



Edison Electric
INSTITUTE

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Senior Vice President, Energy Delivery and Chief Solutions Officer

September 2, 2016

The Honorable Travis Kavulla
President
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue, NW, Suite 200
Washington, D.C. 20005

Re: NARUC Draft Manual on Distributed Energy Resources Compensation

Dear President Kavulla:

The Edison Electric Institute (EEI) appreciates the opportunity to provide comments on the National Association of Regulatory Utility Commissioners' *Draft Manual on Distributed Energy Resources Compensation* (Manual). EEI applauds the work that has already been completed on the Manual and the opportunities provided for robust stakeholder feedback. EEI's comments on the Manual are attached.

If you have any questions or concerns, please contact Liz Stipnieks at ELStipnieks@eei.org or at 202-508-5566.

Again, thank you for the opportunity to comment, and EEI looks forward to the adoption of the final Manual in November.

Sincerely,

A handwritten signature in black ink, appearing to read "Philip D. Moeller". The signature is fluid and cursive, with the first name "Philip" and last name "Moeller" being the most prominent parts.

Philip D. Moeller

**COMMENTS OF THE EDISON ELECTRIC INSTITUTE ON
THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS’
DRAFT MANUAL ON DISTRIBUTED ENERGY RESOURCES COMPENSATION**

September 2, 2016

The Edison Electric Institute (EEI) appreciates the opportunity to provide comments on the National Association of Regulatory Utility Commissioners’ *Draft Manual on Distributed Energy Resources Compensation* (Manual). EEI is the trade association that represents all U.S. investor-owned electric companies, international affiliates, and industry associates worldwide. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With more than \$100 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Safe, reliable, affordable, and clean energy drives our economy and powers America. Importantly, EEI members own and operate the energy grid—the platform that is essential for the deployment and continued success of all distributed energy resources (DER).

EEI supports all DER, and our members endeavor to provide the types of services and options that our customers want; however, in order to do that, the right rate structures must be in place and must be fair to all of our customers. EEI appreciates NARUC expending the time, and clearly significant resources, to take a holistic look at the important issues around rate redesign and cost recovery associated with the ever growing deployment of DER, including private rooftop solar, microgrids, storage, demand response, energy efficiency, and more. EEI applauds the work that has already been completed on the Draft Manual and the opportunities provided for robust stakeholder feedback. When finalized in November, the Manual should provide a comprehensive information resource for the state commissions as they look to redesign rates to more appropriately reflect the realities of the growth of DER and the importance of the grid in achieving those goals.

To that end, these comments are divided into three key areas targeted at providing information to better inform the Manual. The first part focuses on the importance of state utility commissions reviewing and redesigning rates now to facilitate the efficient deployment of all DER moving forward. The second part addresses the value of the grid to all customers, including DER

customers, and the importance of recovering the fixed costs associated with it. Finally, the third part will focus on a number of different rate design options, providing examples and additional explanation to help the final Manual provide a fair and balanced view of all of the various rate design options.

I. In Order To Facilitate The Continued Growth Of All DER Technologies, The Time To Reconsider Rate Designs Is Now.

For over a century, electric power companies have efficiently delivered reliable and safe energy twenty four hours per day, seven days per week, three hundred sixty five days per year from central station generators to homes and businesses across the country. Today, a profound transformation is underway across the United States as the way energy is produced and used is changing due to evolutions in technology and customer demands. The electric power industry is adapting to these changes by transitioning to cleaner generation sources and leading the way on renewables and next generation nuclear power. We also are building smarter energy infrastructure with investments that are making the power grid more dynamic and adjusting the system to accommodate two-way power flows at the distribution level to be more responsive to our customers' needs.

At the center of this great change is the distribution grid itself, which is transforming to meet the expectations and new demands that customers have regarding electricity use. Investor-owned electric power companies are investing more than \$100 billion each year to build a smarter energy infrastructure and to transition to even cleaner generation sources. This smarter infrastructure is needed to enable the integration of DER of all types (private rooftop solar, microgrids, storage, energy efficiency, and demand response) as well as other devices and new technologies in homes and businesses. As new technologies increasingly enable energy personalization, many customers want more flexibility and want to be more engaged in managing their energy use. Electric power companies are changing the way services are provided to enable our customers to individualize them. For example, large commercial customers increasingly want renewable energy to meet their corporate sustainability goals. Cities and towns are requesting customized services, such as help with microgrids, smart city services, or renewable energy. Some residential customers choose to install private, rooftop

solar and storage to generate and store their own energy. And, residential customers increasingly want to manage their energy use using connected devices like iPhones and Nest Learning Thermostats and through web-based platforms.

As we continue to move forward into this new energy future, it is more important than ever for the regulatory paradigm to keep pace. The finalization of this Manual in November represents an important step towards achieving that goal. Commissions across the country are well positioned to address the issues related to the increased deployment of DER, and should not wait for higher penetrations in their particular jurisdiction—as currently suggested in the Manual.¹ Under high DER penetration conditions, as seen in states like Arizona, Hawaii, and California, regulators are not just dealing with the challenges of a rate redesign, but also with the problems of substantial cost shifting and increased customer confusion and dissatisfaction.² These challenges can be mitigated or avoided by addressing rate design for DER now.

EEI applauds the Manual on its clear recognition of the well documented issues surrounding the cost shift associated with the status quo of net energy metering (NEM). NEM is a non-cost based relic of a time when meters could only track inflow and outflow and DER private rooftop solar was an expensive fledgling technology. Fast forward to today, and the picture is very different. We have the continued deployment of digital smart meters—nearly 65 million have been installed in close to half of all U.S. households to date—and increased deployment of power grid sensors is providing increased visibility at the sub-feeder level, allowing for more granular operational capabilities. Today’s very capable advanced metering systems can enable more precise, accurate, and equitable rate designs that could not even be considered a decade

¹ See Manual at 60.

² See Energy+Environmental Economics (E3), *Nevada Net Energy Metering Impacts Evaluation* (July 2014), http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf; see also, E3, *Updated Nevada Net Energy Metering Impacts Evaluation* (Aug. 2016), http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14179.pdf; see also, E3, *California Net Metering Ratepayer Impacts Evaluation* (Oct. 28, 2013), <http://www.cpuc.ca.gov/General.aspx?id=8919>.

ago. Moreover, many DER technologies now are mature and widely deployed. Just this past May, the Solar Energy Industries Association (SEIA) announced that there are one million different solar installations nationwide that have been connected to this smarter energy grid by the electric power industry.³ This number is a huge achievement for all involved and a clear marker that it is time for a much needed rate transition.

