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September 13, 2017

The Honorable Chair and Members
Of the Hawai'i Public Utilities Commission
Kekuanaoa Building, First Floor
465 South King Street, Room 103
Honolulu, Hawai'i, 96813

Re: Hawaiian Electric Companies' Final Grid Modernization Strategy, Docket No. 2017-0226

Dear Commissioners and Staff,

The Advanced Energy Economy Institute (AEE Institute) respectfully submits these comments on Hawaiian Electric Companies' (HECO) Final Grid Modernization Strategy (*Modernizing Hawai'i's Grid for Our Customers*), in response to the Commission's invitation for public comments on August 30, 2017. Our comments focus on opportunities related to HECO's report, and provide perspectives on regulatory practices to facilitate grid modernization.

If there are any questions, comments, or concerns related to these comments, feel free to contact us directly.

Regards,

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Before the Public Utilities Commission
Of the State of Hawai'i

In the Matter of the Commission Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy.	Docket no. 2017-0226 COMMENTS

Introduction

The Advanced Energy Economy Institute (AEE Institute) appreciates the opportunity to provide these comments in response to the Hawai'i Public Utilities Commission (hereafter PUC or Commission) Invitation of Public Comment issued August 30, 2017.

AEE Institute is a 501(c)(3) charitable organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy. AEE Institute provides critical data to drive the policy discussion on key issues through commissioned research and reports, data aggregation and analytic tools. AEE Institute also provides a forum where leaders can address energy challenges and opportunities facing the United States. AEE Institute is affiliated with Advanced Energy Economy (AEE), a 501(c)(6) national business association, representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable.

AEE Institute has substantial experience in participating in regulatory reform, grid modernization and "utility-of-the-future" discussions and proceedings across the country. AEE Institute has been very active in the New York Reforming the Energy Vision proceeding for the past three years, and has participated in grid modernization efforts in California, Ohio, Illinois, Michigan, Minnesota, Pennsylvania, Rhode Island, the District of Columbia, and Maryland. We have also worked closely with the National Association of Regulatory Utility Commissioners to provide technical and policy assistance.

Grid modernization strategies will need to change to address, accommodate and benefit from changing technologies on both the grid- and customer-side of the meter, including increasing customer adoption of distributed energy resources (DER).[1] Fortunately, Hawai'i has begun to anticipate these changes and has established several planning and regulatory mechanisms. We commend the Commission for its vision and leadership, and we greatly appreciate the opportunity to engage in this proceeding.

There are currently 42 states that have some open discussion related to grid modernization. The utility sector is experiencing a period of significant change, driven by new technologies, evolving customer needs, public policies, environmental imperatives, and an increased focus on grid resiliency. Yet if managed successfully, these changes offer opportunities for greater customer choice and engagement, the creation of a more efficient and resilient energy system, the creation of a more efficient and resilient energy system, and opportunities for utilities to embrace new business concepts that will sustain them in the decades to come. The AEE Institute supports the Commission's effort to work toward its definition of a modernized grid:

> *"A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Hawai'i to meet its energy policy goals, including integration of renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a secure, open standards-based and interoperable utility network."*

We commend HECO for its development of a grid modernization strategy. We believe that HECO's filing represents a significant effort toward defining a strategy to both meet the needs of customers and work towards Hawai'i's policy objectives. We will briefly comment on four broad themes in our review of the filing:

1. Walk, jog, and run should align with clear policy objectives.

[1] We define DER broadly to include energy efficiency, demand response, distributed generation of all types, energy storage, electric vehicles and microgrids.

2. Sharing data is critical for stakeholder engagement.
3. Regulatory policies and processes should align to facilitate a grid modernization strategy.
4. Utility performance should be rewarded.

Walking, Jogging, and Running Toward Clear Objectives

We agree with the premise that the strategy must take into account dynamic changes in technologies. As noted,

> "investment in an advanced grid will be steady and deliberate, […] With so much new technology arriving, the idea is to focus on near-term improvements that provide the most immediate system and customer benefit but don't crowd out future breakthroughs." (p. ES-2)

It is also important that there is a focus on both near-term and long-term objectives. For example, Table 2 (p. 29) begins to set forth steps for a "walk, jog, run" approach and establishes general timelines for progression on critical distribution functions. We believe that the Commission will want to continue to work with HECO and stakeholders to continue to evaluate objectives and priorities. The planning, operational, and market changes proposed (section 3.3) should be evaluated against those Commission objectives. The Commission's policies play a critical role in identifying the appropriate benefits to prioritize, given policy objectives, market characteristics, and technological change.

We agree with HECO's assertion that any progression should include an evaluation of costs and benefits. This evaluation is important as system operators evaluate new investments, and the timing of those investments. In section 4.2, the proposed cost-effectiveness test methodologies highlight that different categories of utility spending may warrant different evaluation methodologies (see Table 3 at p. 42). The combination of Lowest Reasonable Cost, Total Resource Cost, marginal-neutral rates for DER, and other tests for self-supporting projects (p. 47) presents a robust set of options available to regulators.

We recognize that a wide range of societal benefits are delivered through utility infrastructure. By establishing and developing an appropriate valuation framework, the Commission can guide system planning efforts toward sensible evaluative principles. Other states have recognized that use of the Societal Cost Test provides the most complete picture of the total benefits of an investment. For example, to manage the impact of looking at full societal benefits, many of which are not currently reflected in retail rates, New York, in its Reforming the Energy Vision Proceeding, set the Societal Cost Test as the primary test for all utility investments, but retained the option to use the Ratepayer Impact Measure test as a backstop keep track of rate impacts.[2]

Data Access is Critical for Stakeholder Engagement

Stakeholder engagement processes should be open and transparent. Stakeholders should be involved in discussions regarding system and customer data, modeling assumptions, and modeling scenarios should be so that they can provide feedback on DER solutions and support utilities to identify opportunities to solve system needs more affordably and effectively.

Utilities, customers and third-parties will all be users of system and customer data. To be useful, the data may need to be provided to each of these entities in a different format. Customers will benefit from having access to their AMI data in a customer portal where it can be summarized and used to support them in making decisions about how to manage their energy use, including whether to adopt DER. Utilities will benefit from increased granular system and customer data along with new tools and methodologies to support DERs and system planning. Some of these tools include, but are not limited to:

- Probabilistic forecasting of multiple DER and load growth scenarios
- Forecasting adoption of electric vehicles
- Hosting capacity analyses
- Locational value of DER
- Interconnection studies
- Creation of a uniform benefit cost analysis framework

[2] Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing the Benefit Cost Analysis Framework, Issued and Effective: January 21, 2016.

We recognize that HECO is still developing the ability to use various tools, as well as the ability to collect and develop different levels of granular data. We believe HECO continues to be a leader amongst utilities in data sharing. Improved information availability means greater transparency of system needs, operational concerns, and paths that will encourage innovation and prudent investment by utilities. Appendix E of HECO's plan demonstrates thorough knowledge of system data and a commitment to data sharing for varying applications.

We believe HECO's "My Energy Use" Portal can continue to develop increasingly helpful customer data. Increasingly, customers will also need access to more granular data and energy insights in a timely manner, for example, so that they can act in be informed and educated on how to reduce peak load before they impose costs on the system and incur higher charges as a result. Customers will also benefit from increased information on time varying rates and the impact these actions have on managing their bill. Customers may also choose to delegate their energy management to third parties, who will then be the entities that need access to timely, granular data in a form that they can use. AEE Institute supports the use of standard, downloadable formats for data such as Green Button Download or Connect.

We also want to be sure market participants continue to have an appropriate role in stakeholder engagement. It will be important that market participants have relevant data and opportunities to engage in planning processes. It will be important for the Commission to determine the appropriate role of market participants in planning processes. In the report, HECO asserts:

> *"The evaluation of alternatives will involve proprietary and confidential information to ensure commercially competitive solutions are proposed. Therefore, a select group of non-market participants should be convened." (p. 38)*

Policies should identify appropriate types of data that are commercially sensitive, such that both HECO and market participants are clear on data sharing protocols and stakeholder engagement.

Creating Clear Connections Within and Between Regulatory Processes is Essential

A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system. For example, changes in rate designs are closely tied to decisions customers will make with respect to investments in different types of DERs, and how they will choose to operate them. This, in turn, has important linkages to how data is made available and shared, and to what investments the utility makes to support DER integration.

As an example of best practices, the Michigan Public Service Commission currently uses listservs and working groups to actively manage multiple subject matter working groups to address streams of energy policy responsibilities.[3] We recommend that the complex grid modernization processes be treated similarly, with parallel and distinct working groups and voluntary listservs. This process allows stakeholders to find specific tasks or subjects and will facilitate better engagement.

Valuing Performance is an Opportunity

One opportunity for the Commission and HECO to consider is performance-based regulation (PBR). PBR is a regulatory framework that attempts to align the behavior and financial interests of regulated utilities with public interest objectives and consumer benefits. It does so by rewarding utilities for achieving well-defined performance metrics (outputs), as opposed to providing incentives related primarily to capital investment (inputs).

Within HECO's strategic plan, there is significant opportunity to learn as performance data become more prevalent. That performance data can become the basis for setting objectives (outputs). In a modern grid context, revenue can be closely tied to performance towards policy objective. Clear performance data makes it easier to establish incentives associated with policy objectives and outcomes, including (but not

[3] Michigan Public Service Commission Energy Implementation - URL: http://www.michigan.gov/mpsc/0,4639,7-159-16400_79103---,00.html

limited to) performance on renewable portfolio standards, affordability and rate payer risk, reliability and resilience, customer satisfaction, access to system information, and timeliness of addressing interconnection requests.

To be clear, rewarding performance does not necessarily mean abandoning traditional cost of service approaches. PBR represents an evolution, not a revolution, in regulatory processes and revenue opportunities for utilities, wherein a state may choose to use a hybrid of cost-of-service and PBR approaches. The Commission should consider how a performance-based regulatory framework could help utilities transition toward desired system outcomes. Any metrics and incentives should align with state policy and appropriate Commission authority.

Conclusion

We look forward to further opportunities to contribute to the Commission's important work related to grid modernization and again applaud HECO for a thoughtful and thorough grid modernization strategy for the 21st century.

Relatedly, to support the electricity industry's transition to a modern grid, our sister business association, Advanced Energy Economy (AEE), has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape. Issue brief topics related to critical policy topics of Hawai'i's modern grid, include:

- Optimizing Capital and Service Expenditures
- Advanced Metering
- Data Access
- Distributed Energy Resource (DER) Ownership
- Performance-Based Regulation
- Rate Design for a DER Future
- Energy Efficiency as a Resource

Each of these policy topics will be relevant as HECO continues to build a strategy. AEE Institute appreciates the opportunity to submit these comments.

ACCESS TO DATA

Bringing the Electricity Grid into the Information Age

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Access to Data** lays out why and how access to data is integral to enabling a high-performing modern grid, describes several potential obstacles and questions that utilities and regulators should consider in implementing improved data access, and makes recommendations on the best path forward.[2]

SUMMARY

Data is the lifeblood of today's economy. Timely and convenient access to granular customer and electricity system data is critical to support the development of a modern grid. Such access allows utilities and competitive suppliers to optimize offers and enables individual customers and their designated third-party providers to better manage energy use, consider distributed energy resource (DER) options, reduce costs, and participate in utility demand management programs and emerging transactive energy markets.[iii] In addition, providing third parties with access to anonymized, aggregated customer data and electricity system data is critical to enabling these companies to design and offer products and services that will benefit utility customers, and the electricity grid as a whole.

In order to accelerate data sharing by utilities, policymakers should adopt regulations that enable a data-rich environment that encourages and empowers customers and third parties to use energy billing, system, and usage data.

AEE believes that data must be available in three basic ways to allow customers the greatest control and benefits:

1. A standardized data exchange, such as the Department of Energy's Green Button (if fully and completely implemented), is the most scalable way to provide **individual customer data** to customers and customer-authorized third parties for non-billing products.
2. In states with retail open access, **bill-quality data** for billing of energy is necessary, preferably through Electronic Data Interchanges (EDIs).
3. **Aggregated, anonymized customer data, system data and grid planning data** should be made available on an as-requested basis, as part of targeted utility solicitations for DER solutions, or as part of broader efforts to make such data continuously available so that the market can better develop customer offerings and propose solutions that the utility may not realize are available. For example, California is developing online feeder maps as part of that state's effort to more fully integrate DER on the grid.

Regulations should incentivize utilities to raise customers' awareness and understanding of their ability to access their own data, how to authorize third parties to access the data, and how they can use this data to reduce their energy usage and costs. In addition, utilities should streamline the customer and third-party authorization process for release of data to ensure robust participation in any data exchange. Strong security protocols must be utilized to protect and secure customer and electric system data from bad actors trying to do harm. If done properly these various data access efforts can stimulate job-creating innovation, lead to the development of new products and services, animate the DER market, provide benefits to the electricity

system, enhance customer choice, and support the transition to a modern grid.

It is important to note that these issues are the same as those that have been successfully addressed in other industries, including telecommunications, banking, travel and health care, where greater access to data is transforming the way companies in those industries do business. We expect the same will be true of electricity.

There is a real opportunity for the multiple benefits of data for individual customers and the electric power system as a whole to be realized if the following steps are taken:

1. Adopt foundational regulations and technologies that enable a data-rich environment

2. Promote universal interface standards to exchange data between utilities, customers, retail suppliers, and third parties

3. Incentivize utilities to raise customer awareness and understanding of data's potential to reduce energy usage and costs

4. Develop strong security protocols to protect and secure customer and electric system data

5. Streamline the customer and third-party authorization process to enable robust participation

6. Revisit utility business models to ensure utilities are properly incentivized to help reduce usage, innovate, and animate distribution-level markets

Distributed Energy Resources

AEE defines DER broadly to include distributed generation of all types (e.g., combined heat and power, solar photovoltaics, small wind, fuel cells), energy efficiency, demand response, energy storage, electric vehicles and the associated electric vehicle supply equipment, and microgrids. As such, it includes options for generating electricity, but also for managing how much and when electricity is used.

THE INCREASING VALUE OF DATA

Improved access to data, coupled with the growing ability to analyze and act upon it, are driving change and stimulating innovation in every industry. The electric utility industry is no different, although arguably it has lagged behind other sectors. Access to energy usage data is critical for:

1. Helping customers track and manage their energy use

2. Helping utilities and competitive suppliers to develop new and innovative customer offerings and dynamic rate structures

3. Empowering third-party (non-utility) companies to support the transition to a modern grid

4. Enabling utilities to transition to a more customer-focused culture and business model

Historically, most electric meters were read monthly, severely limiting the actionable data available. Today, with over 50% of U.S. households having electric meters with advanced metering functionality (AMF),[iv] tens of millions of customers now have meters that can collect granular usage data and transmit that data to the utility. Utilities and regional market operators are collecting the data, but the key is making it available in a timely, usable manner, whether directly to customers, their designated third-party providers, or competitive retail suppliers. The data can also be provided in anonymized, aggregated form to third parties to facilitate development of new products and services. At the same time, making electricity system data more readily available promises to unlock additional value from DER by targeting deployment of these resources in constrained areas of the grid and enabling the provision of new services to customers and utilities that lead to benefits greater than those provided by traditional utility investments.

Once the data is made available, it becomes possible to offer customers actionable insights and products that will drive customer behavior and investment in DER that will benefit customers and the grid as a whole. That makes data access a foundational requirement for maximizing the benefits from the substantial investments utilities have made in advanced metering infrastructure (AMI), as well as investments in DER by customers and the advanced energy industry. Modernizing rates is also a critical element. In particular, time-varying rates, which rely on granular data, can create compelling value propositions for customers to invest in DER and energy management options that have them reduce their energy use when it matters most to the grid, lowering the costs of the system overall. When customers have access to data they will also be able to access new technologies in ways that fit their lifestyle.

The current inability of many third parties to access data authorized by their customers is a barrier to fully realizing the benefits of an animated DER marketplace. Without a standardized way to access data, companies

are forced to figure out how each utility stores and makes their data available or must install their own redundant metering on a customer premise to track individual customer loads. In addition, without data, investments in DER and energy management systems are done without full accounting of the costs and benefits they generate for the utility system as a whole. Improved data access will help to optimize and maximize these customer-driven investments to the benefit of all ratepayers.

MAKING DATA AVAILABLE TO DRIVE INNOVATION

As noted above, data access takes three basic forms: (i) **customer-specific data** that can be securely accessed in a timely manner by such customers, their electricity suppliers, and their designated third-party service providers, (ii) **aggregated, anonymized customer data** that can be accessed directly by third-party providers, and (iii) **utility system data** made available to third-party providers. Each has its place in a modern electricity system.

Customer-specific usage data – including daily, hourly, sub-hourly, and near real-time data – will enable new third-party products to be developed and offered to customers. While larger customers may want to track their own energy use, the overwhelming majority of customers need and want utilities, competitive suppliers, and/or third parties to process their usage data and provide actionable insights. With granular customer usage data, an energy efficiency company can more accurately tailor its services and recommendations to target customers; a solar photovoltaic installer can better pinpoint which customers would benefit most from a rooftop array and where that array would most benefit the grid; a retail supplier can offer pricing based on individual usage profiles to optimize the energy market for the consumer; and a demand response company can provide more actionable feedback on customer energy usage to help the customer save money while benefitting all customers by reducing the system's peak demand.

Customer-specific data can also mean data commonly found on a utility bill, such as account numbers, meter numbers, rate class, location on the grid, and retail providers used. This information may be necessary to map the customer to their location on the grid or ensure that the customer is in a rate class that would enable them to participate in a third-party or utility program.

Making aggregated, anonymized customer data and appropriate system-wide data available to third-party companies in a timely manner will enable them to identify and offer more cost-effective alternatives to traditional utility infrastructure investments for the benefit

of customers and the grid. Aggregated customer data can help third-party companies develop new and innovative products and services that apply broadly to targeted customer classes or locations. Customer data is also used by utility-contracted agents, such as energy efficiency providers, for program implementation or evaluation, such as verifying reductions in energy use from energy efficiency programs.[v]

System data – such as information on circuit-level distributed generation (DG) hosting capacity or locations of the grid with capacity constraints (load pockets) or power quality problems – can help DER providers determine the best places to locate DER and respond to system needs with cost-effective DER solutions. This could include geo-targeting customers for energy efficiency services or strategically locating energy storage assets so they can sell load reduction as a service to utilities in lieu of the utility making expensive infrastructure upgrades. In addition, data access will allow customers to fully benefit from all the economic benefits of DER through demand response, market responsive pricing, and proper settlement based on time of production/usage prices.

QUESTIONS TO CONSIDER

While the benefits of increased data access are clear and numerous, there are several key questions to consider to ensure smooth implementation of data access policies and regulations:

- What can be done to enable robust participation by customer-authorized third parties in the marketplace?
- How can utilities and policymakers increase understanding and engagement among industry participants and end-use customers?
- What types and granularity of data should be made available?
- What regulations, privacy standards, and authorization processes are needed to ensure consumer privacy and confidence?
- Should utilities be allowed to charge third parties for access to data, and if so, when and on what basis?
- How will success be measured (i.e., what are the criteria that matter?

