

**Comments of SolarCity
To the NARUC Staff Committee on Rate Design
Regarding the Draft Manual on Distributed Energy Resources Compensation
September 2, 2016**

SolarCity provides clean energy solutions to homeowners, businesses and government organizations. Founded in 2006, the company has hundreds of thousands of installations in 27 states and Washington, D.C. We respectfully submit the following comments in response to NARUC's "Manual on Distributed Energy Resources Compensation" released July 21, 2016.

Executive Summary

NARUC's "Manual on Distributed Energy Resources Compensation" is an important and timely document in light of the rapid maturation and market adoption of distributed energy resources (DERs) over the past several years. Customers are clearly taking a more active role in providing energy services for themselves and others on the grid, as evidenced by both the quantity of demand response services currently provided from behind the meter by consumers and the level of adoption of rooftop solar PV.¹ We believe the Manual, maintained and updated as a dynamic document, could serve as a valuable resource to regulators, utilities, DER providers and consumers.

The draft Manual provides information on a number of topics, but we believe the Manual can benefit from more references and case studies, expanded discussions, more balanced characterization of DERs, and greater emphasis on the process in which regulators should analyze and identify changes to DER programs.

DERs present an unprecedented opportunity to harness the power of consumer demand for and investment in new technologies to help restructure the electric system into one that is cleaner, as well as more reliable, resilient and affordable. The fact that customers want to use their own resources to provide grid benefits is a positive force that regulators should seek to encourage, while helping to ensure that the benefits and costs of the entire system are shared appropriately.

Rather than focusing on the potential benefits these emerging resources could provide, however, the Manual instead presents the emergence of DERs merely as a challenge to be managed or a problem that causes utility revenue erosion and cost-shifting, neither of which are clear and present threats in any jurisdiction. The bigger threat is that regulators may fail to recognize the

¹ According to EIA Form-861, there were more than 6.5 million customers enrolled in demand response programs (<https://www.eia.gov/electricity/data/eia861/>) and the country's 1 millionth solar system was installed in May 2016 (<http://www.seia.org/blog/1-million-solar-strong-growing>).

full grid system benefits of deployment of DERs—as well as the benefits to consumers, society, and technological development—and thus fail to properly account for the rapidly declining need for investment in traditional utility infrastructure and the less centralized, more efficient “smart grid” of the future.

We therefore submit comments regarding ways that regulators can better address these challenges. This includes considerations for reforming utility business models and incentives, increasing data transparency, adopting incentive mechanisms, and clarifying the role of regulators in a future with more DERs. Utility business model reform is needed so that the role of the utility is clearly defined, utilities are able to maintain their financial health even if they are not deploying as much capital, and utilities are not financially conflicted from deploying customer-sited solutions to infrastructure needs. The Manual should encourage regulators to engage in rigorous distribution system planning in order to avoid building redundant systems and ensure that the projected benefits of DERs are realized to the maximum extent possible in order to reduce total energy service costs to consumers.

Moreover, the Manual should use a standard set of objectives against which to assess the pros and cons of the various rate design options. To develop these objectives, the Manual should expand on Bonbright using the updated principles articulated by the Regulatory Assistance Project (RAP), which take into account the development of new technologies unheard of in Bonbright’s time. These principles include: 1) allowing customers to connect to the grid for no more than the cost of connecting to the grid; 2) ensuring customers proportionally pay for the grid services they use and consume; and 3) fairly compensating customers for the full value of all grid services they provide.

The Manual asserts that moving DER customers into a separate rate class is a potentially attractive option for regulators. We disagree. Creating a separate rate class for self-generators is inappropriate given the inherent diversity within rate classes and the insufficient evidence that DER customers are significantly different from the utility’s perspective than other customers. Separate rate classes for DERs would potentially allow the utility to discriminate against customers who wish to employ technologies that compete with and reduce the need for future investments or expenses that utilities have incentives to put into the rate base (and thereby increase their revenues where their rates are set to capture a rate of return).

Finally, we reiterate our previous process requests that all comments received be made available for public review and comment, that you allow for some opportunity to comment on the next draft, and that the document be treated as a living document that will be regularly updated over the coming years. We believe that publicly sharing the comments you have received in a timely manner would make the final product, more informed, and as such it will be a more credible source for state regulators. Perhaps a stakeholder group could host the documents on their

website if cost or logistics prevent NARUC from doing so. Below is a possible schedule that would allow for this review to take place:

- Starting September 2: all previous and new comments posted on the web.
- September 16: deadline for stakeholders to respond to any of the submitted material.
- October 7: new draft Manual circulated.
- October 21: comments on new draft submitted.
- November 12: final Manual released.

We are excited to contribute to this effort and know that, given transparency and openness of process, the resulting regulatory policies will lead to a more reliable, affordable and sustainable grid. Your leadership and that of your regulatory colleagues working in concert with the stakeholder community can make that a reality.

Introduction

The DER Compensation Manual is meant to be a guidebook for regulators seeking assistance for determining the appropriate level of compensation to consumers who choose to control their energy costs by adopting distributed energy resources (DERs) on their side of the electric meter.

In order to accomplish this objective, NARUC should seek to highlight certain state and utility jurisdictions that have to date best analyzed DERs and their costs and benefits to the grid. Those examples should not be used, however, to make definitive statements about how DERs will impact the grid in every jurisdiction. Instead, the goal should be to set a framework for analysis that provides tools for regulators for an open, transparent, unbiased process that recognizes that every jurisdiction is unique. Only with such a framework, in an evenhanded document that fairly assesses values and costs, can consumers be assured that their regulators are acting in their long-term interests and compensating DERs in an appropriate, just and reasonable manner.

The elephant in the room that must also be addressed, either by this Manual or in some other forum, is the issue of the incentives provided to distribution and vertically integrated utilities via the regulated monopoly business model. If new technologies, including DERs, are to realize their full potential to save billions of dollars for all users of the electric grid, we must recognize that that utility business model may be outdated and no longer serves the interest of the consumers that regulators are intended to serve.

DERs are disruptive technologies that can provide value both to the individual consumers who install them and to other grid users via provision of services that would otherwise be provided by

utility-owned equipment at the distribution, transmission and generation levels. As such, they are a direct financial threat to utilities that primarily derive their profit from investments in utility infrastructure. Regulators cannot address one aspect of this issue (rate design) without recognizing and addressing the need to align utility incentives with the goal of least-cost provision of services through deployment and utilization of distributed resources. Rate design should capture the value of benefits provided by DERs. But it is nearly impossible to fully account for those benefits when utilities are financially dis-incentivized from recognizing and capturing them due to business models in which they earn profits primarily through return on rate base.

We present additional information and considerations along five main themes in the sections below. The first is a general overview of DERs and response to the Manual’s assertions about issues they may cause. The second theme is a recommendation that the Manual focus on a process that can guide regulators as DERs grow. The third theme is aligning utility and customer incentives. The fourth theme is rate design and finally, the fifth theme is DER compensation mechanisms.

I. What are DERs?

The draft Manual defines DERs and discusses the increasing importance of DERs and lays out issues that DER can present. While we believe the definitions of DERs in the Manual are sufficient, and that it is important to outline both the potential opportunities and issues they present. We believe, however, that the draft characterizes DERs in a negative light by focusing primarily on “issues” and “challenges” of DERs, and the draft should be revised to be more impartial. The first paragraph mentions that DERs provide “identifiable customer benefits” at the individual level, but hints at the uncertainty of whether benefits accrue to the grid, saying that DERs “possibly” benefit the grid. **(page 15)** This is in contrast to the numerous DER cost-benefit studies (generally focused on distributed solar generation) that have identified multiple grid benefits, including avoided energy, avoided line losses, avoided capacity, transmission & distribution capacity, among other benefits.² **Page 45** of the NARUC Manual lists these and additional benefits, saying that “most methodologies” consider the effects of each of the ones identified.

The question of whether DERs provide net benefits to the grid is tied to study methodology and the benefit and cost categories evaluated within each study. Regardless of methodology, it is indisputable that DERs provide certain benefits to the grid. The dispute is over *net benefits* and

² “A Review of Solar PV Benefit & Cost Studies,” Rocky Mountain Institute (September 2013).

many studies have found that DERs do indeed provide net benefits to all customers and the grid.³ (See Section V of our comments for additional comments about DER costs and benefits).

The first paragraph on **page 15** goes on to say that as DERs pass certain adoption levels, they “can begin to cause significant issues” with regard to ratemaking, utility business models and electricity delivery, adding that regulators should “identify potential economic and grid issues from DER.” Again, this one-sided view of DERs as only adding potential issues to the grid and ignoring the possibility of DERs adding potential opportunities as well should be revised. DERs provide opportunities to enhance and strengthen the grid through grid support services and allow utilities to save on energy and capacity costs in addition to other benefits. This statement also attempts to describe negative impacts without any supporting quantifiable, demonstrable data or a description of what the “issues” may entail. As illustrated below, most states have very low (<5%) penetrations, while only Hawaii experiences medium (10-20%) penetration. Even with Hawaii’s penetration levels, the grid still operates safely and reliably, and the utility is still allowing DERs to be installed across its network.⁴ And while DERs do challenge traditional rate making practices and utility models, this is merely a result of a market becoming more innovative and competitive, an evolutionary change similar to the one recently experienced by the telecommunications industry, which provided enormous benefit. Such a change should not be misconstrued in a negative light.

While we agree that some services and applications should not necessarily be defined as resources (**page 20**), we disagree that there is a “lack of sufficient technology installed which can assist in measuring, and scheduling such resources with greater certainty and confidence.” Furthermore, there is no evidence as to how UL1741 and IEEE 1547 (**footnote 41**) have delayed the introduction of DERs and this supposed lack of standards should not be considered a constraint to DER adoption or their reliable and measurable operations. There are other applicable standards to govern the integration of DERs that currently are in effect and sufficient for ongoing and proposed projects. In fact, there are numerous examples of DERs being deployed to provide grid services around the country.⁵ According to the US DOE Energy Storage Database, there are over 42 MW of projects in operation or announced that make use of distribution level storage to provide grid services or infrastructure deferral in seven US states.⁶

³ See “Rooftop solar: net metering is a net benefit,” Mark Muro and Devashree Saha, The Brookings Institute (May 2016); “Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society,” Environment America (2015); “Maine Distributed Solar Valuation Study,” Clean Power Research (April 2015); “Net Metering in Mississippi: Costs, Benefits and Policy Considerations,” Synapse Energy Economics (September 2014); “Minnesota Value of Solar: Methodology,” Clean Power Research (January 2014); “Nevada Net Energy Metering Impacts Evaluation,” E3 Consulting (July 2014).

