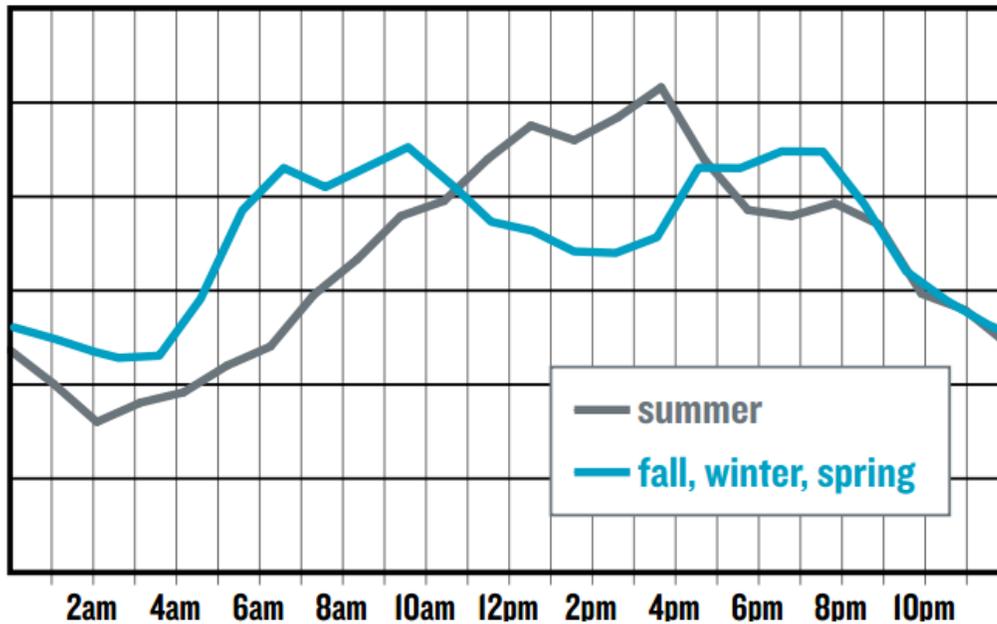
Stakeholder concerns about demand charges should be carefully considered and addressed when designing a new pricing model that includes a demand charge. Many consumer advocates are concerned about bill impacts for low-income customers. Bills under the new rate design should be simulated for a representative distribution of customers in each relevant customer segment and, if certain vulnerable customer groups would see bill increases, transition strategies and tools can be developed to ease this burden. Other stakeholders have expressed a concern that demand charges do not accurately reflect costs due to the diverse nature of residential loads. A broad range of possible demand charge designs should be considered to address this concern (for example, if stakeholders are concerned that a demand charge that is based on an individual customer's maximum billing demand is not cost-reflective, measurement of demand could instead be constrained to a peak period). Another concern is that customers cannot understand a demand charge. This can be addressed through market research that is designed to determine the simple educational messages that best resonate with customers (e.g., "avoid using many appliances at the same time in order to save money on your bill").

Demand charges present a practical and equitable opportunity to improve residential distribution rate design where the necessary metering infrastructure is in place. Successfully transitioning to this new rate structure will require additional research and close coordination with industry stakeholders who present a broad range of perspectives on the topic.

For more information, see Hledik (2014).

⁵⁴ Additionally, proposed legislation in Illinois would recover distribution costs through a demand charge rather than a volumetric charge.





**Based on average prices for January 2012 through April 2014. Nonsummer months include October through May. Summer months include June through September.*

Source: ComEd (2014).

Figure 4. Typical Real-Time Pricing Patterns in ComEd RRTP Rate.

The figure illustrates a typical pattern of hourly real-time prices that customers in ComEd’s RRTP program would face. Prices tend to fluctuate most in summer months when the ComEd system is peaking, though high prices have been observed during winter cold spells as well.

2. Buy/Sell Arrangement

Under the Buy/Sell Arrangement, customers are charged the existing standard rate for all electricity they consume and are separately paid under a different pricing structure for any distribution services they provide.

Advantages

A practical benefit of the Buy/Sell Arrangement is that it does not require any changes to the existing retail rate. Changing the structure of the existing retail rate for all customers is often a lengthy and contentious process. With the Buy/Sell Arrangement, the discussion would focus narrowly on how to establish prices reflecting the value of the services that DER customers provide to the grid.

The Buy/Sell Arrangement also provides utilities with an opportunity to maintain simplicity in the compensation structure for DER customers. Whereas the Granular Rate model would be highly detailed and unbundled, the Buy/Sell Arrangement would allow for the construction of simpler bundled payment structures. Related, the Buy/Sell Arrangement is likely to be attractive



from a customer acceptance standpoint, because there is no risk that a participant’s bill will increase with this approach — DER customers are simply paid for providing services.

The Buy/Sell Arrangement also gives the utility some control over the procurement of distribution services. In developing the tariff that specifies payment for various distribution services, the utility can establish eligibility requirements and other performance guidelines that will ensure a certain threshold of dependability in the services from the DER customer.

Disadvantages

While the Buy/Sell Arrangement certainly has the potential to be simpler for customers to understand than the Granular Rate, there is still a risk that customers may not be able to digest the menu of options available to them. For example, a customer with solar PV and a smart inverter may not know which services their system can provide, or may not be interested in taking the time to read through pages of documentation describing the tariff and its eligibility requirements. The utility could see low enrollment if this is the case. Targeted marketing and outreach could help to overcome this problem.

In jurisdictions where versions of the Buy/Sell arrangement are already adopted or being discussed (e.g., “Value of Solar” models — see the description in Section VI.B of this report), the conversation often gets bogged down in a debate over what should be included in the payment for services.⁵⁵ Utilities may maintain that the payment should be based on avoided costs that would otherwise be incurred by procuring the services from other resources (e.g., building flexible generation capacity that, among other things, provides the needed level of voltage support). Other stakeholders may suggest that the payment should account for “external” sources of value such as emissions reductions. While many would support the notion that accounting for externalities in pricing is an economically efficient approach, the problem is that these proposals in the context of a Buy/Sell Arrangement typically only account for externalities in pricing for specific DERs and not for all resources. This is both inequitable and economically inefficient in the sense that it could lead to suboptimal investments in those specific DER technologies for which the external sources of value are being recognized, when there may be other options, either on the supply side or the demand side, which would provide the same benefit at a lower cost if given similar treatment.

The pricing model works well for utilities if...

The Buy/Sell Arrangement may be an effective option to pricing distribution services in environments where there is very limited appetite for or ability to change the distribution rate structure for all customers, or where there is a significant difference between the retail rate and the value of services provided by DER customers. For example, existing legislation in some states may restrict rate changes for certain customer classes. Assembly Bill 1X in California, for instance, prohibited price increases in the first two tiers of the residential rate, thus preventing time-varying rates from being offered to residential customers on a default basis in the state (although this legislation has been reversed, and the state is now exploring a move to default

⁵⁵ While this has been a barrier in recent deployments, it is possible that well-established and less controversial models will emerge over time.



TOU rates by 2019).⁵⁶ In other cases, if utilities and their stakeholders recently concluded a long and contentious proceeding on rate design, it may not be practical to immediately reform the standard rate, in which case the Buy/Sell Arrangement could be an attractive alternative. Similarly, the Buy/Sell Arrangement could be effective in environments where updates to tariff prices for purchasing distribution services from retail customers can be done regularly and efficiently outside of lengthy rate case proceedings.

The Buy/Sell Arrangement may also be an effective solution for utilities to implement for specific market segments that are capable of providing valuable distribution services, but which the competitive market of aggregators, energy managers and retailers has not been able to effectively access. The utility’s existing relationship with retail customers may allow a Buy/Sell Arrangement to extend the procurement of cost-effective DER services beyond what the competitive market alone could achieve.

One example of a utility Buy/Sell Arrangement for distribution system services is Con Edison’s distribution load relief program. The program provides location-specific incentives for load reductions that are intended to specifically reduce distribution system costs. Customers located in areas of the distribution system where load reductions are more valuable receive a “capacity reservation payment” of \$15 per kilowatt per month, whereas customers located in other parts of the distribution system receive a reservation payment of \$6 per kilowatt per month.⁵⁷ Additional participation incentives are offered as well. Table 9 summarizes the incentive structure of the program.

Table 9. Summary of Incentives in Con Edison’s Distribution Load Relief Program

	Tier 1	Tier 2
Reservation payment (\$/kW-month)	6.00	15.00
Energy reduction payment (\$/kWh)	1.00	1.00
Three-year incentive payment (\$/kW-month)	5.00	5.00

Notes: Con Edison’s distribution system is divided into two zones, representing areas with a higher need (Tier 2) and lower need (Tier 1) for load reductions. The reservation payment is for committed kilowatts of load reduction. The energy reduction payment is for actual delivered reductions in kilowatt-hours during demand response events. The three-year incentive payment is for pledged enrollment for at least three years in the program. Participants must be able to provide at least four hours of uninterrupted load reduction. For additional information, see http://www.coned.com/energyefficiency/demand_response_program_details.asp.

⁵⁶ Assembly Bill 1X was codified in the following language in Section 80110 of the California Water Code: “In no case shall the Commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers up to one hundred and thirty percent of existing baseline quantities, until such time as the department [Department of Water Resources] has recovered the costs of power it has procured for the electrical corporation’s retail end use customers as provided in this division.”

⁵⁷ There are alternative demand response enrollment options that do not include location-specific incentives or a firm reservation of capacity. For details, see “Demand Response Programs Details,” ConEdison, 2013, http://www.coned.com/energyefficiency/demand_response_program_details.asp.



3. Procurement Model

Under the Procurement Model, utilities procure distribution services from non-regulated third parties who aggregate the services provided by individual DER customers and compensate those customers accordingly.

Advantages

The Procurement Model is perhaps the most effective model in maximizing a utility's ability to fully integrate DERs into its long-term distribution system planning initiatives. First, a utility can specifically define products that meet its planning needs. For instance, products could include a five-year term for the provision of peak demand reductions, which would allow the utility to plan to defer capacity upgrades over that time frame in those geographic areas where the peak demand reductions are procured.

Second, the Procurement Model is likely to have the advantage of simplicity from the customer's perspective. While some large customers may wish to bid into the procurement process directly, others will likely sign up with an aggregator. The aggregator will structure incentive payments in a way that appeals to customers. Thus, even if the product design is complex, customers will not necessarily face a complex pricing structure.

Third, relative to the other pricing models, the Procurement Model is likely be the easiest to implement on a location-specific basis — important for avoiding or deferring more costly distribution system investments.⁵⁸ A challenge with location-specific retail rates is that customers may perceive these rates to be unfair (e.g., “Why am I paying more than my neighbor for the exact same service?”). However, customers are used to being offered different products and services from competitive firms all the time (e.g., “You have been selected for a special offer!”). There is less likely to be a perception of unfairness if aggregators are offering different compensation packages to customers.

Another advantage of the Procurement Model is that it is not likely to increase utility exposure to revenue collection risks, particularly relative to the Granular Pricing model. Through the procurement process, utilities specify which services they are buying, the quantity of those services and what they cost. Being able to define and accurately plan around each distribution product that is offered, particularly over a long-term planning horizon, minimizes the risk that distribution services from DER providers will be compensated at rates that are not economic or that the services will be provided at times or in locations that are not useful.

Disadvantages

Relative to the pricing models that modify the retail design — specifically the Granular Rate model and the DER-Specific Rates model — the Procurement Model does little to correct the inequities and unintended cross-subsidies that are embedded in existing rate designs. While the model has the potential to create a robust market for distribution services, other potential problems of current rates — such as under-collecting distribution costs from customers with uncontrolled solar PV systems due to net metering at flat volumetric prices — would remain

⁵⁸ See Cappers et al. (2015) for further discussion of the need for location-specific incentives.



unaddressed. A Procurement Model approach could be coupled with modifications to the existing rate design to address this.

Additionally, if the products defined in the procurement process are too complex, the transaction costs may be too high for aggregators to participate. Similarly, if the potential revenue stream from participation in the market is small, aggregators may not be interested in participating. The result would be low enrollment or offers that are too high to be cost-effective. Thus, customer segments capable of offering useful distribution services may remain without a means to sell those services (likely smaller customers).

The pricing model works well for utilities if...

The Procurement Model will be most effective if utilities have identified a clear need for specific distribution services, because the model requires specificity in defining the products that are being procured. Further, the model will be useful for obtaining those distribution services that are location-specific and focused in particular geographic areas of the grid, given the ability to establish locational auctions or requests for proposals. For example, investor-owned utilities in California have developed distribution resource plans required to “identify optimal locations for the deployment of distributed resources.”⁵⁹

The model will also be most effective where there is a robust and competitive market of aggregators who have the capabilities to provide distribution services. While some large customers may have the sophistication to bid directly into the procurement process, the Procurement Model clearly depends on third parties that have the technical capability and business model that allows them to participate.

Where the Procurement Model is the chosen approach, a strategic question for utilities will be whether to implement the procurement process through a centralized auction or RFPs. Initially, RFPs are likely to be a prudent first step until the capabilities of market participants are well known and the economics of DER-provided distribution services are established. This is a lower-risk strategy than jumping straight to an auction-based approach, due to the higher degree of flexibility in defining products and the lower upfront cost associated with an RFP-based process. The auction-based approach is more likely to materialize as the preferred approach over time as the market for DER services matures.

