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Regulatory Approaches to Grid Resiliency and Security

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Disclaimer

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I. Introduction

The Pennsylvania Public Utilities Commission ("PPUC" or "Commission") has requested that the Regulatory Assistance Project (RAP) prepare a white paper that explores regulatory approaches to cost recovery for measures taken by utilities to ensure grid resiliency and grid security. As a restructured state, the Pennsylvania Commission's jurisdiction is limited to the distribution system of electric distribution utilities (EDUs). Therefore, the discussions and recommendations in this white paper take this factor into account.

There are a number of facets to ensuring a stronger grid that is capable of withstanding a catastrophe or, alternatively, a grid for which outage durations and reliability concerns can be minimized when a major event does occur.[1] First, there are steps that can be taken to identify weaknesses in the grid and strengthen its resilience in such events, either through utility upgrades or the deployment of new technological innovations relying on third-party service providers and customers to provide distributed energy resource (DER) solutions, such as distributed generation or microgrid deployment. There are also strategies that would enable utilities to make investments in advanced data management software and cloud-based data systems. The ability to relay important grid data on a real-time basis can both alert grid managers to problems on their system to prevent an outage and aid in system recovery. Second, there are the measures that need to be taken when large portions of the grid experience an outage, such as equipment and supply sharing programs, with the goal of restoring service as promptly as possible. Finally, there are measures taken to encourage and safely enable customers, neighborhoods, campuses, and communities to physically isolate themselves from a disabled wider grid system during an outage, allowing them to run power generation on their own, as well as improve their ability to survive disruptions.

The Electric Power Research Institute (EPRI) has identified three elements of grid resilience: prevention, recovery, and survivability.[2] An EPRI report in 2013 elaborated:

> *Damage prevention refers to the application of engineering designs and advanced technologies that harden the distribution system to limit damage. System recovery refers to the use of tools and techniques to quickly restore service to as many affected customers as practical. Survivability refers to the use of innovative technologies to aid consumers, communities, and institutions in continuing some level of normal function without complete access to the grid.*

Section II and III of this paper will focus on damage prevention; Section IV will focus on system recovery and Section IV and V will focus on survivability. Solutions employed to address one element may also aid in addressing other of the elements.

All of these options require regulatory leadership in terms of authorizing inquiries into grid resiliency, approving cost recovery mechanisms, and designing rates that encourage innovative solutions. This white paper will explore the following and provide the Commission with options and recommendations as to the following:

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[1] "Catastrophe" or "major event" refers to significant weather events such as major storms or hurricanes, physical attacks on the grid, cyber-attacks, electromagnetic pulse events, or any other event that results in widespread outages.

[2] Electric Power Research Institute (EPRI). (2013, January). *Enhancing Distribution Resiliency: Opportunities for Applying Innovative Technologies*, pp. 4-5. Retrieved from http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889&Mode=download

- Identification of grid weaknesses and solutions;
- Investments in software and cloud-based information data systems;
- Investments in hardware and assets to strengthen reliability; and
- Rate designs that complement these policies.

II. Designing a Planning Process for Upgrading and Strengthening the Grid

Making progress on grid resilience will require a planning process to prioritize critical needs and costs and ensure that the best planning takes place. At the heart of this is the ability to identify strengths and weaknesses on the grid and to then seek the most cost-effective solutions that can lead to the long-term security of the electric system. The process to get there could include requiring the utilities to do a self-assessment; identification of weaknesses, or "hot spots";[3] and creating an integrated distribution planning (IDP) process.

Once the hot spots are identified, the next step is identifying solutions. Utilities face aging infrastructure and must decide on investments for new capabilities. New alternatives to capital solutions can be found on the customer side of the meter. There are opportunities for distributed energy resources (DER) to be used when they are the least-cost solution.

The rules governing utility recovery of resilience-related expenditures can drive utilities willingness to plan and invest. This can include developing appropriate tariffs to compensate DER,[4] expanding the scope of the Distribution System Improvement Rider (DSIC) or utilizing performance metrics, or some combination of all three. The use of a screening process to determine what expense is needed for resilience and will be entitled to distinct accounting treatment might also be helpful.

A. Options for Evaluating the Utility Grid

As a first step it is important to have a good inventory of assets, appropriately mapped in order to determine what needs to be replaced or is ready for routine inspection and maintenance. EPRI notes that "keeping track of assets is crucial for utilities because this management provides an interface between the engineering and the accounting sides of the business. An asset register allows utilities to maintain a database of what assets they own, their predicted lifecycle and their technical specifications."[5] At a minimum, utilities should be required to do this if they are not already.

A more granular effort would include having utilities map out their existing systems through an engineering assessment and identify any infrastructure changes that are most supportive to the grid. This could include identifying stressed areas of the grid where DER and other solutions could be helpful. The mapping could demonstrate where additional DER could most benefit the grid and what

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[3] "Hot spots" as used in this document refers to areas of the grid that are congested or are weakened and need to be upgraded to avoid outages.
[4] This is addressed in Section V.
[5] EPRI, 2013, p. 9.

investments might be needed such as advanced metering infrastructure (AMI) or smart inverters.[6] Back-office systems, as well as management and control that utilities or a distribution system operator need to employ, are both larger items that require attention to enable DER grid support and reliability functions. Given that AMI should be fully deployed by 2019–2020, Pennsylvania is in a good position to begin to realize the fruits of its investment through creative strategies that can include the deployment of DER.

Regardless of the mechanisms chosen—ideally including both an inventory of the system filed by utilities and an IDP process, which will be discussed below—it is important that a regulatory process be created that includes Commission staff and stakeholder involvement with the utility. It may be necessary for the Commission to consider rulemaking to set forth the details of what information the utility should file. This would also include protocols for confidential information. A transparent, public policy, including access to data, will be important to third-party DER vendors who can provide value through lower-cost options to help fortify the grid.

B. Examples of Grid Planning Processes in Other States

Much of the discussion around the country with respect to hardening the grid and making it more resilient recognizes the importance of grid modernization and the role of DERs, which can be used as a distribution tool to effect low-cost improvements to the grid. Below is a sampling of a few jurisdictions which have begun regulatory processes to explore low-cost options for improving the grid.

California

The California Public Utilities Commission (CPUC) has embarked on a two-prong process in response to legislation[7] that requires reform of utility distribution planning, investments and operations to "minimize overall system cost and maximize ratepayer benefits from investments in preferred resources."[8] Thus, the Commission created two proceedings to address integrated distributed energy resource planning and distributed resource planning.[9] The Commission proceedings will be examining rates and tariffs; distribution grid infrastructure, planning, interconnection and procurement; and, wholesale DER market integration and interconnection.[10] The focus of these two proceedings is to ensure maximum consideration of distributed energy resources into the grid through the adoption of grid modernization and interconnection, driven in part by legislation requiring greenhouse gas (GHG) reductions and other requirements.[11] The goals of the California Commission may differ from that of the Pennsylvania Commission, which is focused on preserving the grid in the event of another Hurricane Sandy or similar disaster. But the methods for achieving these twin sets of goals are somewhat similar in

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[6] Advanced Energy Economy (2016, April 25). Distribution Planning in a Distributed Energy Future. Retrieved from http://blog.aee.net/distribution-planning-in-a-distributed-energy-future

[7] California Assembly Bill 327. (2013). *Electricity: natural gas: rates: net energy metering: California Renewables Portfolio Standard Program.*

[8] California Public Utilities Code, Sec. 769(c).

[9] California PUC. Distributed Resource Plans: R.14-08-013; Integrated Distributed Energy Resources: R.14-10-003.

[10] California PUC. (2016). *Distributed Energy Resources (DER) Action Plan Summary and Highlights*. Retrieved from http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20Summary%20and%20Highlights.pdf

[11] Senate Bill 230, adopted in 2015, requires reductions in 2030 GHG levels to 40% below 1990 levels; increase renewable energy generation to 50%, doubles energy efficiency requirements and encourages widespread transportation electrification.

that strengthening the grid in a cost-effective way will involve planning to identify grid vulnerabilities and then a process of choosing the least-cost solution, which could include DERs.

New York

On April 20, 2016, the New York Public Service Commission (PSC) issued an order adopting a distributed system implementation plan guidance and pointed out the need to develop a more transactional, distributed electric grid that meets the demands of the modern economy, including improvements in system efficiency, resilience, and air emissions reductions.[12] In this docket, the New York PSC created the Distributed System Platform (DSP), which combines planning and operations with the enabling of markets. The Distributed System Implementation Plan (DSIP) is the planning and operation portion needed to facilitate DSP activities. The DSIP process includes active collaboration among utilities, stakeholders, and Department of Public Service staff and is designed to develop balanced and effective plans.

The Commission required utilities to make the following three filings:

- A plan and timeline for a stakeholder engagement process during DSIP filing development;
- An individual utility DSIP addressing its own system and identifying immediate changes that can be made to effectuate state energy goals; and
- A supplemental DSIPs by all utilities addressing the tools, processes, and protocols that will be developed jointly or under shared standards to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets.[13]

Minnesota

The Minnesota Public Utilities Commission was interested in exploring grid modernization and in that context, it commissioned a report from ICF International that emphasized IDP as a key element.[14] According to the report, an IDP framework should include the following components:[15]

- **Current Distribution System Assessment:** This would require a rigorous power flow analysis of the current system to provide safe, reliable service to customers at a reasonable cost. Additionally, an assessment of: current feeder and substation reliability, the condition of grid assets, asset loading, and operations, would be needed, as well as a comparative assessment of current operating conditions against prior forecasts of load and DER adoption.
- **Hosting Capacity:** This analysis is used to establish a baseline of the maximum amount of DER that an existing distribution grid (feeder through substation) can accommodate safely and reliably without requiring infrastructure upgrades. Hosting capacity methods also quantify the engineering factors that increasing DER penetration introduces on the grid within three principal constraints: thermal, voltage/power quality, and protection limits.

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[12] New York Public Utilities Commission. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, No. 1401-M-01-01, Order Adopting Distributed System Implementation Plan Guidance, p.4.
[13] New York PUC, p. 3.
[14] ICF International. (2016, August). Integrated Distribution Planning. Retrieved from https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf
[15] ICF International, pp. 6-8.

- **Multiple Scenario Forecasts:** As DER adoption grows, the distribution system will increasingly exhibit variability of loading, voltage, and other power characteristics that affect the reliability and quality of power delivery. This impedes the reliability of singular deterministic forecasts for long-term distribution investment planning. Thus, the report opts for multiple DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements, and enable analysis of the locational value of DERs.
- **Annual Long-Term Distribution Planning:** This annual distribution planning has two facets: first, multiple scenario-based studies of distribution grid impacts to identify "grid needs"; and second, a solutions assessment including potential operational changes to system configuration, needed infrastructure replacement, upgrades and modernization investments, and the potential for non-wires alternatives.
- **Interconnection Studies and Procedures:** Changes to regulation on interconnection processes and the related engineering studies performed by utilities may need to be made to handle the growth in and diversity of DER interconnection requests.
- **Integrated Resource, Transmission, and Distribution Planning:** Where distribution planning is done outside of integrated resource planning and transmission planning (as in a restructured state such as Pennsylvania), it is important that DER growth patterns, timing, and net load shape assumptions and plans are consistent in both distribution and resource plans. Moreover, if DER provides wholesale energy services, the deliverability of DER across the distribution system to the wholesale transaction point needs to be taken into account. This further supports the need for better alignment of the processes for resource, transmission and distribution integrated planning.
- **Locational Net Benefits Analysis:** The value of DER on the distribution system is based on its location in terms of its support to a distribution substation, an individual feeder, a section of a feeder, or a combination of these components. The distribution system planning analyses, identify incremental infrastructure or operational requirements and potential infrastructure investments. The cost estimates of these investments form the potential value that may be met by DERs (and in other words creates the framework to evaluate the cost-effectiveness of a DER option).

There are other examples of states undertaking grid modernization and distribution system planning to address reliability and the influx of DERs. They include Hawaii and Maryland, among others.[16]

C. Grid Solutions

In developing solutions, it is important to consider the level of desired reliability and the costs associated with it to determine what is the optimal expenditure for the optimal gain. As noted by a report prepared for Lawrence Berkeley National Laboratory, "(A) central consideration is the inherent trade-off between economic efficiency and reliability. Maximizing economic efficiency may introduce undesirable operational risks. Conversely, over-investment may create a robust distribution system that

[16] For other examples, see Advanced Energy Economy, 2016.

is prohibitively expensive. An architectural approach based on clear objectives can achieve desired results through coordinated market designs and control mechanisms."[17]

As noted above, the first step is to recognize the grid weaknesses through a variety of mechanisms that can lead to greater identification of hot spots. Once these areas are identified, steps can be taken to address the issues. This can include the utility undertaking improvements, or a competitive bid process to identify the least-cost mechanism for achieving the desired outcomes. As has been demonstrated above, DERs can be deployed as a resource, but also as a tool to help increase reliability. Where areas of congestion are identified that require upgrades to accommodate increased load, a lower-cost solution could, for example, be the addition of distributed PV. Some innovative examples are discussed below:

New York

Under New York's Reforming the Energy Vision (REV) process, Consolidated Edison (Con Ed) proposed using a portfolio of demand- and utility-side resources as an alternative to a $1 billion substation investment. The Brooklyn-Queens Demand Management (BQDM) program is slated to reduce projected load growth by procuring 52 MW of non-traditional solutions within the Brooklyn-Queens hot spot to reduce the area's peak load. Also included in the BQDM program is 6 MW of traditional utility-side measures, two new substation transformers, and 91 MW of load transfers. The total program cost is estimated at $505 million. In order to create an incentive for Con Ed to engage in the most cost effective solution, the NYPSC has offered a 100-basis-point adder to Con Ed's return on equity, depending on its performance.

It is anticipated that the Commission will be looking for more utility examples of this nature.