⁴ <http://www.solarcity.com/newsroom/press/solarcity-launches-smart-energy-home-hawaii>

⁵ <http://www.solarcity.com/newsroom/press/solarcity-launches-utility-and-grid-services>;

<http://www.solarcity.com/newsroom/press/solarcity-and-pge-collaborate-distributed-energy-resource-projects>

⁶ <http://www.energystorageexchange.org/>

Increasing Importance of DER and the Issues it Presents

This section echoes the same negative view of DERs presenting issues for regulators, utilities and customers while at the same time acknowledging that DERs “have yet to reach significant levels of adoption rates in many states...” Rather than encouraging regulators to evaluate the question themselves before coming to this conclusion, the Manual assumes that all regulators will face the same issues, suggesting that some states just may have lower DER penetration and thus have not experienced any of the conceivable future issues. This will cause regulators in states with very low DER adoption to preemptively attempt to adjust rates or add special fees to avoid possible “issues” in the future (e.g. Kansas, Utah and other states with small distributed solar markets have already attempted to address future potential issues).⁷ The Manual should instead emphasize the importance of thorough, fact-based, and market-specific investigations to determine whether any issues are present and any action is necessary. This is mentioned at the end of section D on **page 22**, but it should be underscored before possible issues are listed.

The following papers on rate design and future regulatory models should be added under **footnote #44 on page 21**:

- “Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities,” Lawrence Berkeley National Lab/National Renewable Energy Lab (May 2016).
- “Smart Rate Design for a Smart Future,” Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project (July 2015).

Technology and Physical Issues

The Manual attempts to describe physical or technical issues DERs present to existing grid infrastructure and grid operators but fails to adequately align technology or penetration levels with the issues being described, leading the reader to jump to two flawed conclusions: 1) because the utility cannot control all DERs, DERs inherently cause grid issues, and 2) these issues occur at certain penetration levels but we do not know what those penetration levels are.

- 1) Just because some DERs such as rooftop PV may be non-dispatchable⁸, it does not mean that DERs cause grid issues as a result. DER penetration, especially at the low

⁷ <http://www.greentechmedia.com/articles/read/Solar-Advocates-Claim-Early-Victories-in-Net-Metering-Battles>

⁸ Rooftop solar PV systems with smart inverters are dispatchable and such inverters are coming into common use. In some jurisdictions such as California and Hawaii they will soon be required for all rooftop PV systems. See California Decision 14-12-035 December 18, 2014 (<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF>), and see Hawaii PUC Order No. 32053 at page 52-53.

penetration levels in most US states today, generally shows up to grid operators as a reduction in load in the same manner in which energy efficiency improvements appear. If utilities improve grid sensing and communication capabilities software platforms, such as Distributed Energy Resource Management Systems (DERMS), they will be able to achieve enhanced sensing and visibility on the distribution grid. DER providers themselves may also be able to provide utilities with granular or aggregated DER operational data in near-real-time. In principle, any intermittency associated with DERs is no different from intermittency of demand due to the randomness of consumer behaviors or other customer-specific factors; in fact, it is more predictable because that intermittency is associated with the same weather factors that utilities are already adept at predicting on a day-ahead basis, as discussed below.

- 2) As the Manual mentions, at high penetrations grid issues are often localized at the feeder level, but that is not to say that these issues cannot be anticipated or managed. In Hawaii in 2013, HECO effectively put a moratorium on new rooftop PV installations in most of its service territory due to grid reliability concerns.⁹ However, after a laboratory study with the Hawaiian Electric Companies and the National Renewable Energy Laboratory (NREL), the perceived technical constraint was lifted and the market was reopened in February of 2015.¹⁰ Most of the perceived technical limitations, such as the transient load rejection overvoltage concerns in Hawaii, are based on technical assumptions developed for a centralized power grid. As utilities increase in sophistication and analysis and technologies such as smart inverters and energy storage become the norm, the acceptable level of DER penetration is expected to increase significantly. Planning approaches such as Distribution Resource Plans (DRPs) in California and Distributed System Implementation Plans (DSIP) in New York are good examples of approaches to quantify the impact of DERs on the system. The Electric Power Research Institute (EPRI) has completed significant studies on this topic as well, most notably demonstrating how network hosting capacity can be significantly increased for rooftop PV when it is paired with smart inverters, which are becoming increasingly common across the country.¹¹

The Manual also focuses on the intermittency associated with some DERs, such as rooftop solar stating, “the presence of clouds...can mean that output can vary greatly from moment to moment, including going from 100% output to 0% almost instantaneously.” (**page 24**). Further, the Manual states that this issue is “amplified when DER is clustered in a specific area.” These statements are not supported by any evidence. In fact, the opposite is generally true. First, PV system output does not drop to 0% even in very cloudy or overcast conditions. There is still substantial output from these systems due to ambient reflected insolation on the panels.¹²

⁹ <http://www.bloomberg.com/news/articles/2013-12-26/utilities-feeling-rooftop-solar-heat-start-fighting-back>

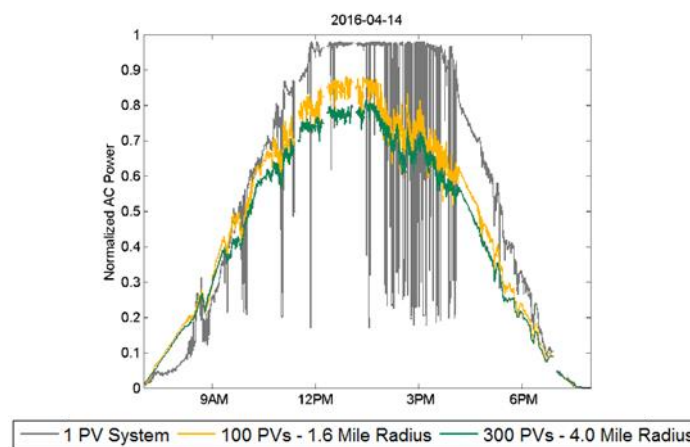
¹⁰ <http://www.solarcity.com/newsroom/press/solarcity-nrel-and-hawaiian-electric-complete-inverter-study>

¹¹ http://dpv.epri.com/hosting_capacity_method.html

¹² <http://www.e3a4u.info/energy-technologies/solar-electricity/system-components/>

Secondarily, due to the PV geographic smoothing effect,¹³ while cloud cover impacts PV generation output, cloud movement is not instantaneous. The way in which light reflects off of clouds results in a geospatial diversity at the ground level. This means that, although cloud cover can impact the output of a single PV array significantly over short intervals, the aggregated impact of cloud cover over a neighborhood of PV arrays is reduced and the resulting voltage and power output for a neighborhood instead is relatively smooth. In the figure below, the normalized AC power output variability over one minute intervals in a single day decreases as the area covered (and number of PV arrays observed) increases.

*The PV Geographic Smoothing Effect*¹⁴



The Manual also mentions flicker as a potential issue from rooftop solar (**page 24 footnote 50**). It is still common for utilities to employ the GE flicker curve, a standard that has been superseded for a number of years. IEEE 1453 *Recommended Practice for the Analysis of Fluctuating Installations on Power Systems* replaced the traditional guidance found in IEEE 141 and IEEE 519 associated with the GE flicker curve. It states that the “curves were developed based on standard rectangular modulations of the 60-Hz sine wave... [and] are not suitable for predicting flicker caused by other sources...random in nature and [with] irregular wave shapes.” Flicker meters and the measurement of short term flicker intensity account for the impact of different wave shapes and ramps specifically as it pertains to human perception. Some distribution system modeling tools now have flicker meter capability through the simulation of cloud motion.

When analyzing flicker, a worst case scenario approach is often adopted where the magnitude of the voltage flicker is taken as the difference between zero PV and maximum PV production. This

¹³ <http://www.slideshare.net/sandiacis/15-michael-mc-carty-pv-geographic-smoothing-effect-eprisandia-symposium-final>

¹⁴ Ibid

approach studies the impact of PV production instantaneously changing from 100% to 0%, an overly conservative assumption given the unlikelihood of such PV behavior. Cloud cover impacts the output of PV, but the slow movement of clouds over several seconds and the way in which the shadow is cast results in a geographic diversity as the area the PV covers increases, as described above. The Manual should use less restrictive and more realistic output ramps or more accurate simulations of resource output variability. Finally, the Manual should recognize that utilities already use weather prediction and sophisticated statistical analysis when planning capacity on a near-term basis (such as “day-ahead” planning). Those same techniques are equally applicable to PV.

Overall, the draft Manual can benefit from additional analysis and citations for claims, such as that “some utilities have already seen output that exceeds an individual feeder’s peak usage,” in order to understand the circumstances of such an event.

Implications for Utility Revenues

The draft Manual presumes that cost recovery issues and cost-shifting from DERs are a given. Despite saying these are “apparent” (**page 22**), the Manual does not provide any citations or examples quantifying cost recovery issues or cost-shifting. Robust data collection and analysis is critically important to assess whether cost recovery and shifting are occurring, the extent to which they are occurring, and whether reforms are necessary. Making changes prematurely can stunt the growth of DERs and prevent all customers from realizing the benefits DERs can provide the system.

One important factor to consider in regards to alleged revenue erosion and cost recovery is the time horizon of costs. The Revenue Erosion and Cost Recovery sections of the Manual take the position that a majority of utility costs are not variable in the short term, but says nothing of the long-term. A key objective of utility planning is to minimize long-term costs, which ultimately redounds to the benefit of all consumers and society. DER can reduce both short-term and long-term costs to the benefit of all customers. While utilities frame this as a revenue loss, over the long-term it can be viewed as a reduction in revenue requirements, which drives down the trajectory of customer’s rates.

It is also important that any alleged cost-shift be compared with rate increases associated with other utility proposals (such as new facilities or increasing return on equity) through an analysis of long-term business-as-usual scenarios and scenarios with customer-sited DER. This allows for any alleged cost-shift to be put into perspective with other factors effecting customer’s rates.

Regarding ownership and control of DER, the draft Manual labels this as an issue because adoption is driven by third parties rather than the utility and that the third parties are responding

to price signals for production rather than grid benefits. Additionally, the Manual claims that there is a lack of visibility and control of when DERs are exporting to the grid, which “give rise to many of the physical problems with incorporating DERs into the grid.” As noted above, DERs must go through an interconnection process in order to assess whether any potential issues may arise, and what can be done to mitigate the issues. While the Manual puts the onus on the DER industry, utilities can provide additional data, such as hosting capacity to help DER providers target areas that can benefit from DERs, and avoid areas where physical issues may arise.

II. Developing a Process to Guide Regulators

The opportunities for DERs and the pace of DER adoption have and will continue to vary by state due to the differing market conditions. This makes developing a Manual with national relevance a difficult task for the staff sub-committee. One way to do so is to outline a general process that can guide regulators as DER adoption grows in their states.