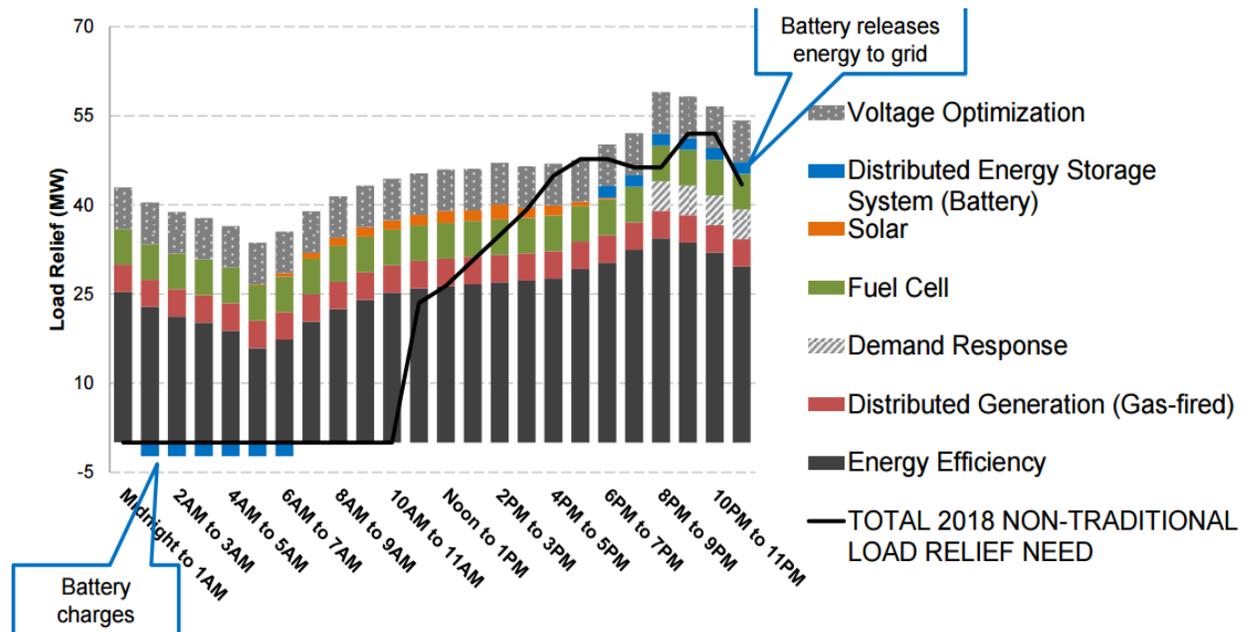
There are many examples of utilities that have procured demand-side resources to avoid or defer investments in grid infrastructure.⁶⁰ One commonly cited recent example is Con Edison’s Brooklyn/Queens Demand Management (BQDM) program. The program is expected to eventually rely on 52 MW of load reductions composed of nontraditional resources such as energy efficiency, voltage optimization, and battery storage to defer the need for upgrades to subtransmission feeders in a constrained part of Con Edison’s distribution system. The demand-side resources are being procured through a combination of utility-implemented programs, RFPs and auctions. Design of the auction process is still underway, though it has been suggested that

⁵⁹ The development of distribution resource plans in California is required by Public Utilities Code Section 769. Additionally, the New York Public Service Commission has required utilities to develop “Distribution System Implementation Plans.”

⁶⁰ For discussion, see Neme and Sedano (2012) and Neme and Grevatt (2015).



a descending clock auction⁶¹ would be used to procure demand response resources.⁶² Figure 5 illustrates the mix of resources that are expected to be part of this initiative.



Source: Con Edison, “Brooklyn Queens Demand Management Program” (BQDM) program update briefing, Aug. 27, 2015. <https://www.comed.com/documents/customer-service/rates-pricing/real-time-pricing/rtpprogramguide.pdf?FileTracked=true>.

Figure 5. Expected 2018 BQDM Resource Portfolio During an Illustrative Summer Day

The figure shows the expected composition of load-reducing resources participating in the BQDM program during each hour of an illustrative summer day in 2018. The load reduction capability is shown relative to the load relief needed in order to defer local upgrades to the distribution system. Energy efficiency represents the single largest source of load reduction in this case.

4. DER-Specific Rates

With the DER-Specific Rates model, a different rate is offered to each class of DER customer to reflect the costs of serving that type of customer, as well as the value of the services the customer provides to the distribution system.

Advantages

As with the Buy/Sell Arrangement and the Procurement Model, the DER-Specific Rates model avoids the need to change rates for non-DER customers. This may allow for a more expedient transition to the new pricing structure.

⁶¹ In a descending clock auction, an initial high price is announced and participants submit bids to provide quantities of demand response at that price. At the end of the round, the auctioneer adjusts the price based on the total quantity bid, and a new round of bidding begins. This process repeats until the total quantity bid equals the amount desired for procurement through the auction. There is precedent for using this approach in electricity markets. See Maurer and Barroso (2011).

⁶² ConEdison (2015).



The DER-Specific Rates model also has the potential to be the easiest option for DER customers to understand. DER customers simply pay a rate that reflects their cost of service as well as the value of the services that they provide to the distribution system, and they do not have to be bothered with information about the various services that they're consuming and providing to the grid.

The DER-Specific Rates approach also does a fairly good job of addressing utility revenue adequacy and, to some extent, inequities. By creating subclasses of customers that have their own cost of service, the utility is able to ensure that it is collecting the necessary amount of revenue from those customers in proportion to their use of the grid. This approach may address any concerns about cross-subsidies between customers who have distributed generation and those who do not. However, if the rate structure for non-DER customers remains flat (not varying by demand on the distribution system through time-varying pricing), other deficiencies in fairness will remain, such as the subsidization of customers with peaky load profiles by customers with flat load profiles.

Disadvantages

The DER-Specific Rates approach requires that a detailed cost-of-service study be conducted for each subclass of DER customers. From an implementation perspective, dividing the customer base into the appropriate number of subclasses and conducting such a study for each may be very costly or otherwise impractical. Further, as new technologies emerge and gain market share, this approach would require that new rates regularly be added to the tariff.

Also, while this approach has the benefit of simplicity to the customer, it lacks transparency and is approximate in nature. In practice, every customer is different in some way. DER customers will have different sizes of PV installations, different combinations of smart appliances, different degrees of automation in their energy management systems, etc. Even with customers divided into many subclasses, the practical necessity of developing simple rates that collect average costs across some of these customers could lead to issues of fairness and inequity.

Finally, a practical consideration for utilities is that DER-specific rates have recently been the subject of accusations of price discrimination. For example, SolarCity filed a lawsuit in Arizona against Salt River Project for introducing a rate specifically to more fully recover costs from residential customers with distributed generation (see Table 10 for a summary of the rate design).⁶³ Intervenors in Nevada have made similar claims of price discrimination in response to NV Energy's proposal for a distributed generation-specific rate.⁶⁴ Alternatively, stakeholders in other states have argued that customers with behind-the-meter generation have distinct operational characteristics and a different cost to serve and should therefore be considered a separate class for ratemaking purposes. While utilities have always offered different rates to customers served at different voltage levels, different income levels, different sources of space heating, and other factors that contribute to a different cost to serve the customer, DER-specific rate proposals will likely be delayed or otherwise subject to expensive litigation. While this risk alone is not a reason to avoid pursuing this pricing model, it is a practical consideration to account for in planning activities.

⁶³ For discussion, see Pyper (2015).

⁶⁴ See intervenor comments in Nevada Public Utilities Commission Docket Nos. 15-07041 and 15-07042.



Table 10. Summary of Salt River Project’s Customer Generation Price Plan

	Summer Peak Season		Summer Season		Winter Season	
	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
Demand charge – first 3 kW (\$/kW)	9.59	0	8.03	0	3.41	0
Demand charge – next 7 kW (\$/kW)	17.82	0	14.63	0	5.46	0
Demand charge – all add’l kW (\$/kW)	34.19	0	27.77	0	9.37	0
Volumetric charge (\$/kWh)	0.0486	0.037	0.0633	0.0423	0.0430	0.0390
Customer charge (\$/month)	32.44					

Note: The rate shown is for customers with a service level of 200 amps or less. For more details about the rate, including time period and seasonal definitions, see Salt River Project (2015b).

The pricing model works well for utilities if...

The DER-Specific Rates model could work in situations where certain DER customer types are — or are expected to be — significant in size (i.e., represent a sizeable portion of the customer base) and are relatively homogenous in terms of their cost to serve and the value of the distribution services that they provide to the grid. Further, the subclass of DER customers should be distinctly different than the class as a whole in order to justify a special rate. Whether to change rates for all customers or just for subclasses is an ongoing topic of debate among utilities, and as of yet there is no clear industry consensus on this issue.

5. Additional Considerations

Technological constraints could limit the extent to which the pricing models can be feasibly implemented. Market adoption of smart meters continues on an upward trajectory, with about half of U.S. households equipped with some form of advanced metering.⁶⁵ By 2030, it seems likely that most utilities will have this capability. Therefore it should be possible in most cases to measure a customer’s time-specific demand from the grid as well as the customer’s output to the grid from sources of distributed generation. But measuring the provision of other services could be more challenging. As a practical matter, it may be necessary to develop average engineering-based estimates of the capabilities of certain DERs and apply these estimates generically to all similarly equipped DER customers. Metering the provision of each service, such as voltage regulation, may not be feasible or cost-effective. It will be critical to ensure that these estimates are accurate and do not overstate or understate the capabilities of DERs. Utilities are required to provide a minimum level of reliability and will need to be able to rely on the distribution services being delivered in the expected quantities in order for them to be beneficial.

Additionally, when developing any of the pricing models, it will be critical not to consider distribution services in a vacuum, without regard for the pricing of transmission and generation services. As has been mentioned throughout this report, coordination of the pricing of these

⁶⁵ Institute for Electric Innovation (2015).



different services is important not only for simplicity and ease in customer understanding, it is also necessary to ensure that utilities and markets recognize the full value of DERs.

6. A Vision for 2030 and Beyond

The preceding discussion of the advantages and disadvantages of the distribution pricing models shows that, while each has its limitations, there are different circumstances under which they are applicable and likely to be effective. A particularly robust approach to pricing distribution services may be to implement a combination of the pricing models described in this report, to varying degrees. In this vein, the following are elements for one possible proposal for a comprehensive utility distribution services pricing model for 2030 and beyond.

- a) **Modestly increase the level of granularity in distribution rates for all customers.** There are deficiencies in existing retail rates that affect all customers, not just those with DERs. Advancements in metering technology allow new rate structures to be offered. The design of rates should be improved to address the most important issues. The vast majority of distribution system costs are associated with constructing, upgrading and replacing the existing physical infrastructure. Actual operating costs — including those costs associated with maintaining power quality — are typically a small share of the total.⁶⁶ In this sense, improving the representation of distribution capacity costs in rate designs should be a priority. For residential and small commercial customers, this could mean introducing a peak coincident demand charge and reducing the volumetric rate proportionally. For larger commercial and industrial customers, this could mean modifying the volumetric portion of the rate such that it varies on an hourly or even sub-hourly basis. For simplicity, other operational distribution services such as power quality maintenance can remain bundled with the pricing of other services.
- b) **Establish a request for a proposals-based Procurement Model.** The Procurement Model would be used to procure those services that are of most value to the distribution system (and perhaps combined with procurement of transmission and generation supply services). Whereas the proposed change in retail rate structure described above would address equity and fairness issues for all customers, the Procurement Model would promote adoption of those distribution services that can be most effectively and efficiently integrated into the utility's long-term distribution planning process. If successful, the Procurement Model could eventually transition to an auction-based approach, which would promote competition in a market-based environment.
- c) **Develop a Buy/Sell tariff for underrepresented customer segments.** To the extent that there are customer segments — perhaps residential and small commercial customers — that are not economic for aggregators to pursue, a Buy/Sell Arrangement could be implemented to give those customers access to sell their distribution services directly to the utility.
- d) **Limit DER-Specific Rates to a limited number of unique applications.** For instance, an optional "smart home" rate with hourly or sub-hourly price variation could be created

⁶⁶ See, for instance, Vogt (2009).



for customers with a significant amount of automation of DERs, as they would be able to handle (and benefit from) this complexity. If modifying retail rates for all customers (as proposed under (a) above) is not feasible, it may be desirable to create additional mandatory rates for customer segments that are distinctly different from the customer class as a whole, such as customers with large uncontrolled solar PV systems.

7. Making the Transition

Before moving forward with any major initiative to unbundle, package and price distribution services, it will be critical to establish a business case for the initiative. The term “business case” is used loosely in this sense, as traditional cost-effectiveness methodologies are not entirely applicable to electricity pricing because they must account for qualitative factors. For instance, how does one put a dollar value on the benefits of fairness and equity? However, the point remains that it will be necessary to understand, even qualitatively, how the benefits of the initiative will compare to the costs of its implementation. In some jurisdictions it may be the case that the value of distribution services provided by DERs represents only a modest portion of the total cost of procuring and delivering electricity (and, therefore a small portion of the average customer’s bill). In these cases, a simple and low-cost approach may be the most practical solution. On the other hand, if these distribution services present a significant potential revenue stream to customers with DERs and could easily be rolled into pricing models for transmission and generation services, then a more sophisticated approach may be justified.

It will be important to understand not only how valuable distribution services are on the margin, but also how “deep” the market is for those services. Today, for instance, the market for frequency regulation from storage in PJM is lucrative but relatively small (an average of 663 MW relative to a system peak of more than 140,000 MW in 2014).⁶⁷ Will demand for distribution services grow in the future? Understanding the magnitude of the market for these distribution services is a critical part of the development of the “business case” for the new pricing model.