New Jersey

The New Jersey Board of Public Utilities recently commissioned a report to provide information for the potential establishment of microgrid policies.[18] One of the objectives of the report is to provide data and technical analysis to the Board, including on emergency operations ("black sky conditions" where there are extraordinary and hazardous catastrophes) in response to Hurricane Sandy and other events that led to major grid outages. Further, the report includes a cost/benefit analysis of operating a microgrid with multiple customers under blue-sky conditions for continuous operations.[19] The microgrid study includes a focus on Level 3 microgrids, known as Town Center Distributed Energy Resources (TCDER), which is a specific type of advanced microgrid. The report concludes that TCDER microgrids for multiple critical facilities "can provide enhanced energy resiliency for critical customers at the local level as well as enhanced reliability and efficiency for usage of the distribution system grid." The TCDER microgrids can accomplish this through enhanced energy efficiency; clean energy generation, including both renewables and natural gas combined heat and power; lower air emissions and

[17] Martini, P., & Kristov, L. (2016, October). Distribution Systems in a High Distributed Energy Resource Future. Retrieved from https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf
[18] New Jersey Board of Public Utilities. (2016). Microgrid Report. Retrieved from http://www.bpu.state.nj.us/bpu/pdf/reports/20161130_microgrid_report.pdf
[19] New Jersey BPU, p. 7.

other environmental impacts; and, overall energy cost savings to the multiple critical customers.[20]

Minnesota

Xcel Energy recently filed a Distribution System Study as a supplemental report to the standard Biennial Transmission Projects Report in which it discusses its grid modernization plans.[21] Xcel points to hosting capacity as a major component in distribution system planning to potentially further enable DER integration by managing installations in areas of constraint. The study notes that there are approximately 778 MW of existing or proposed DG on Xcel's system, and the utility indicates that the report is a way to better understand potential feeder capacity moving forward.

D. Planning Conclusions

The key element in addressing grid resilience and reliability is having a good understanding of the grid and where the strengths and weaknesses are. This can be accomplished in a number of ways, but it is advisable to create a process that includes stakeholder participation given the potential magnitude of costs. Solutions can range from the traditional utility-directed system upgrades, which require investments paid for by utility customers, to more innovative approaches that take advantage of the increasing availability of distributed energy resources. Ratepayers benefit most when cost-benefit analyses are conducted to determine the least-cost options to ensure a reliable grid.

III. Investment in Software/Cloud-Based Information Data Systems

Grid modernization and resilience increasingly requires use of sophisticated data management systems and advanced software to manage, access, and analyze the increasingly massive amounts of data obtainable from smart grid systems. Smart grid technologies, integrated into operations through business process changes and software, can alert grid managers to problems on their system and aid in system recovery. They can also aid third-party providers in the delivery of services and products that end-use customers want that also support the grid. Utilities are only beginning to consider how these technologies and innovations change their business model. Commissions across the United States are also starting to consider how these changes alter the regulatory model and competitive market development. This section focuses on advanced data systems, specifically cloud-based software management, from a regulator's point of view and considers rate treatment of utility cloud-based information data systems acquisitions under both traditional state commission policies and various modifications of those policies.

The backdrop assumption, and traditional treatment in rates, is that software systems can be purchased by a utility and capitalized. Only recently have developments in the software and related industries allowed utilities to subscribe to cloud-based systems. While utility investments in IT and information systems (IS) are often capitalized, the costs of cloud-based software are, instead, typically treated as an

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[20] New Jersey BPU, pp.88-89.

[21] E9 Insight. Xcel Distribution System Study. Retrieved from http://e9insight.com/xcel-files-distribution-system-study/

operating expense as a payment of contract services. Despite these two approaches to utility data management being somewhat functional substitutes, there may be less incentive for a utility to choose the alternative that does not yield a return on rate base. This section explores:

- Allowing recovery of an operating expense as a regulatory asset, with a suitable return;
- Recovering these costs as an operating expense, but creating a performance incentive mechanism that rewards the utility based upon its performance in implementing these measures; and
- Vendor data-handling considerations that are now more salient as large-scale utility data management by third-party contractors (and subcontractors) is increasingly considered.

A. Pennsylvania Context

Pennsylvania is fortunate to have an active Electronic Data Exchange Working Group (EDEWG) and staff in the Commission's Office of Competitive Market Oversight and Bureau of Technical Utility Services who have been working on electronic data exchange for a number of years. The EDEWG has been active in advancing availability of consumer interval usage data through stakeholder discussions and by bringing these issues before the Commission.

In 2016, the Commission approved the EDEWG's *Pennsylvania Web Portal Working Group Technical Implementation Standards*, which lay out the parameters by which electric distribution companies (EDCs) should develop and implement web portals for customer information. These portals should enable the sharing of interval smart meter data with both customers and authorized third-party suppliers.[22]

The Commission's *Pennsylvania Web Portal Working Group* order continues the Commission's implementation of Act 129, under which utilities are expected to install smart meters and make web-based portals available for customers to access their own data. Act 129 also addresses allowing information sharing with third-party suppliers, including electrical generation suppliers (EGS) and providers of conservation services.

With this stakeholder and Commission attention to electronic data issues, Pennsylvania is well situated with significant AMI deployments to move beyond web portal data sharing to more sophisticated data management systems, allowing it to further develop competitive electrical and energy services markets.

Existing Commission rate case treatment of IT/IS investment allows for software to be capitalized based upon its service life (usually for three to five years for this type of property). The accounting definition of a capital asset established by generally accepted accounting principles (GAAP) is that an asset has a useful life of more than one year. Utility accounting treatment of assets is reported by Commission staff to be very stable. Particular software investments are examined in rate cases based on the asset life and related IT application. Naturally, larger investments draw attention of depreciation witnesses. We

[22] Pennsylvania Public Utility Commission. (2016, June 30). *Submission of the Electronic Data Exchange Working Group's Web Portal Working Group's Solution Framework for Historical Interval Usage and Billing Quality Interval Use*, Docket M-2009-2092655 (Order setting implementation timeframe for single user – multiple request functionality and system-to-system solutions by Nov. 3, 2016).

understand from the Pennsylvania PUC staff that software items have become big expense items in rate cases.

Commission staff also report little experience with direct requests to outsource large information system/information technology functions. Call center overflow and meter reading services have been performed by utilities, but no large-scale proposals to outsource IS/IT services are reported. Commission staff further report having no formal preference for whether a utility invests directly in a capital asset. However, while the PUC has approved recovery of outsourced utility expenses, many such contracts have been utility affiliate transactions. Utilities have also had a recent preference to bring these functions back to Pennsylvania based on local service territory knowledge. Whether outsourced or not, the utility is held responsible for all data security and privacy requirements, whether through its own system or the work of a third-party service provider. That said, staff noted that a large-scale outsourcing of customer relations could well result in a customer complaint if information were mishandled, which the Commission would consider if received.

B. NARUC Resolution

The National Association of Regulatory Utility Commissioners (NARUC) adopted a *Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements* at its annual meeting on November 16, 2016, in La Quinta, CA. This resolution observes that the transformation to cloud-based data management is occurring in other sectors and that "[t]o thrive in the future, utilities may need to modernize and transform their business operations. A key element of this may be access to state-of-the-art commercial cloud computing services, which is increasingly delivered via a 'cloud-based' or 'software-as-a-service' model . . . " The resolution also observes that advanced cloud-based data management systems have the potential to provide enhanced security, reliability and flexibility, allowing utilities "to keep pace with innovation and technology."

The resolution continues by observing that cloud-based data arrangements usually involve a periodic payment to a cloud-based vendor. In contrast, on-premise utility data systems often involve capital expenditures upon which a utility can earn a rate of return. Therefore, under prevailing standards, investments in cloud-based resolutions often involves only payment treated as an operating expense—upon which ordinary principles of utility regulation would not allow a rate of return. The resolution posits that the disparate treatment of investments in cloud-based data management versus those in on-premises solutions is an issue. It also posits that utilities should adopt data management systems based on which best meet their business needs, as opposed to based on regulatory accounting treatment, and further encourages commissions to consider allowing a rate of return on both types of data management systems. The resolution:

> encourages State regulators to consider whether cloud computing and on-premise solutions should receive similar regulatory accounting treatment, in that both would be eligible to earn a rate of return and would be paid for out of a utility's capital budget.[23]

[23] NARUC. (2016, November 16). Resolution CI-1/GS-1/WA-1: *Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements*. Retrieved fom http://pubs.naruc.org/pub/4FDD6D6B-F303-DE7B-5B46-7B25C04E6317

The NARUC resolution is not specific as to the regulatory mechanism by which a Commission might allow for a cloud-based system to earn a rate of return or be paid out of a utility's capital budget. This question is explored below.

C. Facilitating Utility Transformation through Data Access

As NARUC observes, the utility sector is moving into the digital age, if somewhat behind other leading industries. As smart grid and smart meter installations generate more data about system performance and customer usage, utilities increasingly need to develop their own systems, whether internal or external or a combination thereof, to manage the data and make it accessible for utility use. A second and related challenge is that this data is very valuable to third-party energy companies that offer distributed generation, storage, and conservation, among other services, which utility customers are increasingly interested in exploring and acquiring. Customer value and related grid value cannot be realized if this data is not made available to third parties with appropriate customer consent. Access to utility system and customer data will either facilitate or stultify utility sector transformation.

In addition to the Pennsylvania Commission, other state commissions are opening dockets to consider utility and ratepayer needs in advanced data management systems. Illinois has adopted Green Button as its default system for third-party access to AMI interval meter data,[24] and the state is also advancing consideration of cloud-based data management systems.[25] New York is establishing data aggregation requirements and related utility reforms. California has authorized utilities to provide web-based platforms to enable customers to share their usage information with third-party providers.[26] Texas is further examining third-party access to data in the legislatively established Smart Meter Texas program.[27] These cases are illustrative of the increased emphasis state utility commissions and utilities are putting on establishing data handling, management, and transparency standards. These standards facilitate utility adoption of advanced data management systems that are consistent with utility needs, customer desires, and facilitation of power sector transformation.

As the NARUC resolution above concluded, cloud-based data management systems usage by utilities is consistent with national business trends and can provide superior customer satisfaction. That said, ratepayers should pay for services that provide value to them and at rates that are just and reasonable and no more.

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[24] Illinois Commerce Commission. (2015, January 28). Case 15-0073. Retrieved from https://www.icc.illinois.gov/docket/CaseDetails.aspx?no=15-0073

[25] Sheahan, B., E. McErlean, E., & and Palivos, A. (2016, March). Are Regulators' Heads in the Cloud? Primary Challenges to Utility, Adoption of Cloud-Based Solutions. *Electricity Policy*.

[26] California PUC. Proceeding A1406001. Application of Pacific Gas and Electric Company for Recovery of Costs to Implement Electric Rule 24 Direct Participation Demand Response. Retrieved from https://apps.cpuc.ca.gov/apex/f?p=401:56:1558344897748::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1406001; New York PSC. Case 16-01574/16-M-0428. In the Matter of Utility Platform Service Revenues and Aggregated Data Access Reforms Supporting the Commission's Reforming the Energy Vision. Retrieved from http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=51412&MNO=16-M-0428

[27] Public Utility Commission of Texas. Case 46204-1. Retrieved from http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=46204&TXT_ITEM_NO=1

D. Allowing Recovery of an Operating Expense as a Regulatory Asset

While it is not clear that current regulatory treatment of cloud-based expenses is insufficient—indeed, current treatment provides protections for ratepayers consistent with traditional rate base approaches—the NARUC resolution suggests that Commissions may want to change regulatory treatment of cloud-based contracts to facilitate a transition to cloud-based information management systems. The rationale to change treatment is to provide a more favorable rate of return on cloud-based information system investments by treating these contracts as capital investments. The subsidiary rationale is that a utility's investments in its own IT system would receive capital treatment for at least the hardware costs and likely some software costs. The treatment of cloud-based system costs could involve different routes, most of which are yet to be fully explored and explained by a Commission.

One route to implement the NARUC resolution would be for Commissions to treat cloud-based expenses as a regulatory asset. In other contexts, such as energy efficiency, there is some precedent for allowing a rate of return on non-traditional utility investments.[28] By granting accounting orders and specific regulatory asset treatment to allow for a rate of return to be earned on non-traditional utility investments, Commissions could authorize recovery of software and related outsourced cloud-service expense payments with an allowed rate of return to the utility.

Issues that a Commission would consider for regulatory asset treatment are:

- Additional costs to ratepayers, driven directly by allowing rate of return treatment for utility expenses now treated as a regulatory asset;
- The length or period for treatment as a regulatory asset;
- Whether each specific contract for data management/software/IS justifies treatment as regulatory asset; creation of a very clear policy on size of contracts and types of data management services that qualify (even within a contract) may be advisable to prevent inclusion of non-qualifying activities under a "data management" contract from being added to rate base as a regulatory asset;
- Such a policy for use in rate cases (or accounting orders) might make it clear how much of each contract must be identified and disclosed, or on the other extreme, whether an entire category of "data management services" can be given lump sum treatment in a single line item; the latter option is probably untenable, as these costs will increase over time and are proposed under the NARUC resolution for more favorable rate-of-return treatment;
- What payment amounts to allow over the life of a specific data management contract for regulatory asset treatment;
- Whether existing services or even contracts for data management and software now treated as an expense will be recharacterized by a utility as regulatory asset—in other words, what existing activities might fall into the new treatment over time thereby costing ratepayers money for increases ROR treatment on existing activities over time;

[28] Swanson, S. (2012, March). *Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency*. Montpelier, VT: Regulatory Assistance Project.

- The rate of recovery on the regulatory asset—whether at the rate of return approved in the utilities last rate case, the average weighted cost of capital, the utilities cost of debt financing or some other rate; and
- If those investments become substantial as they will no doubt increase time, whether an adjustment or examination of the utilities capital structure is appropriate.

The rate for recovery would presumably be the rate of return approved in the last rate case, although arguments could be considered for other rates of return for the regulatory asset. And while it is unlikely in practice, if a utility proposed a major regulatory asset to outsource most of its data management functions, how the proposal would affect the utility's capital structure is one of the issues that may be examined.

The life of the regulatory asset would presumably be correlated with the expected life of the software contract. For cloud-based services that constantly update the software and service package, this expected life may well be the life of the contract. It is very hard to identify actual capital assets among software and databases that are constantly updated. Contracts for more substantial services and for which the Commission sees a ratepayer or quality of service advantage to outsourcing for cloud-based systems may well justify regulatory asset treatment more so than contracts common in the industry in the past, such as meter reading and call center overflow in Pennsylvania. Presumably, only the funds actually expended by the utility would be subject to regulatory asset treatment, and perhaps only a portion of that value representing the software component of such a contract. If the amounts are not yet expended under a contract, those amounts would likely be allowed regulatory asset treatment when they are expended by the utility, and not before.