Section VI of the Manual begins to create this process guide. The work by Paul DeMartini and Lorenzo Kristov that outlines the path for regulators to monitor and promote adoption provides a useful foundation for the Manual to expand upon. The central theme of a process can serve as a timeline that allows regulators to lay the groundwork for more DER integration, not only on the grid itself, but in the regulatory process. Doing so can provide regulators with additional information about promoting DER adoption, what data points to collect and monitor, and when to begin to change incentive mechanisms (with suitable time for DER providers and utilities to respond).

Grid Planning Data Must be Transparent and Accessible

Data transparency and accessibility is one area in which the Manual is currently lacking, and are topics that are relevant in all jurisdictions. Several times throughout the Manual, references are made to limited visibility of DERs on the system along with the limited information available to DER providers to understand problem areas on the grid to target with DER solutions. This is a critical aspect that dovetails with enhanced grid planning strategies. Utilities hold monopoly power over not only their customers and grid infrastructure, but the granular information about grid health as well. Absent this data, and pricing considerations to which it may give rise, DER providers are limited to using system-level data to provide circuit-level solutions, an imperfect approach at best that can be easily refined with access to improved, machine-readable data.

Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings

are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. The table below is an initial set of minimally-required data to foster adequate stakeholder engagement in regards to specific, utility-identified grid needs.

*Data to Foster Engagement in Grid Needs and Planned Investments*¹⁵

DATA NEED	DESCRIPTION
Grid Need Type	The type of grid need (e.g. capacity, reactive power, voltage, reliability, resiliency, spinning/non-spinning reserves, frequency response)
Location	The geographic (e.g. GPS, address) and the system location (e.g. planning area, substation, feeder, feeder node) of the grid need
Scale of Deficiency	The scale of the grid need (e.g. MW, kVAR, CAIDI/SAIDI deficiency)
Planned Investment	The traditional investment to be deployed in the absence of an alternative solution (e.g. 40 MVA transformer, 12kV reconductor, line recloser, line regulator)
Reserve Margin	Additional capacity embedded within the planned investment to provide buffer for contingency scenarios (e.g. 20% margin above expected deficiency embedded within equipment ratings to ensure available capacity during contingency scenarios)
Historical Data	Time series data used to inform identification of grid need (e.g. loading data, voltage profile, loading versus equipment ratings, etc.)
Forecast Data	Time series data used to inform identification of grid need and specification of planned investment (e.g. loading, voltage, and reliability data). Forecast to include prompt year deficiency (i.e. near-term deficiency driver), as well as long-term forecast (i.e. long-term deficiency driver)
Expected Forecast Error	Historical data that includes forecasts relative to actual demands for relevant grid need type in similar projects. Data to be used to evaluate uncertainty of needs and corresponding value of resources with greater optionality (e.g. lead times, sizing, etc.)

While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. The following data should be made available and kept current by utilities in order to encourage broad engagement in grid design.

¹⁵ “A Pathway to the Distributed Grid,” SolarCity (February 2016).

*Data to Foster Engagement in General Grid Design and Optimization*¹⁶

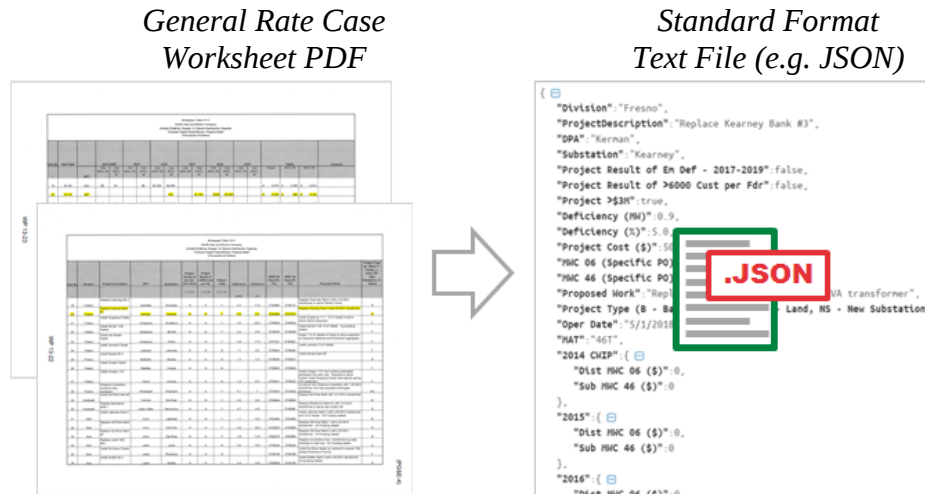
DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

Share Standardized, Machine-Readable Data Sets

Data that is made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format that enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into an electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access.

To illustrate a potential path forward, below is an example of traditional grid capacity needs and corresponding capacity investments as communicated via PG&E's 2017 GRC Phase 1 filing; the image of the text file on the right shows how those same grid needs and planned investments could be translated into a machine-readable format.

¹⁶ Ibid.



III. Aligning Incentives

As evident by the discussion in the previous sections, DERs can provide net benefits to the system, but there are potential issues as well. Aligning utility incentives can mitigate the issues and ensure that the benefits of DERs are maximized.

The draft Manual focuses almost entirely on rate design and fails to address the foundational issue of encouraging adequate utilization and optimization of DERs within the electric grid. The Manual can benefit from an expanded discussion about reforming utility incentives to enable greater utilization of DERs. Reforming these incentives includes considering changes to utility business models, various incentive mechanisms, and clarifying the role of regulators.

Reforming the Utility Business Model

As a whole, DERs – including rooftop solar, battery storage, smart inverters, and controllable loads – have the capability to provide all of the functions of traditional utility infrastructure. They can provide generation capacity, energy, and ancillary services, and by providing those services at the very location where they are consumed, they can reduce or eliminate the need for transmission and distribution investments.

DERs provide these services via a competitive marketplace, which produces more economically efficient outcomes and is better at driving innovation than a market that is structured as a monopoly and governed by fallible humans who may not foresee future applications or benefits, much as electricity was viewed as a curiosity before Edison displaced candles with lightbulbs.

Thus, it is in the interest of state regulators to encourage the competitive marketplace to provide DERs, incorporate them into resource planning and utilize them in a way that reduces the cost of the electric grid for all customers. Unfortunately, however, doing so directly conflicts with the interests of utility shareholders, whose primary source of profit is the same infrastructure investment that distributed resources could displace or reduce.

Because of this “cost of service” model, utilities have traditionally been incentivized to encourage increased energy consumption and make large capital investments and build physical infrastructure to meet system needs instead of promoting conservation, self-generation or other measures that reduce reliance on the bulk generation and transmission system. The financial incentive to increase infrastructure investment ultimately puts upward pressure on rates.

With DERs becoming more widely adopted by customers, those resources should be accounted for in the planning process, but utilities will have little incentive to do so unless they are able to earn financial incentives for relying on them instead of traditional capital projects like generation and transmission capacity. Utility incentives and grid planning should be overhauled to accommodate, encourage and compensate cost-effective DER deployment.

This will undoubtedly require innovation in a traditionally risk-averse environment accustomed to central planning and guaranteed rates of return. Regulatory leadership will be critical. Utilities have recognized the need for regulatory leadership. In its initial distributed system implementation plan presented in the New York REV proceeding, National Grid stressed the importance of the role regulators play in creating and enabling an environment where parties with traditionally conflicting business models can work collaboratively to craft those innovative solutions. National Grid further elaborated that a collaborative approach would “rely on the ability to discover what does not work in a cooperative environment. We need to open our networks to high-tech partners focused on energy efficiency, energy storage, and distributed generation such as solar, wind, and biogas. By turning the grids into innovation playgrounds we can propel the type of market-based advances that lifted the telecommunications and personal computing industries decades ago.”¹⁷

Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

Under the prevailing utility regulatory model, DER benefits cannot be fully captured. Instead, utilities are incentivized to “build more to earn more.” This conflicts with the public interest of building and maintaining an affordable grid and the principles of efficient resource management and discouraging waste. Under today’s regulatory paradigm, utilities see a negative financial

¹⁷ National Grid INITIAL DISTRIBUTED SYSTEM IMPLEMENTATION PLAN; Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV); June 30, 2016; Page 19

impact from utilizing resources for distribution services that they do not own – which includes the vast majority of distributed energy resources – even if those assets would deliver higher benefits at lower cost to customers. This financial incentive model is a vestige of how utilities have always been regulated; a model originally constructed to encourage the expansion of electricity access. However, as customers become increasingly interested in managing and controlling their energy consumption via distributed resources, this regulatory model is becoming outdated.

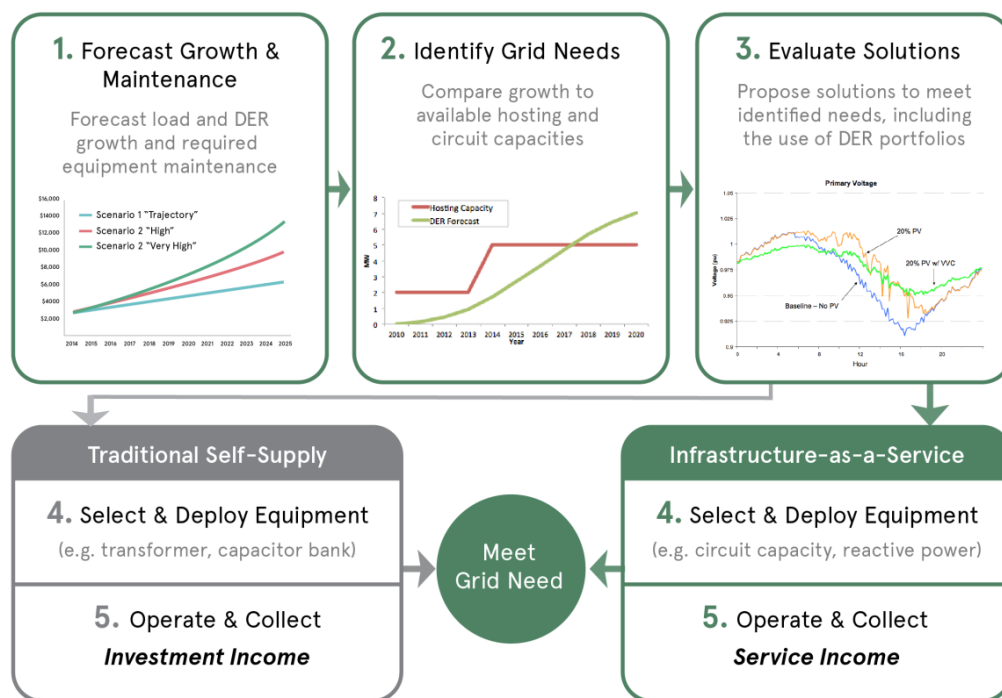
There are other innovative paradigms that regulators should explore. One such reform would be to separate the role of grid planning and sourcing from the role of grid asset owner – such as through the creation of an independent distribution system operator (IDSO). An IDSO would create functional independence between ownership and operations and therefore would neutralize the utility’s decision model when it comes to procurement.