RECOMMENDATIONS FOR IMPROVED DATA ACCESS

The regulated electricity industry has fallen behind other industries when it comes to utilizing and making data available to engage customers and create new products and services. Experience from early adopting states suggests that the following recommendations can help regulators, policymakers, and utilities design and implement a process that best fits their specific needs and circumstances.

LAYING THE FOUNDATION

Policymakers should implement foundational policies to enable a data-rich energy environment as soon as possible. Policymakers and regulators should then direct utilities that have not already done so to submit a business case for deployment of AMF to ensure availability of actionable granular energy usage data.

DATA EXCHANGE INFRASTRUCTURE

Once utilities have collected the necessary data, they should implement a system that provides this data to customers, their retail suppliers (as applicable), and customer-designated third parties. The most scalable way to provide this information to customers and then subsequently to third parties is by a data exchange standard across all utilities. Green Button and Green Button Connect (see box below) are the leading standards for this purpose. AEE believes that they are the appropriate standards to use and that utilities should begin to implement them fully. Already, over 50 utilities and electricity suppliers use Green Button and over 60 million households and businesses have the ability to use Green Button.

Benefits will only be realized if customers can easily take advantage of this access. Regulators should also create rules that ensure standard utility implementation of Green Button across their state. To address inconsistencies in implementation, the Green Button Alliance has commenced a testing-and-certification process to make it easier for a utility to ensure its Green Button implementation complies with the Green Button standard, while also assuring that developers can write a single application that can work across utilities. Utilities should work with the Green Button Alliance to ensure that their implementations of Green Button are fully compliant with the standard.

Green Button

Green Button was established—after a White House call-to-action in 2011—as a technical standard to provide utility customers with access to their energy usage information. Specifically, it is an information exchange standard, which ensures that usage and/or billing data (regardless of the utility) is accessible in a standardized format.[vi] Green Button is also known as the Energy Service Provider Interface (ESPI), established by the North American Energy Standards Board's (NAESB) REQ 21. Green Button currently has two programs:

Green Button Download My Data provides a standardized format for customers to digitally download usage data. Once downloaded, the data can be analyzed or shared with a third party.

Green Button Connect My Data provides an easy way for end users to grant authorization to a third party to retrieve customer data directly from the utility's website.

Early Adopters

In 2015, Pacific Gas and Electric (PG&E) launched its Green Button Connect "Share My Data" program, which allows customers to authorize access to their usage and billing data through a third party's website. With it, PG&E customers no longer have to log in to download and share their energy usage files. Instead, once authorized, the system automatically packages customer data, informs the authorized third-party businesses and securely sends it out.

At this time, National Grid, Consolidated Edison, Duquesne Light Co., Commonwealth Edison, Baltimore Gas & Electric, Pepco Maryland, and Ameren Illinois were all actively planning real-time data implementation that will include Green Button.

Moreover, any Green Button implementation should adhere to the following principles to optimize data access while ensuring privacy, security, and auditability:

1. **Ensure bill-quality data:** Require interval data provided by the utility to customers, electricity suppliers, and third parties is the same data the utility will use to bill the customer.

2. **Provide full data sets:** Standardize the availability of a requisite set of usage, billing, and location data for historical and ongoing data access.

3. **Provide synchronous data**: Once a data request is authorized and authenticated by a customer, data should be delivered on-demand.

4. **Adopt strong security protocols:** Data security must accommodate cloud-based systems.

5. **Ensure quality of service and transparency:** Web services and Green Button Connect platforms must be provided at a sufficiently high level of service, with performance metrics reported publicly.

6. **Provide testing environment:** Utilities should provide a testing environment and a production environment of Green Button Connect for third-party use.

CUSTOMER RELEASE OF DATA

A customer's authorized release of data to a third party (and similarly, the process of the customer simply accessing their data) must be a simple and seamless experience. If not, the customer will likely abandon the process of releasing data, and programs dependent on the use of the data will not achieve their full potential. General principles for the customer experience in authorizing release of data include:

1. **Authentication credentials**: Information asked of the customer for release of data must be easily accessible and knowable without being sensitive. For instance, customers should not be asked to provide their social security number or more information than the utility itself uses to authenticate customer identities.

2. **Accept instant, digital authorization:** A digital signature (including click-through) should be valid for authorization.

3. **Ensure seamless click-through**: A utility account holder should be allowed to begin and end the click-through process on the third-party website. The third party may lead the customer request for the types of data and the time frame of data sharing, and the customer may approve or reject such a request at its sole discretion.

4. **Standardized language**: Standardized language should be presented to the customer to support informed consent. This language should include, but not be limited to, description of data, length of authorization, purpose specification, and revocation.

5. **Reduce customer effort:** The authentication process should require no more than four screens and no more than two clicks to reach completion.

FACILITATING ACCESS TO OTHER FORMS OF DATA

Beyond making individual customer data available to customers and their authorized third-party providers, regulators should also consider whether utilities should make aggregated, anonymized customer data available to third parties to further facilitate development of energy products and services.

Making distribution system data available is of equal importance to customer data, and policymakers and regulators should consider a range of options. One option is to incentivize utilities to seek out third-party solutions for meeting defined system needs instead of pursuing traditional "poles and wires" solutions. So-called non-wires alternatives (NWAs) can serve as cost-effective alternatives to equipment upgrades in situations such as meeting load growth in constrained areas of the grid. Under these programs utilities would procure grid services instead of making direct investments in infrastructure. For this to be effective, appropriate data about the system needs to be made available through the solicitation process, and far enough in advance of the need, so that third-party providers are able to develop proposals that can be compared in an open and transparent manner to the traditional utility solution.

Beyond these targeted deployments, making system data more broadly available should also be part of efforts to develop truly

animated markets. Making utility system planning and operational data available to qualified third parties – including investment plans and data on system constraints and DER hosting capacity – will allow third-party providers to develop offerings to customers and to the utility that are more responsive to customer and system needs, rather than wait for a utility solicitation. An example of this is the development of online feeder maps and hosting capacity analysis in California, being done as part of that state's effort to more fully integrate DER on the grid.

INCENTIVIZING ADOPTION

To animate the market for energy services, utilities must be incentivized to develop an accessible data platform and raise customer awareness and understanding of opportunities to reduce their energy usage and costs. Furthermore, engaging customers and encouraging them to actively utilize the data at their fingertips is necessary for the creation of a truly animated market. This will be more likely to occur if data access is facilitated through utilities' existing customer web portals. Utilities can also be incentivized through new business models or performance metrics that reward them for achieving increased customer engagement and information access. Specific performance categories that should be considered include customer engagement and information access, and information access by market participants.

Beyond these metrics, other performance incentives may also be needed that address other changes that would result from greater customer engagement, such as higher DER penetration. Also, greater benefits from access to data will be enabled by changes to rate designs that send more accurate price signals to customers to encourage beneficial behavior and DER deployment.[vii]

SAFEGUARDING DATA

Developing regulations to protect customers and safeguard data is vital to ensure customer privacy and confidence in the market. First and foremost, any personally identifiable customer data should not be shared without the consent of the customer. The sharing of aggregated, anonymized data need not be subject to consent provided it meets certain conditions. For example, states could apply the "4/80 rule" where data must include at least four customers with no one customer accounting for more than 80 percent of the combined load.

Facilitating data access is premised upon the view that customers should be the owners of their own billing and usage data, and sharing this data with third parties should be at the customer's discretion. That said, if the sharing process between customers and third parties is too cumbersome, very few customers are likely to complete the process. Therefore, AEE believes third parties should be able to initiate a data sharing agreement on a customer's behalf, and the customer should be able to provide consent through a simple "single click" process. To further protect customers, the utility should be required to notify the customer, at the time of downloading or sharing, that providing this data to another company will entail revealing private usage information. Customers should also be advised

to review the privacy and data handling polices of the recipient company before sending their information.

Data Guard Energy Data Privacy Program

In January 2015, The U.S. Department of Energy announced the release of ***Data Guard***. Data Guard is a privacy program that was created by the Department of Energy, utilities, and third-party stakeholders to provide companies with a mechanism to show their commitment to protecting customer data. With ***Data Guard***, a utility or a third-party energy services company commits to a Voluntary Code of Conduct (VCC). If a company violates the VCC they could be subject to an action for misrepresentation under Section 5 of the Federal Trade Commission Act or state law.[viii]

With respect to distribution system data, states will need to decide what level of detail to make available and in what form, given their specific goals for developing distribution-level markets and engaging customers and third parties. While states have legitimate concerns with security, there are levels of system data that can be provided without raising issues. Where it exists, load information for transformers and feeders can be given without any security risk. Feeder locations are viewed as more sensitive, but the Department of Homeland Security[ix] has stated that there is no significant security risk with the release of this data. At the same time, the benefits of providing system data include better competition among solutions to meet system needs, more transparency and accountability in the distribution planning process, and the potential for cost savings to customers over current utility practices. Those states that have carefully considered collecting and making system data available, such as California and New York, have been moving in the direction of making more data available, not less.

PAYING FOR DATA

AEE believes that utilities should not charge customers or companies for receiving near real time, customer usage data through Green Button Connect or other similar standards. While the frequency, granularity, timeliness, and types of data provided can generate costs for the utility, these costs are generally small compared to the costs already incurred by the utilities in deploying AMF and collecting the data – costs that customers already pay through rates. Moreover, given the benefits of making the data available that accrue to all customers, any incremental costs associated with making the data available should be borne by all ratepayers. This does not preclude the option of utilities charging for enhanced data services where individual customers or companies are making requests for non-standard or otherwise customized data or analysis.

A leading state on customer data access and privacy: California

California has taken a comprehensive regulatory approach to consumer energy data access and privacy. Starting in 2008, the California Public Utilities Commission (CPUC) adopted a series of access-to-customer data rules culminating in Decision D.11-07-056 (July 2011), which required all three investor owned utilities (IOUs) to make information available to customers in a consistent manner, specifically providing customers with approximate electricity price, actual usage, and estimated final monthly bill, updated daily. In addition, the utilities were directed to provide bill-to-date, bill forecast data, projected month-end tiered rate, and notifications of crossing pricing tiers. The CPUC also directed utilities to develop a process that would allow customers to utilize a Home Area Network (HAN) to access meter data. The Commission also adopted a framework for protecting customer privacy and differentiated "primary purposes" that did not require customer consent from "secondary purposes" that did. It directed utilities to allow customers to share usage information with third parties with such consent and use a standardized method for third-party access, as well as the use of a standardized customer access format. In a June 2016 Decision (D.16-06-008), the CPUC streamlined its rules by authorizing utilities to use a click-through electronic signature process for verifying customer identity and authorizing the release of data. This decision will improve data access and improve the user experience – critical to boosting the rates of customers that share their data.

CONCLUSION

Data is the lifeblood of today's modern economy. Timely and convenient access to utility and customer data is a necessary and vital component of moving the electric utility industry into the digital age, unlocking value, and engaging customers in new ways. Access to customer data will transform how customers manage their own energy usage and interact with their utility, electricity supplier, and third parties. Access to system data will also allow third-party providers to actively participate in developing and deploying cost-effective solutions to traditional utility infrastructure investments, further animating a distribution level market, engaging customers on their energy usage and pricing, and providing significant customer benefits and cost savings. If the following steps are taken, there is a real opportunity for these benefits to be realized in the near future.

- Adopt foundational regulations and technologies that enable a data-rich environment
- Promote universal interface standards to exchange data between utilities, customers, retail suppliers, and third parties
- Incentivize utilities to raise customer awareness and understanding of data's potential to reduce energy usage and costs
- Develop strong security protocols to protect and secure customer and electric system data

- Streamline the customer and third-party authorization process to enable robust participation

- Revisit utility business models to ensure utilities are properly incentivized to help reduce usage, innovate, and animate distribution-level markets

Whether this future can be realized will depend on policymakers, regulators, utilities, third-party providers and customers working together and devising a plan that is suitable for all parties.

ADDITIONAL RESOURCES

Resource	Link
Center for the New Energy Economy State Policy Opportunity Tracker: Customer Data Access	http://spotforcleanenergy.org/policy/customer-data-access/
American Council for an Energy-Efficient Economy, on Data Access	http://database.aceee.org/state/data-access
GridWise Alliance Policy Position on Data Access & Privacy Issues:	http://www.smartgridinformation.info/pdf/4887_doc_1.pdf
EIA Assessment of Interval Data and Their Potential Application to Residential Electricity End Use Modeling:	https://www.eia.gov/consumption/residential/reports/smartmetering/pdf/assessment.pdf
Mission Data, Index of Mission Data Activities:	http://www.missiondata.org/activities/#index
UtilityAPI, authorization, data formats, and API endpoints:	https://utilityapi.com/docs
California PUC Data Privacy and Protection Decision	http://docs.cpuc.ca.gov/published/final_decision/140369.htm

END NOTES

[1] http://info.aee.net/21ces-issue-briefs

[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.

[iii] Transactive energy describes a marketplace or network of DERs involving multi-sided transactions between utilities, third parties, and end-use customers.

[iv]http://www.eia.gov/electricity/data/eia861/index.html. For more information on AMF see our issue brief titled Advanced Metering, available at http://info.aee.net/21ces-issue-briefs

[v] Contracted agent status, meaning that they work directly on behalf of the utility, allows these companies to access and use individual customer data (for defined purposes) similar to a regulated utility.

[vi] http://www.greenbuttondata.org/learn/

[vii] For more on these topics see AEE's Issue Briefs on Performance-based Regulation and Rate Design.

[viii] https://www.dataguardprivacyprogram.org/

[ix]https://www.dhs.gov/science-and-technology/csd-resources

ADVANCED METERING

Connectivity for the Modern Grid

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Advanced Metering** lays out the concepts of advanced metering infrastructure (AMI) and advanced metering functionality (AMF) and how they can provide benefits to our electricity grid, describes potential challenges and barriers that utilities and regulators will have to grapple with in implementation, and makes recommendations on how to move forward to meet the emerging and varying needs of utilities and their customers.[2]

SUMMARY

Advanced metering infrastructure (AMI) is defined as an integrated network of smart meters, communication networks, and data management systems, which has the potential to transform how utilities, customers, and third-party providers manage electricity generation, delivery, and use. AEE also uses the concept of Advanced Metering Functionality (AMF). Whereas AMI typically refers to a specific technology solution deployed directly by utilities, AMF is a broader term that refers to the capabilities that the technology provides, leaving the door open for a wider range of technologies and solutions to provide the same or similar capabilities.

At a minimum, AMF should include the following:[3]

1. Collection of customers' usage data, in near real-time, usable for settlement in relevant retail and wholesale markets for energy and ancillary services

2. Automated outage and restoration notification

3. Two-way communication between customers and the electric distribution company

4. With customer's permission, communication with and control of smart devices

5. Large-scale conservation voltage reduction (CVR) programs, also called Volt-VAR optimization (VVO)

6. Remote connection and disconnection of a customer's electric service (while maintaining consumer protections)

7. Measurement of customers' power quality and voltage

AEE believes AMF is a foundational component of a 21st Century Electricity System, and as such supports timely and rapid deployment of AMF as part of an enabling platform for other technologies and to allow for the adoption of programs and services that will transform how customers, utilities, and third-party service providers interact with a modern grid.

INTRODUCTION

According to the Energy Information Administration's (EIA) most recent data (January 2015), there are over 58 million AMI meters (also called "smart meters") installed in the United States, representing about 41% of all meters. This level of deployment is noteworthy, considering that, in 2009, there were only 9 million AMI meters.[4]

AEE views the deployment of smart meters as a foundational step towards enabling a smart grid and animating a market in distributed energy resources (DER).[5] The result will be to provide customers with access to a range of technologies and services that can help them better control their energy use and costs. However, advanced meters must be coupled with other technologies, functionalities, and services, such as time varying rates (TVR),[6] for their benefits to be fully realized. On that basis, most of the AMI meters installed in the United States are not yet being utilized to their full potential. For example, only 1% of meters in the United States are AMI-connected to a home area network (HAN) gateway (see box below), which allows the meter to communicate with devices in a customer's home.[7] Similarly, not all smart meters are connected to a meter data management (MDM) system, which provides information to the customer and uses interval data for billing.

The key to getting more out of past and future AMI investments is not simply deploying more meters, but rather creating an integrated network of meters, communication networks, and data management systems, then using that network to improve operations, system planning, and engage customers in new ways.

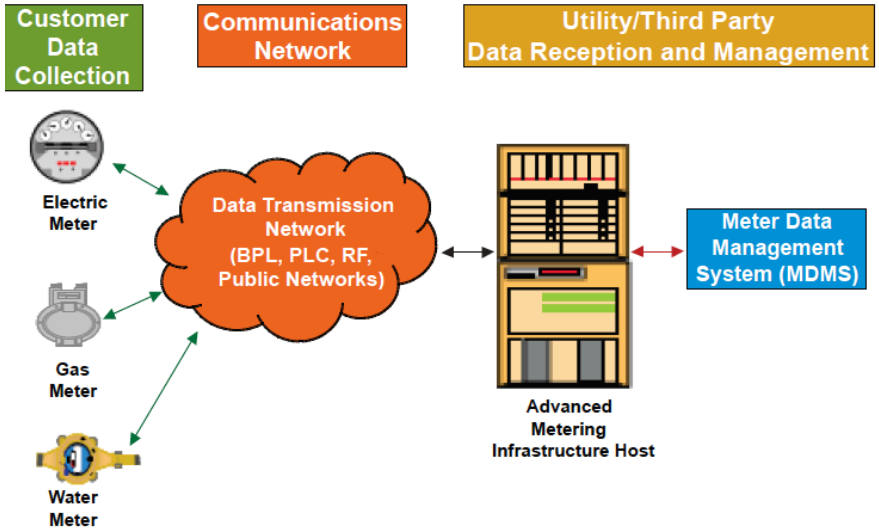
HAN/BAN Gateways

A home/business area network (HAN/BAN) gateway allows smart meters to communicate and transfer information between electronic devices in a customer's home or business. These devices may include in-home displays, smart appliances, computers, smart phones, energy management devices, and distributed energy resources.

AMI connects a home or business to the electric grid through a two-way communication system capable of recording and transmitting data in near-real time between the meter and the utility. This data can also be shared with authorized third-party providers of energy products and services.[8] In some cases, these third parties act as contracted agents of the utility, working seamlessly with the utility on programs such as energy efficiency and demand response. In other cases, the third party is designated by customers and works on their behalf. Regardless, AMI opens the door to a world of possibilities, including digital customer engagement, real-time energy tracking, improved load forecasting, implementation of time varying rates, demand response, real-time outage detection and restoration, dynamic voltage control, and enhanced customer service.