This example illustrates the potential difficulty one confronts in implementing this concept: It is hard to draw firm lines on what outsourced "data management" services actually are. Some utilities have outsourced meter reading and customer service call centers for years. No inducement to outsource meter reading or customer service by favorable rate treatment has been deemed appropriate by any PUC or even proposed for these traditional utility services. Yet data management in cloud-based systems will increasingly became intimately related to how smart meter data is collected, stored, analyzed, and shared with customers in a customer management database—indeed, how it is to be integrated by many utilities with the very same databases used by customer service representatives. Are we opening the door to having some traditional utility operating expense items such as meter reading and customer service to be outsourced and treated as cloud-based regulatory assets? The answer is troubling and far from clear. The previous accounting treatment rule that a contract expense is indeed an expense avoids opening this door. With NARUC now urging Commissions to consider rate basing cloud-based data systems, state regulators will need to grapple with where to draw the line on what services, which contracts, and even what portions of contracts for cloud-based data management services can qualify for regulatory asset and thereby rate base treatment earning a rate of return.

E. Recovery of Software Costs as an Operating Expense With a Performance Incentive Mechanism

An alternative route to encourage the adoption of cloud-based systems would be to offer favorable incentives. So, compared with straight expensing of payments under a cloud-based data contract, a

Commission could grant a performance incentive for contracting for cloud-based software and data management. Setting performance standards requires identification of the goal and then establishing a specific set of metrics or measures to be measured for performance. The performance incentive to be earned could be based on a percentage of the investment. Likewise, whether the incentive is earned could be based on performance of the investment in achieving specific goals such as facilitation of third-party DER markets. The New York PSC is taking that the latter approach in its REV proceeding for allowing certain ROE adders. And there is some precedent for the former approach of allowing a performance incentive on top of a rate of return for capital investments in energy efficiency—though this practice has been abandoned by those few states that experimented with it, suggesting that allowing recovery of additional investments (not linked to performance) may not provide the right set of incentives.[29]

Performance incentive structures are typically allowed for utility performance that is deemed highly desirable and advantageous by state policymakers and/or by the state commissions. Examples of performance-based recovery are numerous, but usually revolve around utility behavior that state policy or officials desire but which a utility is not inclined to take. Further, the desired utility behavior or outcome must go beyond business as usual or prudent utility management and decision-making. The reward of a performance incentive should be associated with superior utility performance, which achieves a specific set of desired utility or energy market outcomes that can be measured to ensure the performance incentive is indeed earned.

Defining the beneficial goals to pursue utility cloud-based contracts would be particularly important to grant performance incentive treatment. Those goals could include superior information and data security; enhancements of data availability to customers and third-party service providers; and exceeding a baseline set by state law, rule, or Commission policy guidance on development of advanced smart grid data management functionality. Those goals then would be refined down to specific metrics and measures to assess whether and how the performance incentive is earned. In any and all cases, granting advantageous rate treatment through a performance incentive structure or regulatory asset treatment would involve a weighing of additional costs to ratepayers against the additional functionality that cloud-based data management systems offer to the utility. This includes the systems' ability to enable the utility to carry out traditional functions, update functions and service to evolving smart grid standards, and offer products and services that ratepayers demand and expect to be available.

F. Combination of Regulatory Asset and Performance Incentive

A performance incentive can be allowed on top of a rate of return to incentivize utility investments that are deemed beneficial to the utility system. For example, the Nevada Commission allowed a rate of return on demand-side management investments by the utility with an additional 5 percent on top of the rate of return.[30] This treatment for DSM investments was in place from 2004 to 2010, when Nevada adopted a lost revenue mechanism. This example shows simply that desirable investments can be incentivized by a combination of rate of return and incentives.

[29] Swanson, 2012, pp. 38-39. The Nevada Commission allowed a rate of return on demand-side management investments by the utility with an additional 5 percent on top of the rate of return.
[30] Swanson, 2012, pp.38-39.

Designing performance incentives to achieve the goals and measuring performance is critical to any performance-based regulation.[31] While a full design of a performance based incentive structure is beyond the scope of this section, the factors that a Commission would want to address include:

- The goal(s) for granting the performance incentive that are intended to be achieved;
- How achievement of the goal(s) can be determined;
- How the achievement can be reduced to a set of measures or metrics to use in granting the performance incentive;
- Establishing a specific formula to award the incentive to utility performance, such as an increase of 50 basis points for customer satisfaction—this would be determined by a survey to be conducted by an independent firm with Commission-approved questions—or 100 basis points for a survey of DER providers asking specific questions about the ability to access utility data and the functioning of the data management system for third-party DER providers (ie, NY REV); and
- Considering ways the performance incentive could be gamed, and ensure no perverse incentives are built in inadvertently; Commissioners would need to ask what could go wrong with the incentive scheme. It is often best to ask these questions in a public process to get the benefit of perspectives and information from a wide variety of stakeholders.

This list is neither exhaustive nor exclusive. Designing the goals, metrics, and compliance parameters for any performance-based incentive is critical to ensuring that ratepayers are receiving the extra value for which they are paying the utility.

G. Contractual Considerations for Utility Data Management

As utilities move more into data exchange arrangements with customers and third parties and contract out some of these functions to utility service vendors—including cloud-based data companies—there is increasingly a need to consider data system reliability, data security, customer privacy, and even data ownership arrangements in these contracts. The Commission may want to consider establishing guidance for utilities or review contracts under which significant utility and customer data will be shared with third parties, including subcontractors who may live in any country in the world. This is not a theoretical concern; we are aware of instances where entire utility customer lists, addresses, and Social Security numbers have been shared with vendor subcontractors and passed onto subcontractors' families in Asia. The same could happen with utility system data, a clearly undesirable result.

As utilities contract for advanced software and associated costs, the sensitivity of information and ability to share it increases the probability that breaches of data security will occur. Customer-specific data can be categorized as personally identifiable information such as individual names; contract information; confidential business information such as building assets, images, or other usage and financial information; and non-private information. Data handling, transmission, and storage requirements should increase in levels of protection as one moves from non-private data to confidential business information to personally identifiable information.

Data breaches can take an almost limitless number of forms. The Pennsylvania Commission has experience with at least two recent data breaches. One involves a natural gas utility whose corrupt

[31] Regulatory Assistance Project. (2000, December). *Performance-Based Regulation For Distribution Utilities*. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf

database allowed some customers to access other customers' billing and customer information. This resulted in a $5,000 fine that could not be recovered from its ratepayers and an order to continue oversight and implementation of systems including training and internal procedures to prevent the release of customer information in the future.[32] The second incident involved an employee posting a picture on social media taken at work with customer information visible in the background. Both incidents reveal two routes that improper training, internal controls and database management be easily result in unauthorized release of utility customer date. Of at least equal concern is utility system data can could result in compromising system reliability and exposing utility systems to hackers or cyber criminals.

The Commission may want to require utilities to adopt a best management practice to require secure file transfer protocol or secure web services for any transmission of utility data to or from its vendors including any transfers to subcontractors of the vendors. Use of password policies and encryption for sensitive data are also standard for IS/IT security and reasonable to expect of utilities as well as their vendors and contractors.

Cloud data and software management introduces the importance of maintaining application security on the software platform in the cloud. This can involve isolating applications into private networks within secure data processing clouds. By ensuring that applications are isolated in this way, with users never allowed direct access to application servers or the application database, the opportunities for hacking, malicious data breaches, and accident data sharing are minimized under the best standards for cloud-based web applications. Provision for data backup is advisable as a best management practice for any large and critical datasets. While the Commission likely does not want to specify system security, network security, and hardware security protocols, it certainly has the authority to specify a best management practice that it expects to meet prudence review—including specifying that the utility will maintain security of data handling and transmission security at all times.

On data ownership, unless a Commission specifies otherwise, the utilities are likely to take the view that all data collecting from its own systems and customer data is owned by the utility. Some vendors may take the view that the data they develop or the form they store that data in is proprietary to the vendor. If the contract is terminated, or the vendor goes out of business, there is a risk that the data will be lost to both the utility and customers. That scenario is fairly easy to address up front with the vendor by specifying that the utility shall have access to all data to be stored in a form that is usable and accessible to the utility. For customer data and customer-derived data, there may also be good reason to specify that the customers own or shall have access to their own data. The Commission can also consider whether it would specify that customers owner, have right to, and may fully access to all of their own customer-related data and analysis at no charge to the customer.

Under certain circumstances, the Commission itself and other state entities may have the ability to access utility system data (subject to appropriate non-disclosure for trade secrets, business-confidential info, or critical energy infrastructure data) and state laws. Those arrangements are perhaps best made by Commission Order in advance of a dispute. Clear rules concerning ownership of data and access to

[32] Pennsylvania PUC. PUC Approves $5,000 Settlement with Columbia Gas of Pennsylvania, Inc. [Press release]. Retrieved from http://www.puc.pa.gov/about_puc/press_releases.aspx?ShowPR=3023

data consistent with Pennsylvania law will set utility, customer and industry expectations as this data is developed, stored and maintained.

IV. Investments in Hardware and Assets to Strengthen the Grid

Being prepared for an outage and having access to an inventory of equipment and supplies can be critical to restoring power after a major event. Requiring each utility to individually maintain a caché of spare parts can be especially costly and redundant. A number of cost sharing options have been developed that the Commission may want to consider either encouraging its electric distribution utilities (EDU's) to join directly; or, use as a model to design its own process. This section will explore the jurisdictional issues of the Commission as it relates to inventories and supplies; performance metrics; the various models in place; and, the cost recovery options.

A. Jurisdictional Issues With Respect to Distribution and Transmission

As noted in the Introduction, the PPUC only has jurisdiction over the distribution system. By contrast, the Federal Energy Regulatory Commission (FERC) has broadly-framed, exclusive jurisdiction[33] over the interstate transmission system.[34] FERC established a seven-factor test that can be used as guidance for determining the delineation between FERC and state jurisdiction over power lines.[35] Thus, the Pennsylvania Commission has the authority to order certain actions with respect to those elements of the utility system that are defined as distribution, and, more broadly for facilities that do not otherwise meet FERC's definition for interstate transmission. With respect to activities to improve grid reliance and security in the State of Pennsylvania that are FERC-jurisdictional (i.e., interstate transmission-related), the Commission can strongly encourage certain activities but cannot order them.

A typical distribution system can consist of substations, distribution feeder circuits, switches, protective equipment, primary circuit distribution transformers, secondary transformers, and services. The distribution system typically delivers voltages as high as 34,000 volts (34 kV) and as low as 120 volts. The following is an illustration of the functions included in a distribution substation:[36]

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[33] FERC has only limited backstop authority in the siting of transmission facilities that are otherwise deemed to be FERC-jurisdictional.

[34] 16 USC 824, 824d, 824e.

[35] The seven factors are: 1) local distribution facilities are normally in close proximity to retail customers; 2) local distribution facilities are primarily radial in character; 3) power flows into local distribution systems, and rarely, if ever flows out; 4) when power enters a local distribution system, it is not reconsigned or transported on to some other market; 5) power entering a local distribution system is consumed in a comparatively restricted geographic area; 6) meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and 7) local distribution systems will be of reduced voltage. See: https://www.epa.gov/sites/production/files/2015-07/documents/20150709webinar.pdf

[36] U.S. Department of Labor. Illustrated Glossary: Distribution System. Retrieved from https://www.osha.gov/SLTC/etools/electric_power/illustrated_glossary/distribution_system.html

Figure 1. Energy flow through a typical substation

A typical transmission system consists of overhead transmission lines, subtransmission lines, and underground transmission lines that carry three-phase current. The voltages vary according to the particular grid system they belong to and can range from 69 kv up to 765 kv.[37]

Thus, the Pennsylvania PUC has clear authority to act with respect to those aspects of the grid that relate to lines that are 34 kv or less and their associated materials and supplies.

B. Resiliency at the Distribution Level

In order to ensure resiliency at the distribution level it is important to have a system that can withstand events with minimal damage and outages. Measures that provide resiliency and protection would include such measures as storm hardening of facilities, selective undergrounding of circuits, and moving substations above 1,000-year flood plains, among other things. Hardening initiatives can also include making physical and structural improvements to lines, poles, towers, substations and supporting facilities. Elevation of existing assets and improvements to floodwalls, where applicable, can also be considered.[38] As USDOE points out, many of the existing issues with regard to the aging infrastructure (for example, clustered and below-grade transformers, fuses and not breakers in many locations, underground ducts running close together and crossing in many shallow manholes) do not have explicit codes and regulations. As a result, and absent codes which would proscribe many of these decisions, when the utility upgrades the infrastructure, they must also determine the level of upgrade that most cost-effectively provides resilience to the system.[39]

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[37] U.S. Department of Labor. Illustrated Glossary: Transmission Lines. Retrieved from https://www.osha.gov/SLTC/etools/electric_power/illustrated_glossary/transmission_lines.html

[38] USDOE, Climate Change and the Electricity Sector, July, 2016, https://energy.gov/sites/prod/files/2016/07/f33/Climate%20Change%20and%20the%20Electricity%20Sector%20Guide%20for%20Assessing%20Vulnerabilities%20and%20Developing%20Resilience%20Solutions%20to%20Sea%20Level%20Rise%20July%202016.pdf, p.55.