In addition to the cost shift, the Manual should also take notice of some of the challenges that state commissions have faced when addressing DER, particularly private rooftop solar at high levels of penetration. One challenge in particular has been the substantial increase in customer confusion about a changing regulatory environment, which has resulted in spiked DER NEM and non-DER NEM customer dissatisfaction. This customer dissatisfaction has been a significant driver in the high profile, contentious proceedings that have played in the high penetration states of California, Hawaii, Nevada, and currently Arizona.⁴ Addressing the rate redesign as early in the process as possible, coupled with increased customer education from DER providers and energy companies alike, will provide increased certainty for a greater number of customers as they consider investments and go a long way to increased customers satisfaction.

In June, the President's Council of Economic Advisors issued a report on incorporating both renewables and DER technologies into the power grid, highlighting the need for states to refine rate structures across the country in a timely manner.⁵ The report concluded that the realization

³ SEIA, *Million Solar Strong*, <http://www.seia.org/campaign/million-solar-strong>.

⁴ The Nevada Public Utility Commission (PUC) in addressing this dissatisfaction stated that “[t]he lack of customer acceptance was compounded by the complete lack of information provided by the small-scale (rooftop) solar vendors (except Bombard) to potential solar customers that NEM rates may change pursuant to SB 374.” Public Utilities Commission of Nevada, Modified Final Order, *Application of Nevada Power Company d/b/a NV Energy for Approval of a Cost-of-Service Study and Net Metering Tariffs*, Docket Nos. 15-07041, 15-07042, (Feb. 17, 2016) at 116.

⁵ Executive Office of the President, Council of Economic Advisors, *Incorporating Renewables into the Electric Grid: Expanding Opportunities for Smart Markets and Energy Storage* (June 6, 2016)(CEA Report), https://www.whitehouse.gov/sites/default/files/page/files/20160616_cea_renewables_electricgrid.pdf.

of the potential benefits of DER requires new approaches to the pricing for electricity to create a “level playing field” that allows all DER to participate.⁶ The CEA Report also stressed that delay and uncertainty are bad for both innovation and technology development.⁷

In order to facilitate the continued growth and development of all DER technologies, the time to address the important issues around utility rate design is now. Because the successful incorporation of DER is critical to both our customers and the energy grid, EEI is focused on getting the right policies in place to support both. To that end, EEI urges NARUC to complete its Manual on schedule as it will provide an important tool for economic regulators as they work through the issues surrounding the adoption of more modern rate designs to efficiently incorporate new distribution and DER technologies. Timely action is the best way to serve customer needs and state policy goals.

II. The Manual Should Promote Investment In The Energy Grid Linked With Appropriately Designed Cost Recovery Mechanisms To Accelerate The Integration Of Current And Future Technologies.

A. The Grid Is The Enabling Platform For All Technologies, Including DER.

Investor-owned electric power companies are investing over \$20 billion each year on distribution systems to build smarter energy infrastructure, transitioning to even cleaner generation sources, improving efficiency, control, and resiliency, and to enable the evolving connection and interaction with the “Internet of Things”—every device with an IP address.⁸ This smarter infrastructure is essential to enable the reliable and efficient integration of new DER, as well as other devices and new technologies in homes and businesses. Customers who install and use these new technologies will continue to use the grid, but in new ways. As the grid interacts with an increased number of DER devices and technologies, the technical complexity of grid operations will increase, while operational efficiency may decrease. To address these

⁶ *See id.* at 34

⁷ *See id.* at 6.

⁸ EEI Finance Department, company reports (Sept. 2015).

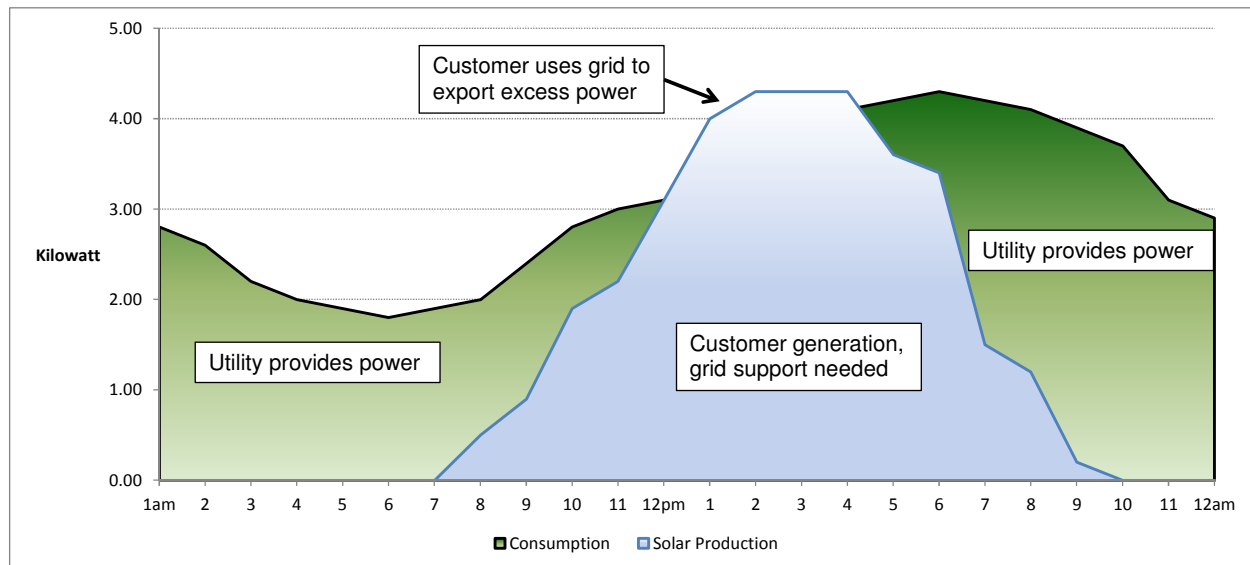
complexities and harness potential efficiencies, electric power companies are working to add more intelligent devices at the energy grid's edge. But for the grid to continue to evolve to provide the services that customers want, and to integrate an increasing number of "things," all customers who use the grid, both those with and without these new technologies, will need to continue to share in the cost of maintaining and operating it. Because many distribution grid services are not directly related to the amount of electricity a customer purchases, this will entail moving toward rates that appropriately compensate the smart grid for all of the *services* it provides, rather than rates so heavily dependent simply on throughput.

