

reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.³⁶

Commission Decisions Approving Higher Fixed Charges

Higher fixed charges have been rejected in numerous cases, but not all. In many cases, a small increase in the fixed charge has been approved through multi-party settlements, rather than addressed by the commission. Where commissions have specifically approved fixed charge increases, they often cite some of the flawed arguments that are addressed in Chapter 5 above. Below we provide some examples and briefly describe the commission's rationale.

Fixed Charges and Recovery of Distribution System Costs

Over the past few years, Wisconsin has approved some of the highest fixed charges in the country, based on the rationale that doing so will "prevent intra-class subsidies... provide appropriate price signals to ratepayers, and encourage efficient utility scale planning..."³⁷ This rationale is largely based on two misconceptions: (1) that short-run marginal costs provide an efficient price signal to ratepayers and will encourage efficient electric resource planning, and (2) that recovering certain distribution system costs through the fixed charge is more appropriate than recovering them through the energy charge.³⁸

As discussed above, a rate design that fails to reflect long-run marginal costs will result in inefficient price signals to customers and ultimately result in the need to make more electric system investments to support growing demand than would otherwise be the case. Not only will growing demand result in the need for additional generation capacity, it may cause distribution system components to wear out faster, or to be replaced with larger components. Wrapping such costs up in the fixed charge sends the signal to customers that these costs are unavoidable, when in fact future investment decisions are in part determined by the level of system use.

Further, using the fixed charge to recover distribution system costs that cannot be readily classified as "demand-related" or "customer-related" exemplifies the danger that Bonbright warned of regarding using the category of customer costs as a "dumping ground" for costs that do not fit in the other

³⁶ In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9299. Order No. 85374, Issued February 22, 2013, p. 99, provided in Schedule TW-4.

³⁷ Docket 3270-UR-120, Order at 48.

³⁸ For example, Wisconsin Public Service Corporation argued that the fixed charge should include a portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduit and conductors, rather than only the customer-related costs.



categories. Use of the fixed charge for recovery of such costs tends to harm low-income customers, as well as distort efficient price signals.

Despite generally approving significantly higher fixed charges in recent years, in a December 2015 order the Wisconsin Public Service Commission approved only a slight increase in the fixed charge and signaled its interest in evaluating the impacts of higher fixed charges to ensure that the Commission's policy goals are being met. Specifically, the Commission directed one of its utilities to work with commission staff to conduct a study to assess the impacts of the higher fixed charges on customer energy use and other behavior.³⁹ This order indicates that perhaps the policy may be in need of further study.

Demand Costs Not Appropriate for Energy Charge

In approving Sierra Pacific Power's request for a higher fixed charge, the Nevada Public Service Commission wrote:

If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable.⁴⁰

Despite declaring that demand-related costs are inappropriately recovered in the energy charge, the commission makes no argument for why the fixed charge is a more appropriate mechanism for recovering such costs. Nor does the commission recognize that customer demand (kW) and energy usage (kWh) are likely correlated, or that recovering demand-related costs in the fixed charge may introduce even greater cross-subsidies among customers.

Settlements

Many of the recent proceedings regarding fixed charges have ended in a settlement agreement. Several of these settlements have resulted in the intervening parties, including the utility, agreeing to make no change to the customer charge or fixed charge. For example, Kentucky Utilities and Louisville Gas & Electric requested a 67 percent increase in the fixed charge, from \$10.75 to \$18.00 per month. The case ultimately settled, with neither utility receiving an increase in the monthly fixed charge.⁴¹ While

³⁹ Wisconsin Public Service Commission, Docket 6690-UR-124, *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Final Decision, December 17, 2015.

⁴⁰ Nevada Public Service Commission, Docket 13-06002, *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*, Modified Final Order, January 29, 2014, Page 176.

⁴¹ Kentucky Public Service Commission Order, Case No. 2014-00372, *In the Matter of Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, page 4; Kentucky Public Service Commission Order, Case No. 2014-00371, *In the Matter of Application of Kentucky Utility Company for an Adjustment of Its Electric and Gas Rates*, page 4.



settlements seldom explicitly state the rationale behind such decisions, it is safe to expect that many of the settling parties echo the concerns stated by the Commissions above.

In conclusion, the push to significantly increase the fixed charge has largely been rejected by regulators across the country as unnecessary and poor public policy. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason. In addition, in late 2015, it appeared that some utilities were beginning to propose new demand charges for residential customers instead of increased fixed charges.

7. ALTERNATIVES TO FIXED CHARGES

Utilities are turning to higher fixed charges in an effort to slow the decline of revenues between rate cases, since revenue collected through the fixed charge is not affected by reduced sales. In the past, costs were relatively stable and sales between rate cases typically provided utilities with adequate revenue, but this is not necessarily the case anymore. The current environment of flat or declining sales growth, coupled with the need for additional infrastructure investments, can pose financial challenges for a utility and cause it to apply for rate cases more frequently.

Higher fixed charges are an understandable reaction to these trends, but they are an ill-advised remedy, due to the adverse impacts described above. Alternative rate designs exist that can help to address utility revenue sufficiency and volatility concerns, as discussed below. Furthermore, in many cases, utilities are reacting to perceived or future threats, rather than to a pressing current revenue deficiency. Simply stated, there is no need to increase the fixed charge.

Rate Design Options

Numerous rate design alternatives to higher fixed charges are available under traditional cost-of-service ratemaking. Below we discuss several of these options, and describe some of the key advantages and disadvantages of each. No prioritization of the options is implied, as rate design decisions should be made to address the unique circumstances of a particular jurisdiction. For example, the rate design adopted in Hawaii, where approximately 15 percent of residential customers on Oahu have rooftop solar,⁴² may not be appropriate for a utility in Michigan.

⁴² As of the third quarter of 2015, nearly 40,000 customers on Oahu were enrolled in the Hawaiian Electric Company's net metering program, as reported by HECO on its website:

<http://www.hawaiianelectric.com/heco/hidden/Hidden/Community/Renewable-Energy?cpsectcurrchannel=1#05>



Status Quo

One option is to simply maintain the current level of fixed charges and allow utilities to file frequent rate cases, if needed. This option is likely to be most appropriate where a utility is not yet facing any significant earnings shortfall, but is instead seeking to preempt what it views as a future threat to its earnings.

By maintaining the current rate structure rather than changing it prematurely, this option allows the extent of the problem to be more accurately assessed, and the remedy appropriately tailored to address the problem. Maintaining the current rate structure clearly also avoids the negative impacts on ratepayers and clean energy goals that higher fixed charges would have, as discussed in detail above.

However, maintaining the status quo may have detrimental impacts on both ratepayers and the utility if the utility is truly at risk of significant revenue under-recovery.⁴³ Where a utility cannot collect sufficient revenues, it may forego necessary investments in maintaining the electric grid or providing customer service, with potential long-term negative consequences.

In addition, the utility may file frequent rate cases in order to reset rates, which can be costly. Rate cases generally require numerous specialized consultants and lawyers to review the utility's expenditures and investments in great detail, and can drag on for months, resulting in millions of dollars in costs that could eventually be passed on to customers. Because of this cost, a utility is unlikely to file a rate case unless it believes that significantly higher revenues are likely to be approved.

Finally, chronic revenue under-recovery can worry investors, who might require a higher interest rate in order to lend funds to the utility. Since utilities must raise significant financial capital to fund their investments, a higher interest rate could ultimately lead to higher costs for customers. However, such chronic under-recovery is unlikely for most utilities, and this risk should be assessed alongside the risks of overcharging ratepayers and discouraging efficiency.