Infrastructure-as-a-Service and Distribution System Planning

Another potential structural reform involves new utility sourcing models, such as *Infrastructure-as-a-Service*, which would allow utility shareholders to derive income or a rate of return from competitively sourced third-party services. This model would help reduce the financial disincentive that currently biases utility decision-making against DERs, encouraging utilities to deploy grid investments that maximize customer benefits regardless of their ownership.

Infrastructure-as-a-Service is a regulatory mechanism that modifies the incentives for the utilities when sourcing solutions to meet grid needs. This mechanism would allow utilities to earn income or a rate of return from the successful provision of grid services from non-utility owned DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecasting, identifying needs and evaluating solutions) remain identical to the current process, but are then followed by the Infrastructure-as-a-Service mechanism’s enhancements to sourcing in steps four (selecting and deploying) and five (operating and collecting).

Utility Planning and Sourcing: Utilizing Infrastructure-as-a-Service Model¹⁸



Under the proposed approach, regulators and utilities can evaluate all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios. If more cost-effective for customers than conventional solutions, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income or a rate of return based on the successful deployment of competitively sourced third-party solutions. This service income would provide fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services and would help mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution “cost plus” regulation.

Creating a pathway for DERs to offer grid services in lieu of utility infrastructure investment would be beneficial for *all* utility customers for a variety of reasons, including customer savings, increased flexibility, customer engagement and greater competition and innovation.

As an example of how utility business model issues can be considered alongside distribution planning, the California Public Utilities Commission recently enhanced the 2016 scope for its Distribution Resource Planning proceeding to formally consider the utility role, business models, and financial interest with respect to DER deployment.¹⁹ Infrastructure-as-a-service is one

¹⁸ “A Pathway to the Distributed Grid,” SolarCity (February 2016).

¹⁹ CPUC Scoping Memo on Distribution Resource Plans, Track III, January 2016
<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K902/157902794.PDF>

mechanism to consider that would reduce the conflict of interest towards third-party services inherent in the utility incentive model today. Regulators in other states may use this model in California as a useful framework to explore alternative resource sourcing mechanisms to encourage cost-effective DER deployment.

Revenue Decoupling and Other Incentive Mechanisms

Revenue decoupling is one mechanism in regulated ratemaking that alleviates the “throughput incentive” that has historically made utilities resistive to energy efficiency and DER technologies (that put downward pressure on sales). Decoupling helps overcome the throughput incentive by enabling a utility to recover its revenue requirements independent of sales volume.

The draft Manual presents a limited discussion of decoupling. This mechanism should receive greater focus because it allows for growth of energy efficiency and other DERs while ensuring utilities recover their revenue requirements. Decoupling can be a particularly effective tool to allow for DER growth while also providing regulators and stakeholders with time to consider future transitions to alternative compensation mechanisms as DER adoption rates rise.

Decoupling should allow utilities the flexibility and incentive to pursue more volumetric rate designs that give customers the signals and ability to conserve (through efficiency measures or the use of distributed resources), without lower sales directly impacting shareholder profit. Revenue decoupling has also been found, in a recent Brattle Group study, to lower risk to bondholders.²⁰

Ideally, decoupling is paired with enhanced prudency review from the regulator to ensure that the utility is seeking the lowest cost solutions and that it has evaluated DER opportunities both in the present and its forecasts of future supply.

There are other mechanisms that the Manual can consider in order to achieve a similar utility indifference to DER solutions, including Performance Incentive Mechanisms. These have been proposed in New York, specifically relating to the Brooklyn Queens Demand Management project where a 100 basis point return on equity (ROE) adder was allocated to Con Ed as an incentive tied to MW achievement levels for the project.²¹ In California, Commissioner Florio’s regulatory incentives proposal is underway to provide similar incentives to utilities in the state.²²

²⁰http://www.brattle.com/system/publications/pdfs/000/004/995/original/Effect_of_Electric_Decoupling_on_the_Cost_of_Capital.pdf?1395776507

²¹ “Staff White Paper on Ratemaking and Utility Business Models”, State of New York Department of Public Services, July 2015, pp. 40-44

²² <http://www.utilitydive.com/news/how-california-wants-to-align-utility-revenue-models-with-ders/417029/>
<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF>

As another example, the United Kingdom adopted an approach to provide utility returns on both operational and capital expenditures (focusing on Total Expenditures, dubbed TotEx) which enabled the utilities to be equally incentivized to invest in capital and operational efficiencies to earn a return.²³

The Role of the Regulator

Two things are clear regardless of the model that ultimately gets adopted in any jurisdiction: regulators have a critical role to play in advancing and accelerating the evolution and modernization of the electric sector; and regulatory leadership will be key to enable these kinds of discussions to occur in a collaborative space and in a meaningful way with all stakeholders being represented at the table.

It is self-evident that across the country, innovation in the power sector has been making strides in states with strong regulatory leadership. California and the NY REV process are some of the best examples, whereby the regulators have created an environment for collaboration and innovation to drive new solutions. One should also recognize that utilities can also drive towards change. Vermont's Green Mountain Power (GMP) is a prime example of utility leadership. GMP has publicly advanced the notion that evolving business models and approaches are key to innovation and ultimately to providing customers the services they need and desire at a lower cost.²⁴

IV. Introduction to Rate Design

Various rate designs are discussed in the Manual. We focus on several rate designs in the sections below to provide suggestions and clarifying comments for the sub-committee to consider.

Fixed Charges and Minimum Bills

Fixed charges and minimum bills are a widely used part of many rate designs. Fixed charges allow utilities to recover cost that do not vary with the usage of electricity. Recently, utilities across the country have increasingly proposed increases to the fixed charge portion of their rate designs. While fixed charges are used to recover a base amount of revenue from customers for connection to the grid, increasing fixed charges can reduce customer price signals and negatively impact low or fixed-income customers while providing limited benefits other than increasing utility revenue assurance. In Q2 2016, the North Carolina Clean Energy Technology Center

²³ <http://www.fortnightly.com/fortnightly/2013/10/trip-riio-your-future>

²⁴ http://www.greenmountainpower.com/upload/photos/4775._GMP_Innovation.pdf

(NCCETC) reports that 42 utilities in 25 states and Washington D.C. either had pending or decided requests to increase monthly fixed charges on residential customers by at least 10%. However, in more than half the cases decided so far in 2016, utilities have not been allowed to increase fixed charges.²⁵

Ratemaking should not simply be used as a tool to guarantee utility revenue. Fixed charges are often inconsistent with policy objectives. Fixed charges do not send effective price signals to customers nor incentivize efficient use of the energy. The fixed charge itself is unavoidable, thus provides no effective price signal to the customers. Furthermore, an increased fixed charge will likely result in a lower volumetric charge, which reduces the economic incentive for careful customer energy management practices and investment in energy efficiency measures. If the fixed charge is increased substantially, the resulting reduction in volumetric charges may be enough to actually stimulate additional consumption thus creating incremental utility investment.

The implementation of fixed charges also reduces customer control over energy costs and can negatively impact low or fixed income customers by forcing a higher fixed payment regardless of reductions in energy use.

Utilities have many other options to address revenue stability issues. The most popular alternative is the minimum bill. Minimum bills are a preferred option to ensure that all customers contribute towards their fixed cost of using the grid, without muting the beneficial signals of an energy rate that reflects long-term marginal costs & incents customer action. This rate design encourages prudent usage, better aligned with investment impacts from consumption and investment in energy efficiency. This means customer choices about usage and, importantly, energy-related investments, will be informed by electricity prices that reflect long-run grid value. The disadvantage is that, for the very small number of customers whose usage is below the “minimum,” this rate design provides no disincentive at all to using the minimum amount of electricity. It can be perceived to have a disadvantage of encouraging additional usage by those users with usage below the minimum billed amount, but there are very few of these customers, and their prospective additional usage increase is minimal.

Time Varying Rates (TVR)

While the Manual gives a brief overview of what TVR is, it does not dive into some of the important issues regulators should consider when determining whether and how to implement TVR. The Manual states that “Time variant rates are designed to recognize differences in a utility’s cost of service and marginal costs at varying times during the day (**page 9**).” However,

²⁵ <https://nccleantech.ncsu.edu/n-c-clean-energy-technology-center-releases-q2-solar-policy-update-to-the-50-states-of-solar-report/>

this framing of the purpose of TVR ignores the fact deemphasizes that well designed and nondiscriminatory TVRs can also create price signals that drive changes to customer behavior, with the aim of reducing system costs and creating benefits for all customers. To maximize the efficacy of TVR achieving this goal, significant effort is needed with respect to piloting specific rate options and educating customers about how they can manage their costs effectively under TVR. Piloting TVR can reveal important findings about customer acceptance, different segments of customers' ability to respond, how much they respond, and which rates they respond most effectively to. Basing TVR exclusively on cost of service is not enough to drive the most economically efficient behavior.

In the final draft of the Manual, we recommend a deeper consideration of the following implementation challenges:

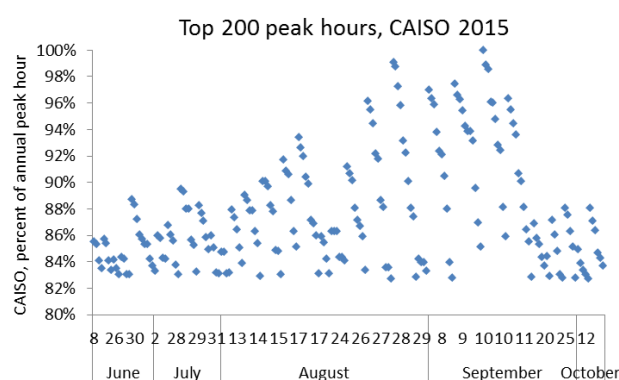
- How to Conduct Effective TVR Pilots
 - Recruiting Representative Samples
 - Addressing Self-Selection Bias
- Customer Education & Outreach to Ensure Customer Acceptance
- Mandatory vs. Default vs. Optional
 - Structural winners vs. structural losers Under Mandatory TVR
 - Bill Protection Under Optional TVR
- Enabling Infrastructure
 - Advanced Metering
 - Billing Systems

Three Part Rates / Demand Charges

The Manual includes two primary discussions about three-part rates/demand charges. The first is a brief overview in the Rate Design Process section (II). While the section is not intended to be comprehensive, there are several generalizations in the summary that may be misleading. The first is the premise that demand charges are enacted to address higher costs of electricity during peak times. While this can be true of coincident demand charges, RMI reported that 66% of existing residential demand charges are based on customer non-coincident peak demand.²⁶ As noted in Jim Lazar's "Smart Rate Design for a Smart Future", solar customers contribute power to the grid during peak times and therefore non-coincident demand charges would be unfair and would not recognize the value the solar customers are providing to the grid. Non-coincident demand charges do not send signals about the high cost of electricity during peak periods.