At the same time, it should be noted that regulated electric power companies have an obligation to serve *all* customers in their service territory—including customers that have on-site electric generation and use the grid for backup service and to sell excess power back to the grid. To meet this obligation, electric power companies must: (1) plan and build generation facilities or acquire generation supply in the market; and (2) plan and build the infrastructure required to reliably connect these generation facilities with customer loads to supply 100 percent of the peak electricity needs of customers (e.g., transmission and distribution lines, substations, transformers and meters). This means that, unlike non-regulated third party service providers, electric power companies are not free to serve only those customers who are convenient or profitable. Policies aimed at meeting increasingly diverse customer needs and interests must recognize this obligation to serve all customers. So long as the electric power grid is made available to all customers that desire service, the costs of building and maintaining that grid must be recovered from all customers.

The grid is the enabling platform that allows central station generation, DER, and emerging technologies to work together. However, the centralized electrical system underpinned by the grid is necessary to reliably meet customer needs. The grid currently provides critical services such as access to generation capacity for back-up and replacement power for when the sun does not shine, the wind does not blow, or there is simply not enough DER to meet demand and provide grid stability. As illustrated by the graph in Figure 1, customers with private rooftop solar systems use the grid 24/7 to provide power when their systems does not generate enough

electricity, when rooftop solar systems generates excess power that is exported, and to balance supply and demand every minute of the day.

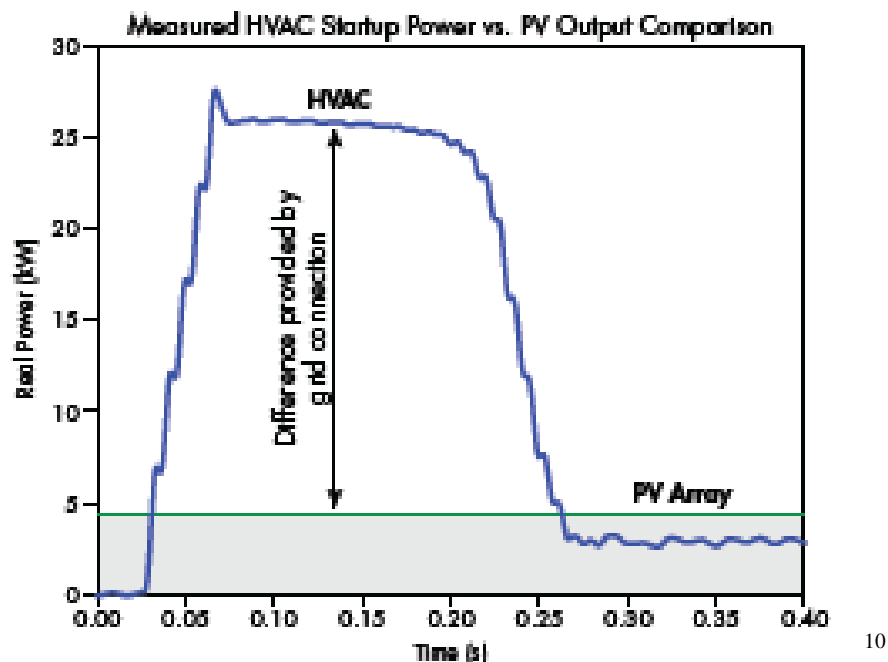
Figure 1. Typical Energy Production and Consumption for a Small Customer With Private Rooftop Solar⁹



⁹ Innovation, Electricity, Efficiency (IEE), *Value of the Grid to DG Customers*, IEE Issue Brief September 2013, Updated October 2013, http://www.edisonfoundation.net/iei/Documents/IEE_ValueofGridtoDGCcustomers_Sept2013.pdf. IEE is now referred to as the Institute for Electric Innovation (IEI).

As the chart in Figure 2 demonstrates, even when a customer's DER system is producing enough power to meet the current energy demands, the simple start-up of a residential HVAC system, which requires a short jolt of power from the grid that can be as much as 5 times the rated output of the average DER system, must come from the grid. Unless coupled with battery storage or significantly over-sized inverters, these transient power needs would cause most systems to trip without the grid to back them up.

Figure 2. HVAC Start Up Power

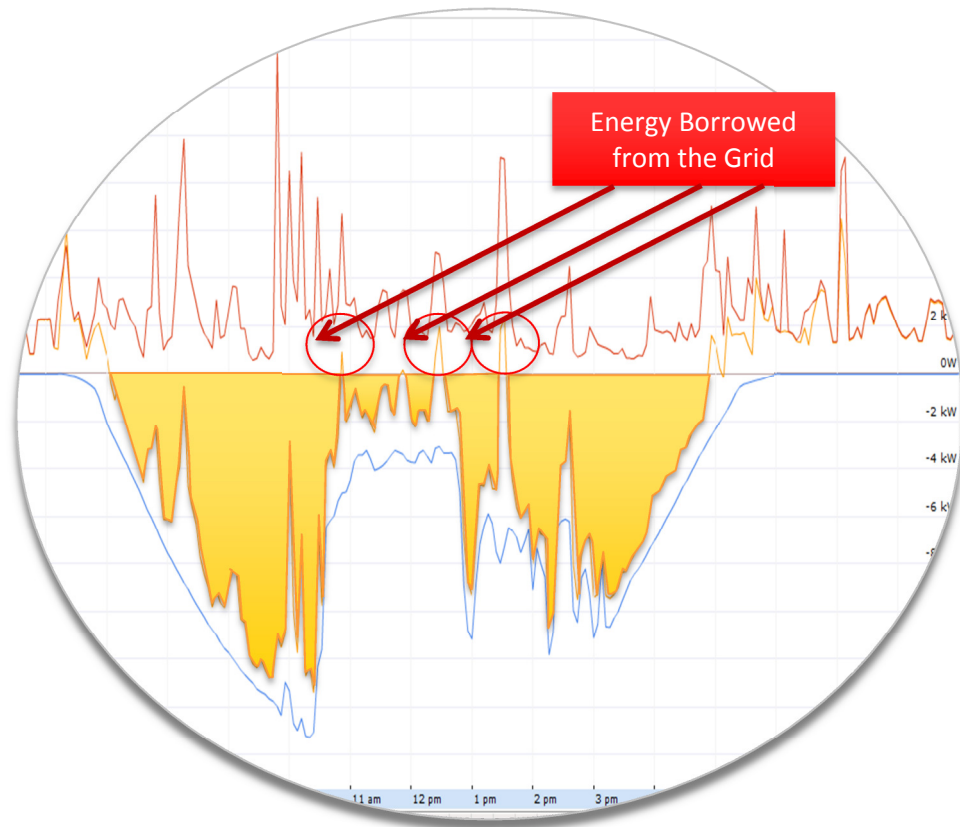


In fact, when broken down even further, the second-by-second data paints an even clearer picture. The graphic below, Figure 3, tracks an Exelon customer's 19kW private residential solar system throughout the day. While this larger residential system produces more energy than needed by the customer much of the time when the sun is out, as evidenced by the graphic, there are a number of times during the day (morning and evening, during cloud shear, or during high

¹⁰ EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, (2014), at 18, <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733&Mode=download>.

premise loading) that still require power being supplied by the grid. For average sized systems (~5KW), more grid power would be required more often.