Minimum Bills

Minimum bills are similar to fixed charges, but with one important distinction: minimum bills only apply when a customer's usage is so low that his or her total monthly bill would otherwise be less than this minimum amount. For example, if the minimum bill were set at \$40, and the only other charge was the energy charge of \$0.10 per kWh, then the minimum bill would only apply to customers using less than 400 kWh, who would otherwise experience a bill less than \$40. Given that the national average residential electricity usage is approximately 900 kWh per month, the minimum bill would have no effect on most residential customers.

⁴³ Of course, the claim that the utility is at risk of substantially under-recovering its revenue requirement should be thoroughly investigated before any action is taken.



A key advantage claimed by proponents to the minimum bill is that it guarantees that the utility will recover a certain amount of revenue from each customer, without significantly distorting price signals for the majority of customers. The threshold that triggers the minimum bill is typically set well below the average electricity usage level, and thus most customers will not be assessed a minimum bill but will instead only see the energy charge (cents per kilowatt-hour). Minimum bills also have the advantage of being relatively simple and easy to understand.

Minimum bills may be useful where there are many customers that have low usage, but actually impose substantial costs on the system. For example, this could include large vacation homes that have high usage during the peak summer hours that drive most demand-related costs, but sit vacant the remainder of the year. Unfortunately, minimum bills do not distinguish these types of customers from those who have reduced their peak demand (for example through investing in energy efficiency or distributed generation), and who thereby impose lower costs on the system.⁴⁴ Further, minimum bills may also have negative financial impacts on low-income customers whose usage falls below the threshold. For these reasons, minimum bills are superior to fixed charges, but they still operate as a relatively blunt instrument for balancing ratepayer and utility interests. Further, utilities will have an incentive to push for higher and higher minimum bill levels.

To illustrate the impacts of minimum bills, consider three rate options: (1) an “original” residential rate structure with a fixed charge of \$9 per month; (2) a minimum bill option, which keeps the \$9 fixed charge but adds a minimum bill of \$40; and (3) an increase in the fixed charge to \$25 per month. In all cases, the energy charge is adjusted to ensure that the three rate structures produce the same amount of total revenues. The figure below illustrates how moving from the “original” rate structure to either a minimum bill or increased fixed charge option would impact different customers.

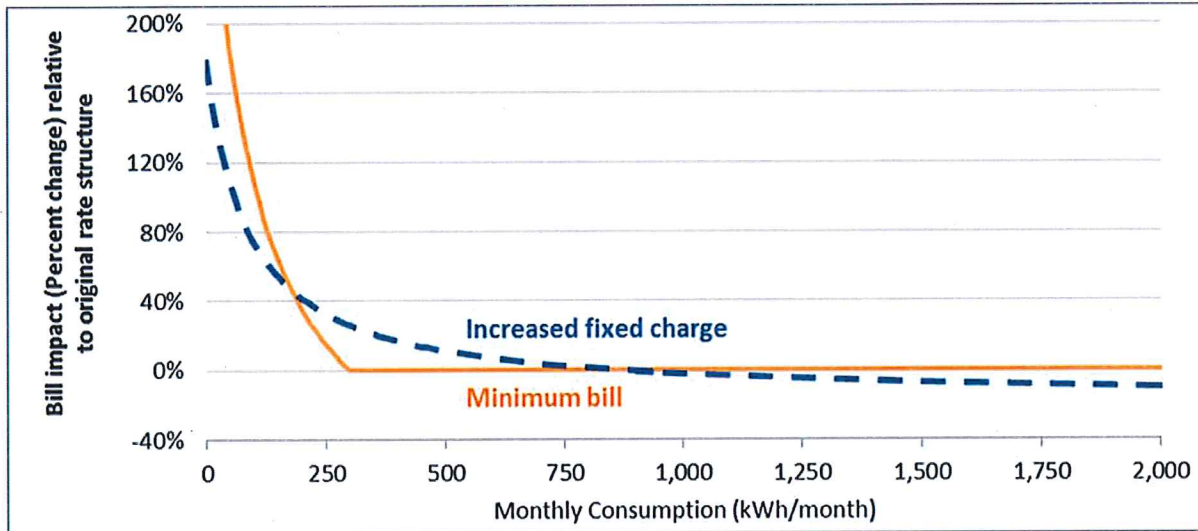
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than \$10.

In contrast, under the \$25 fixed charge, all customers using less than approximately 875 kWh per month (about half of residential customers) would see an increase in their electric bills, while customers using more than 875 kWh per month would see a *decrease* in their electric bills.

⁴⁴ In the short run, there is likely to be little difference in the infrastructure investments required to serve customers with high peak demands and those with low peak demands. However, in the long run, customers with higher peak demands will drive additional investments in generation, transmission, and distribution, thereby imposing greater costs on the system. A theoretically efficient price signal would reflect these different marginal costs in some manner in order to encourage customers to reduce the long-run costs they impose on the system.

Figure 11. Impact of minimum bill relative to an increased fixed charge

Rate Structure	Energy Charge	Fixed charge	Minimum bill
Typical rate structure	10.36 cents / kWh	\$9 / Month	\$0 / Month
Minimum bill	10.34 cents / kWh	\$9 / Month	\$40 / Month
Increased fixed charge	8.48 cents / kWh	\$25 / Month	\$0 / Month



Source: Author's calculations based on data from a representative Midwestern utility.

Time-of-Use Rates

Electricity costs can vary significantly over the course of the day as demand rises and falls, and more expensive power plants must come online to meet load.⁴⁵ Time-of-use (TOU) rates are a form of time-varying rate, under which electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have separate rates for peak and off-peak periods, but intermediate periods may also have their own rates.

Time-varying rate structures can benefit ratepayers and society in general by improving economic efficiency and equity. Properly designed TOU rates can improve economic efficiency by:

1. Encouraging ratepayers to reduce their bills by shifting usage from peak periods to off-peak periods, thereby better aligning the consumption of electricity with the value a customer places on it;
2. Avoiding capacity investments and reducing generation from the most expensive peaking plants; and

⁴⁵ Electricity costs also vary by season and weekday/weekend.

3. Providing appropriate price signals for customer investment in distributed energy resources that best match system needs.

Time-varying rates are also capable of improving equity by better allocating the costs of electricity production during peak periods to those causing the costs.

Despite their advantages, TOU rates are not a silver bullet and may be inappropriate in the residential rate class. They may not always be easily understood or accepted by residential customers. TOU rates also require specialized metering equipment, which not all customers have. In particular, the adoption of advanced metering infrastructure (AMI) may impose significant costs on the system.⁴⁶ Residential consumers often do not have the time, interest or knowledge to manage variable energy rates efficiently, so TOU blocks must be few and well-defined and still may not elicit desired results. Designing TOU rates correctly can be difficult, and could penalize vulnerable customers requiring electricity during extreme temperatures. Some consumer groups (such as AARP) urge any such rates be voluntary. Finally, even well-designed TOU rates may not fully resolve a utility's revenue sufficiency concerns.

Value of Solar Tariffs

Value of solar tariffs pay distributed solar generation based on the value that the solar generation provides to the utility system (based on avoided costs). Value of solar tariffs have been approved as an alternative to net metering in Minnesota and in Austin, Texas. In both places, a third-party consultant conducted an avoided cost study (value of solar study) to determine the value of the avoided costs of energy, capacity, line losses, transmission and distribution.