²⁶ A Review of Alternative Rate Designs, RMI, p.57

Second, the statement “in an effort to identify costs associated with peak, a ‘demand charge’ is one way for a utility to send a peak pricing signal over a certain time period, such as monthly” **(page 10)** is not entirely clear or reflective of how demand charges are often implemented by utilities. Signals to reduce demand in a peak month are not nearly as clear or effective as signals about peak days or peak hours (such as those with coincident demand charges or critical peak pricing events). Demand charges incurred on a single peak demand interval (e.g., single peak hour) on a monthly basis do not tend to reflect peak system demand. Peak system demand, which results in the highest system costs and drives total system capacity need, tends to occur in only a few months each year and are often clustered over the course of just several days or several hours within just a few days each year. In the example below, the top 200 hours of peak demand on the CAISO system in 2015 occurred in only 35 days during the period from June to October.



Section V provides a more balanced discussion of demand charges, their components, and the various considerations. We agree with the conclusions that non-coincident demand charges are “functionally problematic” and that “regulators should be wary of counting on unsupported, promised benefits and cautious when plausible harm may represent itself” **(page 53)**. Demand charges are difficult for customers to understand due to their many facets, including the measurement interval (e.g. 15 minute, 30 minute, hour), measurement period (e.g. monthly, yearly), and the lag customer feedback as to when a peak period is or has occurred.

As always in rate design, any number of combinations of variable, fixed, and demand charges could satisfy revenue requirements, but the relationships and ratio between them, as well as the details of their levels and calculation, can have dramatic effects and possible unintended consequences in practice. For example, a demand charge can be constructed that specifically targets solar load shapes, thereby having a discriminatory impact on DERs and hinder their adoption, which having relatively more muted effects on non-DER customers.

It should be noted that the example demand charge described in Section C.4. (**page 52**) does not describe the utility's proposal in its entirety or capture the complexity of the proposal. The company's proposed legislation would subject all residential customers to three separate demand charges, each measured in a different fashion. The first is a non-coincident demand charge (measured from 6am-9pm) for distribution costs. The second demand charge is for transmission related costs coincident with the utility's peak, and a third is for generation capacity costs based on the ISO's peak. In addition, we do not believe the proposal is an appropriate example for the Manual since the proposal effectively circumvented the regulatory arena by being mandated by legislation.

Additionally, in the discussion about considerations in Restructured Jurisdictions (**page 35**), the draft Manual asserts that demand charges are a better proxy for cost causation on the distribution network than rates based on energy throughput (kWh). We disagree and contend that energy throughput at, and closely tailored to, coincident peak periods (i.e. TOU) is a superior proxy for cost causation than non-coincident demand charges. Coincident peak at the circuit level is a greater risk to the system than an individual's peak demand over a short time interval, which will impose little cost on the utility if it does not coincide with the circuit peak.

Ratchets

While not a rate design on their own, ratchets are a component of rates. A ratchet is a charge based on a customer's highest usage in preceding months (usually 11 to create an annual ratchet). Ratchets have traditionally been tied to demand charges, but "tiered" fixed charges also effectively act as a ratchet.²⁷ The draft Manual does not include a discussion about ratchets, and we believe such a discussion is warranted due to their prevalence and potential impact on DER investment.

Ratchets discourage adoption of energy storage, distributed generation and energy efficiency since they convert variable monthly behavior into a charge that is effectively fixed for a year or more. For example, a customer that invests in storage and is subject to a demand ratchet would not be able to realize bill savings from reducing their peak demand until at least a year after reduction occurs.

As noted in "Smart Rate Design for a Smart Future", demand ratchets "fail to capture the effects of time diversity and non-coincident of a customer's peak demand" and notes that "the increased

²⁷ See National Grid Massachusetts' proposal for tiered residential fixed charges in DPU 15-155. See Testimony from Tim Woolf and Melissa Whited on pg. 9-12 discussing how a tiered fixed charge acts like a ratchet. http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-155%2fCorrected_Testimony_Woolf_and_.pdf

temporal and geographic granularity of customer usage patterns made possible by smart meters obviates the need for demand ratchets and traditional demand charges.”²⁸

Separate Rate Class

The draft Manual suggests that separating DER customers into a different rate class might be a “particularly attractive” option for regulators for several reasons, including reducing cross-subsidies. An example of air conditioning or electric heat as different types of service was mentioned since “the impact on costs is significantly different from those customers that do not have those items.” The existence of the separate rate classes is true, but the Manual should note that rates for electrical heat are often subsidized in order to promote electric heat over natural gas or oil. The mere existence of separate rate classes for electric heat does not also mean that separate rate classes for DER customers are appropriate.

While several considerations are described on **page 28**, the discussion about perhaps the most critical factor, whether DER customers are sufficiently different than other customers, is ambiguous. On one hand, it acknowledges that a customer’s usage can change for a number of reasons besides DER (energy efficiency, fewer family members, etc.) and those customers are not separated into other rate classes. On the other hand, it asserts that moving DER customers to a separate rate class would allay concerns about cross-subsidization.

Rate classes are comprised of very diverse individual load profiles due to different customer behaviors, building stock characteristics, appliance efficiencies and other factors. Given the inherent diversity, it would be unduly discriminatory for regulators to move customers into a separate rate class simply because they have DERs. Moreover, treating customers who self-generate differently from other utility customers could potentially allow utilities to use their monopoly power to build barriers to emerging technologies that might one day compete with the utility.

Back-up and Standby Rates

Similarly, it is inappropriate to assess back-up or standby rates to DER customers. While standby charges are common among PURPA QF generators, they are typically not appropriate for NEM customers (or small DERs more generally) for several reasons. First, DERs are typically much smaller than PURPA QFs. An individual DER system is not large enough on its own to require that a utility build additional generation capacity to ensure its ability to serve that individual in the unlikely event of an outage. In other words, a small DER does not drive higher reserve requirements. While a 25MW QF might reasonably require standby service to ensure its facility can remain powered during an outage of its large onsite generator (and an industrial customer who hosts that generator may be willing to pay for that backup service), an 8kW rooftop solar

²⁸ Lazar, J. Gonzalez, R. 2015. Smart Rate Design for a Smart Future. The Regulatory Assistance Project.

system does not require that same backup service, and standby charges are therefore inappropriate.

Second, DERs benefit from geographic diversity, and therefore have a much smoother generation profile in aggregate than a single generator in one location would have on its own.

Finally, a fleet of DERs has a smaller risk of widespread forced outage. It is highly unlikely that a significant portion of the rooftop solar fleet would experience a generation outage at the same time. When considered as a single fleet of distributed resources, the rooftop fleet is remarkably reliable.

Interconnection Fees/Metering Charges

The first paragraph (**page 58**) in this section of the Manual could be confusing for a regulator to read if they are not already familiar with typical interconnection fees. The language should clearly define separate types or categories of installations, and how those costs differ.

- Class I systems typically up to 20-25 kW have less impact to the grid as long as there is sufficient load on site to reduce significant backfeeding to the grid. Class I systems often require the least amount of system impact review, and can be given a simple interconnection process. Because Class I systems cost the utility the least to process, the interconnection fee should reflect that. The interconnection fee will range from \$75-\$150 or in some cases is free to the DER owner, such as in Massachusetts.
- Class II systems often 25 kW to 2MW require various studies, system modifications, an onsite inspection, and therefore should have the right to pass on those costs to the DER owner. Interconnection costs in Massachusetts for larger systems may include an application fee (\$0-\$7,500 depending on the size of the DER proposed to be interconnected).
- We also recommend that the Manual explain that Class II or larger systems should be given the opportunity to have a preliminary review for an estimate of interconnection costs before proceeding with an in-depth review and being charged the full interconnection cost up front. DER owners should be given the opportunity to understand the estimated cost of interconnecting their system for a small fee before being required to pay for in-depth studies, such as in New York.

The second paragraph of this section of the Manual discusses metering charges for the meter, maintenance, meter reading, and data output that can be included in the customer charge or imposed as a separate charge. Non-DER customers also require a meter, maintenance, meter reading, and sometimes data output. In fact, many utilities are rolling out “smart meters” for *all*

customers because of their non-DER benefits, and would do so without the presence of DERs.²⁹ The Manual fails to clarify that costs should be just and reasonable. If these costs are already being collected in monthly customer charges or energy rates, and there are not additional costs created by DER customers, an additional metering fee is unjust. The cost of a new meter is often a one-time fee that can be recovered in the interconnection application fee rather than an additional monthly metering fee. While meters for DERs do often require additional data output, they often reduce the need for physical meter readers. A full study must be conducted on costs and benefits before approving metering fees.

The Manual fails to recognize that some of the grid upgrades necessary to accommodate a new installation of a DER facility can benefit all customers. In Hawaiian Electric Companies' Distributed Generation Interconnection Plan, the utility companies state, "To this end, the Companies [Hawaiian Electric, Maui Electric, and Hawaii Electric Light] recognize that many of the specific costs attributable to implementation of the DGIP can be viewed as system-level upgrades, which benefit all customers, with some exceptions. The Companies believe the appropriate method for allocating and recovering these costs is to examine each for its ability to provide either system benefits only to DG customers, in which case it may need to be captured in DG customer-specific rates. For example, the Load Tap Changer (LTC) controller replacements, circuit-upgrade programs, and substation transformer upgrades are all improvements that are expected to relieve constraints on reverse power flow due to DG on circuits and substations."³⁰

The third paragraph (**page 59**) states, "Additionally, if the utility determines in the studies conducted through the interconnection process that the DER will require distribution system upgrades, the DER owner is responsible for these costs regardless of the prior DER facilities installed on the distribution system. Thus, the final DER to interconnect is responsible for the total cost of the distribution system upgrade. Moreover, an interconnection fee may prevent DER adoption because the additional fee increases the payback period of the DER investment to the owner." The Manual fails to mention how the final DER owner that wishes to interconnect does not necessarily have to be the one responsible for the total cost of the distribution system upgrade that will likely prevent them from adopting DER. In Hawaii in 2014, the utility companies completed circuit upgrade projects to accommodate new DG on the grid. The costs of the studies and upgrades were allocated to customers in the interconnection queue and to future interconnecting customers to spread the financial burden across a large number of participants instead of by the first DER customer. "This proactive approach will support the continued

²⁹ <http://www.greentechmedia.com/articles/read/50-million-u.s.-smart-meters-and-counting>

³⁰ Docket No. 2011-0206 – Reliability Standards Working Group filed by Hawaiian Electric Companies Distributed Generation Interconnection Plan
[http://files.hawaii.gov/puc/4_Book%201%20\(transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5\).pdf](http://files.hawaii.gov/puc/4_Book%201%20(transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5).pdf)

growth of PV, ensure safety and reliability, and help reduce the financial burden and time duration for DG customers to interconnect.”³¹

The Bonbright Principles and New Principles

In establishing a set of rate design principles by which to guide regulators’ actions on rate design for DERs, the Manual lays out principles and objectives established by James Bonbright in *Principles of Public Utility Rates*, which was originally published in 1961 (**page 6**). When Bonbright’s manual was published, utilities were vertically integrated companies that typically owned and controlled all aspects of the electric system, from the generator to the utility meter.