[39] *Id.*

When planning for distribution system resiliency it is also important to implement measures that can be activated at critical times to restore some normalcy to critical areas as larger system-wide restoration continues after a storm. This potentially could occur through the deployment of micro-grids and distributed generation (discussed in the next section) as well as having a smart grid that can isolate outages. Resiliency in other mission-critical operations can include incorporating into their operations "self-healing" networks and redundant equipment. Technologies can focus on identifying priority users or limited use options as repairs are underway.[40]

The Pennsylvania Commission does have regulations that can serve to review and ensure that their utilities are taking appropriate steps to upgrade the grid in a logical and cost-effective manner. Through its Long-Term Infrastructure Improvement Plan (LTIIPs) proceedings, the Commission can either require that each individual utility address resiliency when filing a LTIIP and demonstrate how the LTIIP will enhance resiliency; or, it can issue a Policy Statement that outlines that resiliency measures and programs should be a part of every utility's LTIIPs and provide some examples of such programs. The Commission can also issue a Notice of Proposed Rulemaking (NOPR) that would add resiliency as part of the LTIIP requirements.[41]

The Commission's rules also allow for cost recovery through a special charge so as to permit the utility to manage the costs of the upgrade without having to file a rate case. If a utility wants to seek cost recovery through a Distribution System Improvement Charge, (DSIC), then it must submit for Commission approval, an LTIIP that contains the following:

- Identification of types and age of eligible property owned and operated by the utility;
- An initial schedule for planned repair and replacement of eligible property;
- A general description of location of eligible property;
- A reasonable estimate of quantity of eligible property to be improved or repaired;
- Projected annual expenditures and means to finance the expenditures;
- A description of the manner in which infrastructure replacement will be accelerated and how repair, improvement or replacement will ensure and maintain adequate, efficient, safe, reliable and reasonable service to customers;
- A workforce management and training program designed to ensure that the utility will have access to a qualified workforce to perform work in a cost-effective, safe and reliable manner; and,
- A description of a utility's outreach and coordination activities with other utilities, Department of Transportation and local governments regarding the planned maintenance/construction projects and roadways that may be impacted by the LTIIP.[42]

As an extra safeguard, the Commission requires that a utility with a DSIC file an informational Annual Asset Optimization Plan (AAO), if it wants to continue to obtain cost recovery through the DSIC. The AAO must include:

- A description that specifies all the eligible property repaired, improved and replaced in the prior 12-month period under its LTIIP and prior year's AAO plan; and,

[40] See, http://www.energyviewpoints.com/2013/01/what-does-grid-resiliency-mean/
[41] http://www.pacode.com/secure/data/052/chapter121/s121.3.html.
[42] *Id.*

- A description of the eligible property to be repaired, improved and replaced in the upcoming 12-month period.[43]

In this manner the Commission can monitor the utility's activities to ensure they are on schedule with what upgrades have been accomplished and what the utility's plans are for the next wave of upgrades.

Having a process in place as described above, provides a transparent mechanism for remaining cognizant of utility upgrades and monitoring progress and costs.

C. Examples of Hardware Inventory Sharing Models

There are several programs currently in place for sharing grid inventory in a major event. Most seem to allow open membership that cuts across jurisdictions, but one, the New York state program, is established by the New York Public Service Commission and operates in New York only.

Edison Electric Institute's Spare Transformer Equipment Program (STEP)

On September 22, 2006, FERC issued an order approving the EEI application to establish the STEP program.[44] At the time of the filing, there were 41 signatories.[45] Under the agreement entered into by the signatory companies, each participating utility is required to maintain a specific number of transformers in various voltage classes and is required to sell its spare transformers to any other participating utility in its voltage class if there is a major event. The amount of spare transformers that each utility must maintain is based on its percentage share of all megavolt-amperes (MVA) that are in use in that class. The number of spare transformers needed in each of nine voltage classes is determined by a formula measuring the number needed to restore the most vulnerable system to an "N-0" status in the event that its five most critical substations in any voltage class are inoperable. At the time of the filing, it was estimated that collectively the program would cost between $50 million and $75 million, spread among all participants.[46]

The Pooled Inventory Management ("PIM") has linkages to the STEP agreements. The PIM is a program that manages joint equipment acquisitions for the nuclear power industry. It agreed to extend the scope of its spare parts program to include transformers. Each utility in the joint acquisition would pay for a portion of the acquisition costs and would pay PIM a fee for administration and maintenance. PIM participants can use the transformers jointly owned under the PIM program to meet their obligations under the STEP agreement. This, therefore provides two pathways for compliance with STEP.

FERC approved the EEI Application for the STEP program, finding it a prudent and cost-effective mechanism to help ensure the reliability of the grid. FERC, however, imposed reporting requirements on all transfers of transformers and stated that rate recovery would be established under separate utility

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[43] *Id.*

[44] FERC. (2006, September 22). Docket Nos. EC06-140-00 and EL06-86-000. Order on Application for Blanket Authorization for Transfers of Jurisdictional Facilities and Petition for Declaratory Order. Edison Electric Institute on behalf of the Jurisdictional Signatories to the Spare Transformer Sharing Agreement. Retrieved from https://www.ferc.gov/whats-new/comm-meet/092106/E-13.pdf

[45] The original signatories include Pennsylvania Power Company, Metropolitan Edison Company, Pennsylvania Electric Company, PECO Energy Company, and PPL Electric Utilities Corporation.

[46] This is based on an estimate that 21 to 31 transformers would be needed with a cost of approximately $500,000 for 200 MVA 138 kV transformers and a cost of approximately $11 million for 2,000 MVA 500kV transformers.

filings under Section 205 of the Federal Power Act. While FERC approved the formula for setting forth the obligations, it made no predetermination as to the reasonableness of the costs. In effect, rate recovery sought through the STEP Programs can be viewed in isolation of other costs and so represents a type of single-issue ratemaking.

Thus, it would appear that most of Pennsylvania's major utilities are part of a plan for addressing transformers. The Pennsylvania Commission may want to consider what percentage of transformer costs are covered under transmission versus distribution and create parallel treatment of transformer costs that are allocated to distribution to the extent permissible under Pennsylvania law. A further step for the Commission could be to survey how the program is working and if the remaining Pennsylvania utilities should be encouraged to join.

SpareConnect Program

In addition to STEP, the SpareConnect program provides an additional mechanism for bulk power system (BPS) asset owners and operators to interact with other SpareConnect participants regarding the possibility of sharing transmission and generation step-up (GSU) transformers and related equipment, including bushings, fans and auxiliary components.[47] According to EEI, "SpareConnect establishes a confidential, unified platform for the entire electric industry to communicate equipment needs in the event of an emergency or other non-routine failure."[48]

SpareConnect acts as a complement to the STEP program by providing an additional network of participants who can provide assistance regarding equipment availability and technical resources. Rather than providing or managing a central database of spare equipment, SpareConnect instead provides decentralized access to points of contact at power companies so that in the event of an emergency, SpareConnect participants can quickly connect with other participants in affected voltage classes. SpareConnect does not require participants to provide any information or to make any particular piece of equipment available. Rather, it acts more like an information clearinghouse for those in need of equipment to interact with those that have such spare equipment. The SpareConnect participants who are interested in providing additional information or sharing equipment then work with each other to arrange the specific terms and conditions of any equipment sale or other transaction.

Grid Assurance LLC

On March 25, 2016, the Federal Energy Regulatory Commission issued an Order on the application of Grid Assurance regarding its proposal to establish a spare parts and service enterprise to address inventory needs in the event of a catastrophic or major event.[49] Specifically, Grid Assurance requested the Commission to declare that:

- Contracting for Grid Assurance sparing service and purchasing spare equipment from Grid Assurance following a Qualifying Event[50] pursuant to the Subscription Agreement is prudent;

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[47] EEI. *Spare Transformers.* Retrieved from http://www.eei.org/issuesandpolicy/transmission/Pages/sparetransformers.aspx
[48] EEI, *Spare Transformers.*
[49] FERC. Docket No. EL16-20-000: Order on Petition for Declaratory Order. Grid Assurance, LLC. Retrieved from https://www.ferc.gov/CalendarFiles/20160325163047-EL16-20-000.pdf
[50] A "Qualifying Event" is defined as "any damage, destruction or other material impairment of the safe operation of any equipment comprising the electric transmission system of a Subscriber Group Member, which damage, destruction or

- Grid Assurance subscribers[51] may use single-issue ratemaking[52] to modify existing jurisdictional rates in order to seek to recover the costs of purchasing sparing service and spare equipment from Grid Assurance; and
- To the extent purchases of non-power goods and services from Grid Assurance by any affiliated subscriber are subject to affiliate pricing restriction that prohibit purchases "at a price above market," making such purchases at the pricing described in the Subscription Agreement is permissible.

The Commission granted the first two requests and denied the third request, opting to provide a waiver instead.

Pursuant to the Subscription Agreement, Grid Assurance is obligated to: maintain an inventory of critical spare transformers, circuit breakers, and related transmission equipment optimized for the collective resiliency needs of its subscribers; provide secure domestic warehousing of the inventory of spares in strategic locations; and, release inventory of spares to utility subscribers as needed to respond to a Qualifying Event.[53] The Grid Assurance agreement provides that members can obtain equipment at cost. In the event of a widespread qualifying event affecting several members that each seek scarce equipment, Grid Assurance would make a fair allocation considering such factors as the member's ability to repair the outages and the impacted area.

Under the agreement, subscribers pay a monthly, cost-based sparing service fee that covers costs not recovered from equipment sales, such as warehousing and inventory costs. The Subscription Agreement establishes a cost-based formula for determining costs associated with each equipment class, and common costs associated with all equipment classes, and allocates those costs among subscribers based on their equipment nominations.

The New York Process

After Super Storm Sandy hit the Eastern Seaboard in 2012, New York state put together a commission of leading experts and released the NYS 2100 Commission Report, a comprehensive report that included recommendations to create a more resilient and future-ready energy system.[54]

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impairment is caused by, or the result of: (a) an act of war, terrorism, rebellion, sabotage or a public enemy, or any other physical attack (whether of not such physical attack is conducted in connection with an act of war, terrorism or a public enemy); (b) a cyber-attack, whether or not in connection with an act of war, terrorism or a public enemy; (c) an electromagnetic pulse or intentional electromagnetic interference; or (d) and act of God, a catastrophic event (natural or otherwise) or a severe weather condition, including a solar storm, earthquake, volcanic eruption, hurricane, tornado, derecho, windstorm, wildfire or ice storm." Ibid, pp. 5-6.

[51] Grid Assurance members include: American Electric Power Company, Duke Energy, Berkshire Hathaway Energy Business (US T), Edison International, Eversource Energy, Exelon Corporation, Great Plains Energy, and Southern Company.

[52] "Single-issue ratemaking" pertains to the ability of a company to seek cost recovery of a single expense or investment outside of a generalized rate case where all costs and sources of revenue can be considered together. FERC has made clear that such treatment represents the exception rather than the rule.

[53] Article 1 of the Subscription Agreement identifies the available services under the agreement, including equipment procurement, warehousing and inventory management, inspection, testing, maintenance, and logistics support for transportation and delivery.

[54] NYS 2011 Commission Report. Retrieved from http://www.governor.ny.gov/sites/governor.ny.gov/files/archive/assets/documents/NYS2100.pdf

The Report made a number of key recommendations:[55]

- Strengthen critical energy infrastructure;
- Accelerate the modernization of the electrical system and improve flexibility;
- Design rate structures and create incentives to encourage distributed generation and smart grid investments;
- Diversify fuel supply, reduce demand for energy, and create redundancies; and
- Develop long-term career training and a skilled energy workforce.

The New York PSC also began a proceeding to examine shared critical equipment and infrastructure and issued an order on November 19, 2013.[56] Through a collaborative with utilities, the PSC, New York Power Authority, Long Island Power Authority, and the New York Independent System Operator, a template was developed for filing on-hand inventory levels for items used during storm restoration and other emergencies. In addition to inventory levels, each filing included: the quantity of each item stored in reserve for storm response, the extent and nature of any material shortage that occurred during Hurricane Sandy, the quantity of each item used during restoration, and, existing material handling procedures. Items that would be needed and those that could be readily transferred and used were identified.

Prior to the issuance of the Commission order, the collaborative filed a report on June 3, 2013, with a number of findings and recommendations. The collaborative concluded that while a multi-utility capital asset and critical equipment storage and delivery system already existed in New York, the system should be enhanced to enable further sharing. They recommended stockpiling across the state as opposed to one centralized location to reduce risk and ratepayer costs, using a number of existing locations. The Commission concurred in these findings. However, the collaborative report also stated that standardizing commonly used equipment and supplies would be costly and would require detailed engineering review by each utility. The report claimed that standardization also had the potential to create stranded inventory and unrecoverable costs. While acknowledging design differences, the Commission stated that sharing specifications could result in a part number cross-reference list or a potential to substitute equipment and supplies. The Commission found that continual review and refinement of inventory lists could result in a larger pool of equipment and supplies to draw upon as well as identify opportunities for standardization, which the Commission encouraged.

The Commission approved the collaborative's request for the treatment of materials and equipment as capital assets to be rate-based, rather than simply expensed.[57] The utilities were also required to file annual reports documenting their transactions. Note that the utilities indicated that most of these transactions would not surpass the $100,000 threshold for which Commission approval is granted by operation of law within 90 days of notification.[58]

For compensation, the collaborative proposed that equipment and materials be transferred at replacement cost together with adders for taxes, handling and administrative costs. The Commission

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[55] Id. at 79

[56] New York DPS. (2013, November 19). Proceeding on Motion of the Commission to Examine Utility Shared Critical Equipment and Supplies, Case 13-M-0047. Order Instituting a Process for the Sharing of Critical Infrastructure. Retriwved from http://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/ArticlesByCategory/E42C031A90522BB485257C28007274B1/$File/202_13m0047.pdf?OpenElement

[57] New York Public Service Law, Sec. 70.

[58] New York DPS, p.6.

recommended implementation of uniform accounting practices for the sale of utility shared critical equipment and supplies consistent with principles of cost causation. The selling utility would sell inventory equipment at replacement cost plus costs such as taxes, delivery, etc. The resulting gain or loss on inventory or depreciable plant in service sold would be charged or credited to the respective inventory or depreciation reserve accounts.

Finally, the Commission required the utilities to create a working group to: establish a uniform accounting policy for sharing critical equipment; develop a plan for communicating inventory levels and material changes throughout the year; create an amended list of storeroom locations; provide a detailed breakdown of equipment vendor involvement; and, provide for periodic meetings to discuss and develop best practices.