Value of solar tariffs are useful in that they more accurately reflect cost causation, thereby improving fairness among customers. They also maintain efficient price signals that discourage wasteful use of energy, and improve revenue recovery and stability.

However, value of solar tariffs are not easily designed, as there is a lack of consensus on the elements that should be incorporated, how to measure difficult-to-quantify values, and even how to structure the tariff. Value of solar rates are also not necessarily stable, since value-of-solar tariff rates are typically adjusted periodically. However, there is no reason that the tariff couldn't be affixed for a set time period, like many long-term power purchase agreements.

Alternatively, if the value of solar is determined to be less than the retail price of energy, a rider or other charge could be implemented to ensure that solar customers pay their fair share of costs. Regardless of the type of charge or compensation mechanism chosen, a full independent, third-party analysis of the costs and benefits of distributed generation should be conducted prior to making any changes to rates.

⁴⁶ AMI also allows remote disconnections and prepaid service options, both of which can disadvantage low-income customers. See, for example, Howat, J. *Rethinking Prepaid Utility Service: Customers at Risk*. National Consumer Law Center, June 2012.



Demand Charges

Generation, transmission, and distribution facilities are generally sized according to peak demands—either the local peak or the system peak. The peak demands are driven by the consumption levels of all electricity customers combined. Demand charges are designed to recover demand-related costs by charging electricity customers on the basis of maximum power demand (in terms of dollars per kilowatt), instead of energy (in terms of dollars per kilowatt-hour).

Designing rates to collect demand-related costs through demand charges may improve a utility's revenue recovery and stability. Proponents claim that such rates may also help send price signals that encourage customers to take steps to reduce their peak load. These charges have been in use for many years for commercial and industrial customers, but have rarely been implemented for residential customers.

Demand charges have several important shortcomings that limit how appropriate they might be for residential customers. First, demand charges remain relatively untested on the residential class. There is little evidence thus far that demand charges are well-understood by residential customers; instead, they would likely lead to customer confusion. This is particularly true for residential customers, who may be unaware of when their peak usage occurs and therefore have little ability or incentive to reduce their peak demand.

Second, depending on how they are set, demand charges may not accurately reflect cost causation. A large proportion of system costs are driven by system-wide peak demand, but the demand charge is often based on the customer's maximum demand (not the utility's). Thus demand charges do not provide an incentive for customers to reduce demand during the utility system peak in the way that time of use rates do. Theoretically, demand charges based on a customer's maximum demand could help reduce local peak demand, and therefore reduce some local distribution system costs. However, at the residential level, it is common for multiple customers to share a single piece of distribution system equipment, such as a transformer. Since a customer's maximum demand is typically triggered by a short period of time in which that customer is using numerous household appliances, it is unlikely that this specific time period coincides exactly when other customers sharing the same transformer are experiencing their maximum demands. This averaging out over multiple customers means that a single residential customer's maximum demand is not likely to drive the sizing of a particular piece of distribution-system equipment. For this reason, demand charges for the residential class are not likely to accurately reflect either system or local distribution costs.

Third, few options currently exist for residential customers to automatically monitor and manage their maximum demands. Since customer maximum monthly demand is often measured over a short interval of time (e.g., 15 minutes), a single busy morning where the toaster, microwave, hairdryer, and clothes dryer all happen to be operating at the same time for a brief period could send a customer's bill skyrocketing. This puts customers at risk for significant bill volatility. Unless technologies are implemented to help customers manage their maximum demands, demand charges should not be used.



Fourth, demand charges are not appropriate for some types of distributed generation resources. Some utilities have proposed that demand charges be applied to customers who install PV systems under net energy metering policies. This proposal is based on the grounds that demand charges will provide PV customers with more accurate price signals regarding their peak demands, which might be significantly different with customer-sited PV. However, a demand charge is not appropriate in this circumstance, because PV resources do not provide the host customer with any more ability to control or moderate peak demands than any other customer. A PV resource might shift a customer's maximum demand to a different hour, but it might do little to reduce the maximum demand if it occurs at a time when the PV resource is not operating much (because the maximum demand occurs either outside of daylight hours, or on a cloudy day when PV output is low).

Fifth, demand charges may require that utilities invest in expensive metering infrastructure and in-home devices that communicate information to customers regarding their maximum demands. The benefits of implementing a customer demand charge may not outweigh the costs of such investments.

In sum, most residential customers are very unlikely to respond to demand charges in a way that actually reduces peak demand, either because they do not have sufficient information, they do not have the correct price signal, they do not have the technologies available to moderate demand, or the technologies that they do have (such as PV) are not controllable by the customer in a way that allows them to manage their demand. In those instances where customers cannot or do not respond to demand charges, these charges suffer from all of the same problems of fixed charges: they reduce incentives to install energy efficiency or distributed generation; they pose an unfair burden on low-usage customers; they provide an inefficient price signal regarding long-term electricity costs; and they can eventually result in higher costs for all customers. For these reasons, demand charges are rarely implemented for residential customers, and where they have been implemented, it has only been on a voluntary basis.

8. CONCLUSIONS

In this era of rapid advancement in energy technologies and broad-based efforts to empower customers, mandatory fixed charges represent a step backward. Whether a utility is proposing to increase the fixed charge due to a significant decline in electricity sales or as a preemptive measure, higher fixed charges are an inequitable and economically inefficient means of addressing utility revenue concerns. In some cases, regulators and other stakeholders have been persuaded by common myths that inaccurately portray an increased fixed charge as the necessary solution to current challenges facing the utility industry. While they may be desirable for utilities, higher fixed charges are far from optimal for society as a whole.

Fortunately, there are many rate design alternatives that address utility concerns about declining revenues from lower sales without causing the regressive results and inefficient price signals associated with fixed charges. Recent utility commission decisions rejecting proposals for increased fixed charges suggest that there is a growing understanding of the many problems associated with fixed charges, and that alternatives do exist. As this awareness spreads, it will help the electricity system continue its progression toward greater efficiency and equity.



APPENDIX A – BONBRIGHT’S PRINCIPLES OF RATE DESIGN

In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are:

1. The related, “practical” attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of “undue discrimination” in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
 - (a) in the control of the total amounts of service supplied by the company;
 - (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).⁴⁷

⁴⁷ James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.



APPENDIX B – RECENT PROCEEDINGS ADDRESSING FIXED CHARGES

The tables below present data on recent utility proposals or finalized proceedings regarding fixed charges based on research conducted by Synapse Energy Economics. These cases were generally opened or decided between September 2014 and November 2015.