Since that time, massive changes have taken place in the electric sector – including the Public Utilities Regulatory Policy Act, which mandates access to the grid for customers who self-generate; the deregulation of wholesale energy generation in many jurisdictions; the rise of the environmental movement and concern over pollution and global warming; and the emergence of customer-sited distributed resources at the residential customer level.

In authoring a manual to address ratemaking for DERs, NARUC should not rely solely on a set of principles that were established long before DERs existed, and that pre-date federal regulations designed to protect customers’ right to self-generate. At a minimum, if the NARUC Manual seeks to rely on the Bonbright principles, those principles should be updated to reflect current technology, Federal rules designed to protect self-generators from the utility’s monopoly power, and the public’s interest in promoting new technologies that can reduce electric bills and address concerns about pollution and climate change.

For example, Bonbright’s rate design objective (c) states that “rates should be designed to discourage wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received.” It is not clear how this principle would apply to compensation for self-generation at a time when federal law protects a customer’s right to self-generate. Presumably, if rates should be designed to “discourage wasteful use,” then self-generation to meet on-site load should be encouraged, since this type of generation produces the exact same result as conservation.

Supplementing Bonbright Principles with new Principles that reflect new technologies and market changes can help align incentives and develop a path forward for DERs and utilities. For example, the Regulatory Assistance Project (RAP) has conducted extensive research on the role of emerging customer technology in the utility space and has developed a set of

³¹ Hawaiian Electric Companies 2013 Integrated Resource Planning Report
<http://www.solari.net/documents/portfolio/Solari-Hawaiian-Electric-2013-IRP-Report.pdf>

recommendations for rate design entitled: “Smart Rate Design for a Smart Future.”³² The RAP rate design principles are specifically designed to account for emerging distributed technologies. The Principles put forth in “Smart Rate Design for a Smart Future” are simple, straightforward, unambiguous, and designed to accommodate the current trend of rapid technological change. These principles (listed below) should be applied consistent with the well-established and “accepted economic theory of pricing based on long-run marginal cost.”³³

1. A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
2. Customers should pay for grid services and power supply in proportion to how much they use these services, and how much power they consume.
3. Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.

In outlining these principles, RAP says: “Progressive rate design can make the difference in cost-effectively meeting public policy objectives – to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts – while ensuring adequate revenue for utilities.”

By contrast, RAP warns against rate designs that are primarily intended to stifle the growth of distributed generation or protect the utility’s monopoly. The paper says: “Failing to apply the principles for modern rate design may lead to higher usage and higher bills for customers. Straight-fixed-variable rate designs with large fixed customer charges discriminate against low-usage customers and those with distributed generation, potentially leading customers to abandon the grid entirely.”

Public Policy Considerations

Beyond Bonbright principles, regulators must also consider public policy goals when developing rates. In setting rates for distributed generation technologies, regulators may wish to consider the public policy preferences of their constituents in cost allocation and recovery. For example, constituents concerned about local air quality due to coal plants or climate change or those who wish to preserve undisturbed lands against development from power plants and transmission lines may favor policies that promote distributed resources, even if compensation is higher than the direct monetary value those resources provide to the utility. And some customers may

³² “Smart Rate Design for a Smart Future,” by Jim Lazar, Wilson Gonzalez, and Janine Migden-Ostrander. Regulatory Assistance Project, August 2015.

³³ Ibid.

demand the right to adopt carbon-free technologies and to be compensated for exported energy at a fair rate.

In addition, at a time when some jurisdictions have adopted competitive, unregulated markets for wholesale power generation, regulators may wish to promote customer generation as a way to introduce more competition and resource diversity, and to deter the market power of large generators. Indeed, it was these factors, rather than environmental concerns, that motivated the California Legislature to begin promoting distributed generation through the Self-Generation Incentive Program in 2000.³⁴

V. DER Compensation Mechanisms

Rate design and DER compensation mechanisms are closely related and regulators will need to consider the prevailing rate design when determining DER compensation mechanisms. If significant changes are made to compensation mechanisms or rate designs, regulators will also need to consider “grandfathering” existing DER customers. In this section, we provide comments and suggestions for grandfathering, NEM, and Valuation Methodologies.

Grandfathering

In this section, the Manual provides questions and tradeoffs to consider when debating whether to “grandfather” existing DER customers (i.e. keep them on their current rate schedule for a certain time period) or “transition” them to different rate schedules or classes. The Manual states that regulators “may need to determine whether it is in the best interest to all customers to transition DER customers from one rate schedule to another.” While some of the questions posed for consideration are valid, the Manual provides no detail on the underlying process that would result in such a decision (**page 37**).

First, a regulator must undertake a thorough and fact-specific investigation to determine whether any changes to rate design are necessary in the first place. It should not be a foregone conclusion that compensation rates for DER customers must change. Also, it should include consideration of state policy goals and legislative objectives that may be outlined under statutes related to DERs. For example, in many states, the legislature has created certain policies, such as net metering, to encourage private investment in DERs and renewable technologies.³⁵

³⁴ <https://energycenter.org/self-generation-incentive-program/background>

³⁵ See Louisiana RS 51:3061; Minnesota Stat. 216B.164; Nevada NRS 704.766

When governments implement a policy to foster customer adoption of a long-lived asset, customers will generally assume that the policy on which the value of the asset depends will be in place for most of the useful life of the investment. In fact, most customers will calculate the financial viability of an investment like rooftop solar under the assumption that policy remains largely unchanged during the life of the resource.

If policy is changed abruptly and drastically without protecting customers who made investments under the assumption of policy longevity, utility customers may be less likely to respond to policy incentives in the future. For example, if changes to a net metering tariff are made that reduce the compensation for rooftop solar, but existing customers are not grandfathered, future customers may be unlikely to enroll in the new NEM tariff for fear that they, too, will see rates abruptly changed and the value of their investment diminished. Thus, if rate design changes are deemed appropriate, the regulator should then begin evaluating grandfathering considerations, ensuring that decisions are still in line with stated DER policy objectives.

The Manual should provide more background on the issue of grandfathering, including where it has been implemented and the length of the grandfathering period. The question of whether to grandfather existing DER customers generally comes up when successor DER policies are being evaluated within regulatory proceedings. For example, the California Public Utilities Commission instituted a 20-year grandfathering period both for DER customers who took service under the NEM 1.0 tariff and for new customers who will be taking service under the new NEM 2.0 tariff, stating that this decision will "allow customers to have a uniform and reliable expectation of stability of the NEM structure under which they decided to invest in their customer-sited renewable DG system."³⁶

Kansas and Hawaii have also implemented grandfathering. Kansas law states that customers who began operating a renewable energy resource before July 1, 2014 will be grandfathered through December 31, 2029.³⁷ In Hawaii, the Public Utilities Commission agreed to grandfather customers who had applied for the net metering program before October 12, 2015, though it did not designate a specific time period.³⁸ The Nevada Public Utilities Commission decided not to grandfather DER customers when it instituted a separate rate class to include higher fixed charges and lower volumetric rates that would be phased in over a 12-year period, but NV Energy recently proposed a 20-year grandfathering period for customers who installed systems prior to December 31, 2015.³⁹

³⁶ California Public Utilities Commission, Rulemaking 14-07-002: Decision Adopting Successor to Net Energy Metering Tariff

³⁷ Kansas Stat. 66-1265 and 66-1266

³⁸ Hawaii Public Utilities Commission, Docket No. 2014-0192

³⁹ "NV Energy Takes Strong Next Step to Grandfather Net Metering Customers," NV Energy (July 2016)

Net metering

The section on Net Metering begins with the correct observation that “Net Energy Metering (NEM) is the simplest and least costly method to implement a compensation methodology for DER” (**page 41**). The rest of the NEM section, however, inappropriately presents speculation, conjecture and incorrect information as fact. While the section accurately describes some elements of the current debate around the costs and benefits of NEM, the Manual inappropriately and with no supporting evidence or analysis chooses a “winner” in that debate and concludes that NEM universally imposes costs on non-participating customers.

Following a high-level description of the NEM mechanism, the third paragraph begins: “NEM developed as a straightforward method for interconnection of very small distributed energy systems at a time when residential electric meters were analog systems designed to be read manually. While the high capital cost and operating expenses associated with multiple specialized interval-recording meters could be justified – and were required – for large industrial and commercial electric service customers, such costs would have been prohibitive for residential properties and would have overwhelmed any savings from self-generation.” This statement and the paragraph that follows overlook the fact that in California, NEM has been available for systems as large as 1 MW since 2001.⁴⁰ Additionally, 17 other state net metering programs allow systems sized up to 1 MW or higher.⁴¹

If the state had adopted net metering only as a means to serve small residential customers with analog meters, it could’ve adopted a different compensation method for large self-generating customers. In fact, California has developed other means of compensating industrial customers with fossil generation behind the meter, and NEM is not available to customers who use those fossil generators; it is offered only to generators that use renewable energy. Thus, it is fair to conclude that it is not simply the limitations of metrology that caused the state to adopt NEM, as the Manual asserts. Rather, the state has chosen to provide differential treatment for renewable generation due to the societal and public policy value those resources provide.

Following the discussion of the history of NEM, the Manual attempts to frame the current debate surrounding NEM. In particular, the Manual points out that the proponents of NEM argue that the distributed resources deployed by NEM customers create value for the utility that justifies compensation of exported energy with retail rate credits. The Manual then discusses three “complications” arising from NEM: The possibility that NEM might result in a negative

⁴⁰ “Update on Determining the Costs and Benefits of California’s Net Energy Metering Program as Required by Assembly Bill 58,” California Public Utilities Commission. March 29, 2005
http://docs.cpuc.ca.gov/WORD_PDF/REPORT/45133.PDF

⁴¹ DSIRE Database, North Carolina Clean Energy Technology Center, www.dsireusa.org (see CT, DC, DE, FL, IL, IN, MA, MN, NH, NY, NC, OR, PA, RI, SC, UT, VA)

consumption for the month carried over in a credit; the failure of NEM to account for the difference in value between cost of service and value of kWh; and failure of NEM to account for time or locational differences in costs or value of energy.