D. Summary

This is not an exhaustive list of programs, but does contain the major programs currently in place for ensuring rapid sharing and deployment of critical equipment and supplies should a major event occur. A common thread through all of these programs is that the utilities would purchase equipment and supplies at cost plus pay administrative and handling costs. The only exception is the SpareConnect Program, which is a private negotiation between the buyer and seller. The chart at the end of this section summarizes some of the options available for the Pennsylvania Commission's consideration in putting together a program. It is noteworthy that the majority of Pennsylvania's utilities already belong to the STEP program, which covers spare transformers; however, more is needed to cover other equipment and supplies in the event of a major catastrophe. Other options include a proceeding like New York's to catalog each utility's inventory or to create a collaborative working group among the utilities in the state to update inventories and discuss best practices.

The Commission already has in place reliability standards such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Momentary Average Interruption Frequency Index (MAIFI) and Customer Average Interruption Duration Index (CAIDI), each of which is determined separately on a utility-by-utility basis. Further, the Commission has procedures and processes in place to monitor compliance with reliability standards and to enforce any deviations from those standards.[59] The Commission staff also has broad delegated authority to enforce the standards and require the electric distribution companies to undertake corrective action processes. In fact, the Commission has explicitly cited an electric distribution utility's reliability performance as a factor in lowering or raising the company's return on equity in rate cases. These practices send clear signals to the utility as to Commission expectations for the public good.

As to cost recovery, depending on the option chosen, it appears that subscription fees may already be recoverable as an expense in rates. The acquisition of actual transformers and other supplies could be treated as a regulatory asset and deferred for recovery in the next rate case as there appears to be some precedent for this.

[59] See the following Commission Orders: http://www.puc.pa.gov/pcdocs/1082465.doc on monitoring and procedures; and, regulations on reliability standards and enforcement, http://www.pacode.com/secure/data/052/chapter57/subchapNtoc.html.

COMPARISON OF SPARE PART OPTIONS

	Ownership of Spare Parts	Inventory	Rate Recovery	Management
STEP	Each individual utility maintains specific number	Transformers	Recovery in separate utility proceeding; single issue ratemaking	Coordinated industry-wide program; managed through member committees
PIM	Each utility pays portion of acquisition of cost (partial ownership)	Transformers	Recovery in separate utility proceeding; single issue ratemaking	Nuclear power industry
SpareConnect	Individual owners and sellers	Transmission and generation; step-up transformers and related equipment, including bushings, fans and auxiliary components	Utility applies to regulatory authority	Information network, no manager, parties contract individually
Grid Assurance	LLC ownership – subscription fee for inventory and warehousing	Spare parts and services; transformers, circuit breakers, and related transmission equipment	Recovery in separate utility proceeding; single-issue ratemaking	Grid assurance
New York	Individual ownership; collaborative process	Multi-asset stockpiling	Lightened regulatory requirements for materials and equipment purchased as an expense and placed in inventory and for "pre-capitalized" items that are capitalized and included in rate base when purchased.	Utility working group, Commission oversight

V. Rate Design to Foster Reliability through DER

The topic of rate design and distributed energy resources is one that is receiving considerable attention by US policymakers. In 2015, NRRI reported that 43 states plus the District of Columbia are, or were recently, engaged in legislative or regulatory reviews or actions to alter utility rates and programs affecting distributed resources such as solar PV.[60]

Distributed energy resources and microgrids have a role to play in not only serving individual customers, but also providing services back to the grid as needed. Utility tariffs can be designed to either encourage or discourage the expansion of these options. Among the options to be discussed here are the following:

1. Creation of "microgrid-ready" or "DER-ready" tariffs, in which customer owners or aggregators are compensated for making power available to the utility when it is in need (this work scope will not create these tariffs); and
2. Ensuring that barriers in rate design to customer alternatives are removed.

Distributed energy resources can be, and today largely are, developed and installed with little regard for the overall resilience of the grid. This can change with well-formed price signals that encourage flexible loads, storage, and potential third parties and developers.

There are two distinct opportunities for relying on distributed energy resources to foster grid resilience. First, customers with flexible loads, storage, generation, and customer-sited generation can be relied upon to provide a wide array of supportive services, to include voltage support, energy, capacity, operating reserves or ancillary services at the distribution system level. These services largely fall into the category of "prevention," but can also assist with "recovery."

Second, resilience may come in the form of small-scale microgrids that can be isolated from the grid network at the customer, neighborhood, or community level, when the larger bulk transmission or distribution system is facing challenges. Here, rate design can help to foster customer solutions that promote "survivability."

Inducement can come through rate design or an overlay of incentives to encourage appropriate design and operation of these resources. Current rate design and net metering frameworks rely disproportionately on uniform usage rates that are undifferentiated by time and space. Rate designs that encourage time and location differentiation will also foster grid resilience by encouraging flexible design and operation of DER systems. Well-formed rate design or incentives can also encourage customers to locate resources where the system is vulnerable.

[60] NRRI. (2015, August). *Rate Design for DER.* Retrieved from http://nrri.org/download/nrri-15-08-rate-design-for-der/

A. Current Initiatives

Pennsylvania

The state is currently regarded as a leader on some measures of distributed generation, centering on interconnection and net metering policy, as rated by supporters of these technologies.[61] Pennsylvania has net metering that applies to its 11 electric distribution companies.[62] Virtual net metering is allowed and applied with attributes that are favorable to distributed resources. RECs associated with net metering are initially retained by customers. There is a long list of eligible technologies, including solar PV and wind, that qualify. There is no aggregate capacity limit on net metering. There are carry-forward provisions for crediting future bills from excess generation on a monthly basis. Microgrids are permitted up to 5 MW under a net metering framework, as are residential customers up to 50 kW and non-residential up to 3 MW. Fixed charges, with the potential exception of Duquesne Light, are relatively low in comparison to the unit charges.[63]

As of October 2016, EIA reports that more than 12,400 customers have built more than 250 MW of net metered capacity.[64] As significant as this may seem, it represents just over 0.5 percent of all utility capacity in the state, which totals more than 42,000 MW.[65] Nationally, the net metered capacity is about 1.1 percent of utility total generating capacity.[66] However, the pace of net metering (nationally) continues to grow exponentially from a low base. At the beginning of 2011 there was less than 1 GW of net metered capacity. Six years later, the figure is approaching 13 GW. The pace of growth in Pennsylvania is following a much slower path.

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[61] See freeingthegrid.org, produced by IREC and Vote Solar. Pennsylvania scores an "A" for net metering and a "B" for interconnection.

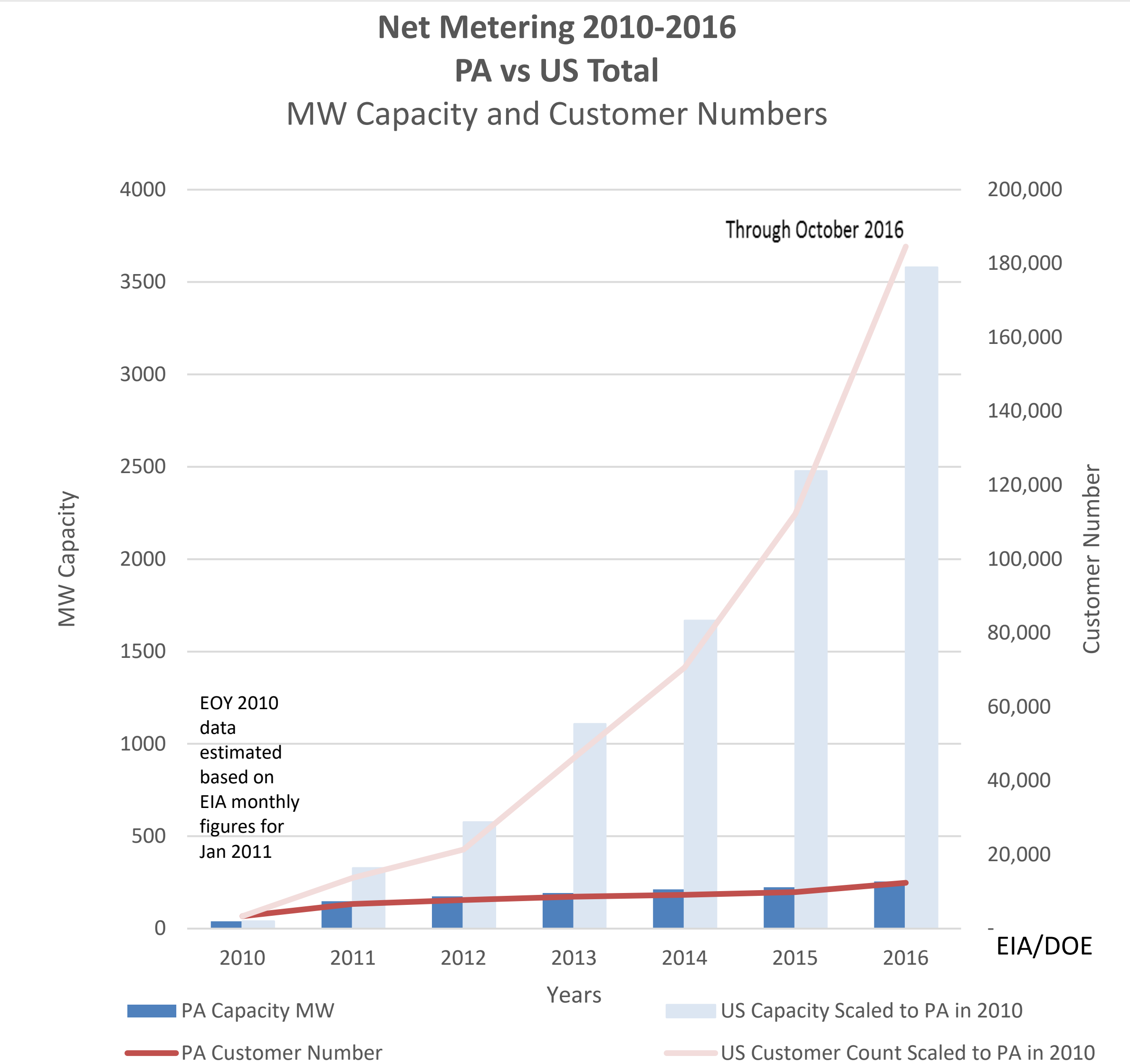
[62] See Dsireusa.org.

[63] See Openei.org. Based on a fairly quick examination of the data reported in the Openei database in relation to EIA data, it appears that only Duquesne's fixed monthly charges account for more than 11% of residential monthly bills.

[64] EIA Form 826. Retrieved from https://www.eia.gov/electricity/data/eia826/

[65] https://www.eia.gov/electricity/annual/html/epa_04_07_a.html

[66] EIA reports about 12.9 GW of net metered capacity for October of 2016, compared to utility total capacity of 1,167 GW of total generation capacity. See http://www.eia.gov/electricity/data.cfm#gencapacity and http://www.eia.gov/electricity/data/eia826/



Note: The chart attempts to show the scale and patterns of net metering growth in PA relative to the US. In order to do so, both PA and the US rely on the Pennsylvania data for 2010 as a base year, then scaled over time to reflect the relative patterns of growth. The reader should observe the exponential growth occurring in the US relative to a much slower pattern of growth in PA.

Utilities have responded with proposed changes to rate design to increase the fixed monthly charge.[67]

Other State Initiatives and Responses

Among the states, net metering is the dominant rate design mechanism compensating customers for on-site small-scale electric production. Interest in addressing rate design for distributed resources is motivated by a number of factors, perhaps chief among them the utility concern that DG may fail to pay its fair share for the use of the electric grid, or alternatively the concerns of its proponents that DG is

[67] NRRI, 2015. See Table A-1.

inadequately compensated for the value of services provided.[68] Currently, 41 states plus DC have some form of mandatory net metering.[69] Two other states have utilities that *allow* some form of net metering. Four states have compensation rules other than net metering. Depending on the relationship between rates and utility costs (or avoided costs), the scale of net metering may be viewed as a threat to the current utility business model and methods of cost recovery.

Net metering has proved instrumental in fostering the development of distributed generation. As noted above, net metering contributes to more than 1 percent of the nameplate generation in the US, and about 0.5 percent in Pennsylvania. Nameplate capacity is provided, since we have federal data, but the amount of energy as a proportion of national totals is far less since the capacity factors for PV solar (the dominant distributed resource capacity) ranges from 10-20 percent compared to the use fleet average of 44 percent.[70] The growth rates are perhaps telling. From 2010 to late 2016, capacity has more than doubled every two years. A disproportionate share of net metering is associated with just one technology, solar PV, contributing 97 percent of this capacity.

Depending on the region, at lower levels of saturation, solar PV can help reduce summer peak requirements and improve the load shape. In most regions at high levels of contribution contribute to the declining load factors of utilities.[71] Depending on the region, PV solar may contributed more or less to peak reduction. In Hawaii, the impact on peak led to a peak reduction, but simulations for three other regions in the US (Seattle, Phoenix, and Chicago; see graphic on next page) suggest minimal impacts on peak.

These concerns are heightened in an era of flat to declining loads and load factors[72] nationally. Some assert that DG adopters are undermining the financial foundation of the electric system. Others are asserting that customer investment can serve to replace utility investment, potentially leading to a reduction in overall utility costs.

Advocates of further development of these resources are concerned that the shift toward greater reliance on distributed resources and microgrids has slowed or been skewed by existing rate design and recovery systems that have been slow to respond to the change. There has been a significant shift toward lower-cost and higher-performance distributed resource technologies. Only a share of these are driven by utilities. In addition to lowering costs, enabling technologies allow customers to manage loads, provide grid-related service, or increase the ability of utilities to monitor and measure services flowing from the grid to customers, or from customers to the grid. Specific technology drivers here including the smart grid and meter infrastructure, improvements in energy efficiency of end uses, lower costs of distributed generation (esp. solar PV), smart inverters, declining costs of storage, electrification of the transportation sector, and the flexibility of customer loads to respond to customer, utility, or third party intermediary.