Table 1. List of finalized utility proceedings to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Alameda Municipal Power (CA)	AMP Board vote June 2015	\$9.25	\$11.50	\$11.50	
Ameren (MO)	File No. ER - 2012-0166 Tariff No. YE-2014-0258	\$8.00	\$8.77	\$8.00	Company initially proposed \$12.00. Settling parties agreed to \$8.77. Commission order rejected any increase, citing customer control
Appalachian Power Co (VA)	PUE-2014-00026	\$8.35	\$16.00	\$8.35	
Appalachian Power/Wheeling Power (WV)	14-1152-E-42T	\$5.00	\$10.00	\$8.00	
Baltimore Gas and Electric (MD)	9355, Order No. 86757	\$7.50	\$10.50	\$7.50	Settlement based on Utility Law Judge
Benton PUD (WA)	Board approved in June 2015	\$11.05	\$15.60	\$15.60	
Black Hills Power (WY)	20002-91-ER-14 (Record No. 13788)	\$14.00	\$17.00	\$15.50	
Central Hudson Gas & Electric (NY)	14-E-0318	\$24.00	\$29.00	\$24.00	
Central Maine Power Company (ME)	2013-00168	\$5.71	\$10.00	\$10.00	Decoupling implemented as well
City of Whitehall (WI)	6490-ER-106	\$8.00	\$16.00	\$16.00	
Columbia River PUD (OR)	CRPUD Board vote September 2015	\$8.00	\$20.45	\$10.00	
Colorado Springs Utilities (CO)	City Council Volume No. 5	\$12.52	\$15.24	\$15.24	
Connecticut Light & Power (CT)	14-05-06	\$16.00	\$25.50	\$19.25	Active docket
Consolidated Edison (NY)	15-00270/15-E-0050	\$15.76	\$18.00	\$15.76	Settlement
Consumers Energy (MI)	U-17735	\$7.00	\$7.50	\$7.00	PSC Order
Choptank Electric Cooperative (MD)	9368, Order No. 86994,	\$10.00	\$17.00	\$11.25	PSC approved smaller increase
Dawson Public Power (NE)	Announced June 2015	\$21.50	\$27.00	\$27.00	Based on news articles
Empire District Electric (MO)	ER-2014-0351	\$12.52	\$18.75	\$12.52	Settlement
Eugene Water & Electric Board (OR)	Board vote December 2014	\$13.50	\$20.00	\$20.00	
Hawaii Electric Light (HI)	2014-0183	\$9.00	\$61.00	\$9.00	Part of "DG 2.0"
Maui Electric Company (HI)	2014-0183	\$9.00	\$50.00	\$9.00	Part of "DG 2.0"
Hawaii Electric Company (HI)	2014-0183	\$9.00	\$55.00	\$9.00	Part of "DG 2.0"
Independence Power & Light Co (MO)	City Council vote September 2015	\$4.14	\$14.50	\$4.14	Postponed indefinitely
Indiana Michigan Power (MI)	U-17698	\$7.25	\$9.10	\$7.25	Settlement
Kansas City Power & Light (KS)	15-KCPE-116-RTS	\$10.71	\$19.00	\$14.50	Settlement
Kansas City Power & Light (MO)	File No. ER-2014-0370	\$9.00	\$25.00	\$11.88	
Kentucky Power (KY)	2014-00396	\$8.00	\$16.00	\$11.00	Settlement was \$14/month; PSC reduced to \$11
Kentucky Utilities Company (KY)	2014-00371	\$10.75	\$18.00	\$10.75	Settlement for KU LGE
Louisville Gas-Electric (KY)	2014-00372	\$10.75	\$18.00	\$10.75	Settlement for KU LGE

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Madison Gas and Electric (WI)	3270-UR-120	\$10.29	\$22.00	\$19.00	
Metropolitan Edison (PA)	R-2014-2428745	\$8.11	\$13.29	\$10.25	Settlement
Nevada Power Co. (NV)	14-05004	\$10.00	\$15.25	12.75	Settlement
Northern States Power Company (ND)	PU-12-813	\$9.00	\$14.00	\$14.00	Under previous rates, customers with underground lines paid \$11/month
Pacific Gas & Electric Company (CA)	R.12-06-013, Rulemaking 12-06-013	\$0.00	\$10.00	\$0.00	\$10 minimum bill adopted instead
PacifiCorp (WA)	UE-140762	\$7.75	\$14.00	\$7.75	Commission order emphasized customer control
Pennsylvania Electric (PA)	R-2014-2428743	\$7.98	\$11.92	\$9.99	Settlement
Pennsylvania Power (PA)	R-2014-2428744	\$8.86	\$12.71	\$10.85	Settlement
Redding Electric Utility (CA)	City Council Meeting June 2015	\$13.00	\$42.00	\$13.00	Postponed consideration until 2/2017
Rocky Mountain Power (UT)	13-035-184	\$5.00	\$8.00	\$6.00	Settlement
Rocky Mountain Power (WY)	20000-446-ER-14 (Record No. 13816)	\$20.00	\$22.00	\$20.00	
Salt River Project (AZ)	SRP Board vote February 2015	\$17.00	\$20.00	\$20.00	Elected board of SRP voted Feb. 26 2015
San Diego Gas & Electric (CA)	A.14-11-003 & R.12-06-013, Rulemaking 12-06-013	\$0.00	\$10.00	\$0.00	\$10 minimum bill adopted instead
Sierra Pacific Power (NV)	13-06002, 13-06003, 13-06004	\$9.25	\$15.25	\$15.25	
Southern California Edison (CA)	A.13-11-003 & R.12-06-013, Rulemaking 12-06-013	\$0.94	\$10.00	\$0.94	\$10 minimum bill adopted instead
Stoughton Utilities (WI)	5740-ER-108	\$7.50	\$10.00	\$10.00	
We Energies (WI)	5-UR-107	\$9.13	\$16.00	\$16.00	
West Penn Power (PA)	R-2014-2428742	\$5.00	\$7.35	\$5.81	Settlement
Westar (KS)	15-WSEE-115-RTS	\$12.00	\$27.00	\$14.50	Settlement
Wisconsin Public Service (MI)	U-17669	\$9.00	\$12.00	\$12.00	Settlement
Wisconsin Public Service (WI)	6690-UR-123	\$10.40	\$25.00	\$19.00	
Xcel Energy (MN)	E002 / GR-13-868	\$8.00	\$9.25	\$8.00	Commission order emphasized customer control