Figure 3. Tracking Residential Private Solar Activity Throughout the Day



B. The Manual Should Maintain Defined Terms As Generally Understood And Used In A Rate-making Context.

As rate mechanisms evolve, it is important to use terms of art accurately and consistently. For example, the Manual, as well as the discussion during the town hall meeting held on July 22, 2016, included assertions that all costs are variable over time, and that theoretically, the long run and short run marginal cost are equal. While this is may be sound economic theory, specifically

within the theory of perfect competition,¹¹ it simply does not apply to the concept and practice of rate design, and it does not apply to industries with regulated, large fixed network cost investments with 40-year asset lives (i.e., transmission and distribution) that are not acquired “just in time,” but require years to plan, design, and install, and are driven in part by an effort to capture long-term economies of scale (often described as “lumpiness”).¹² Rate making is based on a snapshot in time, called a test year, and the recovery of the costs associated with providing service in that test year. Once the test year is established, the costs associated with that year are fixed. Moreover, the exercise of delineating between the short-run and long-run for the identification of variable costs can be very misleading. It is simply not reflective of the imperfect market that is reality, where investments are “lumpy” and cost recovery is deliberately spread over many years.¹³ Therefore, the Manual should continue to use the standard definitions of “fixed” and “variable” costs in the rate-making context to appropriately reflect costs that must be incurred by load serving entities to provide service to all customers and costs that vary based on customer consumption.

¹¹ A perfectly competitive market is a hypothetical market where competition is at its greatest possible level. It is generally understood to be an unrealistic hypothetical and not indicative of any specific market, and certainly not of the electricity markets. *See generally*, Economics Online, Perfect Competition, http://www.economicsonline.co.uk/Business_economics/Perfect_competition.html.

¹² If applying marginal cost theory to the pricing of DER, it is critical that we unbundle, at least for purposes of calculating marginal costs, generation, transmission, and distribution, and, in regard to generation, unbundle it into capacity and energy. Doing so would avoid confusing the costs that are being incurred with the basis upon which they are being incurred.

¹³ Costs must be subject to discipline, which can be provided by either markets/market mechanisms or cost-based regulation. This discipline assures not only value to consumers, but also enables more efficient price signals. For rate discipline purposes, regulators may want to watch for trends in pricing outcomes. For example, the declining costs of solar panels, which have been quite substantial in recent years, is reflected quite well in large scale solar prices, but much less so in the net metered prices of distributed solar. Such discrepancies could serve as a “canary in the mine” warning to regulators that the current pricing structure is not efficient.

C. Rate Designs Must Be Updated To Properly Fund Infrastructure, Which Is the Enabling Platform For Our Energy Future.

Updating rate designs is critical because legacy rate designs expose customers to increasing cost-shifts due to new DER technologies that break the traditional one-to-one association between the purchase of electricity and the use of the energy grid. For a host of reasons, including technology limitations and policy considerations, residential retail rates historically have been designed to recover the overwhelming majority of the total costs of service—primarily driven by infrastructure needs—on the basis of energy consumption, with most (typically over half) of the fixed costs and capacity-related costs rolled into that volumetric charge. This approach does not work when a customer’s use of the grid is separated from the amount of electricity the customer purchases. Rate designs that reduce the use of volumetric (kWh) charges for recovering fixed costs are needed to ensure that infrastructure costs are equitably shared across all customers that use and rely on the grid.¹⁴ In addition, NEM policies need to be revised so that customers with private rooftop solar pay their equitable share of grid costs and are credited appropriately for the excess energy that they provide to the grid.

As discussed above, in order to serve all customers, a utility has to make investments in infrastructure related to generation (directly or indirectly), transmission, distribution, and metering and customer services (such as billing and customer inquiry). Generation costs consist of capacity costs and energy costs. Generation capacity costs are a function of peak demand. Capacity investments tend to be cost intensive, and have long asset lives and capital payback structures. Generation energy costs, which for purposes of this discussion, are not considered infrastructure costs, are generally a function of electricity consumption and fuel costs, and will vary from hour to hour depending on the mix of generation sources. Distribution and transmission costs are also generally a function of peak demand as well as where resources and customers are located—the system must be built to meet maximum system demand in order to maintain reliability and serve all of its customers. Distribution and some transmission networks

¹⁴ For additional information on rate design, refer to the EEI *Primer on Rate Design for Residential Distributed Generation* (Feb. 2016), <http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf>.

are generally sized to meet peak demand at the locational level while the transmission system and generation capacity are sized to meet system peak demand. The costs of metering and customer services vary with the number and type of customers and are considered a fixed cost for each customer. As more and more DER are added, the distribution system must be equipped to enable and connect these resources. Although the increased energy produced by DER might impact future needs for generation, the role of the distribution system becomes more critical and more complex and thus can impose significant technical, economic and business challenges on utility operations. In fact, in areas with large concentrations of DER, additional investment in the distribution grid is also required.