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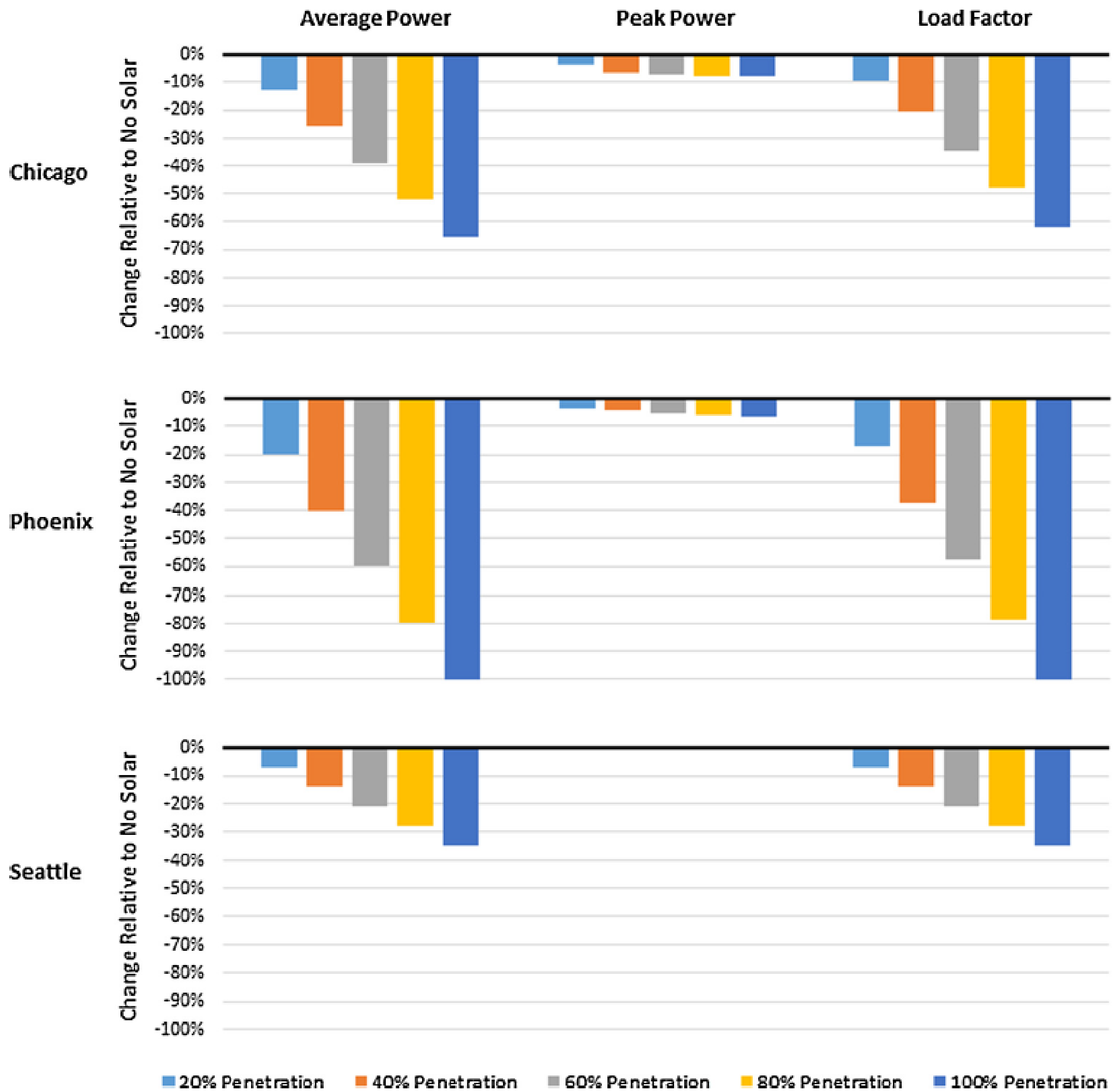
[68] Linvill, C., Shenot, J., & Lazar, J. (2013). De*signing Distributed Generation Tariffs Well*. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/rap-linvillshenotlazar-faircompensation-2013-nov-27.pdf

[69] DSIRE USA.

[70] US total capacity in 2011 was approximately 1,024 GW. Total generation from the power sector was approximately 3,900 TWhs. Source: EIA.

[71] Janko, S., Arnold, M., & Johnson, N., (2016, July). Implications of high-penetration renewables for ratepayers and utilities in the residential solare photovoltaic (PV) market. *Applied Energy.*

[72] Peak to average energy use ratios are increasing in many regions of the US, including PJM. See EIA: http://www.eia.gov/todayinenergy/detail.php?id=15051#tabs_SpotPriceSlider-7



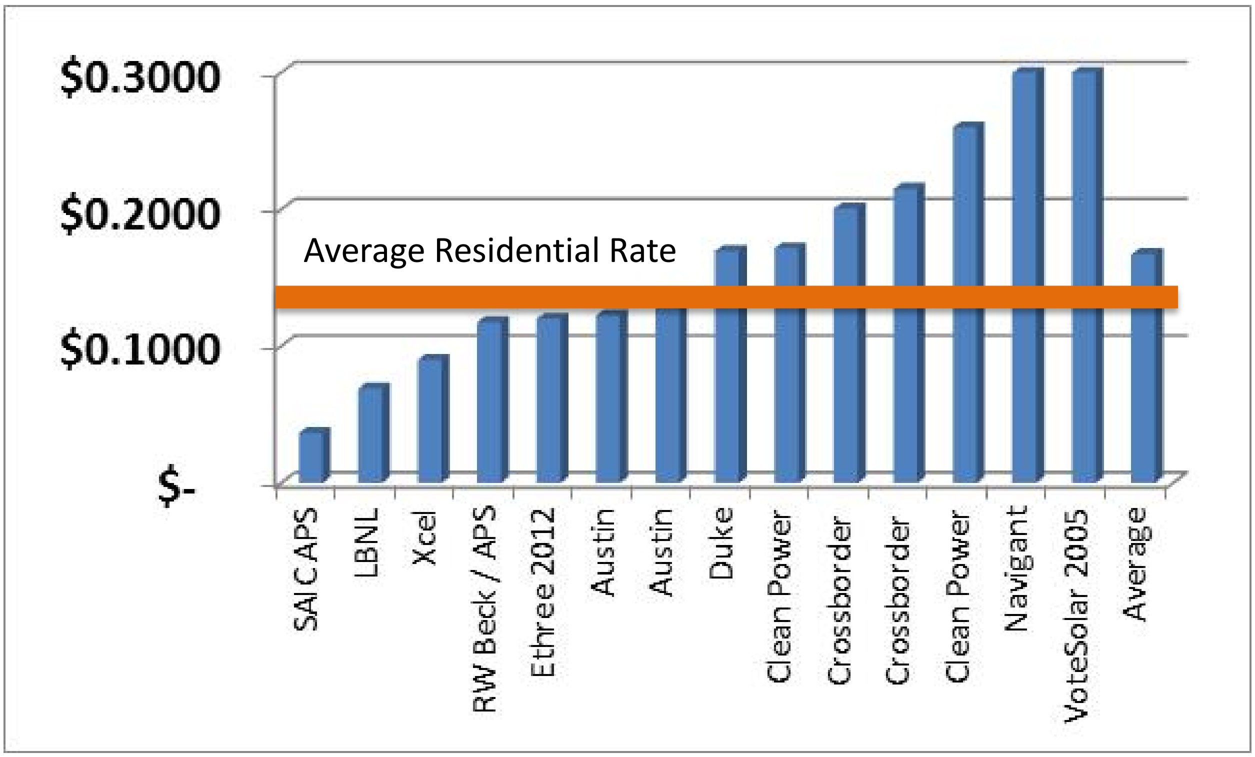
Change in grid metrics at various solar PV penetration rates with optimal solar PV capacity for the ratepayer.

For most utilities, there seems to have been little or no need for major rate reform in recent years. In states where efforts are under way, they include four major types of rate design proposals: 1) higher fixed charges; 2) demand charges for residential and small commercial customers; 3) higher minimum monthly bills; and 4) changes in the terms and conditions for net metering.[73] In broad terms these can be cast as reactions to the popularity of net metering. Proposals also include time-differentiated rates, changes in standby charges, tiered or block rate structures, and various alternatives to net metering, such as feed-in tariffs, two-way rates, or value of solar tariffs. Some of the regulatory proposals fall in

73 NRRI, 2015.

the context of general rate cases, while others are being heard in single-purpose hearings. These options are described in more detail in the sections below.

Much work has sought to establish a clear relationship between the existing rates and their relationship to cost both nationally and in Pennsylvania. The graphic below shows a summary of the relationship between price levels and estimates of value of solar. The analysis performed by Pennsylvania pursuant to state law showed that solar PV does not pass the prescribed TRC cost-benefit analysis test prescribed in the law.[74] What these studies show is that that the value proposition of installing PV for both participating and non-participating ratepayers varies widely by jurisdiction. The benefit/cost ratios run the risk of further decline as penetration levels rise and create new pressures on utilities to invest in the distribution network. Utilities can strengthen or weaken the performance on these analyses by making adjustments to the economic tests applied. Another path, however, might involve the framework of rate design and incentives that apply to distributed generation.



Study of Multiple Studies on the Value of Solar. ***Source: RMI***

B. Relevant Principles and Guidelines for Rate Design

There is a long list of issues around rate design and tariffs that could be addressed through this paper. Circumstances likely vary considerably from one jurisdiction to the next, making it a challenge to provide specific guidance for rate design that consistently serves-long term ratepayer value. Traditional

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[74] Pennsylvania PUC. (2015, February 13). Statewide Evaluation Team, Distributed Generation Potential Study for the State of Pennsylvania, Pursuant to Act 129. Retrieved from http://www.puc.pa.gov/pcdocs/1355000.pdf

principles of rate design provide an important touchstone. Such principles can be accessed through a fairly long list of authors, including notables such as Bonbright and Phillips.[75] Featured here are concerns about economic efficiency, fairness, simplicity, stability, adequacy, and customer satisfaction. These principles still have standing and can guide rate design for microgrids and distributed resources. Clearly the context has changed, but the principles can be modified in ways that they can continue to apply. Important changes here that are listed below include the ability to rely on some form of time-varying price enabled by the widespread deployment of smart meters, as well as cost reductions and innovations in distributed resource technologies.

C. Rate Design Practices Advocated by Distributed Resources and Utility Response

There are a wide variety of existing practices employed to promote distributed resources. Among the main pathways to rate design that are commonly supported by distributed renewable energy generation proponents are the following:

1. Net metering: This allows the customer to use its own production on premises to back off the monthly meter charges. Typically, the customer is paying a uniform or inclining block rate (cent/kWh), and net metering allows the customer to use their production to offset consumption when paying the electricity bill at the end of the month. Many details here are important and represent variations that allow customers to carry forward bill credits or receive payment for excess generation at the end of the month. Even these added features can play an important role in customer economics and the size and character of their customer-side solutions.
2. Virtual or aggregate net metering: Under aggregate net metering, customers may use multiple locations under the same person or organization (e.g., university or government). Under virtual net metering, customers are not required to have the physical production on site at their location.
3. Feed-in tariff: These are usually a separate price that is paid by the utility over a 15-to-20-year period for the production from a qualifying renewable generator. The qualifying rate is usually determined through either an administratively determined cost-based rate, or through a determination of that rate through a competitive bidding process that is stratified by technology.
4. Utility rate structures: Rate structures with higher ratio of per-kilowatt-hour to per-customer charges tend to encourage qualifying distributed generation by allowing customers to benefit to a greater extent for reducing their consumption of electricity from coming from the grid. These rate structures are not specifically designed to promote distributed resources. Rather, they are (or should be) linked to traditional principles for rate design that attempt to link the design of rates to components of costs, or cost causation, in order to promote both fairness (cost causers pay) and economically efficient outcomes. Nevertheless, in conjunction with net metering, they

[75] Alt, 2006; Bonbright et al., 1988; Braithwait et al., 2007; Kahn, 1988; Phillips, 1993; and Public Utility Research Center, 2015. Bonbright's ten principles are sometimes bundled into five general principles: 1) efficiency, 2) equity, 3) adequacy, 4) stability, and 5) customer satisfaction. See, for example, Moeller, P. (2016, February 2016). Primer on Rate Design for Residential Distributed Generation [Memo to president of NARUC]. EEI.

contribute to the customer's economic case for building or participating in distributed resource customer generation (primarily solar).

5. Third-party ownership: While not strictly a rate design issue, it is closely linked. Here, third parties are allowed to play a role in interacting with retail consumers. In the example of solar, one option is third-party ownership over the electricity produced by the solar panels, selling that electricity to the consumer at a fixed price or rate. The consumer does not pay for the solar panels, but only purchases the electricity they produce. EIA reports that approximately 30 percent of distributed solar falls under these arrangements.[76] New models are emerging for third parties to provide value added between customers (as flexible loads or prosumers) and grid operators for the collective benefit of all.

Other rate design options include:

6. Time-varying pricing: This includes both traditional time-of-use pricing and dynamic pricing frameworks. California and Hawaii, two states that are experiencing high levels of DER, especially solar PV, are moving toward the adoption of default time-of-use pricing to help improve performance of DER in relation to the grid.[77]
7. Demand charges: These are price signals sent to retail customers based on kW rather than kWh. Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month.[78] Interest in demand charges has largely been driven by DER's potential effect on utility cost recovery. Kilowatt-based demand charges cannot be offset by net metering rates or similar programs.[79] Therefore from a utility perspective, this reinforces a stable source of revenues in the face of declining net usage. Interest in demand charges is also driven by greater adoption of AMI that allows effective low-cost measurement of demand.[80] However, demand charges, especially used in conjunction with ratchets (establishing a fixed charge for customers over the month or year), may appropriately be viewed as a blunt instrument relative to grid value. Demand charges are a shortcut, measuring each customer's individual highest usage during a month, regardless of whether the usage was coincident with the system peak. Customers may also find ways to undercut these charges through a combination of demand response, energy efficiency, or storage. There is, however, less assurance that customer steps to avoid the charge will match the system benefit that the utility might hope to encourage.
8. Fixed charges and minimum bills: Fixed charges, or "customer charges," do not vary by any measure of use of the system. They are typically used to recover the costs of connecting customers to the grid (the meter and drop wire). Higher fixed charges serve the objective of revenue stability for utilities. However, the economic foundation for such charges rests on a

[76] Openei.org. US Electric Utility Companies and Rates [Database by ZIP code]. Retrieved from http://en.openei.org/datasets/dataset/u-s-electric-utility-companies-and-rates-look-up-by-zipcode-feb-2011/resource/e2676f04-e95b-4463-acbe-0352a6d138dc?inner_span=True

[77] NARUC Staff Committee on Rate Design. (2016, November). Distributed Energy Resources, Rate Design and Compensation, p. 98. Retrieved from http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

[78] Lazar, J., (2015, December). Use Great Caution in Design of Residential Demand Charges. Natural Gas & Electricity. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf

[79] NARUC Staff Committee on Rate Design, p. 98.