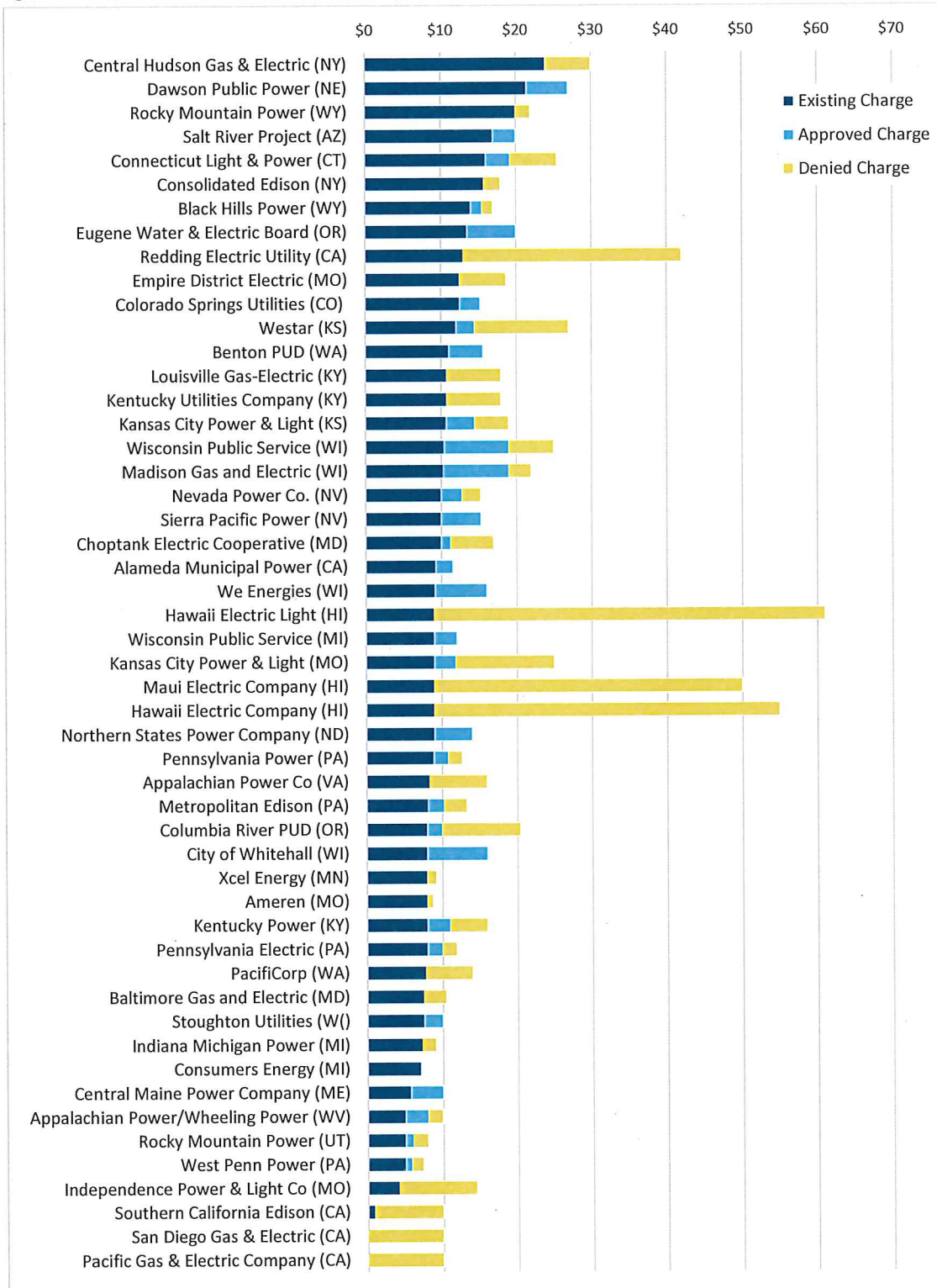
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Table 2. Pending dockets and proposals to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Avista Utilities (ID)	AVU-E-15-05	\$5.25	\$8.50		Active docket
Avista Utilities (WA)	UE-150204	\$8.50	\$14.00		
Detroit Edison (MI)	U-17767	\$6.00	\$10.00		Proposed order has rejected residential increase
El Paso Electric (TX)	44941	\$7.00	\$10.00		Public hearings ongoing
El Paso Electric (NM)	15-00127-UT	\$5.04	\$10.04		Public hearings ongoing
Energy Arkansas, Inc. (AR)	15-015-U	\$6.96	\$9.00		Active docket
Indianapolis Power & Light (IN)	44576/44602	\$11.00	\$17.00		Active docket, values reflect proposal for customers that use more than 325 kWh
Lincoln Electric System (NE)	City council proceeding	\$11.15	\$13.40		City council decision is pending
Long Island Power Authority (NY)	15-00262	\$10.95	\$20.38		Rejected by PSC, LIPA Board has ultimate decision
Montana-Dakota Utilities (MT)	D2015.6.51	\$5.48	\$7.60		BSC based on per day not per month, values converted to monthly
National Grid (MA)	D.P.U. 15-120	\$4.00	\$13.00		Proposed as part of Grid Mod plan, presented as "Tier 3" customer, for use between 601 to 1,200 kWh per month
National Grid (RI)	RIPUC DOCKET NO. 4568	\$5.00	\$13.00		Presented as "Tier 3" customer, for use between 751 to 1,200 kWh per month
NIPSCO (IN)	44688	\$11.00	\$20.00		Active Docket
Omaha Public Power District (NE)	Public power	\$10.25	\$30.00		Based on news coverage of stakeholder meetings. No specific number submitted, \$20, \$30, \$35 where floated past stakeholders
PECO (PA)	R-2015-2468981	\$7.12	\$12.00	\$8.45	Settlement not yet ratified
Public Service Company of New Mexico (NM)	15-00261-UT	\$5.00	\$13.14		Public hearings ongoing
Portland General Electric (OR)	UE 294	\$10.00	\$11.00		Proposed
Pennsylvania Power and Light (PA)	R-2015-2469275	\$14.09	\$20.00	\$14.09	Settlement not yet ratified
Santee Cooper (SC)	State utility	\$14.00	\$21.00		Pending, expected decision in December 2015
Springfield Water Power and Light (IL)	Municipal board	\$5.76	\$12.87		Pending as of Oct 1 2015
Sulfur Springs Valley Electric Coop (AZ)	E-01575A-15-0312	\$10.25	\$25.00		Active docket
Sun Prairie Utilities (WI)	5810-ER-106	\$7.00	\$16.00		
UNS Electric Inc. (AZ)	E-04204A-15-0142	\$10.00	\$20.00		Active docket, hearings in March 2016
Xcel Energy (WI)	4220-UR-121	\$8.00	\$18.00		

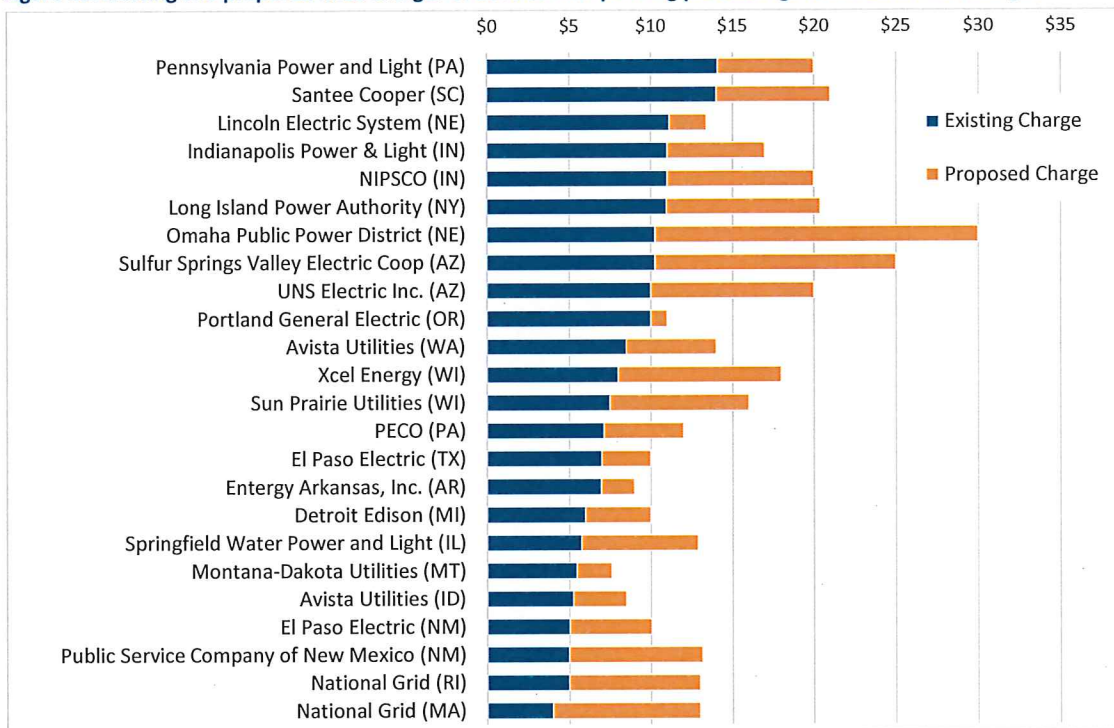
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Figure 13. Existing and proposed fixed charges of utilities with pending proceedings to increase fixed charges