A key step in understanding the magnitude of the potential benefits of new distribution pricing models is to develop a detailed assessment of future distribution system needs, along the lines of studies that have been developed by utilities in California⁶⁸ and are under development in New York. These plans should account for a robust range of possible future scenarios of DER adoption in their assessment of distribution system needs. Estimating the need for and cost of distribution services through a forward-looking assessment will provide a sense not only of investment needs under “business-as-usual” conditions but will importantly also help to identify the range of possibilities, given substantial uncertainty in how DERs will evolve, among other uncertainties in distribution system planning.

Customer considerations will also be important when making the transition. If the new pricing model will affect customer bills, care will need to be taken to ensure that customers are gradually exposed to the new price signals. This will allow time for education about the new pricing model and will avoid sudden, unexpected bill changes. Several tools are available to facilitate this type of transition.⁶⁹ Figure 6 summarizes possible elements of a transition plan, though it is important to recognize that the applicability of these options will vary from one

⁶⁷ Monitoring Analytics, LLC (2015).

⁶⁸ See “Distribution Resources Plan (R.14-08-013),” CPUC, <http://www.cpuc.ca.gov/General.aspx?id=5071>.

⁶⁹ Faruqui and Hledik (2009).



state to the next depending on the objectives of the local regulators, utilities and their stakeholders.

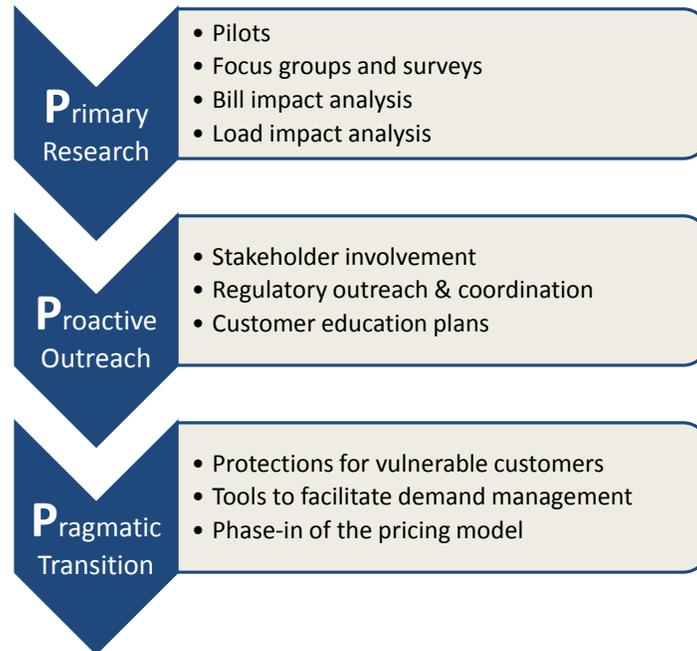


Figure 6. Possible Elements of a Plan for Transitioning to a New Pricing Model
The figure identifies activities that could be elements of a transition to a new pricing model. Possible activities include primary research, customer outreach and education, and the provision of tools, protections, or other methods to phase-in the new pricing model. The appropriate path forward will vary by utility. It will be important to strike the balance of a deliberate transition without unnecessarily delaying the move to improved pricing models.

Ultimately, with deliberate incremental improvements to the distribution pricing model, DERs can be integrated into the system in a way that cost-effectively maximizes the value they can provide while being fair to customers and maintaining a reliable power grid.



B. Utility Customer Perspectives on the Distribution Pricing Models by Jim Lazar

From a consumer perspective, the author suggests the following principles guide the evaluation of whether a pricing mechanism recognizes the role of the parties and the burden of costs:

- **Principle 1:** A party that is in control of a DER function should bear the economic consequences of exercising that control; correspondingly, the party (or its agent) who bears the economic consequences of exercising control over a DER should exercise control over the DER.
- **Principle 2:** A party in control of a DER should be presented with appropriate economic opportunities and consequences so that efficient choices will be made.
- **Principle 3:** The owner of a DER should be appropriately compensated when another party exercises control of the DER for that party's own or another's benefit.

Residential and small commercial utility customers, especially those who use modest amounts of energy, will typically have a simplified view of electric service. They want it available at all times, at a reasonable cost. For the most part they have no awareness of the potential ancillary services their refrigerators, water heaters or PV systems might provide to the system. Nor do they have much inclination to actively manage their energy use beyond relatively simple TOU or critical peak pricing that guides major energy usage choices, like when they do laundry and at what temperature they set a programmable thermostat. Certainly, they would like to reduce their electric bill, but they usually will address this desire through “easy” options like turning off the lights when leaving a room, installing efficient lighting, adding weather stripping and insulation, or acquiring smart appliances (likely with utility incentives).

Typical consumers will approach the four pricing options with some combination of apathy and bewilderment. The Granular Rate option will not be pragmatic for small consumers. The more sophisticated the pricing design, the less likely these consumers will be able to understand and respond effectively.

Many goods and services that consumers use have cost structures that are at least as complex as that for the electric power sector. A new automobile may cost \$20,000, but benefit from \$200 million of engineering development by a \$150 billion/year company. No “cost of service” study is available for review by an auto purchaser telling the consumer whether the price offered by a dealer meets the “fair, just and reasonable” standard imposed by most state public service laws on electric distribution companies.⁷⁰ Conversely, there is no “Consumer Reports” to consult on one’s electric utility, telling you whether the “value” provided is justified by the price charged. Cost is an input to the utility cost calculus, not a driver of value from the customer perspective.

Similarly, consumers purchase gasoline, groceries and other essentials at market prices from a supply network with an extremely complex cost structure. In most cases, that supply network boils down the complex cost structure to relatively simple and understandable pricing.

⁷⁰ For example, Revised Code of Washington 80.28.022 requires the Commission to “fix just, reasonable, and compensatory rates.”



Consumers need the same from the electricity sector in order to make rational decisions with a reasonable effort. The critical role of the utility regulator is to ensure that complex costs are reflected with reasonable accuracy in relatively simple prices.

The four approaches presented in Section III do not all lend themselves to application for individual consumers, absent other innovations such as significant automation of end uses and DER controls. The potential applicability of the four approaches from a consumer's perspective is briefly discussed immediately below. Then, example pricing approaches for specific DERs are presented and examined in the context of these approaches.

Granular Rate: It is not pragmatic for an individual residential or small business consumer to attempt to understand a retail rate that separately prices such components of distribution service as voltage support, frequency regulation, on-peak capacity, off-peak capacity or reserves. Only a very large user with a dedicated energy manager is likely to understand these terms or the metrics to which they apply. Evidence is clear that consumers do not spend much time analyzing their electricity costs and often do not actually know the rate design under which they are served.⁷¹ The discussion of demand charges is particularly applicable here. Experience shows that small-use customers are unlikely to understand or be able to constructively respond to demand charges.

Buy/Sell Arrangement: A Buy/Sell arrangement may meet the need for customer understandability and customer ability to evaluate the economics of available alternatives. For example, if the utility agrees to buy all of the capability of a PV system (and take over the real-time system management), the consumer can compare this payment to the cost of ownership and make a reasoned decision whether to invest.

Procurement Model: The Procurement Model may be an energy service company aggregating the total DER-enabled service capabilities of multiple customers, an appliance manufacturer or dealer aggregating the capability of multiple smart appliances in disparate homes, or a municipality aggregating not only electricity service but also water, wastewater, and other household usage to minimize the total cost of overall utility service to the consumer. Because this approach shields the customer from the confusing detail of the underlying cost and pricing structure, it may meet the consumer's need for simplicity. And, because the aggregator is dealing with large amounts of controllable load and resources, that same complexity provides an opportunity for creative marketing and operational approaches to extract value from those loads and resources that an individual DER owner might not be able to realize.

DER-Specific Rates: A DER-specific rate charges a different price for electricity service to each customer, depending on the type of DERs they have and the services those DERs require and can provide to the utility system. This avoids the need for an a la carte Granular Rate, rolling services together into a single price for power delivered and power received. Consumers invest in DERs and desire a financial return. However, many also invest to achieve some measure of energy independence or to use their preferred sources of energy. Each of these drivers forces the

⁷¹ Evidence before the California PUC in 2014 in Docket 12-16-013 indicated that only a minority of consumers understood that they were served on an inclining block rate design, even though California was famous within the industry for having a far higher rate for each incremental block of electricity consumption.



regulator to address some fundamental principles in designing rates that are fair, just and reasonable.

As discussed earlier in this report, the roles of the utility and of the consumer are changing. An optimal balance of costs, services and pricing may be difficult to achieve, but the options now available create a much more complex potential relationship between the innovative consumer installing DERs, the passive consumer desiring economical and reliable utility service, and the utility trying to adapt to a changing environment.

1. Granular Rate

Table 11 is an example of a Granular Rate. The customer would face separate charges for individual distribution capacity and distribution services and would pay only for those used.

Table 11. Illustrative Granular Rate

	Systemwide Average Rate [A]	Locational Rate Adjustment [B]	Total Rate [C]=[A]+[B]	Amount Used [D]	Total Charge [C] x [D]
Capacity Need for Consumption					
System Peak Charge (\$/kWh)	\$0.0108	\$0.0100	\$0.0208	300	\$6.24
System Off-Peak (\$/kWh)	\$0.0020	\$0.00	\$0.0020	700	\$1.40
Class Peak Charge (\$/kWh)	\$0.0064	\$0.01	\$0.0164	400	\$6.56
Class Off-Peak Charge (\$/kWh)	\$0.0010	\$0.00	\$0.0010	600	\$0.60
Grid Connection Charge (\$/kWh)	\$0.0050	\$0.00	\$0.0050	1,000	\$5.00
Capacity Need for Net Excess Generation					
System Peak Charge (\$/kW)	\$0.00	\$0.00	\$0.00	0	0
Local Distributed Generation Coincident Peak Export Charge (\$/kW)	\$0.00	\$1.50	\$1.50	0	0
Power Quality and Reliability					
Frequency Control (\$/kWh)	\$0.0005	\$0.00	\$0.0005	1,000	\$0.50
Voltage Support (\$/kWh)	\$0.0003	\$0.00	\$0.0003	1,000	\$0.30
Power Factor Control (\$/kWh)	\$0.0010	\$0.00	\$0.0010	1,000	\$1.00
Other Power Quality Services (\$/kWh)	\$0.0002	\$0.00	\$0.0002	1,000	\$0.20
Other Services					
Maintenance (\$/kWh)	\$0.0005	N/A	\$0.0005	950	\$4.75
Metering and Billing (\$/Month)	\$5.00	N/A	\$5.00	1	\$5.00
Other Administrative (\$/Month)	\$1.00	N/A	\$1.00	1	\$1.00
Taxes and Fees					
Sales Tax (%)	3.0%				\$0.98
Total					\$33.53



DEMAND CHARGES: AN OBSOLETE CONCEPT

Electricity tariffs for large-volume commercial and industrial customers have contained demand charges for decades. These recover a portion of system capacity costs based on the customer’s highest (one hour or less) usage during the billing period. Some analysts have called for this approach to pricing to be extended to residential consumers. This is an unfortunate trend that fails to take advantage of the more detailed data now available from smart meters and the associated meter data management systems.

Demand charges were always a second-best proxy for the customer’s fair apportionment of system capacity costs. In the past, the only way to collect hourly data was with chart recorders and tedious transcription. And demand charges were deployed when system costs were not as time-variant as they are today, with baseload power plants meeting some needs, lower-cost peaking units meeting other needs, and inexpensive demand response and storage available for short-duration demands.

Citing NARUC standards adopted in the 1950s, Garfield and Lovejoy told us a half-century ago that some part of capacity costs should be assigned to every hour of the year, so that all customers using capacity make some contribution toward capacity cost, with a concentration of these charges during high-load periods. The data we have today allow a much better hourly matching of varying costs to varying demands.

The only components of an electric distribution system designed with consideration of the demands of individual customers are the final line transformer and any secondary lines between the transformer and the customer premises. The rest of the system is designed based on group demands on a circuit, area demands on a substation, and collective demand at the transmission level.

Pricing of shared distribution system capacity based on individual customer demands simply serves to shift costs to apartment dwellers and others whose diversity of usage is better accounted for at the system level than at the meter level. Smart meter data allow us to move beyond simple monthly demand-based pricing to hourly-based pricing to recover all shared system costs. Rather than measure only the single highest hour of usage, we can measure every hour of usage. Demand charges treat the customer using capacity for only a few hours (such as the high school stadium) exactly the same as a customer using relatively the same level of capacity at all hours (such as the 24-hour mini-mart). Hourly pricing — incorporating capacity costs at some level in the energy price for each hour — is much more granular and precise in recovering these costs than monthly demand charges.

With hourly data on customer usage, capacity costs can now be accurately assigned to every hour and recovered from each customer according to their usage. Table 12 shows how time-varying prices can meet all of the principles of equitable cost allocation set forth by Garfield and Lovejoy, while demand charges fall short of this concept of equity. The table compares the extent to which coincident peak demand charges, non-coincident peak demand charges, or time-varying energy charges best reflect appropriate recovery of capacity costs, according to the framework identified by Garfield and Lovejoy.

Table 12. Application of Garfield and Lovejoy Criteria to Demand Charges

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time the customer preempts (uses) the capacity, the more the customer should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant costs.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Users of interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

Source: Garfield and Lovejoy (1964), 163–164.

CP - Coincident Peak; NCP - non-coincident peak; TOU - time-of-use. Y indicates that the rate option meets the criterion; N indicates that the rate design does not meet the criterion.



Individual residential and small commercial consumers will not be prepared to respond to a granular retail rate that separately prices the services that a solar PV customer needs or can provide, that a grid-integrated water heater (GIWH) can provide, or that a small battery storage system can provide.