THE CONCEPT

AMI typically refers to the full measurement and collection system, which includes three major components, shown in the figure below: smart meters with integrated communications at the customer site; a two-way communications network between the customer and a service provider, such as an electric, natural gas, or water utility; and data reception and management IT systems that collect, store, and make the information available to the service provider.



9

Since AMI represents a specific set of technologies, AEE also uses the concept of Advanced Metering Functionality (AMF). More precisely, AMI is typically understood as the utility-owned[10] complete technology solution that has been the primary means to date by which AMF has been provided, in both vertically integrated and restructured markets. As technology evolves, there may be additional options for achieving the same functionality and for adding new functionality as well. For example, third-party solar companies already provide web-based and mobile tools that allow customers to view their historical and near real-time consumption as well as track their solar PV output, and demand response companies operate their own networks and control centers. These and other providers continue to develop and offer new energy management options.[11]

AMF, whether provided by AMI or some other means, provides a platform for utilities and third-party service providers to offer highly granular data on individual customers' energy usage, in some cases with near real-time access. These data are essential building blocks for customized load management programs and other services that can empower customers to effectively and simply

control their energy usage and costs. AMF can also improve system-wide efficiency by enabling utilities to develop more precise real-time load monitoring and forecasting capabilities. These capabilities, when combined with DER scheduling, can reduce reliance on expensive and inefficient peaking power plants to meet peak demand. AMF also provides benefits in the areas of utility planning, asset management, reliability, power quality, dynamic Volt/VAR optimization (including in combination with smart inverter capabilities), and reduced system losses.

The individualized, granular, and timely data provided by AMF is indispensable for customer engagement efforts. For example, with AMF, DER providers can analyze customer usage patterns and develop tailored recommendations for DER offerings or rates that will produce the greatest savings for each customer's circumstances. AMF can also empower customers to take control of their energy bills through timely, individualized insights such as high bill alerts.[12] Of equal importance, AMF allows for the measurement and verification of changes in consumption of individual customers so that they can be accurately accounted for and valued, for example, in peak-time rebate programs.[13] The use of AMF data is also beneficial for achieving savings through behavioral energy efficiency, and is essential for enabling mass-market demand response (DR) delivered through targeted communications, and the use of time-varying rates (TVR). These enable customers to become much more engaged with their energy usage and to manage their own energy costs while also helping to optimize performance of the grid.

AMF Enables Time Varying Rates

While AMF provides a number of benefits by itself, many of its potential benefits are realized by enabling other technologies and services, such as time-varying rates. Examples of AMF-enabled time-varying rates at work include a Sacramento Municipal Utility District critical peak pricing pilot, which achieved a 26% savings at peak hours, and a Baltimore Gas and Electric (BGE) peak time rebate program that saved consumers in BGE's capacity zone $162 million in capacity charges and $7 million in avoided transmission and distribution infrastructure costs. Non-BGE customers in adjacent zones saved an additional $126 million due to the program, illustrating how benefits extend to the system at large, including non-participants. Elsewhere, customers in Vermont and California reduced their peak demand by up to 3.5% in response to targeted behavioral messaging made possible by AMF.

QUESTIONS TO CONSIDER

There are a variety of questions involved in an AMF deployment: Who will own and maintain the infrastructure? Which customers should receive AMF? What is the most cost-effective deployment strategy? Who will pay for deployment? How will privacy concerns with regard to customer and third-party access to data be handled? What standards and oversight is required if third parties provide AMF (e.g., billing accuracy, data access, privacy)?

Regulators and policymakers must decide which AMF components should be owned and maintained by the utility, by customers, or by third parties. Utility ownership has been the most common option to date, but ultimately ownership of AMF components should depend on several criteria:

- Overall total cost of ownership
- Regulatory incentives (e.g., utilities earn returns on capital investment, while third-party ownership of specific components may be mandated)
- Capabilities (e.g., third parties may have greater expertise or scale to own and operate)
- Risk (e.g., shifting ownership to another party may lower overall implementation risk for the utility)

The selection of an AMF solution is unique to each utility's circumstances and is dependent on a number of factors, including geography, customer density, scalability and growth, and use cases.

Before undertaking the investment, the benefit-cost ratio for AMF should also be considered. A comprehensive benefit-cost analysis should be used to build a business case for AMF deployment that includes the full range of use cases, including the benefits of timely access to granular data; operational and customer benefits, including access to enhanced energy efficiency, demand response, and customer engagement programs; as well as how AMF can contribute to meeting state policy goals. By planning comprehensively, regulators can ensure that consumers receive a strong return on their investment.

Finally, customer and third-party data access is a topic that will become increasingly important once AMF is widely deployed. We support efforts to provide customers with more data and to make it easy for those customers to share such data with authorized third parties. The available data – such as daily, hourly, sub-hourly and near real-time usage information – will enable new DER-related products and services to be developed and offered to more customers. Although increased access to data raises privacy concerns, those concerns can be addressed and mitigated by establishing data access standards, customer authorization procedures, and potential data exchanges.[14]

CONCLUSIONS AND RECOMMENDATIONS

There is no one-size-fits-all solution for a successful AMF deployment. Nevertheless, past experience suggests that the following basic framework can be used to help policymakers, regulators, and utilities design and implement a program for deployment that best fits their specific needs and circumstances.

LAYING THE FOUNDATION

For timely and effective AMF deployment, policymakers should begin a dialogue among utilities, third party providers, customers, and other stakeholders. The stakeholders involved must educate themselves on the concept of advanced metering, consider all possible barriers to adoption and the unique challenges in their service territories, and establish a practical framework to achieve a successful deployment.

DEVELOPING A PLAN

Experience globally (about 500 million AMI meters) and in the United States (approximately 60 million AMI meters) has shown utility ownership to be the most cost-effective in the vast majority of cases. However, third-party providers can help with customer engagement and DER deployment, either on behalf of the utility or on their own, enabled by AMF.

Next, utilities and regulators must decide upon the most cost-effective deployment strategy. As a general rule, the benefits[15] of AMF – both operational and direct customer benefits – are best achieved through universal deployment rather than on a customer-by-customer basis. Full-scale deployment enables both the framework for DER and customer facing solutions that provide immediate benefits of AMF. Evidence from large-scale AMI deployments has shown that wide deployments generate more robust benefit-cost results due to capturing economies of scale, enabling more customer benefits, and maximizing operational efficiencies. The cost for installing each meter increases when deployment is targeted at only some of the customers in a designated area, and some of the benefits of AMF cannot be fully realized unless all customers have the technology.

In addition, AMF deployment must include back office and data management systems to allow a customer full access to their data in a form they can benefit from. An AMF deployment without this capability is likely to be less expensive but also far less beneficial to customers relative to the costs they are to bear.

ENABLING THE FULL SUITE OF BENEFITS

While there are immediate operations and maintenance (O&M) and service quality

benefits associated with the deployment of AMF itself, most customer benefits are contingent on further actions by utility regulators that enable options such as time-varying rates, integration of plug-in electric vehicles, Volt-VAR optimization, distribution automation, demand response, and behavioral energy efficiency. In order for regulators to make fully informed decisions, they should require that utilities explore AMF deployment through business cases that capitalize on the full functionality available. This would include evaluation of O&M savings and benefits, and also provide estimated customer benefits for a range of other technologies and solutions enabled by AMF, such as energy efficiency and demand response. Immediate customer benefits can be delivered through engagement applications such as web portals, personalized energy management tools, rate analysis, and usage alerts.

Furthermore, the benefits of AMF will not be fully realized unless policies are instituted *before* AMF is deployed, rather than after, so that customers and their designated third parties gain access to data in a timely fashion. This information should be provided through the utility provider's website (e.g., via *Green Button Connect*), Electronic Data Interchange (EDI) capability in areas where energy is billed through a competitive supplier, and through real-time information accessed from smart meters on the customer's premise.

In instances where AMF has failed to live up to its promise, failure can often be traced back to lack of data access and the lack of quantification of customer and societal benefits. Therefore, utility regulators should request annual reporting, as one way to ensure that the value of the investment is maximized.

Advanced metering functionality is a foundational element of the modern grid, with the potential to transform how customers, third parties, and utilities manage electricity generation, delivery, and usage. AMF can improve system-wide efficiency, reliability, and resiliency as well as fuel and resource diversity, either directly or as an enabler of other technologies and services. It can also lead to better DER integration, increased customer engagement, customer bill savings, and third-party market animation. Whether AMF lives up to its potential depends on how it gets put to use. Policymakers, regulators, utilities, and customers all have a role to play in getting the most out of the investments.

Customer Benefits

Customer benefits are often what makes AMI deployment cost effective. Baltimore Gas & Electric's peak time rebate (PTR) program, *Smart Energy Rewards*, made up 50% of the total benefits presented in its AMI business case, equivalent to $1.25 billion over the 15-year expected life of the AMI components. In total, customer benefits accounted for 70% of the total benefits.[16] Any AMF business case must include a commitment to achieving well-defined and quantifiable customer benefits, along with a detailed strategy for how customer benefits are to be achieved.

END NOTES

[1] http://info.aee.net/21ces-issue-briefs
[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.
[3] Massachusetts Department of Public Utilities. 23 December 2013. Order 12-76-A in the Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid (12-76). Available at http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=12-76%2f12-76-Order-7382.pdf.
[4] http://www.eia.gov/electricity/data/eia861/index.html
[5] Distributed Energy Resources are defined broadly to include energy efficiency, demand response, distributed generation of all types, energy storage, electric vehicles, and microgrids.
[6] For more on TVR, see our Issue Brief on Rate Design in a DER Future.
[7] http://www.eia.gov/electricity/data/eia861/index.html
[8] For more on data sharing, see our Issue Brief on Access to Data.
[9] https://www.ferc.gov/EventCalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf
[10] The utility need not own or operate all components of an AMI system. For example, it can outsource operation of the meter data management function.
[11] For example, see: https://us.sunpower.com/residential-solar-energy-system-equinox/
[12] Similar to data limit alerts from mobile phone providers, high bill alerts use AMI data to notify customers if they are on track to receive a higher-than-average bill. These alerts can be coupled with individualized tips to help save energy and avoid high bills.
[13] A peak time rebate program is one of several options utilities can implement via AMF to achieve peak load reductions by sending signals to participating customers.
[14] For more information on privacy and data access, please see the issue brief on *Access to Data*, available at http://info.aee.net/21ces-issue-briefs
[15] Ahmed Faruqui "The Customer Side Benefits of Smart Meters," Presentation, Brattle, Nov 7, 2013. Available at:http://www.brattle.com/system/publications/pdfs/000/004/953/original/The_Customer-Side_Benefits_of_Smart_Meters.pdf?1383853357
[16] Baltimore Gas & Electric Company, 2011, "Application for Authorization to Deploy Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Costs", Case Number 9208.

DISTRIBUTED ENERGY RESOURCE OWNERSHIP

Emerging roles for regulated utilities and third-party providers

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

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To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Distributed Energy Resource (DER) Ownership** lays out the basic issues associated with DER ownership in the context of a changing utility system, addresses potential questions that policymakers and regulators will have to grapple with, and makes recommendations on the path forward.[2]

SUMMARY

The question of what entities, under what circumstances, can own distributed energy resources (DER) is focused on the appropriate roles for regulated monopoly utilities and their unregulated affiliates, and whether they should be allowed to compete with third-party service providers to own DER and provide DER services. DER ownership is perhaps the most contentious element of the larger question of the role of the regulated utility in the evolving electricity industry. As a general matter, a well-functioning competitive market is preferable to a heavily regulated one. Competitive service providers bring innovation, financial creativity, and increased customer choice, and must compete with each other to continually improve on costs, technology, and service quality in an effort to attract customers. However, where such markets do not exist, and there is a compelling public interest objective, the regulated utility can bring its resources and capabilities to bear. In these specific circumstances, utilities can work in collaboration with competitive providers to offer new services and reduce costs. Utility-sponsored energy efficiency and demand management programs are prime examples.

Where regulated utilities are allowed to own DER and provide DER-related services, a chief concern is mitigating market power and the utility's inherent competitive advantages to prevent the regulated utility from stifling the development of a competitive market. Nevertheless, initial utility involvement can help meet important policy objectives and lay the foundation for the development of a vibrant competitive market in the future. For example, electric vehicles (EVs) offer significant benefits for individual users and society at large, yet deployment is constrained in part by a lack of charging infrastructure. Since the competitive marketplace has yet to deliver sufficient infrastructure, it is appropriate for regulated utilities to invest in EV charging infrastructure under appropriate rules in order to accelerate EV adoption.

Although these issues arise more often in the context of restructured electricity markets, where the monopoly utilities are generally prohibited from owning generation assets, similar issues also arise in vertically integrated markets where DER – whether connected on the utility side or customer side of the meter – falls outside of traditional utility asset ownership considerations, and can be owned and operated by third-party DER companies as well as directly by utility customers. Solutions and approaches will thus vary across jurisdictions.

AEE recommends that, where viable competitive DER markets can and do exist, non-utility companies should generally be the ones to own DER and provide DER services. But there are specific circumstances where the regulated utility could also be allowed to own DER and provide DER-related services, especially if such ownership supports a transition to more fully animated and competitive DER markets. However, before

regulated utilities are allowed to own DER, there are several concerns that must be alleviated, such as the ability of regulated entities to exercise market power and achieve an unfair competitive advantage. AEE also supports the ability of unregulated affiliates of regulated utilities to own DER just like other third parties, subject to enforcement of suitable codes of conduct that govern interactions between the regulated utility and the unregulated affiliate, to ensure a level playing field for all providers in the marketplace.

Distributed Energy Resources

AEE defines DER broadly to include distributed generation of all types (e.g., combined heat and power, solar photovoltaics, small wind, fuel cells), energy efficiency, demand response, energy storage, electric vehicles and the associated electric vehicle supply equipment, and microgrids. As such, it includes options for generating electricity, but also for managing how much and when electricity is used.

INTRODUCTION

As DERs become a more integral part of the 21st century electricity system and as utilities look for new revenue and earnings opportunities, the question of what entities should be allowed to own, operate, and control DERs and provide DER services is becoming increasingly important. On the one hand, many utilities see DER ownership as a natural extension of their traditional asset-based business model and view themselves as best suited to provide cost-effective solutions. On the other hand, competitive service providers believe they can provide the most innovative and cost-effective DER solutions and that utilities would exercise market power and achieve an unfair competitive advantage if they are allowed to be in direct competition with non-utility companies. As a result, DER ownership runs up against the fundamental question of what constitutes a monopoly function, and is therefore within the bounds of regulated utility activities, versus what can be provided by the competitive market, and therefore should fall outside the scope of monopoly utility service.

AEE views the continued and increased adoption of DER as a key element in the evolving electric grid. Particularly, we see DER deployment as critical to development of a more flexible, reliable, resilient, and clean grid that gives consumers greater choices and control over energy use and costs. In many states today, a range of valuable DER products and services are provided to individual customers via the competitive marketplace.

We believe that consumers ultimately will benefit from the innovation and creativity that competitive DER companies can offer, and that greater deployment of DER should be led by these companies.

However, we also believe that regulated utility companies should be allowed to own DER and provide DER services under specific circumstances and with certain provisions to support the development of a robust, modern distributed grid. Regulated utilities also have an emerging role in creating and operating a distribution grid of the future that can support and benefit from a robust competitive DER market.

There is no single model for DER ownership. Outlined in this Issue Brief is a set of guiding principles that can be used in each regional setting to achieve the desired outcomes. Variations in regulatory structure, socioeconomic conditions, resource availability, technology readiness, and legacy infrastructure are all reasons why approaches to DER ownership will differ from one jurisdiction to the next.

THE PARTIES INVOLVED

Utilities' relationship with DER is not and will not be one dimensional, and in the near future is likely to encompass a range of structures. There will likely be some DER activities, products, and services that the utility or its contracted agents are best positioned to deliver, while others are better delivered by non-utility companies, whether directly to customers, to the utility on behalf of customers, or as independent owners/operators of DER on the distribution system. Before outlining our recommendations, it is important to clearly define the entities that may be involved, as there are at least four that could deliver DER products and services:

1. Regulated utilities are the monopoly distribution companies (in restructured states) or the vertically integrated entities (in traditionally regulated states) who are the exclusive providers of electric service to customers in a given service territory.

2. Contracted agents are companies that contract with a utility to provide DER products and services to customers on behalf of the utility, or procure DER products and services from customers and provide them to the utility. From the customer perspective, the relationship between the utility and provider may be seamless, in that the customer primarily sees the product as a utility service. In this arrangement, data privacy and other operational requirements are provided for in the contract between the contracted agent and the utility. An example of a contracted agent is a company that implements a utility-sponsored energy efficiency program under the utility brand.

3. Direct-to-consumer competitive service providers, or "third-party providers," are

non-utility companies that contract directly with customers to deliver products and services. Customers of competitive service providers continue to interact with their utility, for example, to receive their energy usage data, as well as with the competitive service provider, which could use the data authorized by the customer to provide a product or service. Competitive service providers may also provide services to utilities using DER, for example, by aggregating customer-owned DER in response to a utility solicitation for non-wires alternative projects or in a utility demand management program.

4. Unregulated utility affiliates are companies owned by the same parent company as the regulated utility, but that provide services similar to those of direct-to-consumer competitive service providers.

QUESTIONS TO CONSIDER

When deciding which entities should be allowed to own, operate, and/or control different DER products and services, there are not always clear-cut delineations. A variety of questions must be considered before policymakers can make a decision in regard to DER ownership.

Should a regulated entity be allowed to provide products or services that are provided, or could be provided, by the competitive market? If yes, under what circumstances should this be allowed and what should be done to mitigate concerns over market power and unfair competition that are bound to exist when a regulated monopoly participates in competitive markets? What limits should be placed on types of products and services that can be offered by the regulated entity, and to whom?

Should a regulated utility be allowed to provide value-added products and services to individual customers? Should a regulated utility be allowed to own DER on a customer's premises, behind the meter or on the utility side of the meter? Should regulated utility ownership of DER be limited to the provision of basic utility services?

Should an unregulated utility affiliate be allowed to own DER within the service territory of the regulated utility? How can regulators create a level playing field between them and other competitive service providers, where there may be a clear preference for the regulated utility's parent company to favor its unregulated affiliate?

What role should utilities play in the control of DER assets? What integration services are essential for the utility to provide and how should this integration function play out in DER control, for the benefit of customers overall, regardless of who owns the asset?

HOW TO APPROACH DER OWNERSHIP

Although there is no one-size-fits-all policy for DER ownership, certain parameters can be used to help policymakers design and implement policies that best fit their specific needs and circumstances. Here are AEE Institute's recommendations for DER ownership:

BASIC VS. VALUE-ADDED SERVICES

Decisions on utility ownership of DER will depend in part on whether the DER is used to provide basic or value-added services.