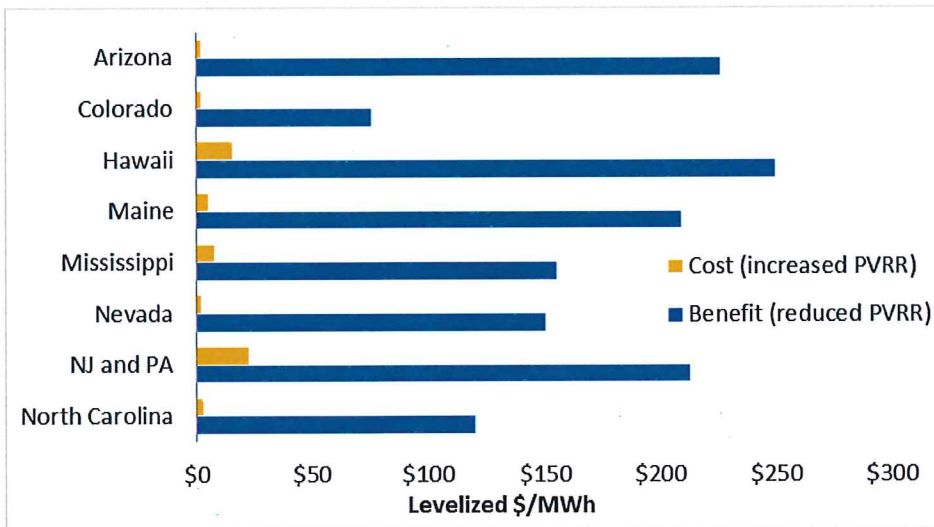


APPENDIX C – NET METERING IMPACTS ON UTILITY COSTS

A utility’s revenue requirement represents the amount of revenue that it must recover from customers to cover the costs of serving customers (plus a return on its investments). Customers who invest in distributed PV may increase certain costs while reducing others. Costs associated with integration, administration, and interconnection of net energy metered (NEM) systems will increase revenue requirements, and thus are considered a cost. At the same time, a NEM system will avoid other costs for the utility, such as energy, capacity, line losses, etc. These avoided costs will reduce revenue requirements, and thus are a benefit. These costs and benefits over the PV’s lifetime can be converted into present value to determine the impact on the utility’s present value of revenue requirements (PVRR).

Over the past few years, at least eight net metering studies have quantified the impact of NEM on a utility’s revenue requirement. Key results from these studies are summarized in the table and figure below. Note that only those costs and benefits that affect revenue requirements are included as costs or benefits. If a study included benefits that do not affect revenue requirements (such as environmental externality costs, reduced risk, fuel hedging value, economic development, and job impacts), then they were subtracted from the study results. Similarly, the costs presented below include only NEM system integration, interconnection, and administration costs.⁴⁸ Other costs that are sometimes included in the studies but do not affect revenue requirements, such as lost revenues, are not included.

Figure 14. Recent studies indicate extent to which NEM benefits exceed costs



⁴⁸ Historically, some utilities have offered incentives to customers that install solar panels (or other NEM installations). While these incentive payments do put upward pressure on revenue requirements, the incentives themselves are removed from Figure 14 and Table 3 to help compare costs and benefits when utility-specific incentives are taken out of the equation.

Table 3. Net metering studies that report PVRR benefits and costs

Year	State	Funded / Commissioned by	Prepared by	Benefit (\$/MWh)	Cost (\$/MWh)	Benefit-Cost Ratio
2013	Arizona	-----	Crossborder Energy	226*	2	113
2013	Colorado	Xcel Energy	Xcel Energy	75.6	1.8	42
2014	Hawaii	HI PUC	E3	250*	16	16
2015	Maine	Maine Public Utilities Commission	Clean Power Research, et. al.	209	5	42
2014	Mississippi	Mississippi Public Service Commission	Synapse Energy Economics	155	8	19
2014	Nevada	State of Nevada Public Utilities Commission	E3	150	2	75
2012	NJ and PA	Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association	Clean Power Research	213*	23*	9
2013	North Carolina	NC Sustainable Energy Association	Crossborder Energy	120*	3	40

*Indicates that the value displayed in the table is the midpoint of the high and low values reported in the study.

Source: Synapse Energy Economics, 2015.

Arizona

The Arizona study, performed by Crossborder Energy, presents 20-year levelized values in 2014 dollars.⁴⁹ Benefits include avoided energy, generation capacity, ancillary services, transmission, distribution, environmental compliance, and costs of complying with renewable portfolio standards. The avoided environmental benefits account for non-CO₂ market costs of NO_x, SO_x, and water treatment costs, and thus are included as revenue requirement benefits. The benefits range from \$215 per MWh to \$237 per MWh. Figure 14 and Table 3 present the midpoint value of this range: \$226 per MWh. The report estimates integration costs to be \$2 per MWh.

Colorado

The Colorado study, performed by the utility Xcel Energy, presents 20-year levelized net avoided costs under three cases in the report's Table 1.⁵⁰ The benefits include avoided energy, emissions, capacity, distribution, transmission and line losses. The benefits also include an avoided hedge value, which does not affect revenue requirements. Removing the hedge value from the benefits yields a revenue

⁴⁹ Crossborder Energy. 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Page 2. Table 1.

⁵⁰ Xcel Energy. 2013. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System. Executive Summary, page V.

requirement benefit of \$75.6 per MWh. The study estimates solar integration costs to be \$1.80 per MWh.

Hawaii

The Hawaii study, performed by E3, presents the 20-year levelized costs and benefits of NEM on the various Hawaii utilities (HECO, MECO, HELCO, and KIUC). The base case NEM benefits are \$213 per MWh for KIUC,⁵¹ \$234 per MWh for MECO,⁵² \$242 per MWh for HELCO,⁵³ and \$287 for HECO.⁵⁴ Figure 14 and Table 3 present the midpoint of these values: \$250 per MWh. The NEM revenue requirement costs are estimated to be \$16 per MWh, which includes integration costs (\$6 per MWh) and transmission and distribution interconnection costs (\$10 per MWh).⁵⁵

Maine

The Maine study, prepared by several co-authors, presents the 25-year levelized market and societal benefits for Central Maine Power Company.⁵⁶ The revenue requirement benefits, including avoided costs and market price response benefits, are \$209 per MWh. The study estimates the NEM revenue requirement costs to be \$5 per MWh, reflecting NEM system integration costs.

Mississippi

The Mississippi study, prepared by Synapse Energy Economics, presents base case 25-year levelized benefits associated with avoided energy, capacity, transmission and distribution, system losses, environmental compliance costs, and risk.⁵⁷ The total revenue requirements benefit is \$155 per MWh, which excludes the \$15 per MWh risk benefit. The NEM administrative costs are estimated to be \$8 per MWh.

Nevada

The Nevada study, conducted by E3, presents costs and benefits on a 25-year levelized basis in 2014 dollars. The study estimates the costs and benefits for several “vintages” of rooftop solar. Figure 14 and Table 3 present the vintage referred to as “2016 installations,” because this is most representative of

⁵¹ E3, Evaluation of Hawaii’s Renewable Energy Policy and Procurement, January 2014, page 53, Figure 26.

⁵² Ibid. Page 50, Figure 23.

⁵³ Ibid. Page 47, Figure 20.

⁵⁴ Ibid. Page 43, Figure 17.

⁵⁵ Ibid. Pages 55 and 56.

⁵⁶ Clean Power Research, Sustainable Energy Advantage, & Pace Law School Energy and Climate Center for Maine PUC. 2015. *Maine Distributed Solar Valuation Study*. Page 50. Figure 7.