Under the Granular Pricing approach, the customer would pay separately for each of the distribution services received and credited for each service the customer provides. Because the discrete distribution services provided each have a very small value, it is impractical for an individual consumer to act based on Granular Pricing. From a consumer perspective, this is not a viable option without significant automation of the controls. Customers would enter their criteria for receiving or providing distribution services, and the control system would manage their consumption, production, storage and reliability.

It is likely that some customers would choose a lower level of reliability than the grid default under this technology-assisted framework. Others would use on-site resources and load controls to exact a higher level of reliability. In both cases, technology enhancements would be the key to effective consumer response.

The underlying granular costs that would be used for this pricing approach may be very important for setting compensation for other pricing models, including Buy/Sell Aggregator and DER-Specific Rates.

For small consumers, Granular Pricing will not be pragmatic. It will be attractive to aggregators (including distribution system operators offering GIWH aggregation service), but impossible for individual consumers to respond to. An aggregator, operating hundreds or thousands of GIWH units, can respond to Granular Pricing in operating the aggregated resource. But the aggregator will need to develop a simpler reward structure for the consumer.

2. Buy/Sell Arrangement

In Section III, we present an illustrative distribution rate design for a Buy/Sell Arrangement. This rate provides only the distribution charges, which is an incomplete picture of the values that DERs bring to the utility system. The majority of the values are reflected on the power supply side of the equation (see Table 13). As discussed later, it is crucial to consider all of the benefits when evaluating DERs.



Table 13. Buy/Sell Arrangement: Charges and Payments

Distribution System Use Charges			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.03	1,000	\$30.00
Customer charge (\$/month)	\$10.00	--	\$10.00
		Total Charges	\$40.00
Location-Specific Distribution Services Payments			
			Credit
Capacity services (\$/month)			(\$3.00)
Power quality services (\$/month)			(\$2.00)
		Total Credits	(\$5.00)
Total Bill			\$35.00

The Austin Energy Value of Solar Tariff (VOST) is an example of a Buy/Sell Arrangement reflecting all of the benefits of DERs (see Table 14). Historically, such arrangements have had the simple format of a retail rate paid by the customer for all power consumed and a fixed or contract price paid for all generation delivered to the grid. The Value of Solar concept reflects long-run costs, which is in keeping with economic pricing principles.

In the Austin VOST, customers can easily see that if their electricity usage stays in the lower blocks, they receive more for power delivered than they pay for power received. The state of Minnesota also has allowed a VOST as an alternative to net metering for customer solar installations.

Table 14. Austin Energy Residential Rate and Value of Solar Tariff

Rate Component	Summer	Winter
Customer Charge	\$10.00	\$10.00
Usage Charges		
0-500 kWh	\$0.09	\$0.07
501-1,000 kWh	\$0.13	\$0.07
1,001-1,500 kWh	\$0.15	\$0.13
1,501-2,500 kWh	\$0.16	\$0.14
Value of Solar Credit	-\$0.11	-\$0.11

Source: Austin Energy, Dec. 2, 2015, including major rate components and riders, rounded to the nearest cent.



Advantages

A retail Buy/Sell arrangement provides the customer a **cost**-based retail rate, equal to that offered to other customers, and the utility a **value**-based wholesale purchase price. Because the power delivered to the customer is a non-differentiated product, including historical resources, which includes all grid services, and the power delivered to the utility is a specific type of new resource valued at long-run marginal cost, these prices may be very different.

It is essential that the Value of Solar tariff recognize the “new” and the “renewable” characteristics of the power being purchased by the utility, as well as the seasonal and time-varying nature of the production.

Current Value of Solar or other existing solar compensation models in the United States do not identify discrete services that a smart inverter can provide.⁷² These capabilities could be recognized in a Buy/Sell Value of Solar tariff by either an increment to the fixed monthly credit to the customer or an increment to the per-kWh credit to the customer.

Figure 7 and Figure 8 show how the Value-of-Solar rate may — by happenstance — equal the retail utility price. Each measures different values in different ways.



Figure 7. Comparison of Utility PV Value and Average Cost

⁷² The state of Hawaii recently modified its interconnection policy to mandate inverters with certain ride-through capabilities. No discrete compensation framework has yet been decided.





Source: Regulatory Assistance Project.

Figure 8. Utility Average Cost of Service.

The balance between retail rates (which reflect the utility average cost of service) and fair compensation for customer-generated power is complex. There are fundamentally different products on each side of the equation.

Disadvantages

The Buy/Sell model works well for PV and smart inverters and for batteries, where a different price may apply to power flowing from the customer to the grid depending on the basket of power system services that the installed system can provide. It does not work well for purely demand-side resources, such as GIWHs where the value comes from curtailing grid service from time to time or from accelerating grid service. It is not clear what the customer is “selling” to the distribution system operator (DSO — the distribution utility or an independent entity serving as the DSO) or power supplier in this case and how the customer is compensated for the power supply services provided to the grid operator (as opposed to the DSO).

3. Procurement Model

In the Procurement Model, the DSO would procure the services provided by DERs by making a direct payment to the consumer or by making a payment through an aggregator. For example, for a GIWH acquisition, the DSO would pay:

- A capital contribution to secure the installation — perhaps \$200 toward the purchase and installation price
- A monthly payment for each month when the unit is in service — perhaps \$10/month

These payments would be for the distribution services provided by the GIWH. Because this technology can also provide storage services for power supply, the customer or aggregator



might also enter into a separate or combined contract to provide diurnal or dynamic control of the load for power supply system benefits.

Under the Procurement Model, a solar installer, a vendor of premium inverters, a GIWH marketer, or a battery storage company could sell the combined flexibility provided by hundreds or thousands of such systems to the utility. Rather than a simple three-tier pricing model, as above for the Buy/Sell Arrangement for smart inverters, the vendor could provide a customized product to the distribution utility and a separate customized product to the supply system operator or control area, based on the individual services that each sought to acquire and granular cost data.

The ultimate consumer would receive payment from the DSO or aggregator — a one-time payment, periodic payments or both.

Advantages

The principal advantage of the Procurement Model is that vendors can respond constructively to system pricing incentives, and use marketing tools to attract consumers to install the DERs that provide the most value. The customer can be in a no-lose situation, getting offsetting value for installation of equipment that may have no incremental cost (if the vendor applies the prospective benefits to offset the acquisition cost) and ongoing bill savings.

Disadvantages

The most obvious disadvantage of the Procurement Model is that consumers will likely receive only a fraction of the economic benefits that their DERs provide, with aggregators extracting substantial portions of the value. This will be a challenge for aggregators. If they can save customers \$2 per month, will customers care? This can lead to very high saturation rates of desirable DERs, but with the bulk of the value going to the marketers, not to the consumers.

4. DER-Specific Rates

A DER-Specific Rates approach would charge customers a different rate based on the type of DERs they have installed. The customer would see a simple rate design that provides incentives to choose the equipment package with the best economics for their situation.

Table 15 shows an example of DER-Specific Rates. This rate design, for residential service where a GIWH is installed, provides a specific rate credit depending on the level of service provided by the customer.



Table 15. Illustrative GIWH-Specific Residential Rate

Standard Residential Rate			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.03	1,000	\$30.00
Customer charge (fixed \$/month)	\$10.00	—	\$10.00
		Total Bill:	\$40.00
Rate for Customers With Uncontrolled Electric Water Heating			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.04	1,000	\$40.00
Customer charge (fixed \$/month)	\$10.00	—	\$10.00
		Total Bill:	\$50.00
Rates for Customers With Controlled Electric Water Heating			
	Price	Amount Used	Total Charge
Volumetric charge (\$/kWh)	\$0.025	1,000	\$25.00
Customer charge (fixed \$/month)	\$10.00	—	\$10.00
		Total Bill:	\$35.00

This rate allows the customer to use all power at the standard residential rate, with a higher rate for service that includes uncontrolled water heating, and a discount for power if the customer installs a GIWH. The customer could override the GIWH controls, providing unrestricted operation of the water heater for a daily fee, which is approximately three times the normal charge for GIWH service (based on 10 kWh/day of typical usage).

Table 16 shows an actual DER-Specific Rate, applied by an electric cooperative in Minnesota, with lower prices for off-peak and interruptible end uses.

Table 16. Lake Country Electric Cooperative’s “Energy Wise” Rate

Rate Component	Rate
Summer Energy Price (June–August)	\$.1198/kWh
Winter Energy Price (December–February)	\$.1098/kWh
Shoulder Energy Price (Other Months)	\$.0998/kWh
Off-Peak Space Heating; Off-Peak Water Heating	\$.0465/kWh
8-Hour Interruptible Water Heating; Cycled Air-Conditioning	\$.058/kWh

Source: Lake Country Power: Rates and Rebates.

<http://www.lakecountrypower.coop/viewpage.php?pagename=ratesandrebates>

This utility offers a discounted rate for off-peak space heating and water heating and controlled water heating and air-conditioning. Because these controlled uses are concentrated in very low-cost periods, the price is even lower than the shoulder energy price that applies to other uses; this is, in effect, a super off-peak price within a two-period pricing scheme.

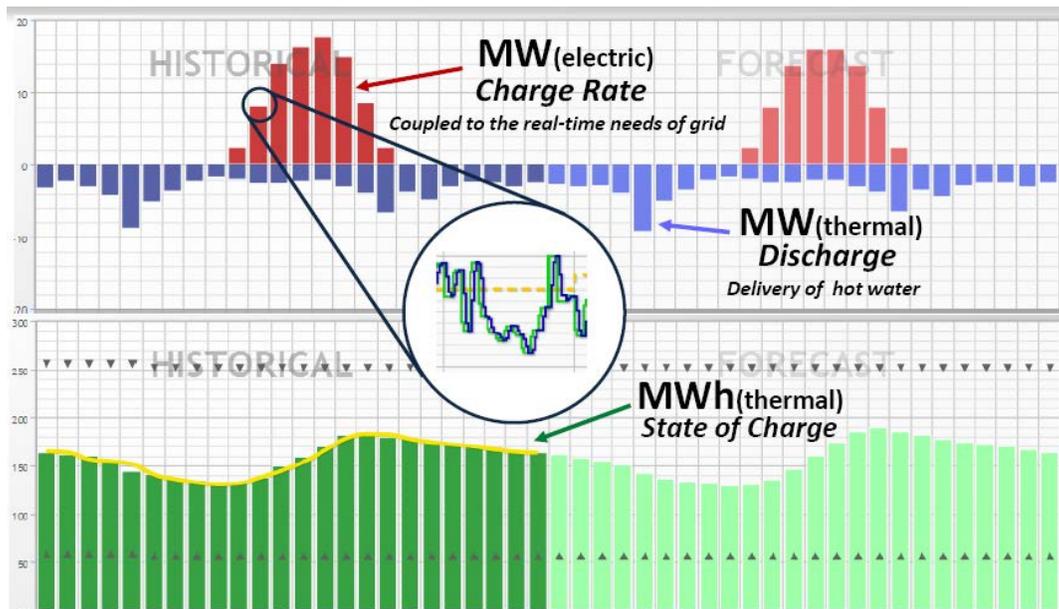


Where installed, electric resistance water heaters use an average of about 8 kWh/day to 15 kWh/day, depending on the household. They are a major component of residential consumption.

Modern GIWH technology can provide flexibility to the distribution system and the electric supply system in several ways:

- **Diurnal Time-shifting:** Heating water when power is cheap and curtailing use when power is more valuable can enable the customer to take advantage of lower electricity prices during periods of lower demand.
- **Grid Relief:** The distribution grid operator can curtail load during periods when the distribution system is strained, independent of wholesale market prices for power.
- **Active Control:** By keeping some water heaters charging at all times, and some not charging at all times, a control area operator or aggregator can provide ancillary services including frequency regulation, voltage support and spinning reserves.

Figure 9 shows the hypothetical operation of these different controls across a 48-hour period for a GIWH network. This particular system, modeled by Steffes Corporation, is set to charge during the hours of the day when solar PV production is available, and to provide active ancillary service support at all hours when charging is occurring.



Source: Steffes Corp.

Figure 9. Hypothetical Operation of GIWH for Diurnal and Real-Time Load Control
 The blue bars represent hot water consumption; red bars reflect charging of the water heater during select hours (either daytime for solar or nighttime for off-peak energy); green bars reflect the overall amount of storage. The inset shows the water heater charging load controlled from second to second to provide ancillary services.



Because these benefits are spread between the distribution system operator and the power supply system, coordination is critical in designing appropriate pricing.

Pragmatically, the energy storage function of GIWH is reasonably well-compensated with a time-varying power supply rate. If a critical-peak pricing element is incorporated, the water heater must be actively controlled by a party aware of this dynamic rate.

Advantages

Under DER-Specific Rates, the customer can see very clear savings from their choice of GIWH, compared with the standard rate. In the illustrative distribution rate design in Table 15, only the distribution system benefits (not the power supply benefits) are reflected; in the Lake Country Coop rate design in Table 16 both power supply and distribution system benefits are incorporated.

Disadvantages

This approach does not easily lend itself to the select services that customers could choose under a more granular approach to pricing. All of the grid benefits of GIWHs and all of the power supply benefits of GIWHs are built into a single pricing scheme, designed to be understandable and attractive to the consumer. But a heat-pump water heater, for example, is not equally able to provide ancillary services in the way an electric resistance water heater can, even though it can provide diurnal savings. The complexity of having separate rates for specific types of DERs, even within a given technology category, may defeat the objective.

5. Additional Considerations

a) Bill Simplification

Today's electricity bills have become more of an accountant's scorecard than a consumer information medium. The explosion of surcharges, adjustment clauses, and taxes that are itemized on customer bills make them all but impossible for consumers to understand. Bill designers have not tended to translate all this information into clear bottom-line unit prices.