Basic services are those that the regulated utility provides as it carries out its monopoly functions, as defined in statute and regulations. These services are provided or available to all customers, with costs recovered from all customers. Historically, the regulated utility has invested in its own infrastructure (power plants, transformers, poles, wires, meters) to meet its basic service obligations. A DER example would be a utility-owned battery at a substation used to meet its basic service obligation for reliability and power quality. Another example would be a utility procuring targeted demand reductions from customers and third parties who invest in DER to avoid a substation upgrade in a constrained area of the grid.

Value-added services are optional, enhanced services, whether provided by regulated utilities or the competitive market. Customers would choose to receive such services as an addition to basic service, with the costs of those services borne by the user. An example of a DER-related value-added service is the sale, installation, and financing of behind-the-meter distributed generation.

Under the circumstances detailed below, utilities should be allowed to own DER assets for the provision of basic services, but should also be incentivized to procure DER services from the competitive market to meet those basic service needs, especially if they can be procured at lower cost. With respect to value-added services, which are mainly provided today by the competitive market, the regulated utility should be more constrained in its role to avoid direct competition between regulated entities and unregulated competitors.

PROGRAM ADMINISTRATION VS. DELIVERY

The DER ownership question arises most frequently in the context of distributed generation and energy storage. Other DER assets and products, such as energy efficiency and demand response, have traditionally not entailed significant direct asset ownership by utilities. In those cases, assets are generally owned by the customer or a third party (e.g., energy efficient appliances, smart thermostats, energy management systems) and the nature of the relationship between customer and provider is more transactional or service-based. For these DER assets, the utility role has

generally been one of program administration, as exemplified by energy efficiency and demand response programs, whereas the competitive market is generally involved in product and service delivery, such as conducting energy audits and installing energy efficient or distributed generation equipment.

DER OWNERSHIP VS. DER CONTROL

It is also important to distinguish between ownership of DER assets and control of those assets. The utility retains the obligation to maintain an electricity system that is safe, reliable, efficient and that meets the needs of all customers. Integration of DER into this system will largely remain the role of the utility. As a result, utility control of DER, or programs and markets that govern the dispatch of DER, regardless of who owns it, will become increasingly important as DER penetration rises. There must be clarity about how the DER owner gets compensated for allowing utility control, and vice versa, if a utility provides aggregation and dispatch services for the benefit of DER owners, how the utility is compensated for providing that service.

WHO OWNS WHAT?

With the foregoing in mind, for each of the four main entities that could deliver DER products and services, the following provides high-level recommendations for who should be allowed to own what:

Regulated utilities should be allowed, and indeed encouraged, to procure DER products and services from customers and competitive service providers. Ownership should also be allowed in certain circumstances (see below), including when DER can be used to meet the utility's obligations for basic service. However, even when utility ownership is permitted, the utility should make use of competitive procurement, whenever possible.

Contracted agents should be allowed to deliver basic and/or value-added services to customers, with appropriate conditions to ensure full and fair competition among all types of providers and to protect against potential subsidy of competitive services by regulated entities. Examples include delivery of utility-sponsored energy efficiency programs and direct load control programs.

Direct-to-consumer competitive service providers should be allowed to provide DER products and services to customers (e.g., energy intelligence software and onsite distributed generation), own and/or operate DER on behalf of customers, or independently own/operate DER connected directly to the utility system (e.g., energy storage and community solar projects). Competitive service providers should also be allowed to provide services to utilities, whether in response to utility solicitations for specific needs or via tariffs designed to encourage DER-based solutions.

Unregulated utility affiliates should generally be allowed to compete with competitive service providers, but there are circumstances under which this may be prohibited. At a minimum, allowing unregulated affiliates to engage in the market requires that regulators establish clear rules that govern interaction between the unregulated affiliate and the regulated utility, to ensure a level playing field in competitive markets. The only time an unregulated affiliate should be able to sell DER

services to the regulated utility should be in an open market opportunity, preferably with the winning bids selected by an independent evaluator.

We further recommend that regulated utility ownership of DER be exercised only in cases where DER is not available through a non-utility option and limited to the following categories:

- Sponsorship and management of energy efficiency and demand management programs, with utilities contracting with competitive service providers for the delivery and implementation of such programs, unless no competitive service provider is available.[3]

- Ownership of distributed generation (DG) or energy storage assets on utility-owned property, including substations, for purposes of maintaining reliability, providing balancing and ancillary services, and performing other related grid functions, which constitute elements of basic service. If the ownership and operation of such assets results in revenue not associated with the provision of basic service, such as price arbitrage facilitated by energy storage, such revenues should be returned to ratepayers or be subject to a shared saving mechanism.[4]

- Provision of distribution services and interconnection for multi-customer microgrids. This type of microgrid has characteristics that lend themselves to close collaboration between competitive service providers and regulated utilities, such as for dispatch and settlement. Customer-sited DER assets associated with these microgrids would be owned by the customer or a third party, not the utility.

- Programs that address underserved segments of the market that could benefit from initial involvement of regulated utilities until a competitive market emerges. The utility role should be targeted to the barriers that impede the development of a robust market serving these specific segments, and such involvement should end once a competitive market exists.

- DER demonstration projects as part of a broader research and development effort into innovative solutions for increasing the penetration of such resources on utility distribution circuits without compromising reliability or power quality. Such demonstrations should ideally be carried out in close collaboration with contracted agents and third parties.

If the unregulated utility affiliate is allowed to participate in the competitive marketplace within the regulated utility's service territory, code of conduct rules should be established and enforced to make sure the unregulated affiliate does not enjoy an unfair competitive advantage due to its relationship with the regulated utility or parent company. Examples of what would be included in such a code of conduct are:

1. Unregulated affiliates should not be able to use the regulated utility name and resources, nor should they be able to conduct joint marketing and advertising.

2. Unregulated affiliates should be prevented from having access to the utility's customer or operational data unless the same is available to all other providers under the same terms.

3. Personnel practices should preclude actions that could convey an unfair market

advantage (e.g., revolving door of personnel between regulated and unregulated affiliates or shared personnel, even if through a fee structure)

4. Regulators should be able to audit the financial and accounting records of the affiliate to ensure compliance.

Two examples of rulings on regulated utility ownership of DER

In New York's Reforming the Energy Vision proceeding, the issue of regulated utility DER ownership was addressed in a February 2015 order.[5] In that order, the Commission limited utility DER ownership to situations where:

1. Procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative

2. A project consists of energy storage integrated into distribution system architecture

3. A project will enable low or moderate income residential customers to benefit from DER where markets are not likely to satisfy the need

4. A project is being sponsored for demonstration purposes.

In California, the utility commission recently ruled that the state's three major investor-owned utilities should be permitted to own electric vehicle supply equipment (EVSEs) on a case-by-case basis and directed them to submit plans for deploying EVSEs to accelerate the development of the EV market. In 2016, the three large IOUs[6] received approval for direct ownership of EVSEs totaling $197 million in investment. Two of the proposals include direct ownership of EVSEs by utilities while one calls for private ownership to be facilitated with utility incentives (in this case the utility will own all infrastructure except for the EV charging units themselves). In January 2017, all three large IOUs filed plans[7] focused on medium and heavy-duty vehicles, calling for a total of $1.07 billion in investment. These rulings serve as examples of where market conditions support utility DER ownership in that they address a specific situation where a competitive market does not yet exist (especially the fact that third-party EVSE ownership is generally not a viable model yet due in part to low numbers of EVs on the road) and meet a public interest objective to support the state's existing policy goal of deploying 1.5 million EVs by 2025.

ALIGNING UTILITY INCENTIVES IN THE CONTEXT OF THE EVOLVING GRID

To further ensure that regulated entities do not exercise unfair market power to achieve a competitive advantage, regulated utility DER ownership should be contingent on two principles:

1. Establishing a regulatory paradigm and financial incentives such that regulated utilities are indifferent between themselves or non-utility companies owning DER, and they are incentivized to effectively integrate and operate all DER regardless of ownership.

2. Using open competitive procurement of DER solutions by regulated utilities as the first option, but allowing regulated utility DER ownership if such procurement fails to surface a suitable solution.

In order to ensure incentives are properly aligned, policymakers should establish a regulatory framework that incentivizes utilities to invest in solutions that result in the utility distribution and tariff system supporting non-utility owned DER to allow for the greatest system and customer net benefit. Policymakers should explore performance-based incentive mechanisms that compensate utilities based on how well they deliver service and achieve performance requirements and public policy objectives, as opposed to simply rewarding them for increased capital investment.[8] This can include incentives for maximizing the operational value of all DER. Regulatory reforms to equalize the value of operating expenses for services with capital investments can also help to address this issue.[9]

California's Regulatory Incentive Proposal

In April 2016, Commissioner Michael Florio introduced a regulatory incentive proposal, which was subsequently approved in December 2016, in CPUC's Integrated Distributed Energy Resources proceeding (R1410003). The regulatory incentive is structured as a pilot program to test the effect of incentives on utility sourcing of services from DER, addressing the potential conflict between the Commission's policy objectives and the utilities' financial objectives. Specifically, it directs the state's IOUs to develop pilot programs offering a shareholder incentive (4% pre-tax of the payments paid to a DER provider) for the deployment of a cost-effective DER solution that displaces or defers a utility expenditure (either capital or operating if the proposed DER plus the shareholder incentive is the cheaper option).

LEVELING THE PLAYING FIELD

It is also essential to ensure that regulated utilities are prevented from using their monopoly status to erect competitive barriers to non-utility providers, which may be able to provide cost-effective products and services or innovative value-added services on their own. If a regulated utility offers a DER solution before soliciting responses in the competitive market, it could have a chilling effect on private sector

investment and deprive customers of significant benefits. As noted above, DER products and services are already provided today by the competitive market. Regulatory and utility decisions should recognize that if products and services can be provided by the competitive marketplace, this should be the preferred option before regulated utility ownership is pursued.

Policymakers can consider different ways to ensure that the process of soliciting DER solutions from non-utility companies is fair, open, and transparent. This might include an independent entity administering the bidding process and determining cost effectiveness of different solutions. An independent, technically competent administrator will be more likely to appreciate and promote the innovation that will lead to least cost, highest value solutions. The timing of such solicitations is also important. There should be sufficient lead time for competitive DER providers to propose solutions that can be implemented in time for the need to be met.

Maine's Non-Transmission Alternative Coordinator

In April 2016, the Maine Public Utilities Commission opened a proceeding (2016-00049) to develop the framework for selecting a non-transmission alternatives (NTA) coordinator to develop cost-effective alternatives to transmission projects. The Commission is deciding whether the coordinator should be a role for the utility or a third party. Once this is decided, the Commission will develop a RFP for a third-party entity or a rate incentive proposal if the utility acts as the NTA coordinator.

VALUE-ADDED SERVICES

The general principles laid out above are consistent with a limited role for regulated utilities providing value-added services, which, as noted above, are primarily offered by the competitive market today. This recommendation is based on the important regulatory principle of separating activities that can be accomplished via the competitive market versus a regulated monopoly. If the regulated utility is permitted to own DER for the provision of value-added services, any services they offer should be focused on addressing specific conditions that inhibit development of a competitive market and supporting a transition to such a competitive market.

An unregulated utility affiliate, on the other hand, should be permitted to own DER and compete with non-utility companies to provide value-added products and services. But, as described above, the regulatory framework must ensure that they do not have access to and are not able to use the resources of its regulated affiliate or parent company to subsidize its offerings and gain an unfair competitive advantage.

SPECIFIC USE CASES

There may be times when the general principles outlined above may not be applicable and should be tested against specific cases. For this reason, we believe that utilities should have the ability to make filings requesting approval of a certain DER program or customer request that may fall outside the above guidelines. We suggest that regulators develop a process for reviewing these proposals on a case-by-case basis, including periodic review of approved offerings, to determine if the conditions that warranted the initial approval still exist.

CONCLUSION

The electricity sector is changing, and with it comes the need to re-examine the role of the utility, taking into account the contributions that can be made by other parties to the operation of the grid and to providing customers with improved services and greater choices and control over energy use and cost. DER ownership is a complex issue that needs to be addressed as part of this grid evolution. The recommendations herein are based on the important regulatory principle of separating activities that can be accomplished via the competitive market versus a regulated monopoly, while recognizing that there are specific circumstances where regulated utility ownership of DER may be appropriate. The utility also has an important role to play as the owner and operator of the grid to which DER will connect and interact. This includes making investments in the grid to facilitate DER integration and developing and providing services to DER companies to help maximize the benefits of DER investments.

Regardless of the market structure, having clearly defined roles for regulated utilities and competitive suppliers will lead to better outcomes than if regulated and unregulated entities are in direct competition with one another. It is up to policymakers and regulators to develop a regulatory framework and clear rules for DER ownership that ensure a smooth transition to a 21st century grid.

END NOTES

[1] http://info.aee.net/21ces-issue-briefs

[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.

[3] For example, opt-out behavioral energy efficiency or behavioral demand response programs require both access to customer data and service relationships with all customers. For these reasons, the regulated utility or the designated energy efficiency utility may be uniquely able to provide these services, although the services may be best provided by an outside provider selected by a competitive procurement process.

[4] A mechanism that allows savings from particular programs to be shared by both the utility and ratepayers, to encourage utilities to pursue opportunities that benefit customers but that may not otherwise yield financial benefits to the utility.

[5] Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.
Order Adopting Regulatory Policy Framework and Implementation Plan, February 26, 2015.

[6] California Public Utilities Commission Application A1502009, Decision D1612065; Application A1404014, Decision 1601045; and Application A1410014, Decision D1601023.

[7] California Public Utilities Commission Application A1701020

[8] For more information, see our Issue Brief on Performance-Based Regulation, available at http://info.aee.net/21ces-issue-briefs

[9] For more information, see our Issue Brief *Optimizing Capital and Service Expenditures*, available at http://info.aee.net/21ces-issue-briefs

ENERGY EFFICIENCY AS A RESOURCE

The Power of Getting More from Less

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Energy Efficiency as a Resource** lays out challenges and opportunities for energy efficiency in the context of the evolving grid, describes several potential obstacles and questions that utilities and regulators should consider, and makes recommendations on the path forward.[2]

SUMMARY

Energy efficiency (EE), broadly defined, means using less energy to provide the same, or often superior, energy services. EE is most commonly thought of as technology that reduces energy use relative to traditional technologies, such as LED lighting and high efficiency appliances and heating and cooling equipment. But today, EE also includes the use of sophisticated energy management systems, internet-connected thermostats, and data analytics. EE can deliver both sustained reductions in energy use by improving baseline efficiency, as well as targeted reductions by giving customers actionable information to manage energy use during specific times, such as during peak demand periods.

Many benefits come from EE technologies and practices, including: cost savings to customers, consumer empowerment and engagement, improved facility operations and building energy systems reliability, enhanced grid performance, reductions in future electricity rates, and job creation.[3] EE is widely recognized as the lowest cost resource for meeting electricity needs. Even in states that have pursued EE policies for many years, EE remains cost effective, with significant untapped market potential. Strong EE polices and investment help keep electricity bills low for all by reducing the need for investment in new and expensive generating assets, as well as new transmission and distribution infrastructure.

The EE market has undergone significant changes in response to developments in technologies, markets, and public policies. This has largely been driven by the influx of connected devices, deployment of advanced metering functionality[4] and the "internet of things," which have increased the ability of utilities, third parties, and customers to remotely access data and act upon it. In addition, there continue to be advances in EE technologies and new innovative tools that leverage this new data through analytics to provide personalized and actionable information about energy consumption.[5] As a result, increasingly sophisticated energy consumers continue to drive toward purchases of energy efficient products and services.

Despite its many benefits, EE faces barriers to achieving its full potential. To overcome these barriers, states should implement policies supporting energy efficiency, creating market certainty for services and products that reduce energy consumption and helping customers manage their energy bills. Well-developed policies such as energy efficiency resource standards (EERS), revenue decoupling, and building codes and standards are critical for driving higher levels of efficiency. Integrated resource plans (IRPs) that take into consideration the value that demand-side technologies can provide, as well as robust EE potential studies, are also necessary components for setting strong EE targets and funding requirements. States that enable robust markets for EE will benefit from more

efficient use of energy and the economic growth and investment of successful companies providing energy efficiency services.

In addition to these foundational policies, the increasing sophistication of EE products and services opens up the possibility for innovative solutions and approaches that value EE as a resource on par with traditional, supply-side options. AEE believes that such market-driven EE, in its various forms, can serve as an important component of the electric grid of the future, and be a complement to more traditional EE policies. Specifically, AEE finds that **open procurements** for EE resources; **diverse financing options, targeted demand side management; increased customer engagement; updated evaluation, measurement, and verification practices** (EM&V); and **rewards for performance** can accelerate EE deployment, spur EE industry growth, and provide savings for electricity customers.

A BREADTH OF ENERGY EFFICIENCY OPTIONS

Energy efficiency refers broadly to products and services intended to reduce the energy used by consumers and businesses while providing the same or superior quality of the energy services. Examples are many, and include energy efficient LED lighting, Energy Star rated appliances and electronics, building energy management systems and high-efficiency heating and cooling systems. In the era of big data and data analytics, EE also includes behavioral programs, where customers are given actionable energy information and insights and are able to reduce energy use in response. Because many of these energy efficient technologies and services offer superior performance to their standard counterparts, they can also positively impact business productivity. For example, an EE retrofit in a commercial building can make workers more productive by improving lighting and providing more comfortable indoor temperatures.

The U.S. Energy Efficiency Market

The U.S. building efficiency sector is large, accounting for $68.8 billion in revenue in 2016.[6] Overall, U.S. Building Efficiency products and services grew 8%, or $5 billion, that year, led by energy efficient lighting and commercial building retrofits, both up 7%, reaching $26.4 billion and $8.4 billion, respectively.

MARKET BARRIERS

Incremental needs for energy services can be met by either increased supply or increased efficiency of energy use. In most cases, pursuing energy efficiency is the lowest-cost option for meeting those additional needs. Nevertheless, energy efficiency markets have historically faced barriers that have prevented EE from reaching its full potential. The American Council for an Energy Efficient Economy identifies four common barriers:

- Imperfect information on potential technological options and performance.
- Incentives that differ between energy users and those who would invest in EE measures, such as landlord-tenant relationships.
- Externalities that occur when costs or benefits are not included in prices, such as unaccounted-for societal benefits.
- Imperfect competition of quasi-competitive markets, as in the case of markets with limited suppliers of EE services
- Limited financing options, especially given that EE often entails incremental investment over traditional technologies, with savings accruing over time.

Additional barriers include:

- Limited data access and visibility into energy use and costs (visibility helps to spur action)
- Utility EE programs may not offer deep EE savings to enough customer types
- Some rate designs can hurt EE returns on investment, such as recent efforts by some utilities to increase fixed charges and reduce volumetric energy charges.7

In addition to these barriers, most electric utilities operate under a regulatory framework and business model that encourages them to increase sales, as opposed to helping their customers use energy more efficiently. Thus, in the absence of policies that incentivize utilities to promote EE, utilities focus on traditional drivers of growth, such as increased electricity sales and new investments in traditional generating capacity and electricity system infrastructure.