⁵⁷ Synapse Energy Economics for Mississippi PSC. 2014. *Net Metering in Mississippi*. Pages 33 and 38.

costs and benefits in the future. The revenue requirement benefits, including avoided costs and renewable portfolio standard value, are estimated to be \$150 per MWh. The E3 study also reports the “incentive, program, and integration costs” to be \$6 per MWh.⁵⁸ This value includes the integration costs, which were assumed by E3 to be \$2 per MWh.⁵⁹ Customer incentive costs are not included in any of the results presented in Figure 14 and Table 3, so the revenue requirement costs for Nevada include only the integration costs of \$2 per MWh.

New Jersey and Pennsylvania

The New Jersey and Pennsylvania study, prepared by several co-authors, presents the 30-year levelized value of solar for seven locations.⁶⁰ The benefits include energy benefits (that would contribute to reduced revenue requirements), strategic benefits (that may not contribute to reduced revenue requirements), and other benefits (some of which would contribute to reduced revenue requirements). To determine the revenue requirement benefits, the benefits associated with “security enhancement value,” “long term societal value,” and “economic development value” are excluded. The highest reported benefit value was in Scranton (\$243 per MWh) and the lowest value was reported in Atlantic City (\$183 per MWh). Figure 14 and Table 3 present the midpoint of these two values: \$213 per MWh. Similarly, they present the midpoint of the solar integration costs (\$23 per MWh).

North Carolina

The North Carolina study, prepared by Crossborder Energy, presents 15-year levelized values in 2013 dollars per kWh. The benefits are presented for three utilities separately. A high/low range of benefits were presented for each benefit category (energy, line losses, generation capacity, transmission capacity, avoided emissions, and avoided renewables). The low avoided emissions estimate reflects the costs of compliance with environmental regulations, which will affect revenue requirements, but the high avoided emissions estimate reflects the social cost of carbon, which will not affect revenue requirements. Therefore, the low avoided emissions value (\$4 per MWh) is included, but the incremental social cost of carbon value (\$18 per MWh) is excluded. The lowest revenue requirement benefit presented in the study is \$93 per MWh for DEP, and the highest one is \$147 per MWh for DNCP (after removing the incremental social cost of carbon). Figure 14 and Table 3 present the midpoint between the high and low values, \$120 per MWh, as the revenue requirement benefit. The study also identifies \$3 per MWh in revenue requirement costs.

⁵⁸ E3 for Nevada PUC. 2014. *Nevada Net Energy Metering Impacts Evaluation*. Page 96.

⁵⁹ *Ibid.* Page 61.

⁶⁰ Clean Power Research for Mid-Atlantic & Pennsylvania Solar Energy Industries Associations. 2012. *The Value of Distributed Solar Electric Generation to NJ and PA*. Page 18.



GLOSSARY

Advanced Metering Infrastructure (AMI): Meters and data systems that enable two-way communication between customer meters and the utility control center.

Average Cost: The revenue requirement divided by the quantity of utility service, expressed as a cost per kilowatt-hour or cost per therm.

Average Cost Pricing: A pricing mechanism basing the total cost of providing electricity on the accounting costs of existing resources. (See Marginal Cost Pricing, Value-Based Rates.)

Capacity: The maximum amount of power a generating unit or power line can provide safely.

Classification: The separation of costs into demand-related, energy-related, and customer-related categories.

Coincident Peak Demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Cost-Based Rates: Electric or gas rates based on the actual costs of the utility (see Value-Based Rates).

Cost-of-Service Regulation: Traditional electric utility regulation, under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost-of-Service Study: A study that allocates the costs of a utility between the different customer classes, such as residential, commercial, and industrial. There are many different methods used, and no method is "correct."

Critical Period Pricing or Critical Peak Pricing (CPP): Rates that dramatically increase on short notice when costs spike, usually due to weather or to failures of generating plants or transmission lines.

Customer Charge: A fixed charge to consumers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage. Sometimes called a Basic Charge or Service Charge.

Customer Class: A group of customers with similar usage characteristics, such as residential, commercial, or industrial customers.

Decoupling: A regulatory design that breaks the link between utility revenues and energy sales, typically by a small periodic adjustment to the rate previously established in a rate case. The goal is to match actual revenues with allowed revenue, regardless of sales volumes.

Demand: The rate at which electrical energy or natural gas is used, usually expressed in kilowatts or megawatts, for electricity, or therms for natural gas.



Demand Charge: A charge based on a customer's highest usage in a one-hour or shorter interval during a certain period. The charge may be designed in many ways. For example, it may be based on a customer's maximum demand during a monthly billing cycle, during a seasonal period, or during an annual cycle. In addition, some demand charges only apply to a customer's maximum demand that coincides with the system peak, or certain peak hours. Typically assessed in cents per kilowatt.

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

Embedded Costs: The costs associated with ownership and operation of a utility's existing facilities and operations. (See Marginal Cost.)

Energy Charge: The part of the charge for electric service based upon the electric energy consumed or billed (i.e., cents per kilowatt-hour).

Fixed Cost: Costs that the utility cannot change or control in the short-run, and that are independent of usage or revenues. Examples include interest expense and depreciation expense. In the long run, there are no fixed costs, because eventually all utility facilities can be retired and replaced with alternatives.

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

Fully Allocated Costs or Fully Distributed Costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Incentive Regulation: A regulatory framework in which a utility may augment its allowed rate of return by achieving cost savings or other goals in excess of a target set by the regulator.

Incremental Cost: The additional cost of adding to the existing utility system.

Inverted Rates/Inclining Block Rates: Rates that increase at higher levels of electricity consumption, typically reflecting higher costs of newer resources, or higher costs of serving lower load factor loads such as air conditioning. Baseline and lifeline rates are forms of inverted rates.

Investor-Owned Utility (IOU): A privately owned electric utility owned by and responsible to its shareholders. About 75% of U.S. consumers are served by IOUs.

Joint and Common Costs: Costs incurred by a utility in producing multiple services that cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula. Examples are distribution lines, substations, and administrative facilities.

Kilowatt-Hour (kWh): Energy equal to one thousand watts for one hour.

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

Load Shape: The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.



Long-Run Marginal Costs: The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Marginal Cost Pricing: A system in which rates are designed to reflect the prospective or replacement costs of providing power, as opposed to the historical or accounting costs. (See Embedded Cost.)

Minimum Charge: A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Operating Expenses: The expenses of maintaining day-to-day utility functions. These include labor, fuel, and taxes, but not interest or dividends.

Public Utility Commission (PUC): The state regulatory body that determines rates for regulated utilities. Sometimes called a Public Service Commission or other names.

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

Rate Design: The design and organization of billing charges to distribute costs allocated to different customer classes.

Short Run Marginal Cost: Only those variable costs that change in the short run with a change in output, including fuel; operations and maintenance costs; losses; and environmental costs.

Straight Fixed Variable (SFV) Rate Design: A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Time-of-Use Rates: A form of time-varying rate. Typically the hours of the day are segmented to "off-peak" and "peak" periods. The peak period rate is higher than the off-peak period rate.

Time-Varying Rates: Rates that vary by time of day in order to more accurately reflect the fluctuation of costs. A common, and simple form of time-varying rate is time-of-use rates.

Variable Cost: Costs that vary with usage and revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. (See Short Run Marginal Cost.)