In order for DERs to deliver usable benefits to customers, they will need to do so in a simple and automatic way. Customers will likely be drawn to third-party aggregators or appliance manufacturers who offer some kind of simple upfront credit and ongoing, monthly credits while taking on the actual dispatch or configuration of the DER and handling the interface with the DSO (utility or independent DSO) and power supplier. Alternatively, utilities that integrate DER services into their tariff structures in a seamless way may also see higher customer participation in demand response and ancillary services.

Unbundling services and itemizing them on customers' bills are unlikely to be of much benefit to customers and may actually be counterproductive. As the bills become more detailed, customers are likely to understand them less and more likely to largely ignore them. Anyone who has tried to decipher the detail in a cellular telephone bill is familiar with the problem. In short, for DERs to be successful in the ancillary services market at the small customer level, customer bills must be easy to understand.



Regulators need to work on simplifying bills by incorporating tariff riders, taxes, and other adjustments into an effective price per unit of consumption that customers can respond to. The illustrative example in Table 17 shows a residential rate with five adjustment clauses and two taxes as it would appear to a customer today and, below that, the effective rate that these prices, adjustments and taxes actually produce so that customers see the effective rate somewhere in the bill.

Table 17. Illustrative Itemized Rates Versus Simplified Rates

Example of an electric bill that lists all adjustments to a customer's bill			
Your Usage 1,266 kWh			
Base Rate	Rate	Usage	Amount
Customer Charge	\$5.00	1	\$5.00
First 500 kWh	\$0.05000	500	\$25.00
Next 500 kWh	\$0.10000	500	\$50.00
Over 1,000 kWh	\$0.15000	266	\$39.90
Fuel Adjustment Charge	\$0.01230	1,266	\$15.57
Infrastructure Tracker	\$0.00234	1,266	\$2.96
Decoupling Adjustment	\$(0.00057)	1,266	\$(0.72)
Conservation Program Charge	\$0.00123	1,266	\$1.56
Nuclear Decommissioning	\$0.00037	1,266	\$0.47
Subtotal			\$139.74
State Tax	5%		\$6.99
City Tax	6%		\$8.80
Total Due			\$155.53
The above rates, with all of the surcharges, credits and taxes applied to each of the usage-related components of the rate design			
Base Rate	Rate	Usage	Amount
Customer Charge	\$5.565	1	\$5.56
First 500 kWh	\$0.07309	500	\$36.55
Next 500 kWh	\$0.12874	500	\$64.37
Over 1,000 kWh	\$0.18439	266	\$49.05
Total Due			\$155.53

Source: Shirley, Weston and Lazar (2011).

b) Broader Public Interests

There are a number of public interests that overlay all of these issues, including consumer protection, public safety, system reliability, economic impact, environmental protection, public health and climate change. The first four of these are within the traditional bounds of utility regulators. Others are primarily within the realm of other agencies.



Nonetheless, it is useful to regulators to specify the policy context when considering how to deal with the myriad potential functions of DERs. This is especially critical when assessing the responsibilities of utilities to adapt the electric system to both new technologies and new policy objectives.

The broad public interest encompasses the short- and long-run perspective of the electricity consumer and of others affected by electricity consumption. The benefits may be broadly categorized as utility system benefits (which accrue to all electricity consumers), participant benefits (for the individual consumer) and societal benefits (which go beyond the service scope of the affected electric utility).⁷³

With respect to DERs, there are similar utility, participant and societal benefits. In the simple case of a rooftop solar PV system:

- The distribution system derives the energy, capacity and other grid services that a PV system with a smart inverter can provide.
- All customers receiving power from the PV system at a standardized rate also enjoy fuel cost risk and fuel supply risk benefits.
- The participant derives the energy bill savings that the system provides, plus rooftop shading benefits and personal satisfaction from owning a renewable energy resource.
- Society derives environmental benefits.
- Demand reduction-induced price effects⁷⁴ accrue to all system customers.
- Macroeconomic benefits, such as increased domestic employment or balance of payments benefits, accrue to the entire region or beyond.

These benefits are not all reflected in the utility's revenue requirement, cost of service, or pricing framework. Almost any attempt to quantify these benefits will fall far short of consideration of the entire universe of impacts. The broader public interests also include the risk of anti-competitive behavior (see text box) and possible operational constraints created by current DER policies.

⁷³ See Lazar and Colburn (2013). The concepts applied to energy efficiency measures are largely transferrable to other DERs.

⁷⁴ Demand Response Induced Price Effects (DRIPE) are changes in overall price levels for commodities resulting from management of small levels of demand for those quantities over a time period. See Chernick and Neme (2015).



POTENTIAL FOR ANTI-COMPETITIVE BEHAVIOR

Utility management may be tempted to raise engineering and operational barriers as a way to address financial concerns and thus, veer into the realm of anti-competitive activity. This is becoming increasingly difficult to do as operational experience has grown and the DER industry has matured. Even so, utility commissions and their staff may lack the engineering and technical expertise to address system operational issues and are likely to err on the side of caution, deferring to the utility's expertise to avoid potential grid failures and the political fallout they might generate.

Many utilities will be tempted to take a defensive posture to protect the existing system from the impacts of DERs, but this will likely prove futile in the long run.¹ The better approach is to envision the reformulated system that is likely to result and navigate the least-cost path to get there.

In addition, there are myriad issues, generally couched in reliability concerns, the utility can raise if it is so inclined, which are hidden in the black box of system operations. Sunshine is often the best antiseptic for this problem. Experience has shown that a public stakeholder forum to address such issues is especially useful in resolving them.

The types of DERs and, in particular, the control systems and inverters associated with DERs, are rapidly evolving. Newer technologies may enable DERs to provide additional services not now available. An example is the emerging role of smart inverters in Hawaii, where high PV saturation has created an immediate need for deployment of new technology.

6. A Vision for 2030 and Beyond

The author applies three fundamental principles for modern rate design to provide electricity service for all consumers connected to distribution systems:⁷⁵

- **Universal Service:** A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- **Time-Varying:** Customers should pay for grid services and power supply in proportion to how much they use and when they use it.
- **Fair Compensation:** Customers supplying power to the grid should be compensated fairly for the value of the power they supply. (This principle extends to all DER benefits, not just power supply.)

Other important principles related to distribution system services for DER customers include the following:

Near-Universal Participation of DERs: Substantially all DERs in a service territory should be participating in grid-support services and enrolled in compensatory programs. By 2030, the inverters on most PV systems in service today will require replacement, and smart inverters should be the obvious (or only) choice over this period.

Active Control of Multiple End-use Loads: Utilities (or independent DSOs), power suppliers, and the aggregators cooperating with them should establish dynamic controls, based on consumer-established control criteria, for major end-use loads. These should include water heating, space

⁷⁵ Lazar and Gonzalez (2015).



conditioning, water pumping, laundry equipment, electric vehicle charging, and pool and spa equipment at a minimum. At least 30 percent of total consumption should be under some form of price-driven management.

Simple Arrangements: The arrangements between utilities, aggregators, power suppliers and consumers to enable active controls should be simple enough for consumers to understand and sufficiently remunerative to enable a high level of participation.

7. Making the Transition

If insufficient attention is given to the needs of consumers, programs to expand the use of DERs will likely come up short, and the potential economic, environmental and societal benefits will be forfeited. To succeed, the industry must ensure innovation with compensatory programs, entice consumers with attractive programs, and protect system reliability at acceptable minimum levels. This transition is not a place for timidity, but neither is it a place for carelessness.

To succeed, regulators, utilities and other stakeholders should:

- a. **Keep it simple.** The consumer interface of any approach must be one that a consumer can understand in seconds, not minutes or hours, and should provide support for customer choices, including standards for disclosure, customer service quality and dispute resolution. The procurement options that lend themselves to simplicity vary by type of resource, and several depend on a well-developed scheme of aggregators. There must be a role for mass-market players — large retailers — in any aggregator scheme.
- b. **Incorporate power supply benefits.** Many DER benefits accrue on the power supply side of the utility service ledger, not only on the distribution side, the focus of this report. Where the distribution utility is also the power supplier, providing aggregation through a regulated, vertically integrated utility can help assure that power supply benefits of DERs are part of the value proposition for consumers. In restructured regions, regulators will need to ensure that aggregators pursuing DER benefits accurately convey both the distribution system and power supply benefits to consumers in a manner that is both understandable and compensatory. While this report discusses distribution system benefits, the potential power supply benefits associated with DERs likely have an even greater magnitude. The proper compensation framework for these is beyond the scope of this report.
- c. **Build a Value Proposition That Works.** Incorporating DERs into an existing power supply and distribution system invariably involves some complexity that will damage the chances of success. A key is to develop value propositions for both consumers and the utility system that provide clear value to both. This report addresses some key technologies that have this potential. But unless all costs and all benefits are effectively compiled, it is unknowable if the total value proposition is positive. We can learn from the experience with energy efficiency that sometimes resources (e.g., insulation and replacement windows) must be bundled together to provide a value proposition that meets overall economic, reliability and psychological metrics for consumers. We also can draw examples from smart grid deployment, which requires not only smart meters and data management, but also bundling of DERs



together with line loss reduction and system reliability benefits to provide an overall value proposition that is acceptable.

- d. **Address Non-Energy Benefits in Valuation Mechanisms.** Many DERs have extensive non-energy benefits (NEBs), including participant and societal benefits.⁷⁶ Some of these accrue to consumers, some to communities and some to the planet. While the pricing of services to and from the distribution utility should not incorporate NEBs that accrue outside the power system, consumers can use the NEB valuations in making their own judgments as to whether to embrace DERs.
- e. **Expect Some Measures to Be Unviable or Uneconomic.** This transition will require creativity, nimbleness and testing unproven technologies. Regulators and utilities must embrace the risk of failure that accompanies exploration into new spaces. Regulators learned that some level of R&D budget was necessary for effective expansion of energy efficiency programs. Experience with energy efficiency programs has shown that while some measures and some methods of procurement have not been cost-effective, overall these programs have been highly beneficial to consumers. Cost-effective DER deployment may be likely to have similar results, with some things not working out optimally, but with significant net benefits overall. Some efforts to incorporate and compensate DERs will prove to be not cost-effective, and some measures will not work as well in practice as the engineering studies that precede deployment. A reasonable level of failure must be acceptable. The perfect must not be the enemy of the good. Incentives must be based on a solid risk-return framework.⁷⁷
- f. **Protect Vulnerable Customers.** Care should be taken to protect vulnerable customers who may lack the resources or access to information to take advantage of the benefits of DER ownership. The good news for most customers with respect to DERs should not become bad news for those least able to manage this transition.

⁷⁶ For a deeper discussion of non-energy benefits, see Lazar and Colburn (2013).

⁷⁷ See Kihm, Lehr, Aggarwal and Burgess (2015).



VII. Conclusions and Recommendations

The rapidly changing market for DERs — and the needs of utilities, consumers and the industry producing equipment for the DER market — demand that careful attention be given to pricing issues. Utility regulators are faced with yet another task that expands their scope of inquiry and influence.

The best approaches cannot be predicted with certainty. Carefully designed pilot programs and adequately funded evaluation efforts will be needed to ascertain which approaches meet the needs of all participants.

These pilot efforts fall into several broad categories:

- **Gather stakeholder input.** Regulators may need to convene generic dockets or rulemaking proceedings in order to invite input and comment from all affected parties. No one can predict all of the relevant issues for every DER technology, and those technologies are changing rapidly. The timing of these proceedings will depend on the ripeness of issues in each jurisdiction, with those jurisdictions experiencing rapid deployment of DERs needing to move quickly.
- **Conduct market research.** Market research will be needed to assess customer understanding and acceptance of the pricing models. Identifying educational messages that resonate with customers will inform the design of the models and maximize customer acceptance. Market research will also inform what services consumers are willing to provide, what alternatives they are willing to consider in system design and operation, and what essential values they are unwilling to compromise. Evaluating existing complex rate designs for the level of customer understanding will provide some guidance. Working with manufacturers and vendors of DERs that are now marketing their products will provide insights into what messages resonate with consumers, and what values they ascribe to DERs that they are now acquiring.
- **Quantify the cost and value of distribution services that would occur in an environment of high DER adoption.** Distribution costs and savings will vary by utility. They can represent a large share of the customer's bill in some jurisdictions and a lower share in other jurisdictions. There is also the question of how much of the distribution cost can be avoided through provision of distribution services by DERs and how this compares to other sources of value, such as the avoidance of generation capacity and fuel costs. Quantitative analysis of the magnitude of the opportunity will help to shape future pricing initiatives.
- **Implement pricing pilots.** Location and technology-specific pricing pilots must test how customers, third-party aggregators and equipment suppliers respond to the new pricing models. Effectiveness of the models in facilitating meaningful load reductions can be demonstrated through pricing pilots. Such pilots also will allow the models to be tested and refined in a controlled setting with a limited number of customers before they are considered for deployment on a full-scale basis. It may be desirable to implement these pilots in a broader geographic area than a single utility or regulatory boundary, because in addition to distribution system impacts, many DERs provide benefits best measured at a regional level — at the independent system operator/regional transmission



operator level or multi-utility control area. Such pilots would need to be coordinated between one or more state regulators and the regional market operator.

- **Assess power supply impacts.** Pilots can examine the interaction of DER impacts on the power supply system with DER impacts on the distribution system — for example, changes to peak load, system dispatch and air emissions. This report addresses only distribution system pricing issues, not the potentially much larger impacts of DERs on bulk power supply markets.
- **Determine if certain broad categories of distribution services or ancillary services can be most economically provided through the use of DERs.** Studies can be undertaken to measure the economic savings and environmental impacts associated with a shift from traditional infrastructure to DERs providing certain distribution system and ancillary services. In particular, this report highlights certain ancillary services that may be provided at lower cost with DERs than with conventional supply options. This is another area where the impacts of DERs go far beyond the distribution system services addressed by this report.