Figure 4. The Mismatch between Energy Costs and Energy Pricing: An Illustrative Example from a Representative Investor Owned Utility

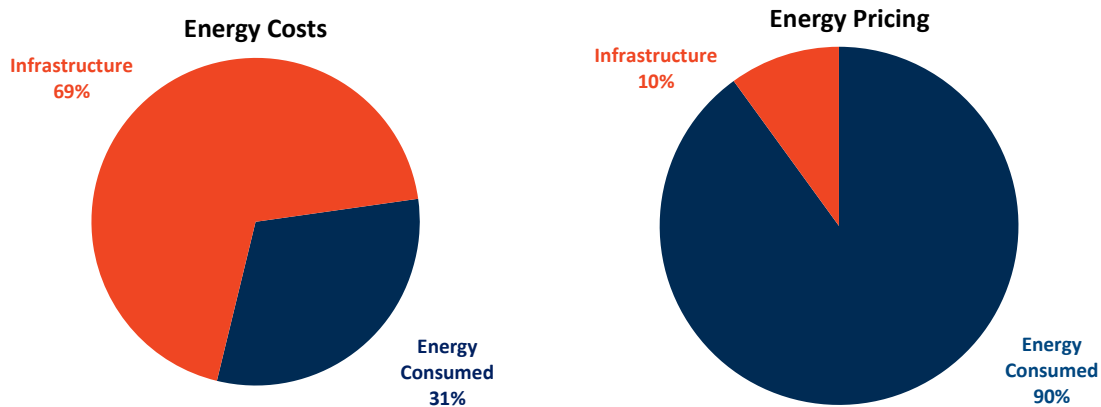


Figure 4: The Mismatch between Energy Costs and Energy Pricing: An Illustrative Example from a Representative Investor Owned Utility shows the difference between the calculated costs of serving a residential customer compared to the way that these costs are recovered by the utility. It is clear that even though only a fraction of the calculated costs vary with energy consumption, almost the entire amount of revenue is collected based on variable energy consumption charges (\$/kWh). With the recent increases in the amount of DER installed in most jurisdictions across the U.S., this volumetric rate structure, which is not cost-reflective, is increasingly failing to meet the objectives of good rate design. This failure is exacerbated by the utilization of NEM.¹⁵

The fundamental regulatory principle of assigning costs to cost causers is ever more important as customers have new opportunities to generate and store electricity. When rate structures are not reflective of the cost structure and cost causation, customers receive price signals that lead them to behave in inefficient and costly ways, which result in a misallocation of resources. The most straightforward approach to cost-based rate design for distribution or grid services is to support rate design with cost causation by properly aligning the fixed and variable price signals sent by

¹⁵ EEI, *Primer on Rate Design for Residential Distributed Generation* (Feb. 2016), <http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf>.

delivery rates with the fixed and variable costs imposed by customers' demand of the delivery system.

Today's fixed charges (discussed in more detail in the next section) are far below utilities' cost of providing grid services, which, as previously discussed, include transmission, distribution, generation capacity, and ancillary and balancing services. Yet, the public does not understand this distinction because we—utilities, regulators and other stakeholders—have made electricity pricing far from transparent. Educating customers about what they are paying for when they purchase electricity—both grid services and energy—is critically important.

III. The Inclusion And Balanced Explanation Of A Variety Of Rate Options Is An Important Aspect Of The Manual.

As the Manual correctly concludes, there are a number of potential rate design options that state commissions can consider to ensure that the grid is funded equitably by all customers who use it. EEI applauds the Staff Subcommittee for their work in pulling together this compendium of rate options. In support of that effort, and in specific response to the requests made during the Town Hall meeting, the following provides additional information and examples to help supplement the discussion of a number of those rate options: fixed charges, grid access charges, demand charges, net energy metering, separate rate class, revenue decoupling, minimum bills, and value of solar.

A. Additional Discussion For Consideration In The Fixed Charges Section Of The Manual.

As discussed in the Manual, the most straightforward approach to cost-based rate design for grid services is to properly align the fixed and variable costs of providing those grid services to customers.¹⁶ A recent Nevada PUC order expressed this same principle: “The simplest way to develop an equitable pricing structure is to adopt prices that mirror the cost structure. Specifically, the fixed costs should be collected through fixed charges and costs which vary with

¹⁶ See Manual at 54.

consumption should be collected through volumetric charges.”¹⁷ In other words, fixed and variable charges should be commensurate with the fixed and variable costs of serving each customer or customer class. For example, a typical residential electricity customer consumes, on average, about 1,000 kWh per month and pays an average monthly bill of about \$110.¹⁸ About half of that bill (i.e., \$60 per month) represents the costs related to the non-energy services provided by the power grid. Yet today, the highest fixed charge on a residential monthly electric utility bill is about \$25 per month, and the average fixed charge is about \$10 per month.¹⁹ The discussion in the Manual should be expanded to recognize this disparity between current fixed costs and fixed charges.

B. The Manual Should Include A Discussion Of Grid Access Charges.

What is not discussed in the Manual under the fixed charge discussion is the potential utilization of a grid access charge (in addition to a customer charge) to cover basic distribution grid costs from all residential customers. In Ontario, the Ontario Energy Board (OEB) approved a residential rate design policy under which all distribution service costs are recovered through a fixed monthly charge. This charge is currently being implemented over four years, with gradual increases in the fixed charge to cover 100 percent of the distribution grid costs.²⁰ Fair billing, grid innovation and enabling customer uptake of new technologies are among the OEB’s objectives for this change.

¹⁷ Nevada Order at 146. Pricing structures with three parts—monthly fixed charges, charges based on demand, and volumetric charges—most closely mirror the cost structure of electric energy companies. *See id.*

¹⁸ *See IEI, supra*, n.9 at 3-4.

¹⁹ Lisa Wood, *et al.*, *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Lawrence Berkeley National Laboratory (June 2016), https://emp.lbl.gov/sites/all/files/lbnl-1005742_1.pdf.

²⁰ Ontario Energy Board, EB-2012-0410, Board Policy, *A New Distribution Rate Design for Residential Electricity Customers* (Apr. 2, 2015), http://www.ontarioenergyboard.ca/oeb/Documents/EB-2012-0410/OEB_Distribution_Rate_Design_Policy_20150402.pdf.

Similarly, the Nevada PUC has made gradual steps that better align prices with the cost structure. In 2013, consistent with its policy of gradually establishing a cost-based energy delivery charge, the Nevada commission established, for residential customers located in northern Nevada, a \$15.25 monthly service charge designed to reflect 100 percent of components of the energy grid located closest to the customer.²¹ Recognizing that additional progress needs to be made, in 2014, the PUC increased the basic service charge for residential customers in southern Nevada and provided direction to Nevada's energy companies to develop energy deliver charges that reflect 100 percent of distribution grid costs.²²

C. The Demand Charge Section Of The Manual Should Provide The Same Balanced Discussion As The Other Rate Options Sections.