As a result, many customers are not taking advantage of all cost-effective energy efficiency available to them, despite it being in their economic interest.

POLICY AND MARKET RESPONSE

In recognition of these well identified market barriers, as well as the significant public benefits of greater EE deployment, policymakers have developed a number of responses. These include:

- More stringent codes and standards for buildings, appliances, and other equipment.
- Utility- or state-run (or authorized) EE programs.
- Energy Efficiency Resource Standards (EERS), which require utilities and other obligated parties to procure mandated levels of energy efficiency, similar to renewable portfolio standards for renewable energy.
- Statutory requirements that utilities pursue all cost-effective EE.
- System benefits funds, where a small amount of money is collected from each utility customer each month and pooled to fund EE delivery.
- Regulatory changes, such as revenue decoupling, that mitigate the financial incentive for utilities to continually increase volumetric sales.
- Performance incentives for utilities to achieve high levels of energy efficiency.8

Competitive suppliers of EE products and services are also responding by pursuing free-market mechanisms with new energy efficiency technologies and services that can deliver solid returns on investment for building owners.

FORMS OF ENERGY EFFICIENCY DELIVERY

A variety of delivery mechanisms exist for EE, tailored to the needs of different customer types. So-called mass-market customers (residential and small commercial) are typically best served directly by utility programs whereas free-market mechanisms by industry, ESCOs, as well as utilities, serve larger commercial and industrial customers.

Public utility-sponsored programs are evaluated through a cost-effectiveness framework. In some jurisdictions, benefit-to-cost ratios for each *individual program* must be greater than one. In others, the *overall portfolio of programs* must pass the benefit-cost test, which AEE views as a superior approach. Measuring cost-effectiveness at the portfolio level can be beneficial because it

allows for flexibility to include innovative programs that do not directly produce savings but are necessary to increase overall participation in EE programs, such as marketing. Regardless, if utility programs, which are funded by public purpose customer surcharges on ratepayer electric bills, are not cost-effective, state utility commissions do not authorize them. Lawrence Berkeley National Laboratory estimates the U.S. average "total cost of saved energy" for customer-funded utility EE programs at $46/MWh, based on an analysis of programs in 20 states over a five-year period.[9] And because some of these costs are borne by participants, the average costs to the program administrator (usually the utility) are even less, at just over $20/MWh.

While utilities serve as program administrators, program delivery is typically done by third parties, either acting on behalf of the utilities as contracted agents, or in delivering products and services directly to participating customers via the competitive marketplace. This combination has proved very effective at delivering value for all customers – participants and non-participants alike – while achieving state policy objectives.

Across the United States, utility-sponsored energy efficiency programs have grown into a multi-billion annual market that is delivering highly cost-effective energy services to customers.

Outside of utility programs, various market constructs provide opportunities for cost-effective energy efficiency delivery, including Pay for Performance (P4P) and other industry-led innovations. This includes performance contracting offered by Energy Service Companies (ESCOs), who primarily service municipalities, universities, schools, and hospitals, which collectively have been termed the "MUSH" market.

For performance contracting, ESCOs evaluate and install a package of EE measures for their customers. Often, those installations have little or no up-front cost to the customer, as the ESCOs recover their costs through the energy savings generated. In fact, if the project does not generate the savings forecasted, ESCOs pay the customer the difference.

In other P4P models, there are two primary ways in which energy efficiency savings are paid:

- **Standard-offer programs,** which set a price for each unit of energy saved
- **Bidding programs**, in which implementers or customers compete for contracts that specify an amount of energy savings to be achieved, and pay the price offered by bidders (e.g., the utility) for savings as they occur.

P4P has the potential to grow as more granular data about customer energy use becomes available, allowing for more accurate measurement of actual savings, as opposed to the deemed savings approaches that have been used in the past. While more common with commercial and industrial customers, the approach could expand to smaller customers via the participation of third-party aggregators.

EMERGING PRACTICES FOR THE FUTURE OF ENERGY EFFICIENCY

While traditional programs remain the cornerstone of energy efficiency deployment, some jurisdictions are examining whether it is possible to move toward more market-based models for EE, which would effectively treat EE more like a resource on par with traditional supply resources. Advances in evaluation, measurement, and verification (EM&V) mechanisms and measuring savings at the meter will be a key enabler of this evolution. EM&V has always been an important aspect of energy efficiency delivery, but data analytics and automated EM&V practices can enable more precise assessment of EE effectiveness. This, in turn, would allow for new procurement models. For example, when a utility determines that an upgrade of a portion of its transmission and/or distribution grid will be needed in the future to avoid a load constraint, a "Non-Wires Alternative" (NWA) that uses targeted energy efficiency or other means to reduce future load on the grid may prove to be more cost effective.

To deliver value to consumers and energy savings to electricity systems, markets must provide sufficient certainty for a wide array of technologies and business models. AEE recommends specific design elements to encourage effective EE implementations. In particular, AEE encourages regulators to consider policies and practices that encourage open procurement, customer engagement, EE financing, targeted DSM and use EM&V to reward performance. These different procurement models could still be supported with an underlying policy requiring utilities to meet annual EE targets or requiring them to pursue all cost-effective EE.

OPEN PROCUREMENT.

Market procurement of EE implementations must be open, clear, and sufficiently predictable enough to sustain energy efficiency as a business opportunity. Flexible approaches to procurement should reward innovation and encourage investment in EE. Markets rules should set clear requirements and aim to reduce transaction costs of EE measures and address barriers.

As an example, utilities can issue EE requests for offers (RFO) to the competitive market to solve an identified need. Pacific Gas & Electric in California is issuing RFOs for EE projects and other greenhouse gas-free energy resources to replace the generation from the Diablo Canyon nuclear power plant, which is set to retire in 2025. The first round of RFOs will be for EE only.[10]

CUSTOMER ENGAGEMENT.

Information feedback and customer engagement programs are helping customers discover new ways to save energy through on-line energy management tools. By leveraging data analytics and customer intelligence, these

tools provide customized energy insights and actionable information to encourage energy savings. On-line web portals provide customers with energy saving tips, load disaggregation, billing insights, energy data access, and usage alerts. Collectively, these insights empower customers to become more engaged, while increasing satisfaction and leading to higher participation in EE programs.

DIVERSITY OF FINANCING OPTIONS.

There should be creativity in options for financing to ensure the value of EE is delivered and that parties share in costs and benefits appropriately. Upfront costs to consumers, including those who could most benefit from EE measures, should be considered a barrier to market activity. Increasing access to financing options may create new and compelling value propositions for customers, utilities, and financing institutions. Property Assessed Clean Energy financing, or PACE, which uses tax liens to engage commercial debt markets and provide repayment of energy upgrade costs through property tax bills, is one example. Emerging models, including on-bill financing for utility customers, may also drive energy efficiency investment.

The P4P and open procurement arrangements described earlier also create opportunities for innovative EE financing that treats EE similar to supply side options. Whereas a utility might enter into a power purchase agreement (PPA) for electricity supply, it could instead enter into a savings purchase agreement (SPA) for specific load reductions brought about by EE deployment. This opens up the possibility of using project finance for EE instead of traditional financing options, which often rely on individual customers investing out-of-pocket or borrowing to pay for EE. With project finance, the stream of savings over time produces a cash flow that can be financed like any other project.

UPDATING EVALUATION, MEASUREMENT, AND VERIFICATION PRACTICES.

Traditional EM&V consists of comparing a given measure to the performance characteristics of a replaced measure, then multiplying the difference by the life of the new measure. However, new technologies provide increasingly sophisticated ways to quantify the actual performance of EE measures once in use. For example, smart meter data can be used for energy savings calculations and rewards. Advances in monitoring EE performance may help market participants guide decisions about EE investments.

REWARDING PERFORMANCE.

Performance-based frameworks for utilities identify outcomes that are sought, and then align earnings, often through specific rewards, for attaining certain levels of performance. Linkages between financial rewards (or penalties) for utilities and desired outcomes must be better aligned with EE innovations. In markets for utility programs, desired outcomes can be linked to an index of performance in addition to, or in place of, the basic cost of providing services.[11]

Rewarding performance should be accompanies by other regulatory reforms. General rate-setting practices create an inherent financial disincentive for utilities to participate in EE programs, given that a successful energy usage reduction program would have a direct negative impact on utility revenue, and could impede a utility's ability to fully recover its costs. Revenue decoupling mechanisms are now being used in many states to ameliorate these disincentives, so that utilities may invest in EE programs without the associated negative effect on earnings. Revenue decoupling breaks the traditional link between a utility's revenues and earnings. For most mass-market customers of utilities, their monthly bill contains a relatively small fixed monthly charge, and most of the bill is derived from a volumetric charge based on electricity consumed. But as customers consume less, they avoid the related volumetric charges, which reduces revenue collection. By employing a decoupling mechanism, the volumetric charge is adjusted (e.g., through a surcharge mechanism) so that the required revenues are collected, even though consumption has declined.

CONCLUSION

Energy efficiency will continue to play an increasingly important role in a modern electricity system. Policymakers and regulators have a range of established and emerging practices to ensure that markets for EE continue to grow and make the most out of innovative technology and services. Taking advantage of the latest technology and data analytics, in particular, opens up possibilities for new EE procurement models that can continue to drive cost-effective EE deployment, save money for customers, and improve the electric power system for all.

END NOTES

[1] http://info.aee.net/21ces-issue-briefs

[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE's members.

[3] Approximately 2.2 million jobs in the United States are associated with energy efficiency. http://blog.aee.net/at-more-than-3-million-jobs-advanced-energy-is-a-big-and-growing-source-of-employment-in-the-us

[4] For more information, see AEE Institute's Issue Brief on *Advanced Metering.*

[5] For more information see AEE Institute's Issue Brief on *Access to Data*

[6] Advanced Energy Economy. *Advanced Energy Now 2017 Market Report.* http://info.aee.net/aen-2017-market-report

[7] For more on this topic see our Issue Brief on *Rate Design for a DER Future.*

[8] For more information, see our Issue Brief on *Performance-Based Regulation*

[9] The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: Estimates at the National, State, Sector and Program Level, Ian M. Hoffman, Gregory Rybka, Greg Leventis, Charles A. Goldman, Lisa Schwartz, Megan Billingsley, and Steven Schiller, April 2015.

[10] https://www.hubs.com/power/explore/2016/06/efficiency-energy-storage-renewables-planned-due-to-diablo-canyon-retirement.

[11] For more information, see our AEE Issue Brief *Performance Based Regulation*

OPTIMIZING CAPITAL AND SERVICE EXPENDITURES

Providing utilities with financial incentives for a changing grid

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Optimizing Capital and Service Expenditures** describes this emerging issue, reviews regulatory approaches for putting capital and service spending on an even playing field, and makes general recommendations on a path forward.[2]

SUMMARY

Throughout the economy, companies are finding new efficiencies and operational benefits by meeting technology needs through services provided by third parties rather than investing in physical assets that they own and manage.[3] However, this trend toward services has been slow to take hold in the utility industry because it conflicts with the prevailing utility business model. Since capital investments are the main driver of utility profits in this model, services that can improve the utilization of, defer, or replace capital investments have the effect of reducing utility opportunities for profit. This can bias utilities away from service-based alternatives that may be more cost effective for their customers. Since many state-of-the-art technologies are offered only as a service, utilities face an artificial barrier to improving the quality and cost-effectiveness of the electric power service delivered to their customers.

As more technologies shift to services, this not only presents a barrier to optimizing investments but also a threat to the stability of utility earnings. While utilities may not have a financial motivation to look for greater efficiencies through technology-based services, the cost-effectiveness of these services may push utilities in this direction anyway. Realizing that both customers and utilities stand to benefit through equalizing the earnings opportunities between traditional capital solutions and service solutions that can replace them at lower cost, several state utility commissions have explored mechanisms to correct the bias toward capital investments that is inherent in cost-of-service regulation.

Some of these mechanisms, such as capitalization of a service contract or the use of regulatory assets,[4] are often used today without any changes in regulation. These mechanisms allow utilities to place "service assets" in the rate base and depreciate them like capital investments. Other possible regulatory mechanisms could provide additional motivation, such as allowing the utility to retain a share of the cost savings from service-based solutions. This issue brief will explore the impacts of different regulatory mechanisms and make some general recommendations for implementation.

NEW SERVICES FOR UTILITIES

As new technologies develop today, they are frequently offered as a service, where the provider owns the technology, operates, and maintains the technology and guarantees an outcome or an output in the contract. This is in contrast to the sale of a technology as a physical asset, where the maintenance, operation, and final outputs are the responsibility of the purchaser. Services take advantage of the experience of specialized companies in operating specific types of assets, and can provide significant value compared to an ownership-based model. Often these services can be delivered more effectively because the service provider pools assets and more efficiently utilizes capacity, compared with each utility acquiring enough capacity to serve its own needs.

Cloud computing is a prime example of a service that embodies all the benefits described above. For decades, utilities have deployed their own IT resources and servers, purchased software, and hired staff to manage and operate the systems. This requires a significant investment of onsite computing capacity and internal staff development to make all of the resources function properly. If the utility were to purchase the software as a service (SaaS), with all of the security and IT infrastructure supplied by the service provider and its own network of partners and vendors, the utility could leverage the specialization and expertise of the provider and benefit from cost efficiencies through use of shared infrastructure (such as the provider's data center). Cloud computing also allows utilities to scale capacity up or down on demand, providing much greater flexibility than a system that is owned and operated by the utility. Making use of SaaS also ensures that the systems are always up to date, will not become obsolete, and are easier to keep secure. However, for regulated utilities, if cloud computing is treated as a service expense, it replaces an earnings opportunity – the capital expenses related to IT infrastructure and software – with a service expense that earns the utility no return.

These principles that apply to cloud computing – scalability, flexibility, security, resource efficiency – often apply to other parts of the utility business. Various forms of non-wires alternatives (NWAs) rely on services that, in many cases, can effectively replace utility capital expenditures. Take, for instance, a distribution transformer that is reaching its capacity limit due to growing peak demand in the summer. On one of the feeders served by the transformer, a large customer is considering purchasing a battery for reliability and to reduce their demand charges. The utility could contract for dispatch rights on the battery during the top summer demand hours, alleviating the need to invest in an expensive new transformer. The customer can make use of the battery during the other hours for energy arbitrage, backup power, and demand charge savings. While the utility saves by not purchasing an expensive transformer, it is in essence replacing that equipment and capital investment with a service contract for dispatch rights. The same scenario is applicable to a

contract with a demand response provider, which pays its customers to reduce peak demand, aggregates that peak demand reduction, and sells it to the utility to offset the need for the new transformer investment.

As described in depth later, the loss of earnings that a utility incurs by choosing more cost-effective, service-based options can be offset through a number of methods that aim to provide utilities with equivalent earnings.

THE REGULATORY MODEL AND UTILITY PROFIT DRIVERS

The current form of cost-of-service regulation has been around for many decades and has served both customers and utilities well. Utilities deploy capital that they raise from lenders and equity investors to make the long-term investments needed to provide electricity to customers: poles, wires, transformers, generators, etc. Over time, utility customers pay for the cost of these investments in rates. Regulators set rates that allow utilities to recover the cost of their initial investment (yearly depreciation) plus the cost of debt and return on equity (the cost of capital or carrying costs) on the undepreciated amount. These carrying costs reflect the return lenders and investors require for providing the capital and account for both the time value of money and the risk, small though it may be, that the capital may not be repaid to lenders and investor equity may decrease in value. As utilities enjoy some of the lowest risk profiles and best credit ratings in the economy, they can borrow and provide returns to investors at relatively low rates.

The way that utility shareholders profit is that regulators usually afford investors an opportunity to earn a higher rate of return on their equity than the cost of equity[5] – the return provided by other companies in the economy with a similar risk profile. This is part of what makes utilities an attractive investment. Currently, utilities around the country are allowed to earn an average of 10%[6] return on equity while companies with a similar risk rating on average yield about 7.5%.[7] The 2.5% difference is *economic* profit. This spread between the cost of equity and the return on equity (often referred to as *r-k*) is the driver of investment for a utility. If regulators provide a return that is lower than what other companies provide, investors incur opportunity costs. Capital would likely leave utilities for higher returns at other companies with a similar risk profile, harming the ability of utilities to make necessary investments. However, allowing investors to earn an above-market rate of return has the opposite effect and drives utilities to increase their capital investments. As utilities invest more in transformers, wires, and other plant, profits increase.

In addition to capital expenditures, utilities can also increase earnings through closely managing their operating expenditures, such

as maintenance, salaries, and fuel. These operating expenditures are recovered in rates, but unlike capital expenditures, utilities do not earn a rate of return on them. Instead, as an incentive to keep costs down, operating expenditures that exceed the level provided in a utility's current rate plan are, up to a set threshold, paid out of the utility's earnings and are not passed on to customers. Additionally, many states have an Earnings Sharing Mechanism (ESM), which allows a utility to retain a share of unspent operating funds as profit to incentivize efficient use of operating funds. In some cases, these unspent funds can be invested in capital and earn a return, thus expanding the rate base without special regulatory approval. As a result, utilities work to minimize their operating expenditures, both to avoid the risk of expenditure overruns eating into their profits and to potentially retain some of the unspent operating funds as profit.

When cost-of-service regulation was designed, it made sense to focus incentives on minimizing operating costs. System needs could usually only be fulfilled with a few types of capital investments (poles, wires, generators, transformers, etc.), while operating expenditures were generally seen as overhead. Regulators were responsible for making sure the system was built to be reliable with the lowest possible capital investment.

Today, due to innovations in technology and business models, utilities have far more options for meeting their operating goals of reliability, safety, cost-effectiveness, and quality of service. In some cases, operating expenditures (such as services from SaaS and distributed energy resources[8]) can more cost-effectively fulfill system needs than the traditional capital investments. But shifting spending from capital investment to operating expenses runs counter to the incentive structure favoring fixed, long-lived capital assets that still predominates in the utility sector.

This presents a dilemma. Utilities take very seriously their responsibility to serve customers with safe and reliable power, but they also take seriously their duty to deliver earnings to their shareholders. Thus, the regulatory framework at times makes utilities choose between serving the best interests of their customers and serving the best interests of their shareholders. For the reasons described above, utilities lack the right incentives to minimize their capital costs, especially if the reduced capital costs are accomplished through an increase in operating expenses.

The goal of the regulatory reforms that are the subject of this brief is to incentivize the utility to optimize among all potential expenditures, whether they are for capital investments or service contracts, for the ultimate benefit of customers. Utilities know their own systems better than anyone and are in the best position to leverage that knowledge to seek out efficiencies. But without the necessary financial motivation on the part of utilities, the current system relies on regulators with incomplete information to identify and attempt to enforce efficiencies. Resolving the conflicts inherent in the system should thus not only benefit customers and utilities, but also ease the burden on regulators.