Pragmatically, there is a role for federal coordination or national scope for at least a portion of this broad research agenda, so that redundant experimentation is avoided and research gaps are not inadvertently created. Some geographic areas, where DER deployment is already rapid, may be the best locations for an initial research agenda to proceed. Hawaii and California, with high levels of deployment of distributed PV, are two obvious examples.

Regions with little DER deployment also provide useful laboratories for testing ideas that have not yet germinated in the marketplace but provide significant promise. For instance, the Southeastern states, with the highest penetration of electric water heaters in the nation and a large air-conditioning load, may be an ideal laboratory for testing the services that GIWH and storage can provide to the grid. The Pacific Northwest, also with a high penetration of electric water heaters, a consumer base with a long history of energy awareness, and growing renewable energy integration needs, could also be an attractive market for this type of research. Ultimately, it will be important to tailor the pilots to regional needs and resources.

For each pilot we recommend that an evaluation oversight panel be comprised of technical experts, utilities, consumer advocates, environmental specialists and regulators. With all of these perspectives represented, the risk of designing an approach that “won’t work” or “won’t fly” will be minimized.

DERs are being deployed at a rapidly growing rate. The value of the services that DERs offer and the additional costs that they may introduce are not fully reflected in existing pricing models. The pricing of services to and from DERs will dictate the economics of future deployment. Now is the time to begin the transition to improved pricing models. Well-designed research and policy development will ensure that the industry is able to fully capture these new opportunities.



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Appendix A. Glossary

Adjustment Clause

A rate adjustment mechanism implemented on a recurring and ongoing basis to recover changes in expenses or capital expenditures which occur between rate cases. The most common adjustment clause is the fuel and purchased power adjustment clause which tracks changes in fuel costs and costs of purchased power. Some utilities have weather normalization adjustment clauses which correct for abnormal weather conditions.

Advanced Metering Infrastructure (AMI)

The combination of smart meters, two-way communication systems, system control and data acquisition systems and meter data management systems which together allow for metering of customer energy usage with high temporal granularity, the communication of that information back to the utility and, optionally, to the customer with the potential for end-use control in response to real-time cost variations and system reliability conditions.

Aggregation

Bundling of multiple customers or loads to achieve economies of scale in energy markets. Aggregation also takes advantage of the diversity of loads among customers and enables price risk management services to be offered to those customers.

Aggregator

A company that offers aggregation services and products.

Alternating Current (AC)

Electrical current that reverses its flow periodically. Electric utilities generate and distribute AC electricity to residential and business consumers.

Ancillary Services

One of a set of services offered in and demanded by system operators, utilities and, in some cases, customers, which generally address system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services “necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.”

Appliance

Any device that consumes electricity. Appliances includes lights, motors, water heaters, electronics, and typical household devices such as washers, dryers, dishwashers, computers and televisions.

Average Cost

The revenue requirement of the utility divided by the quantity of utility service associated with that revenue requirement, expressed as a cost per kilowatt-hour for an electric utility.

Avoided Cost

The cost not incurred by precluding the need for an incremental unit of service. Avoided cost includes the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, compliance with environmental regulations, and line losses associated with power delivery.



Baseload Generation

Electricity generating units which are most economically run for extended hours. Typical baseload units include coal-fired and nuclear-fueled steam generators.

Blackout

The complete cessation of the delivery of electricity to some or all end-use customer loads. The most common point of failure is in the distribution system, which typically affects a relatively small subset of customers who connect “downstream” from the failure. Failures at the transmission and generation level may cause wide blackouts or even interconnection-wide failures. When an interconnection-wide failure occurs, system operators must use cold start-capable generators to bring the system back online.

Brownout

Reductions of voltage or frequency to some or all parts of the electric grid. Brownouts occur when loads exceed available generating supply by small margins. An imbalance in load and supply caused by excessive loads will cause the frequency of the system to decline as well as a decline in voltages, especially on portions of the system remote from generation. Significant increases in the imbalance of load and supply during a brownout may lead to a blackout.

Bus Bar

A bus bar is the point at which the output of a generating unit is interconnected to external equipment. A generating unit’s capacity will be expressed in terms of its potential power output at the bus bar. Any power consumed internally by the generator or in its control systems is not included in its bus bar output.

Buy/Sell Arrangement

In the Buy/Sell Arrangement, a utility customer’s transaction with the utility is bifurcated into two parts. In the first part, the “buy” transaction, the customer pays for its use of the distribution system through a simple, bundled rate that does not account for services provided by the customer (for example, through an on-site distributed energy resource). That rate structure could be consistent with the largely volumetric rate that is in place for most utilities today. In the second part, the “sell” transaction, the utility pays the customer for services provided by the customer. The payments could be in the form of bill credits or direct payments and based on a structure that looks very different than the rate that the customer pays.

Capacity

The ability to generate, transport, process or utilize power. Capacity is measured in watts, usually expressed as kilowatts or megawatts. Generators have rated capacities which describe the output of the generator at its bus bar when operated at its maximum output at a standard ambient air temperature and altitude. Transmission and distribution circuits have rated capacities which describe the maximum amount of power that can be transported across them and which vary inversely with ambient air temperature. Transformers and substations have rated capacities which describe the amount of power that can be moved through their transformation systems and switching equipment.

Capacity Factor

The ratio of total energy produced by a generator for a specified period to the maximum it could have produced if it had run at full capacity through the entire period, expressed as a percent.

Circuit

Generally refers to a wire which conducts electricity from one point to another. At the distribution level, multiple customers may be served by a single circuit from a local substation or transformer.

Combined Heat and Power

A method of producing power in conjunction with providing process heat to an industry, or space and/or water heating for buildings.



Coincident Peak Demand

The combined demand of a single customer or multiple customers at a specific point in time or circumstance, relative to the peak demand of the system, where system refers to the aggregate load of a single utility or multiple utilities in a geographic zone, interconnection or some part thereof.

Connection Charge

An amount to be paid by a customer to the utility, in a lump sum or in installments, for connecting the customer's facilities to the supplier's facilities.

Cost Allocation

Division of a utility's cost of service among its customer classes. Cost allocation is an integral part of a utility's cost of service study.

Cost of Service Study

An analysis performed in the context of a rate case which allocates a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given customer class represents the revenue required to be collected from that class through the rates to be set in the rate case.

Critical Peak Pricing

A rate design in which a limited number of hours of the year are declared by the utility, usually on a day-ahead basis, to be critical peak demand periods, or when system reliability is at risk due to generation or transmission equipment failures, and during which prices the customer pays will be very high. The typical purpose of critical peak pricing is to reduce demand during the small number of hours of the year when electricity costs are highest.

Curtailement

Reduction in customer load in response to prices or when system reliability is threatened. Price responsive curtailment is made possible through curtailment programs or competitive markets. Utilities typically have a curtailment plan which can be implemented if system reliability is threatened. Critical loads, such as hospitals, police stations and fire stations, may be given high priority and be last to be curtailed in an emergency; non-critical loads such as some industrial and commercial customers may be the first to be curtailed. Many customers enter into specific contracts specifying their protection from or willingness to be curtailed. They may also have interruptible tariffs which, in return for a price discount, allow the utility to curtail service on short notice.

Customer Charge

A fixed charge to consumers each billing period (e.g., monthly), typically to cover metering, meter reading, and billing costs that do not vary with size or usage. Also called a Basic Charge or Service Charge.

Customer Class

A collection of customers sharing common usage or interconnection characteristics. Common customer classes are residential, small commercial, large commercial, small industrial, large industrial, agriculture (primarily irrigation pumping), mining and municipal lighting (street lights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads (e.g., electric vehicle charging or solar photovoltaic generation customers may be placed in their own subclass), the capacity of their interconnection (e.g., the size the electric service panel), or the voltage at which they receive service.



Customer-sited Generation

Generation located at a customer's site. Examples of customer-sited generation include solar photovoltaic systems and combined heat and power systems, as well as backup generating units. Most customer-sited generation operates on the customer's side of the utility meter, but may be interconnected to the grid, which requires it to operate synchronously with the electric system and makes it subject to certain operational and equipment requirements. Output from customer-sited renewable energy generation is often accounted for under net energy metering tariffs.

Decoupling

A form of revenue regulation in which the utility's non-variable costs are recovered through a prescribed level of revenues, regardless of sales volume. Under traditional regulation, prices remain constant between rate cases, based on test year sales volumes, regardless of the actual sales volume experienced by the utility. As a result, actual revenues, and implicitly utility profits, rise or fall from expected levels as sales volumes increase or decrease. Decoupling fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume and maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of a fixed inflator or the number of customers served (called revenue-per-customer decoupling). Full decoupling also has the effect of weather-normalizing revenues — that is, the effects of abnormal weather are removed to assure recovery of the target revenues.

Default Rate

The applicable rate schedule if the customer does not affirmatively choose a different rate option. When new rate designs are offered or experimental rates are implemented, the utility uses an opt-in or opt-out approach for determining what rate a customer will pay. Under an opt-in approach, the default rate may be the same rate the customer would have paid before the new rate design was made available. Under an opt-out approach, the default rate is the rate associated with the new rate design. In the context of competitive markets and retail competition, the customer pays the default rate unless the customer chooses a competitive alternative.

Demand

In theory, an instantaneous measurement of the rate at which power is being consumed by a single customer, customer class, or the entire electricity system. Demand is expressed in kilowatts or megawatts. Demand is the load-side counterpart to an electric system's capacity. In practical terms, electricity demand is measured as the average rate of energy consumption over a short period of time, such as 15 minutes or an hour. For example, a 1,000 watt hair dryer run for the entirety of a 15-minute demand interval would record 1 kW of demand. If the hair dryer were run for only 7.5 minutes, the metered demand would be 0.5 kW. Recording demand requires an interval meter or a smart (advanced) meter.

Demand Charge

A charge paid on the basis of metered demand. Demand charges are usually expressed in dollars per watt units (kW or MW). Demand charges are common for large commercial and industrial customers, but have not typically been used for residential customers because of the high cost of interval meters. The widespread deployment of smart meters enables the use demand charges for any customer served by those meters.

Demand Meter

A meter capable of measuring and recording a customer's demand. Demand meters include interval meters and smart meters.

Demand Response

A customer's change in energy use in response to system reliability conditions or wholesale market prices or generation costs.



Direct Current (DC)

An electric current that flows in one direction, with a magnitude that does not vary or that varies only slightly.

Distributed Energy Management System

A system of control and communication allowing one or multiple parties to use distributed energy resources to supply energy, capacity or ancillary services to customers, the distribution system or the bulk power system.

Distributed Energy Resources (DERs)

A resource at or near customer loads which generates energy or changes energy consumption. Distributed energy resources include customer-sited generation, such as solar photovoltaic systems and emergency backup generators, distributed energy storage, energy efficiency and responsive loads.

Distributed Generation

An electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation (owned by the customer, utility or a third party), such as solar photovoltaic systems, but may include utility-owned generation placed within the distribution system.

Distribution

The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Distribution Locational Marginal Pricing

An unbundled rate for distribution services which introduces temporal and spatial granularity into the rate design. This concept extends the notion of transmission-level nodal pricing, also known as locational marginal pricing, down to the distribution level.

Distribution Management System

The combination of Supervisory Control and Data Acquisition (SCADA) systems and related logic systems that allow a utility to control switches and other distribution system equipment.

Distribution System

The portion of the electricity system used to distribute energy to customers. The distribution system is distinguished from the transmission system on the basis of voltage.

Distribution System Operator (DSO)

The entity which operates the distribution portion of an electric system. In the case of a vertically integrated utility, the DSO also provides generation and transmission services. In many restructured markets, the DSO provides delivery services and energy services only as a provider of last resort.

Energy

A unit of demand consumed over a period of time. Energy is expressed in watt-time units, where the time units are usually one hour — i.e., kilowatt-hour (kWh) or megawatt-hour (MWh). An appliance placing 1 kW of demand on the system for one hour consumes 1 kWh of energy.

Energy Charge

A price component based on energy consumed. Energy charges are typically expressed in dollars per watt-hours, such as \$/kWh or \$/MWh.

Energy Efficiency

Achieving the same or greater end-use value while reducing the energy required to achieve that result. Energy efficiency implies a semi-permanent, longer-term reduction in the use of energy by the customer.



Externalities

Costs or benefits that are side effects of economic activities and are not reflected in the booked costs of the utility, such as health care costs from air pollution.

Federal Energy Regulatory Commission (FERC)

The U.S. federal agency with jurisdiction over interstate transmission systems and wholesale sales of electricity.

Fixed Charge

Any fee or charge which does not vary with consumption. Monthly customer charges are a typical form of fixed charge. Some jurisdictions apply a connected load charge based on the size of the service panel or total expected maximum load. Minimum bills and straight fixed variable rates are other forms of fixed charges.

Fixed Costs

An accounting term for costs which do not vary within a certain period of time, usually one year. (This term may be misapplied to costs associated with plant and equipment, which are denoted as “fixed assets” in accounting terms.)

Flat Rate

A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Frequency

The cycles per second of an alternating current electric system. In most of North America, the electric system operates at a nominal 60 cycles per second, expressed in Hertz (Hz). All of the generators connected to an interconnection are required to synchronize the cycles of their own equipment to that electricity system. From a system operator’s point of view, loads must be constantly and near-instantaneously matched to generation output in order to maintain system frequency within a narrow allowed band (e.g., 59.9 Hz to 60.1 Hz). Many generators and loads are designed to automatically disconnect from the grid when system frequency exceeds allowed limits, which may cause serious disruptions to service, including brownouts and blackouts.