The first “complication” listed in the Manual is not really a complication but rather just a feature of the NEM compensation formula (**page 42**). The second “complication” is a fairly accurate description of the debate around NEM: While NEM proponents argue that renewable distributed resources produce value to the utility and society that justifies compensation at or above the retail rate, detractors assert NEM customers are compensated at a higher value than their systems provide.

Unfortunately, this debate cannot be solved through conjecture or rhetoric, largely because the answer will be different in different utility territories. For example, in service territories with competitive wholesale energy markets and thin reserve margins, high market clearing prices during summer afternoons could easily justify payment of the retail rate for electric generation during that time that reduces the market clearing price or avoids the need to run expensive and inefficient generation. Moreover, there are many instances where it will be less expensive for the utility to meet long-term capacity expansion needs through customer self-generation (supplemented by wholesale market purchases where necessary or appropriate) than through new infrastructure investment.

Thus, the only way to settle the debate about whether NEM customers are being compensated appropriately or not is to conduct a comprehensive cost-benefit analysis. NARUC could help foster that process by helping to develop a standard set of costs and benefits for net metering analysis. We would note, however, that the Manual has correctly identified NEM as the “simplest and least-costly method to implement a compensation methodology for DER.” Thus, if a cost-benefit study finds that costs are greater than benefits, the appropriate response would be to maintain the basic NEM structure but reduce the value of compensation – for example through minimum bill, time-of-use rates, or subtractions from NEM credits.

The Manual also cites as a “complication” the fact that NEM does not account for time or locational differences in costs or value of energy. While it is not necessarily true that NEM does not account for time differences – since NEM can be used in conjunction with time-of-use rates (e.g. NEM 2.0 in California) – the Manual is correct that NEM does not account for locational differences in the value of energy. However, since NEM-generated electricity is generally both produced and consumed within the distribution network, it is likely that NEM’s locational value is generally *higher* than remote-generated electricity.

As distributed energy grows in scale and customer adoption, it makes sense for utilities to direct those resources in locations where they provide the most value, potentially by offering

differential tariffs in different locations or by contracting directly with DER providers. This is precisely what California has done in its “Distribution Resource Planning” (DRP) proceeding, which requires utilities to create distribution resource plans to “identify optimal locations for the deployment of distributed resources.”

In tandem with the DRP proceeding, California has also instituted an “Integration of Distributed Energy Resources” (IDER) proceeding intended to identify and create customer incentives and other compensation mechanisms to direct distributed resources to the locations where they provide the most value. Because DERs’ value in part derives from the deferral of utility capital investments, however, it may be necessary for regulators to address utility incentives to deploy utility-owned infrastructure, rather than customer-sited resources as a means to meet distribution and transmission infrastructure needs. It is for this reason that CPUC Commissioner Florio introduced a ruling in the IDER proceeding proposing a means for utility shareholders to earn revenue from customer-sited distributed resources that defer potential infrastructure investments.⁴²

Following the discussion of the debate around the potential costs and benefits of NEM, the Manual again makes a number of statements that are not substantiated. The Manual claims that sending energy back to the grid increases the cost to operate the system, but it does not provide any evidence to support this claim or any explanation of what causes this supposed cost increase.

In fact, contrary to the claim that solar imposes a cost on the grid operator, California’s grid operator – the California Independent System Operator – has said in a number of instances that solar power reduces the cost to operate the grid. For example, at a workshop on California’s response to the drought of 2015, a representative of the CAISO specifically credited solar generators with helping the state deal with low hydroelectric conditions by helping meet the need for power during the summer without resorting to expensive and dirty “peaker” plants.⁴³ Moreover, PG&E recently credited a combination of DERs – rooftop solar and energy efficiency – with avoiding the need to make \$196 million in transmission investments in the CAISO’s most recent transmission plan.⁴⁴ In addition, Rochester Gas & Electric in New York is seeking to reduce peak loading on individual transformer banks through the use of DERs, which would save \$11.8 million in substation upgrades.⁴⁵

⁴² “Assigned Commissioner’s Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment,” April 4, 2016. <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF>

⁴³ “Overview of California’s Current Drought and its Effect on the Energy System,” presented by Dede Subatki of the California ISO on August 28, 2015.

⁴⁴ Cal-ISO Board Approves Annual Transmission Plan.” California Energy Markets, April 1, 2016.

⁴⁵ “New York utility turns to DERs to avoid \$11.8M substation upgrade,” Robert Walton, Utility Dive (July 2016), available at <http://www.utilitydive.com/news/new-york-utility-turns-to-ders-to-avoid-118m-substation-upgrade/422599/>

Statements asserting that NEM increases costs for the grid operator without any supporting evidence – and despite significant evidence to the contrary – constitute poor analysis and potential bias on the part of NARUC staff. Those statements should be removed from the NARUC Manual (**pages 43-44**).

Likewise, NARUC should strike the statement in the same paragraph (**page 44**) that claims: “by overcompensating the NEM participants through their avoidance of kWh charges, NEM necessarily is imposing these avoided costs on the nonparticipants.” Again, this statement is not supported by any analysis. It is critical that regulators use fact-specific analyses rather than rely on such generalizations. There is in fact a large body of evidence supporting the opposite conclusion: NEM provides more benefit to nonparticipating customers than it costs under numerous circumstances. For example, the Brookings Institution recently examined studies of the costs and benefits of net metering from government agencies and academia and found that “net metering is more often than not a net benefit to the grid and all customers.”⁴⁶

The second to last paragraph in the NEM section offers a great example of why the NARUC Manual should advocate for a study of costs and benefits, rather than simply concluding that costs always outweigh benefits. That paragraph presents a hypothetical situation in which there is so much solar energy coming onto the grid that the grid operator must lower the service of dispatchable power plants to minimum load, and then ramp the plants up quickly again as solar power wanes. While this hypothetical situation is certainly possible in states with very high concentrations of solar PV, most states are not in that situation.

In fact, many states may experience the opposite situation – they have very little solar generation and face a need to build new generating resource to meet peak load. In this situation, solar would actually save customers money by avoiding the need to build or contract with those peaking resources. In fact, even in California, the state with some of the highest rooftop solar PV concentrations in the country, rooftop solar was saving customers money through avoided need to contract with peaker plants as recently as 2016.⁴⁷

Because net metering *could* create a net cost for the grid in some situations – and clearly creates a net benefit in others – the correct recommendation for the NARUC Manual is for each jurisdiction to study the costs and benefits and consider its long-term resources needs before deciding on policy for DER compensation. To say that that rooftop solar under net metering creates a net cost for utility customers in any and all situations is simply not true, and statements to that effect should not be included in the Manual.

⁴⁶ The Brookings Institute: “Rooftop solar: Net metering is a net benefit,” by Mark Muro and Devashree Saha. May 23, 2016. <http://www.brookings.edu/research/papers/2016/05/23-rooftop-solar-net-metering-muro-saha>

⁴⁷ “Rooftop Solar Helps Push Dirty Gas Plant off Financial Life Support,” by Matt Vespa. Sierra Club. June 12, 2016. <http://www.sierraclub.org/planet/2016/06/rooftop-solar-helps-push-dirty-gas-plant-financial-life-support>

The section on net metering concludes with a paragraph (**page 44**) that asserts that NEM does little to encourage customers to use less electric service overall. Again, this assertion is not correct and should not be included in the NARUC Manual. While the paragraph correctly points out that under inclining block rates, customers have less incentive to conserve when they are in a lower tier, this statement is true regardless of whether or not the customer has solar PV and net metering. By contrast, a NEM customer on a flat rate would not see any reduced incentive to conserve compared with a non-NEM customer, unless the NEM customer had a system that was over-sized compared to usage – a situation that is usually prohibited under NEM. Moreover, under time-of-use rates, NEM customers would face the same financial incentives as non-NEM customers: they would seek to conserve during peak periods and shift usage to off-peak periods.

Value Methodology

The Value of Resource (VOR) and Value of Service sections (**page 45**) in the Manual describe eleven potential benefit/cost streams that should be considered when determining how to value a specific DER. We agree that these value streams are important, but we would also posit that this initial list is incomplete and should also include the following:

- **Voltage, Reactive Power, and Power Quality Support** – value of avoiding or reducing the cost required to maintain voltage and frequency within acceptable ranges for customer service
- **Conservation voltage reduction (CVR)** – The value of enabling CVR benefits by providing localized voltage support
- **Equipment life extension** – The value of extending the useful life and improving the efficiency of distribution infrastructure by reducing load and thermal stress on equipment
- **Reliability and resiliency** – The value of avoiding or reducing the impact of outages on customers
- **Market price effect** – The value of reducing the electric demand in the market, hence reducing the market clearing prices for all consumers of electricity

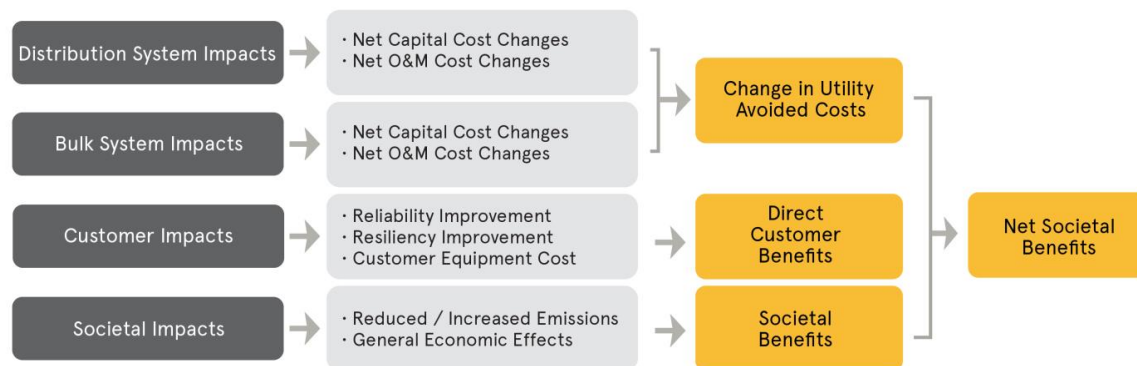
It is well understood that not all of the value streams identified in the Manual and above apply to all types of DERs and all locations, but all should be considered when determining the value of resources. With additional grid data provided by utilities (described in more detail below), these value streams can be more easily quantified for a specific or suite of DER solution(s).

Enhancing Traditional Cost/Benefit Analysis and Describing Benefits as Avoided Cost

A key component of cost/benefit analysis commonly used for valuing the benefits of DER is the avoided cost concept, which considers the benefits of a policy pathway by quantifying the reduction in costs that would otherwise be incurred in a business-as-usual trajectory. While

avoided cost calculations can be performed with varying scopes,⁴⁸ there is some degree of consensus on what the appropriate value categories are in a comprehensive avoided cost study. Groups like IREC⁴⁹ and EPRI⁵⁰ have attempted to take these standard valuation frameworks even further, describing general methods for valuing some of the benefit categories that are often excluded from traditional analyses.