UTILITY ACCOUNTING

In discussing the utility business model, it is necessary to briefly touch on accounting rules. Utilities need to comply with two different accounting standards, the Uniform System of Accounts (USofA) established by Federal Energy Regulatory Commission (FERC) and the U.S. Generally Accepted Accounting Principles (GAAP) adopted by the Securities and Exchange Commission. Each serves a different purpose.

FERC established USofA to create uniformity in reporting and to provide the Commission with the information it needs to carry out its duty of ensuring that the rates of jurisdictional utilities are just and reasonable. GAAP was created to provide standards for the financial statements of public companies. GAAP is meant to increase transparency and uniformity in public financial statements for the benefit of investors, while USofA is meant to provide energy regulators with sufficient and accurate information to perform their oversight duties. FERC has been clear that USofA, not GAAP, is the key accounting system for regulatory purposes, noting that if GAAP conflicts with the accounting and financial reporting needed by regulators to fulfill their statutory responsibilities, then USofA supersedes GAAP.[9]

Most states voluntarily adopt USofA as published by FERC,[10] but state utility commissions have the ability to adapt them. While implementation will require less change if new regulatory mechanisms are compatible with existing accounting standards, these standards are not limitations on state authority. If a commission believes that it can better protect customers and improve the way utilities earn a fair return through regulatory changes that are incompatible with USofA and GAAP, it has the authority to do so. Some specific examples are given below.

REGULATORY SOLUTIONS

A number of states have explored or enacted solutions that attempt to address the loss of earnings to utilities when services replace capital expenditures. Below are some general observations about the potential strengths and weaknesses of each regulatory solution.

CAPITALIZATION OF A PRE-PAID SERVICE CONTRACT

The first solution is to pre-pay the total cost of a service contract for a specified term and place the amount of pre-payment in the rate base. This would allow the utility to depreciate the contract over a number of years and collect carrying costs (which include the shareholders' return on equity) on the undepreciated amount until the contract is fully depreciated. In this

case, the pre-paid contract functions as any physical asset would in the utility's rate base.

Arguably, this is only a minor departure from the current regulatory framework, and for some types of services, would not require adjustments to regulation and accounting practices at all. For instance, regulatory assets are commonly used in many states where large expenses are paid but then carried by the utility (with carrying costs) in order to avoid immediate impact on rates. An example of this is plant decommissioning. Under USofA, utilities may place services into one of several different accounts. For instance, Software-as-a-Service can be placed in USofA Account 303, which is reserved for Miscellaneous Intangible Plant.[11] Another option is USofA Account 165, which is reserved for pre-paid contracts.[12]

For state regulators looking for a first step to resolve the impact of lost earnings by utilities choosing a service solution rather than a capital investment, this capitalization approach is a good option, but it does have several limitations.

First, assuming the capital investment and the pre-paid service contract are similar in costs, the utility will be neutral to either option; however, if the service contract offers significant savings relative to the capital investment, the utility may lack motivation to pursue that option, as it will reduce the utility's opportunity for earnings. Other regulatory approaches described below attempt to share some of the cost savings with the utility as an incentive for the utility to produce the cost savings in the first place.

Second, the lifespan of the asset also matters in determining total utility returns, as depreciation is tied to the useful life of the asset. If the contract is only for three years, the value will depreciate at 1/3 of total value per year. Compare this to a 30-year asset, which depreciates at 1/30th per year. As utilities earn carrying costs (which includes investor return) yearly on the undepreciated value, a shorter lifespan is less attractive than a long one. The same amount of initial investment can provide a larger amount of return over time if it has a longer useful life.

Third, as capitalization requires a service contract to be paid up-front so that the costs can be depreciated over time, services that are available only short term or only through yearly service contracts are not compatible with this approach. As an alternative, some approaches below allow for services to be treated as short-term expenses.

NEW YORK: NON-WIRES ALTERNATIVE SHAREHOLDER INCENTIVES

The New York Public Service Commission has implemented a NWA shareholder incentive,[13] which combines the capitalization of service costs, as described in the first solution of this section, with a shareholder incentive consisting of a share of the benefits produced by the NWA relative to a traditional solution. If a utility chooses to defer or avoid a distribution upgrade through NWAs, the utility can recover the costs of the NWA, including the cost of incentive payments paid by the utility to customer and third-party owned resources, over 10 years and collect its carrying costs over that time.

This functions as a regulatory asset, as previously described. However, in order to

encourage the utility to pursue more cost-effective solutions, the utility can also receive a 30% share of the difference between the net present benefits of the NWA and the traditional solution that it replaces. The net benefits of each project are determined by New York's Benefit Cost Analysis (BCA) framework, which includes societal benefits such as emissions and carbon reduction in addition to energy and capacity benefits. For other states that want a simpler process or narrower range of benefits considered, the total cost of the NWA and projected cost of the avoided capital expenditures (including carrying costs) could be compared, and the incentive could be set as a share of the difference.

As the utility's incentive is based on a share of the net benefits, which are the remaining benefits after costs are subtracted, the utility should be motivated to keep down the cost of implementing the NWA. In addition, Con Edison requested and received regulatory approval for an additional cost-efficiency incentive. Cost overruns and underruns are shared 50/50 between Con Edison and its customers. If the utility reduces costs, it can share in the savings up to 50% of the net present benefits of an NWA. On the flip side, if there are cost overruns in implementing the NWA, the incentive can shrink all the way to zero.

The benefit of the NWA shareholder incentive is that it initially provides the same earnings opportunity for NWA solutions and the avoided capital expenditures. They would both receive upfront investment that would be depreciated over time with the utility return applied to the yearly undepreciated amount. But it goes further and looks at the total lifetime costs and benefits of each solution and provides the utility with an incentive set as a share of the net benefit.

While this mechanism provides a number of good efficiency signals to utilities, it is more complex to implement. The NWA and avoided investment must both undergo a BCA. As discussed above, this could by simplified by merely comparing total costs of the NWA solution vs. the traditional solution. This mechanism also presents the potential for gaming if the utility attempts to inflate the costs of a traditional investment in order to increase the savings and net benefits of the NWA solution. While this type of problem is not new for commission staff, who regularly scrutinize utility capital plans, this mechanism may strengthen the incentive for utilities to inflate them. Additionally, as this solution relies on the capitalization of an expense, it must also be prepaid rather than paid out over time like most payments for services.

NEW YORK: "MODIFIED CLAWBACK MECHANISM"

Prior to implementing the NWA incentive, the NY PSC had modified its net capital plant reconciliation mechanism ("clawback") to compensate for lost earnings related to NWA projects, but in a different way. If a utility is looking to boost short-term earnings, a utility can underspend its capital budget and retain the savings as earnings until its next rate plan period. (A utility that does this would sacrifice the greater long-term earnings on capital investments that were never made.) To compensate for this short-term incentive to underspend, the clawback mechanism returns the unspent capital budget and associated earnings to customers.

During the course of the Reforming the Energy Vision Proceeding, the NY PSC ordered[14] changes to address the potential for the clawback mechanism to interfere with the goal of encouraging utilities to rely on DERs for NWA projects. If the utility were to avoid a capital expense with a DER contract, the clawback mechanism would reduce the capital budget and earnings by the amount associated with the avoided capital investment, while the DER would be procured with a service expense for which the utility would get no additional rate recovery (and therefore risk eating into utility profits through operating expense overruns).

The modification the PSC ordered is relatively simple. If the utility shows that a portion of its capital budget was avoided by a service expense for DER, the clawback mechanism will not be implemented on that portion of the budget. The utility will retain the avoided portion of the capital budget and associated earnings and pay out the service expense without additional rate recovery. As long as the yearly service expense is less than the yearly amount of depreciation and carrying costs in the capital budget, the utility will profit by retaining the savings.

This mechanism has a number of positive traits. First, it allows the utility to share in the savings from making a less expensive service expenditure. Until its next rate case, the utility captures all of the savings, and in following years, the customers receive all of the savings. Also, as the savings are generated through a comparison of yearly costs, the service expenditure can be paid out on a yearly basis and does not need to be prepaid. As long as the yearly expense payments are lower than the cost of the capital investment, customers benefit.

The primary disadvantage of the modified clawback mechanism is that it is only effective for a short time, i.e., for the period of the rate plan. In New York, utilities must file a rate case every three years. After the next rate case, the utility's operating expense budget will increase to include the cost of the DER expense, but the utility will no longer retain the savings from the avoided capital investment. While this covers the ongoing cost of the DER expense, so the utility does not have to absorb it, only during the rate plan in which the initial capital investment was avoided does the utility effectively earn on the DER expense.

If the utility retains the savings only until the next rate case, then the maximum amount of time a utility can earn on the savings is for three years (in the case of New York). This may be sufficient for an asset that lasts five to 10 years, but it is likely to fall well short of providing the earnings expected from a 30-year investment. The timing of the investment can also be a constraint. If the investment happens early in the rate plan period, then the utility can earn for three years, but if the utility makes the investment shortly before the rate plan ends, it may not be able to retain any savings as earnings. Nevertheless, as one of several modifications to earnings that regulators can implements, the modified clawback mechanism can help to incentivize utilities to pursue cost-effective service options.

CALIFORNIA: DER INCENTIVE PILOT

The California Public Utility Commission is piloting[15] a different method for compensating utilities for avoided earnings on NWA ex-

penses. Instead of capitalizing the expense as a regulatory asset, California provides an incentive to the utilities that amounts to 4% of the value of the service expense. This is meant to represent the value of the foregone earnings to shareholders. In the proceeding, there were differing justifications cited for the 4% level. Some argued it would represent the forgone economic earnings relating to the difference between the shareholder's cost of equity and return on equity, as was described earlier as "r-k."[16]

The incentive is a simple solution that aims to provide earnings on a service expense as an offset to the earnings forgone in a capital expenditure. However, as the incentive is based on the cost of the service expense rather than the avoided asset, the utility may still have to forgo greater earnings when it chooses a more cost-effective solution. Even if the incentive is applied to a service expense of equivalent value to the yearly depreciation cost of a capital investment, it will not provide earnings that approach those of a capital investment. The carrying costs on a capital investment are applied to the undepreciated amount, which is many multiples larger than the size of the yearly depreciation until the last year of the asset's useful life. The incentive also provides no means of sharing the savings of an avoided expenditure. On the plus side, the incentive is flexible. As the incentive is based on yearly service costs, it is potentially more suitable for short-term investments of one or two years.

CONCLUSION

States are exploring a number of methods to help utilities efficiently optimize their operating and capital expenditures and deliver better value to customers. Some states are going further by counterbalancing the predominant utility incentive to deploy capital to increase earnings with mechanisms that share the savings when they spend less. One approach, capitalizing service expenditures, is consistent with how states treat regulatory assets today and state commissions could easily adjust their practice to include expenses that cost-effectively offset capital investments. Regulators and utilities can move forward incrementally as they gain more experience in capitalizing these service expenses. As a second approach, commissions could introduce shared-savings mechanisms to provide the utility an incentive to deploy capital more efficiently.

If these regulatory reforms function act as designed, the net effect will be a reorientation of incentives in the regulatory model toward motivating utilities to explore new technologies and seek out efficiencies within their own systems as a means for both increasing profits for their shareholders and delivering better and more cost-effective service to their customers. Utilities should also become more neutral as to who owns an asset if the utility can profit from the asset whether it is owned by itself, a customer, or a third-party. Providing an opportunity for utilities to earn by optimizing their investments and driving down costs should also make the regulatory process easier and potentially less contentious.

END NOTES

[1] http://info.aee.net/21ces-issue-briefs
[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.
[3] The simplest example is a company that decides to lease, rather than own, a fleet of vehicles. Examples within utility procurement are numerous, as explained later, but they include a utility contracting for Software-as-a-Service rather setting up a data center, or a utility contracting for targeted demand response rather than upgrading a transformer.
[4] Regulatory assets are costs or revenues that a regulatory agency permits a utility to place in its balance sheet, effectively treating it like a capital investment.
[5] This concept is explained in much greater detail in a paper published by America's Power Plan. It is recommended reading for anyone interested in greater detail on the subject. See: *You Get What You Pay For: Moving Toward Value in Utility Compensation.* By Steve Kihm, Ron Lehr, Sonia Aggarwal, and Edward Burgess. Available at: http://americaspowerplan.com/wp-content/uploads/2016/07/CostValue-Part1-Revenue.pdf
[6] Average of current allowed returns on equity for major IOUs as listed in PowerPortal, part of Advanced Energy Economy's PowerSuite tools. https://powersuite.aee.net/portal/states
[7] See *You Get What You Pay For: Moving Toward Value in Utility Compensation.*
[8] Distributed energy resources (DER) is defined broadly to include distributed generation of all types, demand response, energy efficiency, energy storage, electric vehicles and the associated electric vehicle supply equipment, and microgrids.
[9] FERC Order No. 552, Issued March 31, 1993.
[10] USofA is mandatory for only those units of utilities that are under FERC's jurisdiction, such as transmission operators. Code of Federal Regulations, Title 18, Part 101.
[11] USofA account 303: "This account shall include the cost of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account."
[12] USofA account 165: "This account shall include amounts representing prepayments of insurance, rents, taxes, interest and miscellaneous items, and shall be kept or supported in such manner as to disclose the amount of each class of prepayment."
[13] Order Approving Shareholder Incentives, New York Public Service Commission, January 25, 2017, in proceeding 15-E-0229.
[14] Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. New York Public Service Commission. May 19, 2016. Proceeding 14-M-0101.
[15] Rulemaking 14-10-003.
[16] It is interesting to note that the CPUC applied the 4% incentive to the total value of the service expense rather than 50% of the total value, which would more closely resemble how a company's return on equity is applied to the value of a capital asset. Utilities fund their capital investments with both debt and equity at a ratio regulated by state commissions. In most cases, equity only funds around 50%, so the return on equity is applied to only this share.

PERFORMANCE-BASED REGULATION

Aligning utility incentives with policy objectives and customer benefits

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

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ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Performance-Based Regulation (PBR)** describes this emerging regulatory approach, provides various performance incentive design options, and lays out recommended steps to follow to implement PBR.[2]

SUMMARY

Performance-based regulation (PBR) is a regulatory framework designed to better align the financial interests and actions of regulated utilities with public interest objectives and consumer benefits. A PBR framework rewards utilities for achieving well-defined outcomes (performance metrics) as opposed to simply incentivizing capital investment (inputs), which is the primary driver today of utility revenue and profits. Regulatory reforms, such as PBR, have the potential to change how utilities, customers and third-party providers generate, deliver, and use energy.

AEE believes that PBR, in its various forms, can serve as a foundational regulatory framework of the electric grid of the future. Future infrastructure investments must be evaluated in light of technological innovations, and judged on the basis of the value delivered by and through those investments. In this regard, AEE supports regulatory mechanisms that enable value creation, long-term viability of the utility business model, and deployment of the modern technologies that will form the basis of a 21st century power grid. In support of these goals, this issue brief lays out the basic concept of performance-based regulation, considers different performance incentive design options, and offers implementation recommendations.

INDUSTRY & REGULATORY EVOLUTION

The U.S. utility sector is in a period of significant change, driven largely by information technology and falling costs for distributed energy resources (DER).[3] At the same time, U.S. electric investor-owned utilities continue to invest on the order of $100 billion annually, as aging infrastructure is replaced and modernized.[4] Those investments must be consistent with the evolving needs of customers and must be guided by regulators to ensure long-term compatibility with the grid of the future.

The energy infrastructure and markets of the future will be more complex, will include a greater number and variety of actors, and will present technical challenges (such as managing two-way power flows over the electricity distribution system and a much larger number of interconnected devices) as well as business challenges (such as the long-term viability of a utility business model now built around increasing capital deployment and rising energy sales). With these developments come challenges, but also new opportunities. If managed successfully, these changes present opportunities for greater

customer choices and engagement, the creation of a more efficient and resilient energy system, and opportunities for utilities to embrace new business concepts that will sustain them in the decades to come.

AEE views new regulatory approaches as necessary for enabling a modern energy infrastructure. Traditional regulatory approaches have supported a rigorous evaluation of investments to control costs of service provision. However, utilities and regulators alike note that these traditional approaches are not designed to foster grid evolution. A future grid characterized by greater intelligence, two-way flow of information and electricity, technological innovation, and high penetration of DERs requires changes to regulatory decision-making. PBR is one option to consider, as it enables utilities to earn incentives for achieving specific outcomes that will be essential to creating the grid of the future.

CORE CONCEPT

The idea of PBR represents an evolution from traditional utility regulation. Regulatory goals, utility earnings opportunities, capital investment incentives, and regulatory processes change to focus on performance. Table 1 below contrasts traditional and PBR frameworks.

Regulatory agencies establish PBR by creating links between regulated utility financial rewards (or penalties) and desired outcomes. These outcomes are tied to an index of performance in addition to, or in place of, the cost of providing services. PBR also can include other elements of regulatory reform, such as revenue decoupling and multi-year forward-looking rate plans. Used together, these changes to cost-of-service regulation can better align regulated earnings with desired outcomes.

PBR frameworks can also accelerate the way regulation reacts to market dynamics. Traditional regulatory processes can lag industry developments. This regulatory lag may unintentionally limit economic growth potential, slow technological advances and deployment, and negatively impact utility financial performance.

There is no one-size-fits-all solution for successful PBR deployment. Nevertheless, experience suggests that the following basic framework can be used to help policymakers and utilities design and implement changes that best fit their specific needs and circumstances.

Table 1 – Core PBR Concepts Compared to Traditional Regulation

	Traditional Regulation (Cost of Service)	Performance-based Regulation
Goals	Focus on reliability, affordability, adequacy of highly centralized electricity delivery systems. Consumers are protected from monopolistic power through reasonable rates and careful regulatory oversight.	Focus on traditional regulatory goals, as well as specific outcomes defined by policymakers, utilities, and stakeholders. Consumers are ensured reliable services. Facilitates opportunities for customer and third-party value creation and innovation.
Incentives for Utilities	Revenues are earned through recovered costs. Regulators approve costs, which are embedded in basic rates, often based on per-unit (volumetric) energy usage. The utility is incentivized to increase usage to drive up revenues.	Revenues are earned through a variety of rates and programs. Incentives are designed, communicated, and evaluated. Rates are designed to vary for value propositions to facilitate reliable services and technology deployment.
Earnings	Regulators evaluate prudent cost of expenditures for services, with the level of capital expenditure primarily driving earnings.	Utilities optimize total expenditures (capital and operating) and regulators reward valued outcomes. Regulated earnings are adjusted (up or down) based on performance against specific metrics.
Time Scale	Short-term focus on cost minimization, with a traditional long-term capital planning process.	Balanced focus on short-term cost minimization/near-term grid reliability investments and longer-term investment in future grid architecture, improving performance and achieving public policy goals.