Fuel and Purchased Power Adjustment Clause

A rate adjustment mechanism that allows utilities to recover all or part of the variation in the cost of fuel, purchased power, or both from the levels assumed in a general rate case.

Generation

Any equipment or device that supplies energy to the electric system. Generation is often classified by fuel source and operational or economic characteristics (e.g., “must-run,” baseload, intermediate, peaking, intermittent or load following).

Granular Rate

The Granular Rate is a highly disaggregated retail rate that prices each major distribution or other service separately. Customers are billed based on the amount of each service they use.

Grid

The electric system as a whole or as a reference to the nongeneration portion of the electric system.

Grid-Integrated Water Heater (GIWH)

A customer-sited electric water heater equipped with communication and control equipment allowing it to be turned on or off by automated equipment or remotely by the customer, a third party, the distribution utility or system operator.



IEEE Standard 1547

An electric industry standard governing the engineering and performance criteria for interconnection of customer-sited generation to the electric system. Generally, under IEEE 1547, a customer-sited generator would be required to automatically disconnect from the electricity system in the event the grid becomes unstable or fails. An updated version of the standard is currently being drafted to enable system operators to communicate with smart inverter-equipped customer generation, dispatch it for certain ancillary services, and allow it to continue to serve the customer's load in the event the grid becomes unstable or unavailable.

Incremental Cost

A cost of study method for ratemaking based on the short-run cost of augmenting an existing electricity system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deploy the next unit of capacity in the form of generation, transmission or distribution.

Independent System Operator (ISO)

An entity other than a utility that has multi-utility or state responsibility for ensuring an orderly wholesale power market, the management of transmission lines, and the dispatch of power resources to meet utility and non-utility needs. An ISO controls and operates the transmission system independently from the utilities that serve end-use customers. This usually includes control of the dispatch of generating units and calls on demand-side resources over the course of a day or year.

Interconnection Agreement

A contract between a utility and a customer or third party governing the connection and operation of customer-sited generation which is operated synchronously with the electric system.

Interval Meter

A meter capable of measuring and recording a customer's demand. An interval meter measures demand by recording the energy used over a specified interval of time, such as 15 minutes or an hour.

Islanding

Placing the electric system into a configuration in which some part of it is electrically separated from the rest of the system, but remains energized and operative. A system may be islanded to facilitate maintenance or equipment upgrades or in response to a system failure or instability. In the context of distributed generation or microgrids, a single customer or small group of customers might be islanded during a system outage to be served by one or more distributed generation resources. IEEE Standard 1547.8 governs the conditions under which islanding may occur.

Line Transformer

A transformer directly providing service to a customer, either on a dedicated basis or among a small number of customers.

Load

The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system or in a more specific sense to denote the customer demand at a specific point in time.

Load Factor

The ratio of the average load of a customer, customer class, or the electricity system to peak load during a specific period of time, expressed as a percent.

Load Following

The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as load following resources at any given point in time.



Load Shape

The distribution of electricity usage across the day and year.

Long-Run Marginal Costs

The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs.

Losses

The energy (kilowatt-hours) and power (kilowatts) lost or unaccounted for in the operation of an electric system. Losses are usually in the form of energy lost to heat, sometimes referred to as “technical losses.” However, energy theft from illegal connections or tampered meters, sometimes referred to as “non-technical losses,” also contribute to losses.

Market Clearing Price

The price at which supply and demand are in balance with respect to a particular commodity (e.g., electricity) at a particular time.

Meter Data Management System

A computer and control system which gathers metering information from smart meters, makes it available to the utility and, optionally, to customers.

Metered Demand

The maximum demand recorded by a customer’s meter. Where demand charges are used, metered demand represents the billing units used to calculate the demand charge. Metered demand may also be used to measure demand response or demand curtailment and, when coming from smart meters, to inform system operators about the status of the electric system or to inform customers about their current usage levels.

Minimum Bill

A rate design which charges a minimum amount of money in return for a designated amount of energy, which must be paid even if the customer’s actual usage is less than that amount of energy.

Net Energy Metering

A rate design which allows a customer with distributed generation, typically solar PV systems, to receive a bill credit at the full retail rate for all energy injected into the electric system.

Non-Energy Benefits

Benefits associated with the use of an energy resource, other than the energy itself, such as environmental and health benefits associated with energy efficiency.

On-peak and Off-peak Periods

On-peak periods are when customer demand is generally highest and system costs are higher than average. Many retail rate designs and utility programs are designed to reduce on-peak usage. Off-peak periods are set for when system costs are lower. Time-of-use rates typically apply to usage over broad blocks of hours (e.g., six hours for summer weekday afternoons versus all other hours in the summer months), with on-peak prices that are higher than off-peak prices. Some time-of-use rate designs also include a mid-peak period.



Opt-in and Opt-out (rate recruitment approaches)⁷⁸

Voluntary rate recruitment can take one of two forms: (1) customers are left on their existing rate and provided the opportunity to “opt-in” to new rate options or (2) customers are placed on a new rate and given the opportunity to “opt out” — either to their old rate or to another rate alternative. (In both cases, customers opt out of one rate and in to another.) In the context of a rate design study, the terms opt-in and opt-out generally are used in reference to the rate that is the subject of the study. In other words, customers are recruited to opt in to an experimental rate, or customers are allowed to opt out of the experimental rate.

Peak Demand

The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, all of the customers in a class, or all of a utility’s customers during a specific period of time — an hour, day, month, season or year.

Peak Load

The maximum total demand on a utility system during a period of time.

Peaking Resources

Peaking generation is used to serve load during periods of high demand. Peaking generation typically has high fuel costs or limited availability and often has low capital costs. Peaking generation is used for fewer hours than baseload generation. Energy storage and demand response are other types of peaking resources.

Peak Time Rebate

A rate design which provides a bill credit to a customer who reduces usage below a baseline level during a period of high peak demand or when system reliability may be at risk. Peak time rebates are an alternative to critical peak pricing rate designs.

Photovoltaic (PV) Systems

An electric generating system utilizing photovoltaic cells to generate electricity from sunlight. PV systems may be used in off-grid, stand-alone applications or operated synchronously with the electric system using a power inverter that converts the PV system output to AC power synchronized with the electric system.

Power Factor

The fraction of power actually used by a customer’s electrical equipment compared to the total apparent power supplied, usually expressed as a percentage. A power factor indicates the extent to which a customer’s electrical equipment causes the electric current delivered at the customer’s site to be out of phase with electrical system voltage.

Power Quality

The power industry has established nominal target operating criteria for a variety of properties associated with the power flowing over the electric grid. These include frequency (expressed in kHz), voltage (V or kV), power factor (kVa or lead/lag degrees) and harmonics. Power quality describes the degree to which the system, at any given point, is able to exhibit the target operating criteria.

Power Quality Services

Any services or activities delivered to the electric system which are designed to improve power quality.

⁷⁸ Adapted from U.S. Department of Energy Smart Grid Investment Grant Technical Advisory Group Guidance Document #2: Non-Rate Treatments in Consumer Behavior Study Designs, Aug. 6, 2010.



Public Utility Commission (PUC)

The state regulatory body that determines rates for regulated utilities. The name varies by state — for example, in some states the agency is called the Public Service Commission.

Rate Case

A proceeding, usually before a regulatory commission, involving the rates and policies of a utility.

Rate Design

Specification of prices for each component of a rate schedule for each class of customers, calculated to produce the revenue requirement allocated to the class. In simple terms, prices are equal to revenues divided by billing units, based on test year or assumed usage levels. Total costs are allocated across various price components such as customer charges, energy charges and, typically for large customers, demand charges. Each price component is then set at the level required to generate sufficient revenues to cover those costs.

Reactive Power

Some end-use appliances, typically motors as they commence operation, can draw some of their energy requirements from the electricity system's magnetic field, rather than from the intended flow of energy, causing the customer's load to become out of phase with the system. Additional energy — called reactive power — must then be injected into the system to maintain the magnetic field. Customers typically pay an adjustment charge for drawing reactive power from the system.

Real-Time Pricing

A rate in which the price for electricity fluctuates frequently (e.g., every hour) to reflect changes in market prices.

Regional Transmission Operator (RTO)

An independent regional transmission operator and service provider established by FERC or that meets FERC's RTO criteria, including those related to independence and market size. RTOs control and manage the high-voltage flow of electricity over an area generally larger than the typical power company's service territory. RTOs also operate day-ahead, real-time, ancillary services, and capacity markets and conduct system planning.

Regulatory Lag

The lapse of time between a petition for a rate increase and formal action by a regulatory body.

Reliability

A measure of the ability of the electric system to provide continuous service to customers over time. Reliability standards for the United States are set and maintained by the North American Electric Reliability Corporation and its regional counterparts, as well as by RTOs/ISOs and electric utilities. Compliance with reliability standards is compulsory.

Request for Proposals (RFP)

The initial step in a resource procurement process in which a buyer describes the products or services sought to be purchased. An RFP is usually publicly published and serves as an invitation to potential providers to put forth the terms and conditions under which the described products or services would be provided.

Reserves

The amount of capacity that a system must be able to supply, beyond what is required to meet demand, in order to assure reliability when one or more generating units or transmission lines are out of service.



Revenue Regulation

A regulatory approach which allows a utility to collect a target revenue level regardless of its sales volume. The target revenue may be fixed between rate cases or may be allowed to change formulaically between rate cases.

Revenue Requirement

The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.

Smart Appliance

An appliance capable of communicating with a data acquisition and control system owned by the customer, the utility or a third party.

Smart Grid

An integrated network of sophisticated meters, computer controls, information exchange, automation, information processing, data management, and pricing options that can create opportunities for improved reliability, increased consumer control over energy costs, and more efficient utilization of utility generation and transmission resources.

Smart Meter

An electric meter with electronics that enable recording of customer usage in short time intervals and two-way communication of data to and from the utility and, optionally, between the customer and the meter.

Spinning Reserve

Any energy resource which can be called upon within a designated period of time which system operators may use to balance loads and resources. Spinning reserves may be in the form of generators, energy storage or demand response.

Straight-Fixed Variable Rate

A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Substation

A facility with a transformer that steps voltage down from a portion of the electricity system which transports energy in greater bulk and to which one or more circuits or customers may be connected.

Synchronous

The interconnection and operation of generation with an AC electricity system in a manner that synchronizes the critical operating parameters of the two. Any generator connected to the electricity system is required to maintain synchronicity within a narrow band in order to maintain system reliability and overall power quality. Critical measures of synchronicity include frequency, voltage, harmonics and phase angle.

System Peak Demand

The maximum demand placed on the electric system at a single point in time. System peak demand may be a measure for an entire interconnection, for subregions within an interconnection, or for individual utilities or service areas.

Tariff

A listing of the rates, charges and other terms of service for a utility customer class, as approved by the regulator (for an investor-owned utility), board (for a rural electric cooperative) or city council (for a municipal utility).



Tariff Rider

A special tariff provision which collects a specified cost or refunds a specific credit for end-use customers, usually over a limited period of time.

Test Year

A specific period chosen to demonstrate a utility's need for a rate change. It may or may not include adjustments to reflect known and measurable changes in operating revenues, expenses and rate base. A test year can be either historical or projected (future test year).

Time-of-Use (TOU) Rate

Rates that vary by time of day, day of the week and season, intended to reflect differences underlying costs incurred to provide service at different times.

Tracker

A rate schedule provision giving the utility the ability to change its rates at different points in time, to recognize changes in specific cost of service items without a general rate case filing.

Transformer

A device which raises ("steps up") or lowers ("steps down") the voltage in an electric system. Electricity produced by a generator is often stepped up to high voltages (345 kV or higher) for injection into the transmission system and then repeatedly stepped down to lower voltages as the distribution system fans out to connect to end-use customers. Some energy loss occurs with every voltage change.

Transmission

That portion of the electricity system designed to carry energy in bulk at high voltage. The transmission system is usually designed to connect remote generating plants to local distribution facilities or to interconnect two or more utility systems to facilitate exchanges of energy.

Value of Solar Tariff (VOST)

A tariff which pays for solar-generated power at a price based on its value to the utility system. The valuation of solar is usually based on some or all of the following: avoided energy costs, avoided capital costs, avoided operation and maintenance expenses, avoided system losses, avoided spinning and other reserves, avoided social costs and any other avoided costs, less any increased costs incurred due to the solar resources, such as backup resources, spinning reserves, transmission or distribution system upgrades or other identifiable costs. A VOST is an alternative to net energy metering and feed-in tariffs.

Variable Cost

Costs that vary directly with energy usage or sales revenue, as well as costs over which the utility has some control in the short-run, such as fuel, labor and maintenance.

Vertically Integrated Utility

A utility that owns generating plants, a transmission system, and distribution lines, providing all aspects of electric service.

Voltage Support

An ancillary service in which the provider's equipment is used to maintain system voltage within a specified range.

Volumetric Rate

A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the purchaser.