The Manual also includes an excellent discussion of demand charges and the various alternatives associated with that type of charge; however, unlike the discussion of other rate options, it includes a somewhat negative editorial indicating that data surrounding demand charges is limited and recommending that regulators proceed with caution.²³ In reality, demand charges have been used for commercial and industrial (C&I) customers for decades, related to both distribution and power supply related costs without controversy. With the deployment of advanced metering infrastructure (AMI or smart meters) to more than half of all U.S. households, demand charges are now feasible for many residential customers. Typically, demand charges result in an allocation of distribution costs based on the facilities required to meet each customer's peak demand during a specific period of time (e.g., one month). Several utilities have successfully offered optional demand charges for residential customers.

Demand charges also have many positive attributes that should be included in any discussion:

²¹ Public Utilities Commission of Nevada, Modified Final Order, *Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto*, Docket Nos. 13-06002, 13-06003, and 13-06004, (Jan. 29, 2014) at 16.

²² Public Utilities Commission of Nevada, Final Order, *Petition of Sierra Pacific Power Company d/b/a Nevada Energy for cost recovery for the Advanced Service Delivery Project and Nevada Dynamic Pricing Trial pursuant to the Order Issued in Docket Nos. 13-06002, 13-06003, and 13-06004*, Docket No. 14-05005, (Nov. 20, 2014) at 14.

²³ See Manual at 53.

- Demand charges ensure that customers with a higher load factor will appropriately receive a lower bill. Under strictly volumetric rates, a customer with a large demand for kilowatts, but very low energy consumption pays very little compared to a customer with the same level of kilowatts demand but a commensurate level of kilowatt-hour energy consumption.
- Demand charges incentivize customers by providing a distinct price signal for demand response and energy efficiency, which allows customers to reduce their peak demand and their electricity bills. This ultimately reduces the costs of the entire electricity system because load factors increase across the system, and the need to build peaking plants is reduced.
- Demand charges can be designed to recover location system-specific grid costs since some portion will vary with peak demands on the system.
- Demand charges can be tailored to be revenue neutral, through a corresponding reduction in energy charges, for customers and for electric distribution companies.²⁴

Demand charges may also be an appropriate rate design structure for partial requirements tariffs, which are discussed in more detail in section III.F, below. This is because the amount of services provided by the grid would likely be related to the customer's maximum demand.

Demand charges could be time-differentiated specifically to encourage load shifting in response to daily solar energy production patterns.

The Manual suggests that there are “many unknowns and uncertainty surrounding the use of demand charges on classes other than C&I—mainly regarding customer impacts,” and then

²⁴ On a related note, the Manual states, “Lastly, demand charges, if a large portion of a customer's distribution bill, would over collect customer costs as demand costs.” Manual at 50. However, the simple fact that a demand charge is a “large” portion of a customer's distribution bill does not mean that there necessarily is an over-collection in the form of demand charges, as the statement asserts.

points to insufficient data about residential demand charges.²⁵ At the same time, it is also worth noting in the Manual that, while there may be some unknowns about residential demand charges, even greater are the unknowns of the impacts and implications of greater DER penetration.

Moreover, in the discussion of demand charges, there are references to the inability of customers to reduce demand, or at least the difficulty of doing so.²⁶ While there may be an initial challenge in educating customers, electricity demand is certainly subject to customer management.

Customers are “sophisticated enough to understand demand charges and can reduce their demand impacts in many ways, including” through the configuration and alignment of DER and private generation in a manner that more closely aligns generation with peak demand.²⁷ Residential customers will be able to leverage a plethora of new technologies emerging in the market that include automated demand management, making demand even easier to manage. In fact, Arizona Public Service (APS) studied the potential impacts of residential three-part demand rates on a customer’s monthly demand, on-peak and off-peak energy usage, and their monthly bill.²⁸ The study evaluated these impacts by looking at customers that switched from a two-part time-of-use energy rate to a three-part time-of-use demand rate. Each customer’s hourly load, monthly usage, and calculated bill were compared before and after switching to the demand rate. In that study, APS found that 60 percent of customers reduced their monthly demand 10.7 percent average reduction, 3.3 percent average reduction for all customers in the study group. In addition, 60 percent of customers also reduced their monthly energy consumption 8.5 percent on average, 2.4 percent average reduction for all customers. While 90 percent of customers saved on their bill 9 percent average reduction for all customers in study group, 15 percent for top 60

²⁵ Manual at 53.

²⁶ See Manual at 11, 50, and 53.

²⁷ Nevada Order at 147.

²⁸ Leland R. Snook and Meghan H. Grabel, *Dispelling the myths of residential rate reform: Why an evolving grid requires a modern approach to electricity pricing*, THE ENERGY LAW J. 29:3 (Apr. 2016) at 72-76.

percent of savers. Clearly, under the right circumstances, appropriately designed demand charges can provide a powerful and actionable price signal to customers.

It also appears that demand rates are criticized for reducing the return on investment (ROI) of the DER owner.²⁹ The manual has clearly identified NEM, as applied to energy charges, as causing a subsidy of grid related costs to the benefit of DER private rooftop solar customers. The removal of a subsidy will always reduce the ROI of the investment previously subsidized, but that does not seem to warrant criticism in the context of the discussion of rate designs intended to fairly compensate electric distribution service providers and all DER customers. Additionally, other types of DER providers and customers may benefit from the use of demand rates as it provides a distinct and more accurate price signal. DER service providers such as demand response aggregators, smart thermostat providers and others may be able to increase the value proposition to customers under such a rate design, increasing the customer ROI for these services. It also is unclear under what authority or mandate economic regulators consider the ROI for products provided by non-regulated entities (i.e., companies that are not public utilities subject to their jurisdiction).

D. Revenue De-Coupling Is A Valuable Tool In A Regulators Toolbox But Does Not Solve The Cost Shift Associated With Net Energy Metering.

The Manual appropriately includes a discussion of revenue decoupling. While inclusion of all rate options in the Manual is proper, it is important to note that non-cost-based approaches, like revenue decoupling, do not address the cost shift issue associated with rate structures (such as NEM) and do not reflect the full cost of grid services. Decoupling has worked well for energy efficiency, and over half the states in the United States have adopted decoupling or some type of lost revenue adjustment mechanism. Although revenue decoupling makes the utility whole in a more timely manner—as if it filed a rate case—this actually exacerbates the cost shift in the underlying rate structure as it reallocates the revenue shortfall to non-DER customers more quickly.

²⁹ See Manual at 53.