[80] Lazar, 2015.

view of capitalized asset costs as not variable with respect to use. This holds only over the short run. In the longer term, capacity requirements and capital costs are fundamentally driven by usage and forecasts of the capacity requirements and associated capital costs, which are a function of usage, generally during local or system peaks. Failure to recognize this means that usage price signals will not encourage conservation and alternative technologies that can effectively reduce future capital commitments by utilities. Minimum bills function in a manner that is similar to higher fixed charges. Utilities here are fundamentally seeking revenue stability in the face of revenue volatility from net metering. California utilities that do not have fixed charges sought and received approval for higher minimum bills from the CPUC.[81]

9. Standby or backup service: Standby service is intended to provide full or partial self-generating utility customers with protection from the loss of service in the event of an unanticipated or planned outage of its own self-generating equipment. The charge is assessed by the utility to assist in the payment of grid services and standby generation and usually comprises a demand charge ($/kW) and an energy charge on a $/kWh basis.[82] However, there are some concerns that utilities are assessing these charges to discourage customers from investing in DER. Standby charges can render these projects uneconomic. Depending on the nature of these DER projects, they may also provide services to the grid that may go unrecognized or uncompensated. Backup service is similar in character to standby service, but is usually not instantaneously available and requires advanced notice. However, the term is also sometimes used interchangeably with standby service. As a practical matter, the merits of such a charge as it relates to DER are fact-specific. Minimum and maximum requirements for these arrangements are sometimes featured. If indeed there is a cost to the system of supporting additional capacity or generation to cover DER, then it should likely be reflected in a charge, or else the cost would be passed to non-participating customers. One approach would be to simply permit a buy-through arrangement in which the customer gains access to wholesale electricity prices at prevailing market conditions. The utility facilitates the buy-through at a small administrative charge. However, if these systems provide grid benefits either explicitly or implicitly, any standby charge should be offset by these benefits. If these systems offer the promise of grid benefits in the future that exceed the costs, it may be appropriate to defer judgement until rate design reforms and new forms of compensation materialize.

D. Considerations That Have Changed

As NARUC notes in its report on rate design options for DER: "What is completely new is that the customer is no longer simply a passive taker of electricity."[83] The customer has become an active participant in meeting its own needs for energy. Customers are responding to the price signals they receive and to a far lesser degree are providing services to the grid (largely energy during periods of high production relative to demand).

Active participation does not, however, assure grid benefit. Potential opportunities for customer-owned or controlled distributed resources are being missed. Among the opportunities are those that relate to

[81] NARUC Staff Committee on Rate Design, p. 118.
[82] NARUC Staff Committee on Rate Design, p. 120.
[83] NARUC Staff Committee on Rate Design.

system reliability. Net metering fosters distributed generation, but not necessarily in a way that will keep the lights on. For this to happen, alternative rate design and compensation are required to increase the visibility and value of delivering grid services. Some form of storage or load flexibility is needed, perhaps in conjunction with controlled management of those loads either by the consumer, its agents, or grid operators. Key attributes of rate design that are needed include those that differentiate compensation according to time and location. Advanced grid capabilities combined with advanced communications increase the visibility of the grid, and potential value of distributed resources, by location. Smart metering and the ability to isolate certain loads through some form of sub-metering can help to facilitate the exchange of value differentiated by time and location.

Other notable changes in recent years include the following:

- Major weather events such as Hurricane Sandy have helped to expose the vulnerability of the grid network. Research from national laboratories has helped to verify that these events are growing in severity, affecting the reliability of the grid.[84]
- Enabling technologies are allowing for easier metering of bi-directional flows of electricity, allowing differential pricing of electricity to flow to the customer and to the grid.
- New devices such as smart inverters offer the opportunity to provide an ever-expanding array of services to the grid on demand.
- The costs of solar PV and storage capabilities, including battery technology, are falling.
- The entry of new technologies associated with electrification of transportation and space heating create new opportunities for flexible use to deliver grid services. EVs represent a special opportunity here, as these loads can fundamentally be viewed as zero or low (incremental) cost storage units capable of providing energy service to the household or back to the grid.
- Enabling technologies allow customers or third parties to monitor, submeter, or aggregate services can be provided by flexible loads or storage.
- Enabling smart technologies in the distribution network are helping to increase the visability of the network to show its vulnerabilities to power quality and reliability due to the rapidly changing characteristics of loads and consumer generation. The value of controlled loads and distributed capacity can be quantified and form the basis for price signals and incentives on a location-based framework that can encourage the development of customer storage and flexible and/or dispatchable loads to cost-effectively support the network in times of stress.
- The entry of new merchant actors, business models, aggregators, and intermediaries that offer the potential to arbitrage or otherwise facilitate or enhance the exchange of value between customers and the utility.

Aggregators can function as entities that can add value by managing and arbitraging the inherent value in distributed resources to the utility and grid operators. They can at the same time enable consumers with regard to self-determination, simplicity, lower bills, and some level of independence.

[84] Larsen, P., et al. (2017, January). *Projecting Future Costs to U.S. Electric Utility Customers from Power Interruptions*. Lawrence Berkeley National Laboratory. Retrieved from https://emp.lbl.gov/sites/all/files/lbnl-1007027_0.pdf

E. Options and Recommendations: Rate Design to Encourage Resources Differentiated to Address Vulnerabilities in Time and Space

Net metering has proven a success for helping to foster new distributed resources and technologies, supply chains to deliver these systems to customers, engaging consumers more directly, and creating new entry and new business models. But continued reliance on net metering in its current form will eventually create challenges for the utility and ratepayers and precipitate the need for reform.[85] As a result, existing net metering consumers (and third-party players) are less focused on developing distributed resource solutions that serve the collective system (including both the customer and the grid) than on capitalizing on the immediate opportunity to keeping costs low and creating customer value. With appropriate price signals or well-formed incentives, the customers can be encouraged to create customer solutions that benefit both individual customers and the collective system, all while securing more survivable localized microgrid solutions.

As indicated above, almost 97 percent of the net-metered capacity that exists is associated with solar PV. There are a number of changes PUCs can make, which may be viewed as either incremental or more significant, and they are listed below. Perhaps chief among these strategies is linking new producer-customers to some form of time- or location-sensitive price or incentive. One approach would be to link net metering or pricing reforms to time-varying pricing. Reforms here are an essential step toward a well-formed cooperative and beneficial (and sustainable) relationship between distributed resources and the utility system that functions as a platform for the exchange of value and backup. Compensation will better reflect value, and will self-correct as the rate design changes over time to reflect the changed daily load shape.

Traditional objectives for rate design likely remain the most useful guideposts. Traditional principles typically focus on a balance of efficiency, fairness, compensatory (to the utility and new business ventures), sustainability, and acceptance by consumers (often focusing on simplicity). Even while these principles continue to have relevance, the environment has changed. The emphasis going forward should probably shift toward establishing a closer link between value and compensation. Distributed resources offer immense potential value to the system if the framework for compensation and rate design can be appropriately linked.

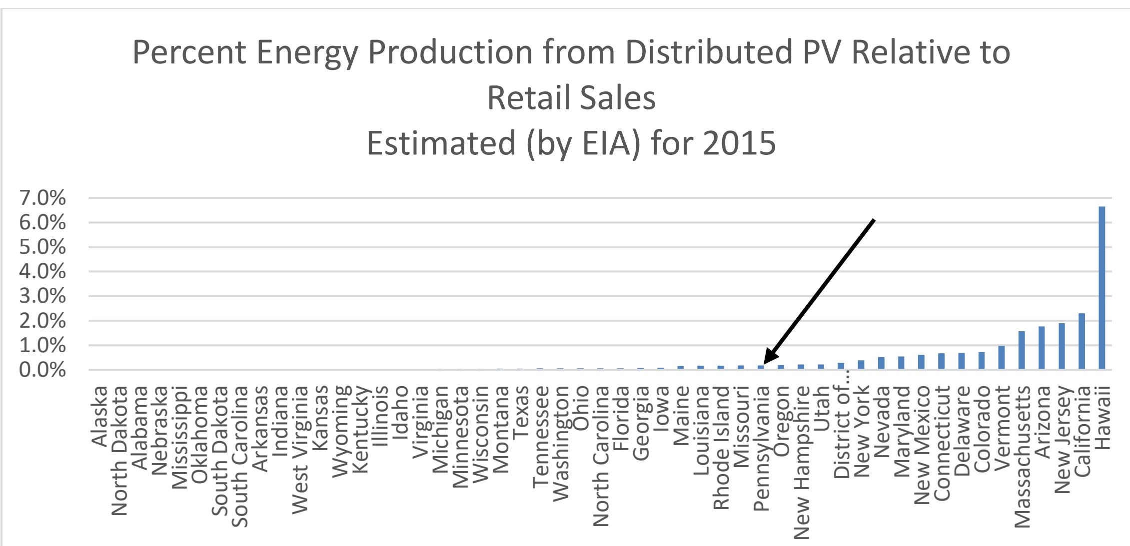
As evidenced by the tremendous growth in net-metered distributed generation, customers and their agents clearly respond to the price signals that they are provided and the value available based largely on weather and location. Additional complexity in transactions between end-use customers and the utility can be managed any number of ways, including reliance on new agents, or relying on the utility to function in their place.

Net Metering and New Features

Some distributed generation technologies, like solar PV, are nascent industry technologies. As such, there is policy justification for some form of subsidy or support sufficient to achieve scale and market presence. Net metering offers a simple policy pathway consistent with this approach. However, the existence and/or extent of the subsidy varies considerably by jurisdiction and likely grows more material

[85] At the relatively low rates of penetration in Pennsylvania currently, utilities appear unlikely to see these as material challenges in the near future. States such as California, Hawaii, and Arizona, however, are confronting these challenges.

with the levels of penetration achieved. Net metering, at least in its current form, can be challenging to sustain at higher levels of penetration than currently experienced in Pennsylvania, which is following a moderate pattern of growth in the penetration of distributed PV.[86] However, at much higher levels of penetration in the state, some form of reconfiguration will be needed. [87] The current framework encourages deeper penetrations of solar PV without the need to increase storage capabilities and service capabilities to complement the grid. State experience in jurisdictions with high levels of penetration would seem to bear out the need for reconfiguration. The graphic below shows where Pennsylvania sits relative to states like California and Hawaii in 2015 that are experiencing challenges.[88] At existing growth levels, Pennsylvania should not be in a situation comparable to California's for many years. Net metering, to the extent that it continues, will ultimately need to be accompanied with new features or abandoned in favor of alternative forms of compensation. Net metering can be used in conjunction with other features of rate design listed in this section. Among them are the following: 1) Net metering could be coupled with usage charges that reflect the full retail rate (the cost over the long term) of delivered electricity consistent with traditional principles, ideally differentiated by time of day. 2) Electricity that flows back to the grid could be differentially compensating at levels that reflect the full value to the system of the electricity and services (including capacity and ancillary services) provided at the time and location it is delivered. Some form of time differentiation of usage rates is needed because the value of electricity varies through the day and under peak and non-peak conditions. Additional services provided to the grid should ideally be differentiated by location, to encourage the placement of new and emerging advanced grid technologies (e.g., smart inverters) or storage where they create the greatest value to the grid.



[86] As can be seen from the graphic on this page, Pennsylvania has a low starting point for distributed PV production relative to retail sales. The latest NREL forecasts for rooftop PV sales in 2030 show significant growth in only a handful of states, and Pennsylvania is not included among the states expecting to see significant growth under the mid-case scenarios. See: Cole, W., et al. (2016). Standard Scenario Report: A U.S. Electricity Sector Outlook. NREL. Retrieved from http://www.nrel.gov/docs/fy17osti/66939.pdf; a data viewer for the states is available at http://en.openei.org/apps/reeds/.
[87] At high penetration levels the impacts on the grid can range from overload-related impacts, overvoltage impacts, reverse flow impacts. See: Seguin, R., et al. (2016). High-Penetration PV Integration Handbook for Distribution Engineers. NREL. Retrieved from http://www.nrel.gov/docs/fy16osti/63114.pdf; and Utility Dive. (2014, October 16). How utilities can mitigate grid impacts of high solar penetrations. Retrieved from http://www.utilitydive.com/news/how-utilities-can-mitigate-grid-impacts-of-high-solar-penetrations/320407/
[88] EIA, Electric Power Monthly, Table 1-17.

Time-Varying Pricing and Loads that Respond to Market Prices and System Conditions

As mentioned, time-varying pricing includes both traditional time-of-use pricing and dynamic pricing schemes (e.g., real-time pricing). This offers customers the opportunity and potential to respond to variations in market or system conditions that translate into higher or lower system costs, based on customers' behavior and sensitivity to these price signals. These pricing arrangements also encourage distributed generation solutions that involve storage or flexible loads. The participation as aggregators of both utilities and third parties further enhances potential pathways without requiring customers to manage or try to optimize promising distributed solutions. Third parties or utilities could potentially manage individual household or commercial loads for the benefit of grid operation, in exchange for a simple bill credit or payment at month's end. Pennsylvania's AMI deployment puts in place one of the critical features for development of these advanced markets, but the sharing of data with third parties (requiring customer consent) requires both advanced data systems and cooperation between the utilities and third-party companies.

Time-varying pricing may also include pricing schemes that are associated with significant new loads that can be isolated and potentially used or shed in emergencies. Here, electric vehicles and space heating loads may represent loads that may be responsive to price signals or can be managed and interrupted remotely for the mutual benefit of the consumer and the grid operators.