IMPLEMENTING PBR

ESTABLISHING AUTHORITY TO IMPLEMENT PBR. When evaluating PBR, stakeholders must operate within the jurisdiction's unique circumstances, including legal, institutional, utility, and financial market considerations. In many states, the utility regulator is uniquely positioned, and has statutory authority, to act related to PBR objectives. However, it must be clear which governmental entity has authority to define what PBR means for the state. This includes a clear ability to act on utility incentives, including valued outcomes. Incentives that align utility revenues and cost recovery with effective performance encourage utilities to invest in a wider array of programs and technologies than they might otherwise consider under existing cost-of-service regulation. When designed appropriately, PBR may provide stability in rates and costs while

facilitating innovation in energy services and technologies and improving performance.

Case Study from Illinois' Smart Grid Act

In October 2011, Illinois passed the Energy Infrastructure Modernization Act (EIMA), which became law as Public Act 097-0616.[5] As part of the broader act, the legislation required Commonwealth Edison and Ameren Illinois to file multi-year metrics to achieve performance goals over a 10-year horizon. This requirement ultimately led to the establishment of tracking and performance measurement on an array of categories, including reliability indices, peak demand reductions, renewable energy adoption, greenhouse gas reductions, reductions in estimated bills, and the adoption of new smart grid technologies.

It is important to identify opportunities and limitations that may impact a PBR framework. Many states have strong foundations that can serve as a basis for establishing PBR. For example, many state regulatory commissions already have authority to connect outcomes (e.g., performance on reliability indices, customer satisfaction metrics, or demand-side management goals) to utility financial opportunities. However, there may be authority that is limited, requiring either scoping a few areas of PBR, or seeking additional authority from lawmakers to pursue additional areas.

STAKEHOLDER ENGAGEMENT. Stakeholder input in defining outcomes is crucial to PBR success. To increase transparency and stakeholder involvement, regulatory processes should ensure stakeholders are part of establishing the critical aspects of PBR plans – such as setting performance targets and incentives. Utilities might understandably try to set easily achievable targets, whereas a regulatory body or other stakeholders may argue for targets that seemed unachievable. Engaging in a collaborative process, with the overarching policy objectives guiding the discussion, is more likely to result in a set of targets and incentives that will promote success and achieve meaningful outcomes.

For example, in Massachusetts, utility-sponsored energy efficiency programs have a strong performance component. An independent Energy Efficiency Advisory Council, made up of a variety of stakeholders, helps set energy efficiency targets and the associated incentive levels. Although the Massachusetts program falls short of a full PBR framework that would apply to a wider range of utility activities, it provides useful real-world experience with a successful program that is large, is embraced by the state's utilities, and combines PBR principles with other complementary polices (such as revenue decoupling).

DEFINING PERFORMANCE. To implement PBR, legislators, regulators, and stakeholders should work together to define, prioritize, and incentivize desired performance. Performance objectives may be specific to a given jurisdiction. Examples of broad categories of performance include customer empowerment, operational reliability and efficiency, environmental sustainability, and market innovation. Specific metrics that can assess performance across these categories

are then defined (see *Establishing Metrics and Incentives* below).

The level of incentive is another important consideration. For PBR to be successful, incentives must be large enough to have the desired effect on utility behavior, but capped to protect consumers. In the UK, where they have implemented a comprehensive PBR framework,[6] incentive levels are relatively large (+/- 300 basis points) but subject to an overall revenue cap, which prevents the utility from "gold plating" investments to drive up earnings without providing incremental benefits to customers. In New York State, which recently implemented a more modest version of PBR as an overlay to cost-of-service regulation, incentives are limited to a maximum of 100 basis points (positive only), but without a revenue cap. In situations where there is no revenue cap, we recommend converting incentives from basis-point adders to an absolute dollar figure, to avoid the situation where the utility may seek to drive up its rate-base investments to increase profits from PBR. For example, in Massachusetts, the incentive levels within its energy efficiency program are set at specific dollar amounts for specific levels of achievement.

ESTABLISHING METRICS AND INCENTIVES.

Generally, performance targets and metrics should be designed around the most important, forward-looking assumptions that impact the business case of a proposed utility investment. Although metric categories should be similar for all utilities in a jurisdiction, actual targets can vary from utility to utility to reflect differences in the customer base, system condition, or other factors.

While each jurisdiction should develop metrics most relevant to its goals, below are examples of specific metrics that are consistent with the evolving nature of the electricity system.

- **Reliability:** SAIDI[7], SAIFI[8], or other indices, if not already subject to performance requirements.
- **Data access:** Consumer access to standardized and actionable energy consumption data; third-party access to system data.
- **Energy efficiency:** Quantifiable reductions in total electricity usage.
- **Peak load reduction**: Targeted demand reductions during peak periods – a primary driver of utility costs.
- **Third-party resource deployment:** Distributed energy resource deployments by third parties (including on behalf of customers).
- **Interconnection:** Volume and processing speed of filling requests to connect resources to the electricity system.

PLANNING IN THE PBR CONTEXT.

Incentives are provided when a utility achieves certain goals (outputs); however, these new output incentives need to be considered in the context of the input incentives under which utilities currently operate. Broadly, output incentives are rewards for achieving certain outcomes, which are the result of a combination of investments, management, and operational decisions (and potentially the decisions of customers and other actors), while

input incentives focus on rewarding the capital invested in certain types of assets. When it comes to investments, utilities have short, medium, and long-term considerations. PBR should not lead utilities to focus on short-term gains at the expense of future performance. Any form of PBR must therefore include planning that provides insight on the impacts of the inputs over all time frames. An important foundation for effective PBR is thus a planning process that can show the reasonable alternatives for various investment and operating choices. This enables effective target-setting against the metrics developed in the PBR framework.

OPTIMIZING BETWEEN CAPITAL AND OPERATING EXPENSES. One goal of a PBR framework is to put operating expenses on a more equal footing with capital investments, particularly when non-capital spending can provide a superior solution.[9] This could be, for example, in procuring load reductions from customers and third parties deploying DER in lieu of a traditional distribution infrastructure upgrade. Another example could be incentivizing permanent peak reduction with targeted energy efficiency investments by building owners that help with near-term operational needs. Under a PBR framework, which does not just reward utilities for capital investment, utilities look at a broader array of potential solutions knowing that those based on operating expenses (e.g., contracts for demand response services, administration of energy efficiency programs) also provide earnings opportunities. Furthermore, incentives and rates could be adjusted regularly pursuant to a review of utility performance and service quality metrics.

PRIORITIZING METRICS AND LEARNING. The foregoing discussion suggests that there are many potential metrics from which to choose. Thus, some prioritization is necessary to make the implementation of PBR manageable. Regulators and other stakeholders should focus performance objectives where there is most need for improvement, where there are opportunities to pursue regulatory priorities, and where there is opportunity for change.

It is important to provide utilities with a reasonable set of initial metrics to gain experience with PBR. Experience in other states with PBR suggests beginning with a few, clear metrics.[10] While metrics should obviously be aligned with regulatory policy priorities, we suggest two other basic criteria in developing a recommended list of initial metrics. These are (i) the ability for near-term implementation and (ii) the ability of individual metrics to inform multiple areas of performance within the broad categories of interest.

COMPLEMENTARY POLICIES. When considering PBR, regulators and policymakers should consider various complementary policies that can make PBR more effective. These are generally targeted at countering the utility bias toward increasing capital investment, which can be an obstacle in making a shift toward rewarding performance. These include:

- **Revenue decoupling**, which removes the disincentive for utilities to reduce volumetric sales.

- **Multi-year forward looking rate plans**, in which base rates are set based on an approved multi-year investment plan, but are reconciled annually with actual investment.

- **Comprehensive benefit-cost analysis**, which is used as a basis for developing multi-year rate plans.

CONCLUSION

PBR offers the potential to achieve policy objectives and improve public welfare while also retooling the utility business model for success in meeting those objectives. Experience shows that, with thoughtful design processes, rewarding performance can work well. Implementing PBR in each jurisdiction needs to be considered in the context of a utility system that is becoming increasingly complex. This suggests that a move toward PBR should also involve considerations of adjustment to the regulatory process as a whole. This should include greater involvement early on by various stakeholders that will ultimately play an integral role in the utility being able to meet its performance targets.

To support PBR as described in this issue brief, utilities and regulators will also need to agree on a form of advanced planning that can better identify the benefits that come from all advanced technologies.

END NOTES

[1] http://info.aee.net/21ces-issue-briefs

[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.

[3] DER is defined broadly to include distributed generation of all types, demand response, energy efficiency, energy storage, microgrids and electric vehicles.

[4] Edison Electric Institute. *Delivering America's Energy Future: Electric Power Industry Outlook*. February 8, 2017. URL:
http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/Documents/Wall_Street_Briefing.pdf

[5]http://www.ilga.gov/legislation/publicacts/97/097-0616.htm

[6] Known as RIIO, which stands for Revenue = Incentives + Innovation + Outputs

[7] System Average Interruption Duration Index which is the average outage duration for each customer served.

[8] System Average Interruption Frequency Index which is the average number of outage interruptions for each customer served.

[9] For more see our Issue Brief on Optimizing Capital and Service Expenditures http://info.aee.net/21ces-issue-briefs

[10] For example, New York selected four metrics for initial inclusion in its "Earnings Adjustment Mechanisms" as part of its Track 2 Order in the Reforming the Energy Vision proceeding (Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. New York Public Service Commission, May 19, 2016. Proceeding 14-M-0101).

RATE DESIGN FOR A DER FUTURE

Designing rates to better integrate and value distributed energy resources

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

September 2017

ADVANCED ENERGY ECONOMY

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

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The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the operation of the electricity system.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Rate Design for a DER Future** lays out the objectives and principles that should guide consideration of new rate design structures for better integrating and valuing distributed energy resources, describes the pros and cons of various rate design options, and makes recommendations on how to move toward a long-term framework that maximizes the benefits of distributed resources for customers and the electricity system as a whole.[2]

SUMMARY

The U.S. electricity system on which we all depend is changing, powered by technological innovations, increased use of distributed energy resources (DER)[3] on what has been traditionally a centralized power system, and changing customer needs and preferences in an increasingly connected world. If DER assets are properly integrated into the existing system, they have the potential to make the grid more efficient, flexible, resilient, reliable, and clean. One key element to this transition is developing rate designs that ensure the equitable allocation of costs, properly value the benefits that DER provides, and allow utilities to fairly recover the revenue required to maintain a system that provides safe, reliable, and universal electricity service.

In order for this new system to succeed, utilities need to adopt more granular and sophisticated rate structures that more closely align the costs of operating the grid with these new distributed resources and that send actionable price signals to customers. To this end, it is important to avoid blunt rate structures such as high fixed charges that send distorted price signals, and instead to move toward a long-term framework that treats all customers fairly – those who make use of DERs and those who do not. AEE generally believes that rate structures should evolve toward time-varying rates (TVRs), which price electricity higher when demand on the system is higher, and net energy metering tariffs that more precisely monetize the value of DER to the system. Some important principles to adhere to include:

- The concept of gradualism in transitioning from current rate designs to future ones, to give customers and DER providers time to adapt to the new rate designs
- "Grandfathering" of rates for existing DER customers, so as not to undermine investments made under existing rates.
- Providing information and energy management tools that allow customers to understand and effectively respond to the price signals they will be receiving.

Rate design is only one component of the changes needed to modernize our grid. Utilities must make foundational investments in enabling technology, such as advanced metering infrastructure and meter data management systems, before many of these more sophisticated rate designs can be implemented. Finally, any changes should include input from all stakeholders to moderate their impact on utilities, customers, and third parties.

INTRODUCTION

The increased deployment of customer-sited DER and the success of demand-side management (DSM) programs in reducing load growth are transforming the U.S. electricity system, making the grid more efficient, flexible, resilient, reliable, and clean, while simultaneously giving customers greater choices and control over energy use and costs. Effective integration of these and other distributed resources and the continued success of DSM programs, such as energy efficiency and demand response, lead to a range of benefits; however, they can also pose challenges for utilities. Among these challenges is that, under traditional rate designs, growth of DERs can lead to reduced revenue collection from customers. This has led some utilities to look for new ways to recover their costs and reduce their risk. Distributed generation (DG) technologies, such as rooftop solar, use the grid in new ways and have become a major focus of rate design discussions and regulatory proceedings around the country. As DER technologies are adopted on a larger scale they will increasingly reveal weaknesses in the rate designs that utilities have traditionally used to recover their costs.

Traditional rate designs are not "bad" per se – they have been developed over many years and have served us well. Nevertheless, regulators, utilities, and other stakeholders are realizing that new rate structures are needed to better accommodate the changes taking place on the grid, and especially to better integrate and value DER. Some changes to rate design and revenue recovery, such as revenue decoupling,[4] have been implemented in several states to address the overall level of cost recovery. But in order to maximize the value of DER for all customers while addressing concerns about the equitable allocation of costs for maintaining the electric distribution system, it will be necessary to consider more extensive changes. As DER deployment increases and as the grid becomes smarter, there is both a need and an opportunity to update rate designs to better meet the needs of the grid, customers, and energy suppliers.

OBJECTIVES OF RATE DESIGN

Before getting into the details of the different rate design options, it is important to define what we mean by rate design and clearly outline the objectives of a modern rate design framework.

Rate design is the process of setting prices and price structures to be paid by customers so that utilities have a reasonable opportunity to recover their revenue requirement (costs plus allowed return). Other key objectives of rate design include fair allocation of costs

across customer classes, and sending appropriate price signals to customers so that they consume energy efficiently and are motivated to act in ways that benefit themselves and the grid as a whole. The diverse objectives and requirements of different stakeholders – utilities, customers, policymakers, DER providers, and society as a whole – make setting rate designs that satisfy all parties difficult. It is as much art as science, and the methodologies in use today have been developed over many decades. Nevertheless, as the U.S. electricity system evolves, rate designs need to follow suit in order to fairly compensate both utilities and DER owners for the services they provide, but also value the full range of benefits and costs that both customers and utilities face in integrating DER into the distribution grid.

This is why it is important to lay out a set of clear and concise principles that should be adhered to when making rate design decisions for a DER future. Good rate design is a complex task, and a well-suited rate design for one particular jurisdiction and one class of customers may vary significantly from what is suitable for others. Below is a list of the traditional objectives that have been considered in setting rate designs, as well as a list of new objectives that should be considered going forward.

Traditional Rate Design Objectives

- Ensure safe, reliable, affordable electricity service
- Enable utility cost recovery and revenue stability
- Ensure stable and affordable utility bills
- Equitably allocate costs to customer classes reflective of cost causation (without an "undue" level of cross subsidy)
- Promote economic efficiency
- Be simple, understandable, and transparent to customers
- Where changes to rates are contemplated, apply principles of gradualism and continuity
- Promote policy goals (e.g., environmental, energy diversity, ʳpower/data security, needs of low-income households)

Emerging Rate Design Objectives

- Provide customers with timely and granular information so that they can make informed decisions about how they meet their energy needs
- Send customers price signals, with greater differentiation to the extent that it is cost effective (e.g., temporal, locational, and customer type)
- Empower customers to take control of their energy usage and costs to benefit themselves and the grid
- Accommodate technologies and service options that take into account new ways that customers can respond to rates, including the use of customer-sited DER

COMMON RATE DESIGN OPTIONS FOR MASS-MARKET CUSTOMERS

Today, a majority of residential and small commercial customers are on simple flat-rate pricing, where most costs are collected on a set per-kilowatt-hour (kWh) basis, regardless of when consumption occurs. While there are benefits to such a straight-forward rate design for these customers – they are easy to understand, stable, and promote economic efficiency – AEE believes that ultimately, more sophisticated rate designs based on granular and precise price signals are needed to meet the emerging objectives of rate design. Utilities across the country have proposed a range of rate design changes, not all of which are consistent with the emerging needs and opportunities associated with DER. For the rate design options discussed below, we identify the pros and cons of each and, if applicable, our recommendations on how they should be structured to be consistent with the above rate design principles.

FIXED CHARGES

Many utilities have recently proposed increasing the fixed charge component of their rates to lock in recovery of a larger portion of their costs and reduce their risk in today's changing environment. Traditionally, fixed charges have been low, typically below $10 a month for residential customers, and were designed mainly to recover direct customer costs, such as metering, billing, customer service, and the cost to connect the customer to the distribution grid. The majority of costs are then allocated to the variable (per kWh) portion of the bill. However, some utilities are now trying to expand the definition of direct customer costs, with potentially significant repercussions for customers.

Cost Shift vs. Revenue Shift

There is considerable debate over whether or not there is cost shifting from DG customers to non-DG customers. DG companies and others have argued that when all costs and benefits are fully taken into account, DG customers are still covering their net cost of utility service and therefore there is zero or minimal cost shift. To understand if any cost shift exists requires a comprehensive valuation of both the benefits and costs of DG on the system. As such, AEE prefers using the term *revenue shift.* Under most existing rate designs, a revenue shift does occur regardless of the valuation, as DG customers reduce their kWh purchases. But a revenue shift and a cost shift are not the same.

Increasing the fixed charge necessarily decreases the variable component of a customer's bill, leaving total revenue collection unchanged. Although the per-kWh rate is lower, the utility gets a more stable and predictable revenue stream. Proponents of higher fixed charges argue that they are fairer than the way rates are typically structured because the majority of a utility's costs are fixed. They also contend that because DG customers consume less energy from the grid,

they do not pay their fair share to maintain the grid while still relying on it, resulting in a cost shift to non-DG customers.

While there is some validity to this argument, increasing fixed charges is a blunt instrument for addressing the issue, as it is too focused on utility cost recovery and not on the other goals of rate design. Higher fixed charges hurt customers who have invested in energy efficiency measures by reducing the per-kWh rate and therefore their bill savings, lengthening the payback period for energy efficiency investments. For the same reason, higher fixed charges discourage future energy efficiency investments. The impact is similar for DG technologies. Higher fixed charges cut into the benefit they receive from reduced electricity purchases, and lower per-kWh rates translate into lower net metering rates for their excess generation.

Higher fixed charges also disproportionately affect low-income customers, who tend to use fewer kWh than other customers. That has made this approach the subject of controversy and stiff opposition from various stakeholder groups, with regulators often denying utility requests for fixed charge increases or approving only modest increases.[5] Consider the following example, based on a recent proposal from Kansas City Power & Light.[6] Increasing the fixed charge for residential customers from $9 per month to $25 per month, with a corresponding decrease in the per-kWh charge would have the following impact: Customers who consume 1,250 kWh per month would see virtually no change in their monthly bill, while low-usage customers who consume only 250 kWh per month would see their bill rise by nearly 40%; high usage customers (>1,250 kWh/month) would see their bills go down.