E. The Minimum Bill Option Should Not Be Considered A Substitute For Fixed Charges.

The discussion of a minimum bill mechanism omits two very important points.³⁰ First, it is important to recognize that a minimum bill has no effect on the underlying problems with a given utility rate structure to the extent that the minimum bill is not set at a level representative of a utilities fixed costs to serve that customer. For example, if an existing rate structure is based on volumetric rates, and a customer reduces their kWh usage (through DER or other means), as long as the total bill amount is still higher than such a minimum bill amount, the customer will not be paying their share of the grid services they are consuming. Consequently, distorted economic signals will exist, and system costs still must be covered by other customers, so significant cross subsidy issues may remain. Second, if a certain minimum bill amount is required to be charged to a customer in one rate period, but in a later rate period, the customer is credited for the difference that the customer would have saved if the minimum bill constraint were not in place, then the mechanism does nothing to alleviate rate structure issues and only really affects the timing of customer payments. As a result, while an option that should be included in the manual, minimum bills should not be considered as an alternative to fixed charges to better align costs with rates.

F. The Value of Resource Discussion Should Recognize That Electricity Is Priced Based On Cost, Not On Value.

If a “value based” methodology is to be considered in the Manual, it is important to remember that in a regulated environment, rates for distribution investment are set to recover costs from customers, not to capture the full value of delivering electricity. Utility regulators simply do not price commodities that are basic needs, like water or electricity, based on “value.” If they did, the price of power would be astronomical given that virtually every industry relies on electricity to create their own “value” and electricity providers would be entitled to claim a portion of that value, and be compensated accordingly.

³⁰ See Manual at 54.

Moreover, the “value of resource” discussion often includes an assessment of various externalities, like emission reductions as estimated by the social cost of carbon, or macro-economic development or job impacts, when defining the benefits of a particular resource to the grid. Not only are these assessments speculative, this approach has never been applied holistically to attribute the same kinds of benefits to other energy resources that provide similar benefits in terms of clean energy, jobs, etc. This dichotomy results in a distorted pricing system that is biased in favor of one resource to the detriment of competitive sources of power that can provide the same benefits, often at lower costs.³¹

Finally, if a “value-based” distribution methodology is adopted, it would need to be adjusted periodically in order to reflect increasing DER penetration levels, as their value is likely to change. In fact, “many observers have pointed out the expectation that as the penetration of DER (especially solar) increases, each additional increment of DER will have diminishing value to the system.”³²

To the extent that a value based approach is used, we believe that the following criteria should be applied:

- Benefits should be readily identifiable and quantifiable;
- Benefits should offset items that would otherwise be included as a recoverable cost in a utility’s revenue requirements; and
- Benefits should be cost-effective in comparison to alternative utility options.

³¹ Under some state programs, like California’s A.B. 32 and the Northeast’s Regional Greenhouse Gas Initiative, a carbon price is applied in a technology-neutral way that is independent of retail rates by requiring all emitting resources to buy allowances equal to their carbon emissions. The price of the allowances in each regime is a factor function of the number of allowances available, not the “value” of the reductions achieved.

³² Susan F. Tierney, Analysis Group, *The Value of “DER” to “D”: The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability*, (Mar. 30, 2016), n.48.
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf.

G. A Separate Rate Category May Be Appropriate For Customers With DER.

The Manual properly points out that, in many instances, it may be appropriate to consider creating a separate DER rate class as growth in DER and future adoption of new DER technologies diversify the characteristics of customer electricity supply and service requirements. Separate treatment of different classes of customers with differing service profiles has long been a way for regulators to provide more equitable treatment for all customers.

The way DER customers use the grid makes them unlike other residential customers and more like some commercial and industrial (C&I) customers, many of whom also self-supply some portion of their energy needs and use the grid to both receive power and export power. Retail electricity rates for C&I customers are designed differently, typically with energy and demand elements, so as better to address both the customers' needs and their use of the energy grid. Accordingly, a separate rate class for DER customers is an option that some state commissions may want to explore as they move to address DER compensation. If pursued, a separate rate class should be technology neutral and focused on how customers in the class use the grid. Creating a technology neutral rate class can address some of the issue raised in the Manual.³³ Specifically, concerns about customer use changes based on appliances, light bulbs, etc. become moot.

Separate tariffs should be considered for customers who choose to change the manner in which they use the grid (both consuming and injecting energy) and receive electric service by installing distributed generation for several reasons. First, there are likely significant differences in grid use, customer load characteristics, and cost of service between DER and non-DER customers that are not reflected under current rate structures. Second, separate would avoid the regulatory challenge of establishing demand charges and other tariff modifications for non-participant customers. Third, a separate tariff option could be designed to provide appropriate price signals to incentivize and reward DER for the benefits they may provide to the grid without impacting tariffs applicable to non-participant customers. Fourth, a separate tariff could more easily be

³³ See Manual at 29.

adjusted DER penetration increases without having to affect the rate or tariff structures of non-participants.

Finally, it is important to note that, generally speaking, all customers' rate structures, and not just the rate structure for a single separate customer class, should align the fixed and variable price signals sent by delivery rates with the fixed and variable costs imposed by customers' demands on the delivery system.

IV. Net Energy Metering At The Retail Rate Is Not The Least Cost Option When Factoring In The Cost Shifts To Other Customers.

In the discussion on NEM, the Manual states that NEM is the "least cost" option to administer, and that NEM provides a "value" of the energy that is sold back to the grid by a NEM customer.³⁴ As discussed below, the question becomes "least cost for whom?"

A. NEM Is Not A Sustainable DER Compensation Mechanism.

NEM is an unsustainable relic of a time when utilities had comparatively primitive meters, wholesale energy pricing was in its infancy, and generation markets were not as competitive as they are today. When NEM was implemented, it was an incentive to jump start the solar industry when there was negligible market penetration and prices for solar panels were high. Many NEM programs were capped specifically because they were seen as short-term enabling policies for a fledgling industry, not a permanent policy. It is clear that times have changed and many of these barriers have been addressed. It should follow then, that it is also time to re-evaluate rate structures.

To provide a balanced view of NEM as a compensation option for DER, the Manual should consider including the following points:

- NEM incents customers to significantly increase their "grid-footprint" in order to produce sufficient excess energy to achieve cumulative net zero grid electricity

³⁴ See Manual at 41.

supply, thereby creating technical and economic grid integration and operational challenges at higher penetration levels.