Bi-directional Energy Pricing

The long-term forward-looking costs of electricity delivered by the central utility distribution system is likely different than the cost or value of electricity delivered at any given time from the customer's distribution system. The utility should be fairly compensated for its costs, as both a matter of fairness to utility shareholders and to other consumers that would otherwise be left to bear the balance. Likewise, customers should be fairly compensated for delivering distributed energy solutions and services that reflect the greatest value to the system.[89] Bi-directional pricing arrangements can include arrangements that are analogous to feed-in-tariff arrangements that establish a set fee, presumably time-of-use value-based rather than cost-based on technology, over a 15-25-year horizon based on the technologies involved. Contracts can be structured to allow room for periodic reviews to reflect the changing character of market conditions and utility exposure to these markets and other changing system conditions. As with time-varying pricing, Pennsylvania's AMI deployment puts in place one of the critical features for development of these advanced markets but the sharing of bi-directional energy price data requires both advanced data systems and cooperation between the utilities and electricity supply companies (load-serving entities).

Compensation for Services Provided

Distributed energy resources and microgrids offer the potential to deliver service to the grid. In its simplest form, this may merely mean the exchange of electrons on a bi-directional basis. However, flexible loads and storage that can be controlled remotely offer the potential for providing any number of services, including capacity, operating reserves, voltage support, and other services that may serve to help the utility to avoid new investment. Smart grid technologies are increasing the visibility of the

[89] Lazar, J. & Gonzalez, W. (2015, July). Smart Rate Design for a Smart Future. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf

distribution system in ways that will help to identify the value of DER resources and encourage their placement where it helps most. Communications and other technologies are enabling the measurement and dispatch of these resources. To the extent that resources are encouraged through incentives and/or rate design, they strengthen incentives for design and operation in ways that can make the grid more resilient and do so economically. The existence of such resources also promises to foster the development of “island-able” systems that can operate independently from the central grid if it is disrupted.

Demand Charges

Interest in demand charges has grown in response to the growing reliance on net metering, as well as combined heat and power systems by commercial and industrial customers. Like higher fixed changes, higher demand charges provide the utility a way of collecting revenues with less concern that its capital or fixed costs will not be collected. Concerns associated with this approach center on whether the design of the demand charges enables an efficient customer response and on the ability of smaller customers to understand and effectively respond. Also, demand charges need to be associated with usage during peak hours and peak events to be efficient and send consumers the right price signals, because different customers use the grid differently and do not necessarily generate demand at the same time. Consequently, the price signal that the customer receives may not effectively match the requirements of the grid during periods when it requires load management or grid services from the customer. To effectively match grid demand, and thus system costs, with customer demand in a meaningful economic way that consumers can respond to efficiently, the distribution system peak-demand needs be associated with demand charges in a way consumers understand. Over the long run, this system design drives down costs because consumers can adjust demand to most efficiently use the grid. To the extent that demand charges are relevant, it seems likely to be for larger customers who have both high coincidence with system peak and the capacity to manage their use to effectively respond in ways that benefit both the customer and the system.

Standby Charges

Customers with distributed resources, microgrids, and interruptible services offer the utility a relatively unique load profile. The additional grid requirements precipitated by distributed energy resources, to the extent that they are positive and material, should indeed be reflected in some increment of charges, lest these costs be borne by other ratepayers. Standby charges tie closely three principles of rate design as they apply to emerging realities. At a minimum, the customer should be able to connect to the grid at the cost of connecting to the grid. Further, customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume. [90] Finally, customers who supply power to the grid should be fairly compensated for the full value of the power they supply., Distributed energy resources that are designed to provide support and deliver services may actually provide a net benefit to the system that should be encouraged through rate incentives and additional compensation rather than asked to bear the additional burden of a standby rate. It may be premature to apply a default standby rate to DER that offers the potential to generate new services and help utility operators to operate the system in a cost-effective and more robust manner.

[90] Lazar and Gonzalez, 2015.

Third Parties and Aggregators

Third-party providers and aggregators offer the potential to help bridge the gap between responsive customers capable of delivering grid services and the desire of customers to just-keep-it simple. As indicated earlier, approximately 30% of net metering solutions have been created by new entrants that help to bridge the gap between the signals created through the rate design, and customer response. Addition complexity and compensation frameworks can further enhance opportunities for this industry to the collective benefit of the utility and the customer. However, many states in the US restrict the participation of these third parties, creating barriers to the delivery of potential solutions.

Many utility design proposals are a reaction to a concerns over lost revenue in the face of growing demand for distributed generation net-metered projects. Even while these concerns appear to have a basis, revenue adequacy concerns should be considered together with other objectives. These include objectives related to economic efficiency and the promotion of more robust distributed resources that can interact well with the grid on the basis of system cost and performance, as well as fair compensation to both the utility and the owners of distributed energy resources that provide grid-related services.

In summary, certain features of grid resilience are closely linked to rate design. Rate design, together with incentives, provides one of the few pathways for utility communicating to the customer the potential value that they can bring to the collective system. Infant industry supports will ultimately have to yield to more sustainable pathways. Traditional objectives for customer simplicity may, quite reasonably, yield to increasing levels of complexity managed through the participation of new third-party participants or grid operators that can serve to reconcile utility requirements to send cost-based price signals or manage loads, while offering incentives and compensation for services provided by producer-consumers.

F. Cutting-Edge Questions in the New DER/Microgrid World

As microgrids and DER systems continue to increase in number, many new questions surface with respect to the relationship between the DER/microgrid and the electric utility. These questions have to do with ownership of the systems, compensation for services received and delivered to them, and the obligation of the utility to provide standby services, among other issues. As there is not a lot of history or case examples in this nascent stage to assess what worked and what did not, regulators will need to rely on sound regulatory principles of fairness as they tread new ground.

Ownership Question

There are two major models to consider with respect to ownership of DERs. The first is utility ownership and the second is non-utility ownership, which could include third-party ownership or customer ownership. Under the traditional utility ownership model, the cost of DER is either included in base rates or is recovered in the wholesale market. Non-utility revenue model options include third-party entities or customer-financed installations. One of the advantages of utility-owned DER is that it can accelerate deployment because the utility can recover its costs in rates, thereby reducing its risk in making the investment in the first place. A utility-owned DER would be treated like any other asset in the utility's system. It would be rate-based and included in the calculation of revenue requirements. If the utility owns the DER, some attention would have to be paid as to whether it is being used to address a specific problem area, whether the utility would bid in competition with other DER companies to provide the service, and whether the utility is inhibiting the development of the competitive market.

It is important to consider the structure of utility ownership. If it is a regulated entity that is engaged in developing DERs or microgrids, codes of conduct that ensure arm's-length, transparent, and documented transactions and communications between the competitive and regulated business become even more critical. This will ensure that a competitive market for DERs and microgrids is maintained to provide cost discipline, fair treatment of unregulated entities without a rate base to charge ratepayers, and diversity of service offerings and quality available in a competitive marketplace. Monopoly utilities start out with a socialized and captive funding advantage that should not be leveraged to the detriment of other enterprises that might seek to offer similar services. This is true unless there is a compelling public interest that the monopoly can use its economies of scope to accelerate deployment of a service critical to that public interest, especially in underserved communities. And in this event, the actions of the monopoly may need to be curtailed once the service is sufficiently deployed. Consumers and the public at large benefit from robust competition, which tends to reduce prices and improve service quality. If the DER/microgrid is owned by a separate utility corporation, attention still needs to be paid to market power and codes of conduct. The least desirable outcome is a deregulated monopoly service provider, because there is neither a competitive market to provide cost discipline, a diversity of options, nor a regulator to control pricing and behavior for services ratepayers pay for entirely or partially regardless of whether they benefit.

Non-utility ownership is the primary mechanism by which DER/microgrids are developed and operated today. Third-party ownership has been growing as more new businesses and markets are developing to provide advanced technology DER services. However, for competitive DER markets to work well, access to customer and grid data is very important. Having good data, for example, enables the third party to establish dynamic rate designs that can provide savings through reductions in demand for the system and for customers, who alter their usage pattern to align better with price signals.

Customer ownership also allows the customer to better align energy usage with DER services, be they generation, storage, or peak-shifting. Customer ownership also opens the possibility of new aggregated revenue streams that result from making its DER available to the utility grid. The customer should be compensated by the utility based on the value of the service delivered considering factors such as time of use and location. The DER customer would pay the utility based upon the applicable tariff rate for its customer class for all power consumed from the utility.

Responsibility for Maintenance and Operation of the DER/Microgrid

With the development of microgrids comes the question of who is responsible for microgrid operation, maintenance, and reliability. This issue does not distinguish between a restructured market such as Pennsylvania's and traditionally regulated jurisdictions. Utilities and load-serving entities (LSEs) are expected to ensure reliability and capacity adequacy subject to state oversight, and also to meet national reliability standards. The question here is the structure of the microgrid arrangement and whether the microgrid or utility takes on the risk of ensuring adequate resources to meet capacity needs. As with combined heat and power (CHP) customers today, microgrids will have a variety of back-up and standby arrangements with the connecting utility. Should the LSE, for example, be required to procure load that includes a margin for microgrids and DERs that are off-line? States already answer this question today with regard to CHP.

A newer question of increasing urgency, however, is whether new provisions to protect the interests of customers in a multi-customer microgrid are necessary. Microgrids serving a neighborhood may involve casual commitments from customers expecting service quality and consumer protections similar to what they are used to. How is this assured? States are in new territory. It may make the most sense for whoever owns the DER/microgrid to be responsible for either performing the maintenance or contracting for load and capacity adequacy. On the other hand, the utility retains the responsibility for ensuring that the interconnection to its grid is without reliability problems, and the regional transmission operator has responsibility for ensuring overall system capacity adequacy with adequate capacity and reserves. If a customer has a grievance with the microgrid operator's service, it may ask the PUC to resolve the issue (a process put in place in many states with the opening to competition of the market for long-distance phone service).

As to the requirements for standby power when the microgrid or DER is offline, there are several options that could be offered to the DER/microgrid for ensuring continuous power availability to its customers:

- Create a reasonable cost-based standby tariff that does not unduly skew the economics of the DER/microgrid system. For example, a standby tariff based on the assumption that a customer will lose power at the highest peak period, and that every other similarly situated customer does as well, is not probable and creates a penalty tariff. A reasonable standby rate that compensates the utility for having the power available without creating a subsidy or a penalty is a reasonable approach.
- Allow the microgrid/DER to buy backup through to the competitive market. This can be done with the option for the utility to administer the transaction for a small fee. In this manner, the customer taking a market price options assumes the risk as to the market price at the time of the outage. Under this scenario, the customer would not pay a standby charge and is taking the gamble that when it needs power, the cost of the power in the market will be less than the cost the utility would have charged for that power plus the monthly standby rate.
- Permit the creation of a pooling/aggregation service among DERs/microgrids that allows them to supplement each other. If each microgrid is built with its own reserve margin or extra capacity, that capacity can be shared by other microgrids if one microgrid experiences an outage. This can be viewed as somewhat analogous to the gas imbalance market, in which gas marketers have arrangements to supplement each other's supply to avoid high penalties for non-delivery from the local gas distribution company.
- For small DERs, standby rates are less of an issue. Within a utility's service territory, while one DER may be drawing more power from the system, another may be supplying power. This can create a balancing effect as well. Moreover, if DER customers are placed on a time-of-use tariff with critical peak pricing or real-time pricing, then the utility would be compensated for providing power based on the cost at the time and would be compensating the DER on the same basis.

Recovery of Utility-Owned DER and Microgrid Infrastructure Resources that are Idle Most of the Year

If utility-owned DER and microgrids are built to be emergency infrastructure resources, then the question arises as to whether that is the sole use of the microgrid—just to provide for emergency reliability or backup services. For example, can the DER and microgrid be used to serve load or to help reduce constraints at the distribution or transmission level? Can the microgrid or DER provide ancillary services? If the microgrid or DER's sole purpose is to be used during a catastrophic event, is that the least-cost, best option to address that need? The military and some local governments are implementing programs to rely on microgrids or DER to address resiliency concerns in the case of an emergency. For example, the military, the City of San Francisco, and the City University of New York, through the U.S. Department of Energy's Solar Market Pathways program, are deploying these technologies as a means of addressing the need for back-up services in the case of an emergency.[91] If the microgrid or DER is going to be built, selling the attributes (capacity and ancillary services) into the market should be explored, as well as other means to maximize the cost-benefit ratio.

In terms of cost recovery, an analogy can be drawn with a peaking unit that is used only a few hours a year and in a vertically integrated rate structure, where peakers are typically placed in the rate base and recovered as part of the revenue requirements (subject to complex class cost-allocations). Of course, as with any capital asset included in rates, there should be a determination that it is prudent first. Because utility-owned DERs and microgrids present new and untested issues, that prudency determination would be best made at the beginning of the process to ensure that the microgrid or DER is necessary and the least-cost option. If so, the next questions are whether it should be competitively bid and which sets and classes of ratepayers should pay for which services the DERs and/or microgrid provide.

VI. Conclusion

The intersection between the desire to create a resilient grid, capable of withstanding catastrophic events like Hurricane Sandy, and the interest in facilitating more customer-sided options point to one path: grid modernization. These two parallel objectives can also be seen as symbiotic; focusing on one can enable the other. To get to the core of strengthening and protecting the grid, it is first necessary to inventory its strengths and weaknesses. There are a range of options for doing this, from utility self-assessments to more robust integrated resource planning. Solutions identified can call for utility upgrades or can provide opportunities for customer participation through strategically located distributed generation, if it can provide the level of reliability needed at a lower cost to the ratepayers. The deployment of modern technologies, such as cloud-based software, AMI, and other utility operational upgrades, can also provide the utilities with needed information to react to catastrophic events as they unfold. And in the aftermath, programs in place to share spare parts will help restore the grid. Finally, regulatory attention is needed to ensure that the rate designs align with the Commission's policy objectives and adhere to principles of cost causation and fairness.

This report is a snapshot providing a range of options to address prevention, recovery, and survivability. Each of these sections stands independently, and options within each section can be pursued by the Commission. Taken as a whole, moving forward on each of the above sections should provide the Commission with a plan that addresses these three key aspects of grid resiliency.

[91] Shenot, J. (2017, March 7). Preparing for Emergencies with Wind, Solar, Energy Storage, and Microgrid [Blog post]. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/preparing-for-emergencies-with-wind-solar-energy-storage-and-microgrids/