An Alternative to Fixed Charges: Minimum Bills

Instead of increasing fixed charges, a minimum bill, properly designed, is a preferable way to provide utilities with a baseline level of revenue recovery while ensuring that all customers contribute some amount for their use of the distribution system. As the name implies, a minimum bill is structured such that customers are required to pay at least a certain amount every month regardless of their level of usage. A minimum bill does not distort price signals the way a fixed charge does, because it does not reduce the per-kWh rate of a customer's bill. If set at an appropriate level, it can reduce the potential revenue shift, because DG customers would not be able to net-meter below the minimum bill. A minimum bill is also easy to understand and would require minimal customer education to implement. However, the specific level of the minimum bill is important. If set too high it can negatively impact low-income customers and also reduce the portion of the bill that customers can control, reducing their incentive for doing so.

DEMAND CHARGES

A rate design commonly used with large commercial and industrial (C&I) customers, but not traditionally used for mass-market customers, is a demand charge. Demand charges are calculated by multiplying per-kilowatt (kW) rates by some measured

demand, so that customers are charged in part based on their peak usage for a given time interval. Demand charges are intended to better align revenue collection with utility costs, because the utility builds out its system to meet its peak demand – both the generation system peak and the distribution system peak,[7] which typically occurs during a few hours of the year (e.g., hot, humid days when air conditioning usage spikes). By charging customers for their maximum demand (kW),[8] as well as total consumption over time (kWh), it is thought that customers will be encouraged to spread their usage as much as possible, reducing the capacity needs of the system, and therefore overall costs. Demand charges can be structured in different ways but are generally either based on a customer's individual peak demand or on their demand at the time that the system peak occurs, as described below.

Non-coincident demand charges are typically based on an individual customer's highest demand during each billing cycle. Demand charges may only apply during certain times of the day or year, or vary depending on the season or time of day.[9] While these charges are assessed without regard to the relationship between the individual customer's demand peak and demand on the system overall, for large commercial and industrial (C&I) customers – who have long been subject to this type of demand charge – their individual peaks often coincide roughly with the system peak, such that the customer's demand requirements align with costs borne by the utility.

While a non-coincident demand charge may make sense for large C&I customers, it does not make sense for mass-market customers, because their individual peaks rarely match up with the system or distribution peak. Residential customers in particular have a wide variety of load profiles,[10] such that residential usage overall tends to have a smoothing effect on the demand curve, with different customers peaking at different times. As a result, charging for the non-coincident peak demand of a typical residential customer tends to unfairly allocate costs to these customers, because their individual demand peak is not a good indicator of their contribution to utility costs.

Additionally, non-coincident demand charges can be difficult to manage. The level and timing of a customer's individual peak demand is not knowable until after that peak has come and gone. For example, if a non-coincident peak demand charge is assessed for the individual customer's peak demand in each billing period, the customer will not know when the peak demand is set until after the billing period is over, at which point it is too late to respond.

Coincident peak demand charges, on the other hand, are based on an individual customer's demand during the system peak, regardless of their non-coincident individual peak. Coincident peak demand charges align more closely with system costs and can more directly incent customers to reduce their usage when it would benefit the system overall. However, coincident demand charges are difficult to implement without advanced metering infrastructure and a robust customer

communication and education program. Since the system peak in a particular time period is not known until after the fact, customers may have to actively manage their demand during multiple time periods (with warnings from utilities or grid operators that a period of high demand is expected) in the hopes of successfully reducing demand during the actual system peak. That said, coincident peak demand charges, if structured properly, are preferable to non-coincident demand charges from a cost-causation standpoint. Nevertheless, because they are difficult to manage, they can have impacts similar to higher fixed charges, and can also introduce additional volatility into a customer's bill.

Demand charges are also difficult for mass market customers to understand. These customers are used to paying for energy on a volumetric basis, much like any other commodity. Introduction of a rate based on peak demand can be confusing and non-intuitive, requiring a level of understanding and active load management that is simply unrealistic for most mass-market customers. The goal of demand charges – recovery of peak-related distribution system costs – may be better achieved through peak-coincident time varying rates, such as critical peak pricing (CPP) and peak time rebates (PTR), which are more easily understood by mass market customers and provide a greater opportunity for energy management (see below for more details).

In order for customers to respond to demand charges they need access to their usage data, they need to have the knowledge to interpret their data, and they must have the ability to take action to manage their usage. Demand charges take away control and predictability in consumer rates because most residential customers do not know when their usage peaks and it is hard for utilities to send accurate price signals to customers so that they can adjust their usage during a narrow window corresponding to the system peak.

In additional, demand charges reduce the incentive for energy efficiency, which may run counter to state policy goals, by reducing volumetric rates and thus the amount of money that customers can save by reducing their overall energy usage. Finally, demand charges hurt the value proposition for non-dispatchable DG (e.g., rooftop solar), as customers may have to pay based on their maximum usage when their solar panels are not generating, even if they are meeting much of their overall electricity needs themselves. For customers with solar, demand charges could provide a strong incentive to adopt energy storage, because it would encourage the customer to actively manage peak load.

Because of the challenges associated with demand charges for mass-market customers, most stakeholders other than utilities are opposed to them.

Targeted demand charges might provide a middle ground. A demand charge that only applies during clearly articulated periods known in advance (e.g., a few hours every weekday afternoon during the summer, similar to a time-of-use rate) could provide value to the system while sending better price signals to customers. Because of the difficulty of mass market customers understanding demand

charges, a targeted demand charge implemented for just a certain subset of sophisticated customers would begin to move towards a more sophisticated rate design that aligns rates with actual costs while giving customers the information they need to manage their bills during those peak periods. This structure would open up the market for third-party companies to provide services (e.g., demand response or behavioral analytics) to assist customers in managing their bills. It would also encourage the use of emerging technologies, such as energy storage.

TIME VARYING RATES

Broadly speaking, AEE believes that time-varying rates (TVRs) are the best long-term option for modern rate design. TVRs can take many forms but they generally work by pricing electricity higher at times when demand on the system is high, incenting customers to reduce their electricity use when it is the most expensive to generate or when there are capacity constraints on the system. This reduces stress on the power grid and lowers wholesale energy and capacity costs by reducing the need for inefficient and costly peaking plants. TVRs can also allow engaged customers to capture the benefits of managing their electricity usage. In states that allow customer choice of energy supplier, the utility could be the platform for data necessary for TVR products, with customers and their designated third parties getting access to this data.[11] This would allow for the greatest array of products and the most customer choice.

TVRs come in four general categories:

Table 1 – Time Varying Rate Categories

Structure	Definition
Time-of-Use (TOU)	The most basic pricing scheme, which consists of a tiered pricing structure with pre-defined peak and off-peak time periods
Critical Peak Pricing (CPP)	Traditional flat-rate volumetric pricing coupled with higher rates during peak demand events that are announced in advance
Peak Time Rebate (PTR)	Essentially the inverse of a CPP: a flat rate coupled with a rebate when customers reduce their usage during a peak demand event.
Real Time Pricing (RTP)	The most sophisticated pricing scheme, with hourly prices determined by day-ahead market prices or real-time spot market prices.

TVRs can be designed with a variety of time intervals, such as long versus short peak periods, and large versus small differentials between peak and off-peak rates. Experience has shown that rate structures with shorter on-peak periods and larger differentials between on- and off-peak rates are more effective at peak demand reduction.[12]

Although we believe that moving to TVR is the best long-term option, how TVR is implemented is important. As with other rate designs, successful adoption and implementation depends on investment in advanced metering and other infrastructure, which will take time. Furthermore, effective customer education and engagement is critical

to the success of TVR. Customers must understand their default rates and any available options if they are to make educated choices about how to best manage their electricity bills under TVR. A lack of customer education and engagement can lead to low levels of customer response, which can frustrate the goals of TVR deployment.

Opt-in vs. Opt-out

One question to consider is whether programs enabled with advanced metering functionality should be opt-in or opt-out. Some utilities consider opt-in the preferred approach, as it is seen as less likely to cause pushback from customers. However, the Sacramento Municipal Utility District's (SMUD) *SmartSacramento Project,* which included the rollout of 617,000 smart meters, found that opt-out was more successful. Under the project, the number of customers under opt-out enrollment (93%) was about 3.5 times higher than for opt-in (24%). While peak period demand reductions per customer were higher under opt-in programs, the larger number of customers enrolled made opt-out more cost effective.[13]

Baltimore Gas and Electric's PTR program is an example of successful customer engagement: Utilizing mass-market education campaigns, as well as personalized pre- and post-event communications, BGE was able to achieve high levels of customer response for their opt-out PTR program.[14] It is important for customers to have load management tools and information at their disposal in order for them to effectively respond to price signals and manage their energy bills. For mass-market customers, this could include the use of automation (e.g., smart thermostats) and third parties to help them manage energy use (which would require third-party access to customer data) to take best advantage of TVR.

SUCCESSORS TO NET ENERGY METERING (NEM)

Net energy metering (NEM), under largely volumetric rate designs, provides compensation for DG, often at the full retail rate, for electricity that is exported to the grid.[15] This works by "spinning" the meter backwards when a customer is generating more electricity than they are using, and spinning it forward when a customer is consuming more energy than they are producing. This essentially allows DG customers to bank the excess electricity they generate and use it when their DG systems are not generating enough to fully offset their electricity use. At the end of a billing period, the customer is either charged for the net consumption or credited for the net exports.[16]

While NEM does not send precise price signals, it is simple to implement and for customers to understand. That has made it a very effective policy for increasing DG adoption. However, as described above, in states with higher levels of DG penetration, NEM raises issues with respect to utility revenue recovery and potential distribution cost allocation, as revenue recovery is shifted onto non-NEM customers.

Thus, as the number of NEM customers increases, pressure is building to find alternative rate designs and successor NEM tariffs for DG customers. The aforementioned rate designs all indirectly affect NEM compensation to varying degrees,[17] but it is

also appropriate to consider direct changes to NEM that could be more sustainable in the long term. In states where DG penetration is low, it may be appropriate to continue traditional NEM rates to facilitate DG deployment. In states where DG deployment is rising and as meters are becoming more advanced, AEE believes it makes sense to consider more nuanced and sophisticated net metering policies, consistent with the principles of continuity and gradualism.

Successors to NEM should more precisely monetize the value of DG to the system, achieve desired behavior changes/outcomes related to electricity use, and also fairly compensate the utility for the service it provides to DG customers. Moreover, it is also appropriate to consider changes to NEM compensation that can apply to all DER, and not just DG, to encourage beneficial integration of DG with other DER technologies (e.g., solar plus storage, or combined heat and power plus demand management). Different DERs have different operating characteristics, different load profiles, and ultimately different impacts on the distribution grid. NEM frameworks that are structured to account more precisely for the value that DER provides to the system – both locational and temporal – would effectively address concerns about revenue shifting to non-DER customers without depriving DER customers of significant value.

One potential framework, based on a "value stack," is being implemented in New York, on an interim basis, primarily for the burgeoning community solar market there and certain behind-the-meter projects that are already on demand-based rates (NEM remains unchanged for residential and small commercial customers).[18] This approach compensates exported energy (netted hourly instead of monthly) based on several price components rather than simply the retail rate. Specifically, the value is based on the utility's avoided costs plus other DER values, including wholesale energy and capacity, distribution, and environmental values. AEE supports the direction being taken, although we prefer an approach that applies the value stack to consumption as well as exports, valued hourly, to ensure that generation that is produced and consumed behind the meter is fully valued (as we proposed in comments submitted in the Value of DER proceeding in New York).[19]

CONCLUSION: A PATH FORWARD

Making changes to rate design is an essential element of modernizing the electricity system. Yet it cannot be considered in a vacuum, as it is only one piece of a larger puzzle, and any modifications need to be considered in the context of other changes in utility operations and regulation.

ENABLING TECHNOLOGY AND ACCESS TO DATA

More sophisticated rate designs require certain enabling technologies before they can be implemented. The first prerequisite is advanced metering functionality (AMF), which includes not only the meters themselves, but also the two-way communications infrastructure and the back-office management systems. AMF allows near-real-time energy tracking, load forecasting, and two-way communication between the utility and the end-user, which are critical to the development of more sophisticated rate designs.[20] Also, mass market customers can benefit from the services of third parties to manage their energy use and properly respond to price signals. However, in order to do this, third parties must have timely access to the data that AMF provides.[21]

PILOTS, CUSTOMER EDUCATION, AND GRADUALISM

AEE strongly supports the principle of gradualism when implementing rate design reforms, to moderate their impact on both customers and third parties. Pilots and demonstration projects should be conducted before wider implementation is contemplated, as they are an integral tool at regulators' disposal to gather data and experience, test the effects of new rate designs, and identify the best way to proceed. However, pilots should not be used to delay the introduction of products that are already proven and working based on the experience of other states or utilities. Given the rapid pace of development of the DER market, pilots should include reasonable timelines for moving successful rate designs into general use. Pilots should also not interfere with competitive options in jurisdictions with retail access.

Another way to roll out new rate designs is through opt-in tariffs. Opt-in tariffs are a good way to test new rate designs with voluntary participants before making changes to default rates. Some utilities have shown that opt-in rate designs can act as more than a test bed, and ultimately achieve high adoption rates. For example, Arizona Public Service (APS) has enrolled over 50% of its customers in an opt-in TOU rate.[22] To accelerate the adoption of opt-in rate designs, regulators also should consider requiring utilities to shadow bill, or offer a guarantee that customers will be better off than before. For example, in its Smart Time Pricing pilot, Philadelphia Electric Co. (PECO) guaranteed it would refund the difference if customers ended up paying more on the TOU rate than they would have on the flat rate. PECO ended up writing only 13 checks, ranging from $1 to $19, and totaling just over $100 in reimbursements in a pilot involving nearly 5,000 customers.[23]

New rate structures (even if limited in scope and application) could require DER providers to quickly create new pricing structures and product offerings in order to guarantee savings for their customers. Therefore, it is also essential for third parties to get a preview of rate changes well in advance in order to model savings appropriately and develop new offerings.

OPEN, COLLABORATIVE REGULATORY PROCESSES

Through experience in several jurisdictions, we have learned that stakeholder collaboration is one of the most important tools for making sure new rate designs succeed. Therefore, we recommend that, to the greatest extent possible, regulators hold open and collaborative proceedings – or workshops, which can be even less formal – to gather information and generate new ideas. This allows regulators to take wide-ranging input and reduce barriers to participation, particularly for stakeholders with limited resources, for whom participation in adjudicated proceedings is difficult. In addition, such open forums (unlike rate cases) can help regulators understand all the options at their disposable and gather input from all parties to understand their views and the potential effects of new rate designs.

New technologies, changing consumer preferences, and the growth in customer-sited DER are fundamentally changing how customers interact with the grid and how utilities recover their revenue requirements. As penetration on the system increases, DER can play a positive role in transforming our electric system to make it more flexible, resilient, and clean. Therefore, it is imperative to design rates that can better accommodate and integrate DER and send more accurate price signals to customers so that their choices lead to beneficial outcomes for all customers.

ADDITIONAL RESOURCES

Resource	Link
National Association of Regulatory Utility Commissioners Rate Design and Distributed Energy Resources Compensation Manual	https://www.naruc.org/rate-design/
"A Review of Alternative Rate Designs" by Rocky Mountain Institute	https://rmi.org/insights/reports/review-alternative-rate-designs/
"Smart Rate Design for a Smart Future" by Regulatory Assistance Project	http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf
"Designing Tariffs for Distributed Generation Customers" by Regulatory Assistance Project	http://www.raponline.org/wp-content/uploads/2016/05/rap-madri-designingtariffsfordgcustomers-final.pdf
"Teaching the Duck to Fly" by Regulatory Assistance Project	http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-teachingducktofly-2014-jan.pdf
"Lessons from Nevada's Net Energy Metering Reforms" by R Street	http://www.rstreet.org/wp-content/uploads/2016/03/59.pdf

END NOTES

[1] http://info.aee.net/21ces-issue-briefs
[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.
[3] DER is defined broadly to include distributed generation of all types, demand response, energy efficiency, energy storage, electric vehicles and the associated charging infrastructure, and microgrids.
[4] Revenue decoupling has been adopted in some form in at least 14 states. Source: AEE PowerSuite.
[5] For example, See Appendix B in *Caught in a Fix*, Synapse Energy Economics, Prepared for Consumers Union, February 9, 2016.
[6] Missouri Public Service Commission Docket ER-2014-0370, adapted from the report *Caught in a Fix*, Synapse Energy Economics, Prepared for Consumers Union, February 9, 2016.
[7] Some rates can have separate demand charges for generation and distribution (which can occur at different times), but for the purposes of this issue brief we address peak demand more generally.
[8] Demand charges may be based on hourly or sub-hourly intervals (e.g., average usage over a 15-minute interval)
[9] For example, demand charges often are higher (or may only apply) during weekday hours in the summer.
[10] California Public Utilities Commission Decision 14-12-080, Application for PG&E for 2013 Rate Design Window Proceeding
[11] See our Issue Brief on Access to Data for more information.
[12] "Time Varying and Dynamic Rate Design," prepared by Ahmed Faruqui, Brattle, for the Regulatory Assistance Project, July 12, 2012. http://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf
[13] https://www.smartgrid.gov/files/CBS_interim_program_impact_report_FINAL.pdf
[14] In 2015, BGE deployed PTR to over 1 million residential customers and achieved a participation rate of 78% and an average peak demand reduction of 16.2%. See: Prepared Direct Testimony of William B. Pino on Behalf of Baltimore Gas and Electric Company. 6 November 2015. Available: http://webapp.psc.state.md.us/newIntranet/casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9400-9499\9406\Item_1\\5_PinoDirect_110615_F.pdf
[15] Generation that is consumed behind the meter offsets retail purchases at the applicable retail rate.
[16] Rules vary with respect to how long credits can be carried forward and at what rate they are valued if there is a payout (e.g., retail vs. wholesale rates). In some jurisdictions, the banked amount disappears when an account is closed rather than being automatically paid to the customer.
[17] This is because any increase in the fixed charge or demand charge component of a bill must be accompanied by a proportional reduction in the variable (or per kWh) portion of the bill. This reduces the net metering credit, effectively lowering the level of DER compensation. On the other hand, TVR does not reduce the net metering credit but it does change its value by making the credit more or less valuable depending on the set per-kWh rate at different times.
[18] New York Public Service Commission Value of DER Phase I decision in Case 15-E-0751, March 9, 2017.
[19] AEE Institute Filing in Case 15-E-0751, April 18, 2016. http://info.aee.net/hubfs/21CES/AEEI-ACENY-NECEC_LMPD_Comments_04-18-2016.pdf
[20] For more details see our Issue Brief on Advanced Metering, available at http://info.aee.net/21ces-issue-briefs
[21] For more details see our issue brief on Access to Data, available at http://info.aee.net/21ces-issue-briefs
[22] Ryan Randazzo, "Arizona leads California on time-of-use electricity plans," The Arizona Republic (May 26, 2015). http://www.usatoday.com/story/money/2015/05/26/arizona-california-time-of-use-electricity/27985581/.
[23] "PECO Smart Time Pricing Pilot Final Report," prepared by Nexant for PECO Energy Company. Filed in proceeding P-2012-2297304 on April 28, 2015, before the Pennsylvania PUC.