- NEM procures grid-supplied excess energy (wholesale energy) at retail prices, without regard to the wholesale market value of the exported energy. All energy, including that produced by solar, is fungible and can be procured competitively in wholesale market. A viable substitute is utility-scale solar generation, whose market prices are approximately 4¢/kWh today, substantially below retail rates.
- The real-time wholesale energy price could become negative during periods of excess solar generation, similar to what has occurred in some wholesale markets when there is an overabundance of variable resources such as wind generation and insufficient flexible generating resources.³⁵
- NEM pricing is not flexible and cannot adapt to changes over time in price of exported solar energy. At higher levels of distributed solar penetration, lower grid benefits and higher power system integration costs are inevitable outcomes. Notwithstanding this, NEM customers continue to receive full retail rate compensation for exported energy regardless of the solar penetration level.
- NEM does not allocate responsibility appropriately for applicable grid integration costs, which will become significant at higher penetration levels.
- NEM does not incent advanced grid-supportive functionality that modern DER systems may provide and is a barrier to the adoption of other types of DER technologies such as energy storage and smart inverters, which are increasingly valuable given the high costs of alternatives to mitigate grid integration challenges.

³⁵ EIA, *Negative wholesale electricity prices occur in RTOs*, <http://www.eia.gov/todayinenergy/detail.cfm?id=6730>.

- NEM does not compensate for the necessary investments in new technologies to protect the grid from cyber security risks.

B. The Manual Appropriately Recognizes The Inequitable Cost Shifts Associated With Net Energy Metering.

The Manual appropriately recognizes that the cost shifts associated with NEM are, in fact, real.³⁶ This finding has been continually supported by independent study after independent study.

For example, a report by Energy+Environmental Economics (E3) for the California Public Utilities Commission (CPUC) in 2013 showed that that NEM would “result in a cost shift of \$1.1 billion annually by 2020 from NEM to non-NEM customers if current NEM policies were not reformed in California.”^{37, 38} Similarly, in 2014, E3 performed a study for the Nevada PUC assessing the cost shift. This study found that NEM provided a \$36 million benefit to non-solar customers—if the costs of utility-scale, universal solar were \$100 per MWh. The study also found that this benefit turned into a cost shift of \$222 million from NEM to non-solar customers over the life of the assets if the costs of universal solar were \$80 per MWh. In 2016, these costs are closer to \$40 per MWh.³⁹ In fact, on August 17, 2016, E3 provided an updated study to the Nevada PUC, which once again confirmed the cost shift, at approximately \$36 million *per year*,

³⁶ See Manual at 31-32.

³⁷ Lisa V. Wood, *Why Net Metering Results in a Subsidy: The Elephant in the Room* (June 13, 2016), https://www.brookings.edu/opinions/why-net-energy-metering-results-in-a-subsidy-the-elephant-in-the-room/#_ftn1.

³⁸ E3, *California Net Metering Ratepayer Impacts Evaluation* (Oct. 28, 2013), at 6, <http://www.cpuc.ca.gov/General.aspx?id=8919>.

³⁹ In fact, what the E3 study provided was a sensitivity analysis, defining the cost shift relative to the costs of utility-scale solar projects. The lower the costs of utility-scale generation, the higher the cost shift from NEM to non-solar customers. See E3, *Nevada Net Energy Metering Impacts Evaluation* (July 2014), at 19, http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf.

associated with the previous Nevada NEM rate structure.⁴⁰ In fact, additional E3 research for Hawaii found that NEM customers receive net benefits while non-NEM customers incur net costs.⁴¹ In Arizona, a study by Navigant Consulting for APS found that customers with private solar are subsidized by those without it.⁴² In Vermont, a study by the state's Public Service Commission also found that a cost shift from NEM customers to non-NEM customers will persist through at least 2021.⁴³

There is also a deeper inequity taking place as a result of NEM. Multiple studies have found that NEM customers tend to be more affluent than non-NEM. All three of E3's state studies found income inequity between NEM and non-NEM customers. And, a report from Acadian Consulting Group for the Louisiana Public Service Commission (LPSC) found that NEM customers within the LPSC jurisdiction had median household incomes of \$60,460 relative to the statewide median household income level of only \$44,673.⁴⁴

⁴⁰ "Overall, for the state of Nevada, NEM generation is a costlier approach for encouraging renewable generation than utility-scale renewables. This is mainly due to utility-scale solar PPA prices having dropped precipitously in recent years, greatly lessening the costs avoid by NEM generation, while distributed solar costs have not dropped commensurately." See E3, *Updated Nevada Net Energy Metering Impacts Evaluation* (Aug. 2016), at 16, http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14179.pdf.

⁴¹ *Evaluation of Hawaii's Renewable Energy Policy and Procurement, Final Report* (Jan. 2014), <http://puc.hawaii.gov/wp-content/uploads/2013/04/HIPUC-Final-Report-January-2014-Revision.pdf>.

⁴² Lisa Frantzis, *Net Metering Bill Impacts and Distributed Energy Subsidies; Report prepared for APS* (Dec. 17, 2012), http://www.navigant.com/insights/library/energy/2012/net_metering_bill/.

⁴³ Vermont Public Service Department, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*, (Jan. 15, 2013), <http://www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf>.

⁴⁴ David I. Dismukes, *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers, Draft* (Feb. 27, 2015), <http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5>.

V. The Manual Should Include Additional Information On The Role of Integrated Distribution Planning.

Integrated distribution planning will increase in importance as DER penetration increases, as DER can impose significant technical, economic, and business challenges on utility operations as well as provide potential locational benefits. An integrated distribution planning methodology will enable a substation-by-substation, and circuit-by-circuit, analysis across a utility's service territory to inform whether there are significant differences in locational value that would need to be reflected in a DER compensation mechanism. The benefits of this approach is that it can incent DER to locate where it has the potential to provide the most valuable to the overall system and is agnostic to the DER technology type.

The distribution benefits to be identified in an integrated distribution planning process should: a) be based on sound distribution system engineering practices; b) be capable of being monetized; c) offset items that would otherwise be included as a recoverable cost in a utility's revenue requirements (excluding indirect benefits); and d) be cost-effective in comparison to alternative options.

VI. Conclusion

Again, EEI applauds NARUC for taking on this incredibly useful task and thanks NARUC for the opportunity to comment on the Manual. EEI urges NARUC to finalize and release the manual in November, and respectfully suggests that, as technology evolves and more information is learned through experience, the Manual be updated periodically.