Volumetric Rate: A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the customer (e.g., cents/kWh, or cents/kW). May also be referred to as the "variable rate." If referring to cents per kilowatt-hour, it is often referred to as the "energy charge."

Adapted from Lazar (2011) "Electricity Regulation in the US: A Guide." Regulatory Assistance Project.



Exhibit MG_3

Exhibit MG_3

Residential NEBO Customers Without Adjustment for Riders Now in Base Rates & Current FCA

	<u>Under Current R-TOU Tariff</u>	<u>Under Proposed R-TOU-kW Tariff</u>	<u>Change</u>
		\$	%
Monthly Impact - Average Bill	\$81.94	\$104.92	28.0%

Residential NEBO Customers Adjusted for Riders Proposed to be Placed in Base Rates

	<u>Under Current R-TOU Tariff</u>	<u>Under Proposed R-TOU-kW Tariff</u>	<u>Change</u>
		\$	%
Monthly Impact - Average Bill	\$81.94	\$98.39	20.1%

The second R-TOU-kW rate estimate incorporates a subtraction of riders being folded into base rates in current GRC application. This was done to make the estimate for proposed R-TOU-kW, which includes these riders in base rates, comparable to the current R-TOU tariff. Riders other than the current FCA that were not incorporated into base rates are excluded from all calculations. The new additions into the FCA were not included because they would affect the current and proposed rates equally on a monetary basis.

Modeling Description

Two different bill impact models were created. The first is based on actual residential DG customer billing data from roughly 200 existing residential DG customers. The second uses average residential customer data for the residential class as a whole and a reference PV system. Both data sets were provided by OG&E in PUD 201500274. The different models return different results because existing DG customers each have unique usage patterns and a unique DG production profile that differ from the average residential customer and the reference PV system. In other words, one is hypothetical, while the other reflects more granular data on the average DG customer.

Model #1: Based on Actual Existing DG Customer Data

Data Sources

- 1.) OG&E response to KJC-1, in PUD 201500274, providing an estimate of bill impacts if all residential DG customers were placed on R-TOU-kW as proposed in PUD 201500274. The spreadsheet contains billing data for a total of 201 existing residential DG customers and compares bills under the existing NEBO R-TOU tariff to the proposed NEBO R-TOU-kW tariff.
- 2.) Updated Fuel Cost Adjustment (FCA) values from Supplemental Package, Volume II, Section K-M, filed in PUD 201500273. Updated values are sourced from Section M, Individual Class Page, W/P M-4-1. The current rather than proposed FCA values were used in all calculations.
- 3.) Riders to be rolled into base rates, from Supplemental Package, Volume II, Section K-M, filed in PUD 201500273. Values are sourced from Section M, Individual Class Page, W/P M-4-1.
- 4.) OG&E proposed R-TOU-kW rates, as detailed in Wai Direct, pg. 27, Table 14.

Methodology

The estimate utilizes the existing formulas in OG&E response to KJC-1 in PUD 201500274. The FCA values contained in the Pricing tab were updated to reflect the current FCA values for winter, off-peak and on-peak times. The Pricing tab was also updated with the proposed customer charge, off-peak and on-peak energy rates, and non-coincident demand rate for R-TOU-kW. All riders that are proposed to remain riders were excluded from the calculations in order to isolate how changes to base rates affect customer bills. Likewise, the proposed additions to the FCA were excluded from the calculations they would affect both (current & proposed rates) monthly calculations equally. In other words, if the proposed FCA inclusions were incorporated into rates calculations for the proposed R-TOU-kW tariff, they would also need to be added to the rates calculations for the current R-TOU tariff so that both reflect their inclusion. Because the volumetric billing determinants would remain the same for each, the monthly monetary impact would be identical.

Estimate #1: The first estimate was prepared to show the *gross* increase relative to current rates, without considering the effects of riders that are proposed to be added into base rates. It therefore compares an average of DG customers' monthly bills under the current rates without considering any riders other than the FCA, with the average monthly bills for those same customers under proposed R-TOU-kW.

Exhibit MG_3

In this way, it captures the effects of both the proposed tariff change, and the more general increase in base rates attributable to riders being added to base rates.

Estimate #2: The second estimate adjusts for the inclusion of riders into base rates by subtracting the revenue that would have been raised under these riders from the average monthly bill calculation under the proposed NEBO R-TOU-kW tariff. The subtraction to monthly charges under the proposed NEBO R-TOU-kW tariff was calculated by multiplying the volumetric rates associated with those riders by the sum of total volumetric sales to residential DG customers in the Billing Determinant tab. The resulting revenue was then divided by 12 months and the 201 residential DG customers included in the Billing Determinants tab to arrive at a monthly charge attributable to riders. Thus in this estimate, the monthly average bill under the proposed NEBO R-TOU-kW tariff is decreased, eliminating the contribution of riders proposed to be added to base rates. This results in an apples to apples comparison where both monthly bill estimates exclude the cost of these riders to DG customers.

Model #2: Based on Average Residential Customer Data with a Reference 4 kW Fixed Tilt PV System

Data Sources

- 1.) OG&E Solar Sandbox model, provided in response to TASC 1-5 in PUD 201500274. This model depicts the how the installation of a reference 4 kW fixed tilt PV system would have on residential DG customer bills under the current NEBO R-TOU rate and the proposed R-TOU-kW rate. It contains an hourly simulation of energy production from the reference PV system, and applies that energy production to average residential customer usage data to arrive at bill savings estimates for a customer under NEBO R-TOU and proposed NEBO R-TOU-kW.
- 2.) Updated Fuel Cost Adjustment (FCA) values from Supplemental Package, Volume II, Section K-M, filed in PUD 201500273. Updated values are sourced from Section M, Individual Class Page, W/P M-4-1. The current rather than proposed FCA values were used in all calculations.
- 3.) OG&E proposed R-TOU-kW rates, as detailed in Wai Direct, pg. 27, Table 14.

Methodology

The modeling used OG&E's energy production modeling from a reference 4 kW fixed tilt PV system and average customer energy usage numbers. Modifications to the rate inputs were made to reflect current FCA rates for winter, on-peak and off-peak times, and to reflect the proposed R-TOU-kW tariff rates. From this, annual and monthly bill savings estimates attributable to PV were calculated for the average customer under the current NEBO R-TOU rate and the proposed NEBO R-TOU-kW rate. One adjustment was made to the existing formulas used by OG&E in the model to correct an error in the calculation of customer bill savings under the current NEBO R-TOU rate. The original model calculated savings under existing winter rates by multiplying total winter energy production by the rate for winter energy consumption of 600 kWh or less. This formula was adjusted to reflect that winter energy production would first offset winter energy consumption above 600 kWh, with any remaining energy production offsetting consumption at the rate for energy consumption of 600 kWh or less. This calculation illustrates the loss in monthly customer bill savings provided by PV under the new rate.

Exhibit MG_3

A second calculation was performed to compare a standard residential customer's bill under the existing R-TOU and proposed R-TOU-kW rate *without* PV. This calculation is necessary to discover how the rate change itself would affect average customer bills, which is the starting point from savings would accrue. These estimates were prepared using the average customer billing data provided by OG&E in its original model and devising new formulas as necessary to generate customer bill estimates.

The total impact of the proposed R-TOU-kW is the sum of lost savings and the estimated change in a customer's bill if they were placed on the R-TOU-kW tariff. These two values were summed together to generate the estimated monthly bill impact from the tariff change. The percentage bill increase is the monetary increase divided by the estimated annual bill with PV under the current R-TOU tariff.