EPRI Cost/Benefit Framework⁵¹



An example from New York

The NY PSC is currently undergoing a comprehensive process to both reform the utility business model and establish the value of distributed energy resources (DERs). This process, known as Reforming the Energy Vision, is meant to change the utilities' financial incentives in order to fully integrate DERs into distribution planning, relieve upward pressure on rates from lower energy consumption through new revenue sources, increase the efficiency of deployed capital, engage customers more on energy efficiency and DERs, and stimulate innovation in energy.

In order to adequately value DERs, the Commission first established the list of avoided costs associated with the bulk system, distribution system, reliability/resiliency, and externalities, and required consideration of both societal and rate-impact tests in decision making. This list is even more extensive than those listed above, including additional benefit and cost categories such as:

- Avoided water impacts
- Avoided land impacts

⁴⁸ "A Review of Solar PV Benefit and Cost Studies", L. Hansen and V. Lacy, RMI, 2013

http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue

⁴⁹ "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation", RMI for Interstate Renewable Energy Council (IREC), October 2013

www.irecusa.org/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

⁵⁰ "The Integrated Grid: A Benefit-Cost Framework", K. Forsten et al., EPRI, February 2015

⁵¹ Ibid.

- Non-energy benefits that relate to utility or grid operations, such as avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts
- Additional ancillary service costs
- Lost utility revenue
- Shareholder incentives
- Net non-energy costs such as indoor emissions and noise disturbances

Utilities were also required to establish detailed and individualized handbooks that would ultimately be used to describe the specific costs avoided through DERs. A collaborative was then formed to solicit proposals and discussion from all parties, resulting in the first joint proposal authored by some of the largest solar industry participants and all investor-owned utilities in New York. In all proposals submitted, parties recommended that an interim compensation mechanism be developed to continue growth of the DER industry in the state, target resources in high-value areas of the grid, and balance customer bill impacts. An interim mechanism will be adopted for implementation by January 2017, with continued work on more precise mechanisms ongoing through 2017.

Additional Avoided Cost Categories not included in the Manual

Voltage, Reactive Power, and Power Quality Support

Solar PV and battery energy storage with ‘smart’ or advanced inverters are capable of providing reactive power and voltage support, both at the bulk power and local distribution levels. At the bulk power level, smart inverters can provide reactive power support for steady-state and transient events, services traditionally supplied by large capacitor banks, dynamic reactive power support, and synchronous condensers.

At the distribution level, smart inverters can provide voltage regulation and improve customer power quality, functions that are traditionally handled by distribution equipment such as capacitors, voltage regulators, and load tap changers. While the provision of reactive power may come at the expense of real power output (e.g. such as power otherwise produced by a PV system), inverter headroom either exists or can readily be incorporated into new installations to provide this service without impacting real power output.

Most wholesale markets, including NYISO, PJM, ISO-NE, MISO, and CAISO, already compensate generators for capability to provide and provision of reactive power.⁵²

⁵² “Payment for Reactive Power”, Commission Staff Report AD14-7, Federal Energy Regulatory Commission, April 2014

Conservation Voltage Reduction

Smart inverters can enable greater savings from utility conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that reduces customer service voltages in order to achieve a corresponding reduction in energy consumption. CVR programs are often implemented system-wide or on large portions of a utility's distribution grid in order to conserve energy, save customers money on their energy bills, and reduce greenhouse gas emissions. CVR programs typically save up to 4% of energy consumption on any distribution circuit.⁵³ The utilization of smart inverters is estimated to yield another 1-3% of incremental energy consumption savings and greenhouse gas emissions reductions.

Equipment Life Extension

Either through local generation, load shifting, and/or energy efficiency, DERs reduce the net load at individual customer premises. A portfolio of optimized DERs dispersed across a distribution circuit in turn reduces the net load for all equipment along that distribution circuit. Distribution equipment, such as substation transformers, operating at reduced loading will experience less thermal stress and will therefore benefit from increased equipment life and higher operational efficiency.

The Manual notes that non-optimized DERs can be cited as having negative impact on equipment life by implying that “the lack of visibility into the current state of any DER and the lack of the ability to control the DER when it is exporting to the grid...give rise to many of the physical problems with incorporating DERs into the grid” (**page 27**). While highly variable generation and load can negatively impact equipment life – such as driving increased operations of line regulators – optimized and coordinated smart inverters mitigate this potential volatility impact on equipment life. Most DER providers are ready and willing to provide utilities enhanced operational insight and situational intelligence relating to their DER operations and dispatch, easily mitigating this perceived issue if the utility can appropriately make use of the data.

Resiliency and Reliability

DERs such as energy storage can provide backup power to critical loads, improving customer reliability during routine outages and resiliency during major outages. The rapidly growing penetration of batteries combined with PV deployments will reduce the frequency and duration

⁵³ “Evaluation of Conservation Voltage Reduction on a National Level”, Schneider, Fuller, Tuffner, and Singh, Pacific Northwest National Laboratory (PNNL) for the US Department of Energy (DOE), July 2010 http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf

of customer outages and provide sustained power for critical devices, as depicted in the adjacent figure.

Improved reliability and resiliency has been the goal of significant utility investments, including feeder reconductoring and distribution automation programs such as fault location, isolation, and service restoration (FLISR). Battery deployments throughout the distribution system can eventually reduce utility reliability and resiliency investments.

Market Price Effect

Wholesale electricity markets provide a competitive framework for electric supply to meet demand. In general, as electric demand increases, market prices increase. DERs can provide value by reducing the electric demand in the market, leading to a reduction in the market clearing price for all consumers of electricity. This effect was recently validated in the U.S. Supreme Court’s decision to uphold FERC Order 745, noting that operators accept demand response bids if and only if they bring down the wholesale rate down by displacing higher-priced generation. Notably, the court emphasized that “when this occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges.”⁵⁴ As a behind-the-meter resource, rooftop solar impacts wholesale markets in a similar way to demand response, effectively reducing demand and thus clearing prices for all resources during solar production hours.

Smart energy homes equipped with energy storage are able to achieve an even greater avoided cost than distributed solar alone. Storage devices that discharge in peak demand hours with high market clearing prices can take advantage of the stronger relationship between load and price at high loads.

The Costs of Distributed Energy Resources

As presented above, distributed resources offer significant customer benefits; however, these benefits are not available without incurring incremental costs to enable their deployment. In order to quantify the net societal benefit of DERs, these costs must be subtracted from the benefits. Costs for distributed energy resources include integration at the distribution and bulk system levels, utility program management, and customer equipment.

Societal net benefits calculations require a comprehensive consideration of costs that society bears as a result of attaining a specified penetration level, including the costs of administering

⁵⁴ Opinion of the U.S. Supreme Court, *FERC v. Electric Power Supply Association et al.*, January 2016, p. 16

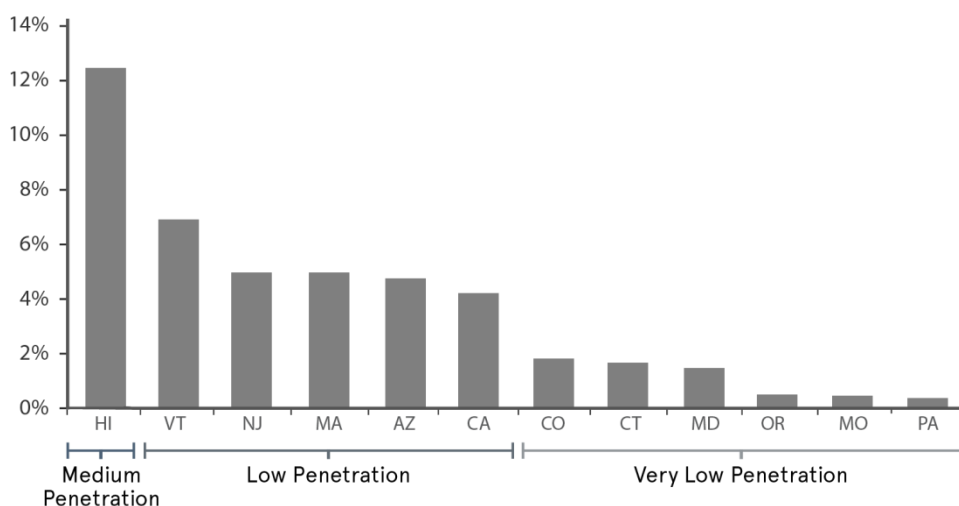
customer programs, grid integration costs needed to accommodate new assets, and the cost of the assets themselves, which are borne by customers.

Distribution Integration Costs

DERs are a critical new asset class being deployed on the distribution grid which must be proactively planned for and integrated with existing assets. At high penetrations, the integration process will sometimes require unavoidable additional investments. However, it is essential to separate incremental DER integration costs from *business-as-usual* utility investments. Recent utility funding requests for DER integration have included costs above those needed to successfully integrate DERs. This subsection will explore typical DER integration costs and evaluate the validity of each type.

While new DER integration rules of thumb and planning guidelines are emerging,⁵⁵ no established approach exists for identifying DER integration investments or estimating their cost. It is clear, however, that integration efforts and costs vary by DER penetration level. Generally, lower DER penetration requires fewer integration investments, while higher penetration may lead to increased investment. As depicted in the following chart, NEM PV penetration levels vary across the U.S.⁵⁶ Most states have *very low* (<5%) penetrations, while only Hawaii experiences *medium* (10-20%) penetration. California exhibits *low* (5-10%) penetration overall, although individual circuits may experience much higher penetration.

NEM Solar Capacity as a Percentage of Total System Peak



⁵⁵ “High-Penetration PV Integration Handbook for Distribution Engineers”, NREL, January 2016
<http://www.nrel.gov/docs/fy16osti/63114.pdf>

⁵⁶ U.S. Energy Information Agency (EIA), July 2015 preliminary data

In assessing these costs, proposed investments should be reviewed to determine whether it was a required incremental cost resulting from the integration of DERs. If so, it should indeed be included in the cost/benefit calculation. If the investment (or a portion thereof) was determined to be a component of utility *business as usual* operations, such investment was not included in the analysis.

Bulk System Integration Costs

Integration of variable resources with the bulk power grid is expected to result in an increase in variable operating costs associated with the way the generation fleet is used to accommodate the variability. To quantify this cost, we generally use \$/MWh values quantifying this cost for a relevant renewable portfolio standard (RPS) for the relevant state being evaluated.

Utility Program Management Costs

To estimate the incremental utility program costs associated with DER adoption, we generally include upfront installation and metering costs as well as incremental billing costs.

Customer Equipment Costs

The costs of DERs themselves must be considered, including the cost of equipment, labor, and financing.