Appendix B. DER Functions

The significant grid functions identified by EPRI include the following:⁷⁹

- **Connect/disconnect function** allows the utility, or a third party, to cause the inverter to connect or disconnect from the grid.
- **Direct battery charge/discharge function** provides a simple mechanism through which the charging and discharging of battery storage systems may be directly managed.
- **Price-based charge/discharge function** provides a simple mechanism through which battery storage systems may be informed of the price of energy to manage charging and discharging accordingly.
- **Coordinated charge/discharge management function** to coordinate with the local needs of the storage users in terms of target charge level and schedule.
- **Fixed power factor function** provides a mechanism through which the power factor of a DER may be set to a fixed value.
- **Intelligent Volt-VAR function** provides a mechanism through which a DER may be configured to manage its own VAR output in response to the local service voltage.
- **Dynamic reactive current support function** provides reactive current support in response to dynamic variations in voltage where the controlling parameter is the change in voltage rather than the voltage level itself.
- **Volt-watt function** provides a mechanism through which a general Volt-Watt function could be configured.
- **Frequency-watt function** to address short-term (transient) frequency deviations (typically dips in frequency) or longer-term deviations related to more fundamental imbalances in generation and load.⁸⁰
- **Price or temperature driven functions** provide a flexible mechanism through which price or temperature may act as the controlling variable for a curve-based control function. **Low-/high-voltage ride-through function** allows DERs to stay connected to the grid during low or high voltage events, rather than immediately disconnecting, as currently required by IEEE Standard 1547.⁸¹
- **Low-/high-frequency ride-through function** is the frequency equivalent of the low-/high-voltage ride-through function.
- **Real power smoothing function** provides a flexible mechanism through which inverters may be configured to provide reactive current support in response to dynamic variations in voltage.

⁷⁹ Common Functions for Smart Inverters, Version 3. EPRI, Palo Alto, CA: 2013. 3002002233.

⁸⁰ EPRI also included a Watt-Power function because it is theoretically possible, but cited no known application. We have excluded it from this list.

⁸¹ IEEE Interconnection Standard 1547, which has applied to PV inverters since 2003. The standard requires PV inverters to disconnect from the grid under system disturbances, whenever frequency drops below 59.3 Hz or exceeds 60.5 Hz. It is now recognized as a threat to system stability where large amounts of PV systems are present, because a loss of one generating facility may cause hundreds or thousands of PV systems to trip offline, compounding the magnitude of the outage. Europe and Hawaii have already moved to newer standards, and IEEE is revising this standard.



- **Dynamic volt-watt function** provides a flexible mechanism through which inverters, such as those associated with battery storage systems, may be configured to dynamically provide a voltage stabilizing function.
- **Maximum generation limit function** allows the utility or a third party to limit the maximum output from the inverter.
- **Peak power limiting function** provides a flexible mechanism through which inverters, such as those associated with battery storage systems, may be configured to provide a peak-power limiting function.
- **Load and generation following function** provides a flexible mechanism through which inverters, such as those associated with battery storage systems, may be configured to provide a following function for loads or generation, primarily associated with distributed battery storage systems.
- **Multiple grid configuration management (including islanding) function** is a complex function providing for how and when a DER would be connected to the grid and injecting energy into or providing other functions on account of changes in the grid configuration (e.g., small islands, regional islands, or changes in distribution or transmission switching arrangements).⁸²

DER-provided Distribution System Services

Table 18 groups EPRI’s smart inverter functions by category. Each of these services would call on one or more of the EPRI-identified functions (whether provided through an inverter or other device).

⁸² “Islanding” refers to maintaining electric service to some portion of the grid that has been physically disconnected from the rest of the grid. An individual customer’s load could be islanded if the disconnection takes place at the customer’s meter or inverter. A group of customers served by a common transformer, circuit, line or substation might be islanded if the disconnection takes place immediately upstream from that transformer, circuit, line or substation. Or an entire region might be islanded if the disconnection takes place at the transmission or transmission substation level.



Table 18. Categorized Functions

Category	Functions
Customer Emergency and Safety Constraints	Disconnect function; Maximum generation limit function
Grid Emergency and Safety Constraints	Connect/disconnect function; Maximum generation limit function; Multiple grid configuration management (including islanding) function; Load following function
System Maintenance and Outage Services	Connect/disconnect function; Maximum generation limit function; Multiple grid configuration management (including islanding) function
System Limitation Services	Maximum generation limit function; Peak power limiting function; Multiple grid configuration management (including islanding) function; Load following function
Reliability and System Stability Services	Low-/high-voltage ride-through function; Low-/high-frequency ride-through function; Fixed power factor function; Intelligent Volt-VAR function; Dynamic reactive current support function; Dynamic volt-watt function; Real power smoothing function; Maximum generation limit function; Peak power limiting function; Multiple grid configuration management (including islanding) function; Load and generation following function
Power Quality Services	Fixed power factor function; Intelligent Volt-VAR function; Volt-watt function; Dynamic reactive current support function; Frequency-watt function; Watt-power function; Dynamic volt-watt function; Real power smoothing function; Maximum generation limit function; Peak power limiting function
Grid Equipment Preservation Services and Customer Equipment Preservation Services	Fixed power factor function; Intelligent Volt-VAR function; Volt-watt function; Dynamic reactive current support function; Frequency-watt function; Watt-power function; Dynamic volt-watt function; Real power smoothing function; Maximum generation limit function; Peak power limiting function
User Preference and Value Services	Price driven functions; Temperature-driven functions; Coordinated charge/discharge management function; Direct battery charge/discharge function; Load and generation following function
Efficiency and Economic Opportunity Services	Price-based charge/discharge function; Coordinated charge/discharge management function; Direct battery charge/discharge function; Price-driven functions; Load and generation following function

Source: EPRI (2013).

For each of these categories of functions and services, we provide a brief discussion of the extent to which the DER customer’s provision of the service may be subject to compensation from the distribution utility. The compensation decision is subject to a number of important factors, including whether there is a need for the service in managing the system and the cost of obtaining the service from the DER customer. Of course, in any market, it is not sufficient for there simply to be a seller of a product; there must also be demand for the product and it must



be sold at an acceptable price. In the discussion below, we comment on the appropriateness of compensation for the services assuming these types of conditions are met.

a) Customer Emergency and Safety Constraints

Given the overall priority of public safety, these functions are better thought of as “rules of the road” constraints, than as services provided by the customer to the grid. As such, no compensation would be due the customer if the utility were to invoke these functions in the face of emergency or unsafe conditions.

b) Grid Emergency and Safety Services

Whether any compensation might be due a DER would depend on the related cause for invoking the function. In the case of a grid emergency or unsafe condition, no compensation would likely be due, unless the condition were caused by the negligence of the utility. In the case of grid maintenance where the utility invokes the multiple grid configuration management function and draws on the DER to island a portion of the system, thereby keeping one or more customers online, the DER should be entitled to compensation for that service to the extent it serves other customers or other purposes of the grid. In theory, a load following function would allow the DER to serve the customer’s load without injecting energy back into the grid. Any opportunity costs associated with not being able to inject excess energy into the grid would be compensable if the utility were at fault for the underlying cause for invoking the function, but not if caused by a third party, such as in the case of an automobile accident which damages a power pole.

c) System Maintenance and Outage Services

As in the case of grid emergency and safety services, the need for compensation to the DER would depend on the nature of the condition and the function being invoked. Functions utilized to protect the safety of workers, customers or the public generally would likely not result in any compensation to the DER. Where the DER is made part of an islanded generation network, however, compensation would be appropriate.

d) System Limitation Services

Where system limitations cause the utility to invoke functions which reduce the output of DERs or adversely impact the economic value of DER to its owner, the scope and obligation of the utility or system operator to compensate DER for that lost value, or to modify the system to avoid underutilizing the DER, raise questions:

- What is the utility’s obligation to adapt its system to the needs and configurations of its customers, versus the need for customers to adapt to the configuration of the system as built by the utility?
- Must the customer bear the cost if the utility’s system is suboptimal as built?
- What if the system is optimal currently, but would no longer be so if the economically optimal amount of DERs were installed?
- Does the utility have an obligation to modify the system to adapt to that world?



The answer to these questions depends, in part, on whether policymakers are proactively moving toward a post-transition electric grid that looks significantly different than today's grid or merely responding to their increased presence. Section VI discusses how regulators can address these questions.

e) Reliability and System Stability Services

A number of DER functions can be brought to bear to help maintain the system within its nominal operating parameters. With smart inverters or other smart controllers, a DER can dynamically add or subtract loads or generation to maintain voltage and frequency. It can also limit maximum and peak power to keep total loads on local distribution components within equipment ratings. Or, a DER can create a constant load or a constant injection of energy on a given portion of the system, by automatically responding to changes in loads or generation by increasing or decreasing the DER load or DER supply to that portion of the system.

With the proposed IEEE Standard 1547.8, inverter-equipped distributed generation such as solar PV and battery storage will be able to “ride through” temporary deviations in system frequency and voltage to help stabilize the system in real time, rather than aggravating system stability by disconnecting from the grid.

In almost all of these cases, the function being deployed is a discrete service for which the DER should be entitled to compensation.

f) Power Quality Services

In an ideal world, the electric current on the electricity grid would present a perfect sine wave curve; have a constant frequency, voltage and wattage; and have no deviations in power factors at all points at all times. In reality, at any given point on the electric system, the power curve may be distorted; the frequency, voltage or wattage may be too high or too low; and power factors may be leading or lagging in significant amounts at any instant.

Almost all DERs can provide some form of power quality service in the form of frequency and voltage support. In addition, inverter-based DERs can produce virtually any waveform and inject it into the local distribution system. Much like noise-cancelling headphones, an inverter can “listen” to the local electricity waveform and output a complementary waveform that corrects defects at that point in the system. These dynamic functions may significantly improve power quality throughout the system, if routinely utilized.

Virtually all of these functions are discrete services for which the DER should be appropriately compensated.

g) Grid Equipment Preservation Services and Customer Equipment Preservation Services

In addition to age and weather, two factors drive equipment deterioration and failure more than anything else: (1) operation of the equipment at or near its rated capacity or in extreme conditions for extended periods of times and (2) frequent and abrupt changes in loadings on equipment. Smart DERs can be programmed or controlled to help limit equipment loads to less than rated capacity or during extreme conditions (primarily high temperature conditions) and to



smooth changes in loads over time to avoid frequent and abrupt changes in loading. Where these functions are called upon to help preserve grid equipment, the utility or system operator should compensate DER customers for those services. Where these functions are invoked to preserve customer equipment, no compensation would be due to the customer, but there may be opportunity costs if this prevents DERs from providing other services to the utility or the system operator.

h) User Preference and Value Services

Customers often have overriding preferences or valuation criteria that affect the use of DERs for other functions. For example, a typical morning household routine may require a hot water supply for showers and a fully charged electric-vehicle battery for the commute to work. Or the customer may be unwilling to provide services to the grid below a certain price, or may seek to avoid taking energy from the grid above a certain price. This may place the customer's DER beyond the reach of the utility or system operator any time it is being deployed for those purposes. The customer will generally bear the direct and opportunity costs associated with invoking preference overrides such as these.

i) Efficiency/Economic Opportunity Services

Efficiency and economic opportunity services are perhaps the easiest to deal with. Here, the customer or a third-party agent would simply be making choices to sell or consume energy or other services based on a valuation algorithm that responds to market or other price signals. Whether these are simple energy exchanges or more technical ancillary services, transactions would clear on the basis of efficiency gains or prices.

Table 19 summarizes the correlation between (a) DER functions, (b) the context or services those functions might relate to or provide and (c) the types of DER that might provide them.



Table 19. Functions,⁸³ Services and Distributed Energy Resources

Category →	Safety, Reliability and System Stability				System and Equipment Constraints			Quality	Economics and Value	
Context/Service → Function ↓	Customer Emergency and Safety	Grid Emergency and Safety	System Limitation	Reliability & System Stability	System Maintenance and Outage	Grid Equipment Preservation	Customer Equipment Preservation	Power Quality	User Preference and Value	Efficiency & Economic Opportunity
Connect/disconnect	PV, B, DG	PV, B, DG		WH, PV, B, DG, T	PV, B, DG		PV, B, DG			
Direct charge/discharge							WH, B, T			WH, B, T
Price-based charge/discharge										WH, B, T
Coordinated charge/discharge						WH, B, T	WH, B, T	WH, B, T	WH, B, T	WH, B, T
Fixed power factor				PV, B, DG				PV, B, DG		
Intelligent Volt-VAR				PV, B, DG				PV, B, DG		
Dynamic reactive current support				PV, B, DG				PV, B, DG		
Volt-watt								PV, B, DG		
Frequency-watt								PV, B, DG		
Watt-power								PV, B, DG		

⁸³ Functions are from EPRI's list of inverter-based functions; however, non-inverter-based resources can provide many of the same functions, as reflected in the table.



Category →	Safety, Reliability and System Stability				System and Equipment Constraints			Quality	Economics and Value	
Context/Service → Function ↓	Customer Emergency and Safety	Grid Emergenc y and Safety	System Limitatio n	Reliability & System Stability	System Maintenan ce and Outage	Grid Equipment Preservatio n	Customer Equipment Preservation	Power Quality	User Preference and Value	Efficiency & Economic Opportunity
Price or temperature driven						WH, PV, B, DG, T	WH, PV, B, DG, T		WH, PV, B, DG, T	WH, PV, B, DG, T
Low-/high-voltage ride-through				PV, B, DG			PV, B, DG			
Low-/high-frequency ride-through				PV, B, DG			PV, B, DG			
Real power smoothing				PV, B, DG			PV, B, DG	PV, B, DG		
Dynamic volt-watt				PV, B, DG			PV, B, DG	PV, B, DG		
Maximum generation limit	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG		
Peak power limit			PV, B, DG	PV, B, DG			PV, B, DG	PV, B, DG		
Load and generation following		WH, PV, B, DG, T	WH, PV, B, DG, T	WH, PV, B, DG, T		WH, PV, B, DG, T	WH, PV, B, DG, T			WH, PV, B, DG, T
Multiple grid configuration management (including islanding)		PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG	PV, B, DG			

B: energy storage system (batteries); **DG:** customer-sited generator; **PV:** solar photovoltaic (PV) system; **T:** air-conditioning thermal storage; **WH:** Grid-Integrated Water Heater

