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An enhanced two-part tariff methodology when demand charges are not used

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ABSTRACT

This proposed methodology uses load research sample data to objectively derive a two-part tariff that minimizes deviations from bills that would occur if we hypothetically implemented demand charges for residential customers. We find that about 50% of the capacity- or demand-related costs should be recovered in the fixed monthly customer charge and 50% recovered through the volumetric energy charge.

1. Introduction

Practical electric utility rate design starts with a three-part tariff, which includes an energy (dollars per kWh) charge, a demand (dollars per kW) charge, and a fixed per-customer monthly customer charge.[1] A longstanding debate persists in public utility regulatory proceedings over the design of electric rates for customers who do not have meters with maximum (kW) demand reading capability or for whom the additional complexity of demand charges is deemed unsuitable. In such situations, rate design is limited to the use of a customer charge and some type of energy charge ($/kWh) design, which may or may not vary based on a customer's total monthly kWh consumption. In actual utility rate cases, the share of demand-related (i.e., capacity-related) costs recovered from the customer charge vs. the energy charge is not typically determined in an objective cost-based manner. Such an objective determination is the purpose of this article.

Determining the best prices for electric public utilities has long been a concern for both academic economists and regulatory professionals. The two spheres, however, have maintained somewhat of a divide in focus. Generally speaking, the academic literature has been an application in normative economics with a view towards allocative efficiency and welfare/consumer-surplus maximization and with less concern for actual regulatory practices and procedures. The academic literature on optimal utility prices starts with linear prices equal to marginal cost as being "first-best" but acknowledges that such a pricing scheme fails to recover all costs for a natural monopoly.[2] The academic literature then followed a progression whereby: (1) second-best Ramsey prices are then used to maximize welfare subject to the constraints that the firm breaks even and that prices be linear[3]; (2) further gains in welfare (but subject to the firm breaking even) are made possible by deviating from linear pricing and by using uniform multi-part tariffs;[4] (3) additional welfare improvements are also possible if we relax uniformity and permit discrimination, tariff options or time-differentiated tariffs.[5]

In its optimal pricing schemes, the academic literature has primarily emphasized the use of volumetric rate elements (e.g., a dollar per kWh energy charge), or variants thereof, and fixed per-customer monthly fees. The academic literature is surprisingly thin in its discussion of demand charges, which are separate charges applied to a customer's "instantaneous" maximum monthly demand (kilowatts, kW). Such discussion has primarily been

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[1] This rate design is commonly known as a "Hopkinson Tariff," attributed to Hopkinson (1892). See also Bonbright, Danielson and Kamerschen, 1988 pp. 399–402 as well as Berg and Tschirhart (1988) pp. 104–105.

[2] A "linear pricing scheme" is a tariff with a single volumetric price per unit of output (e.g., dollars per kWh, known as an "energy charge") that does not vary and that is contained in a tariff with no other parts (such as a fixed per-customer monthly fee, known as a "customer charge"). A "non-linear pricing scheme" is a tariff with multiple parts – either with an energy charge that varies (such as with block rates) and/or with a customer charge.

[3] Ramsey prices involve mark-ups above marginal cost that vary across customer or product groups and are inversely related to a group's demand elasticity.

[4] A Coase two-part tariff sets the volumetric rate equal to marginal cost and the fixed monthly fee recovers the shortfall in revenue due to the pricing below average cost (Coase, 1946). A Coase two-part tariff will typically result in a very large customer charge.

[5] For excellent treatises on optimal utility pricing from a normative, academic perspective see "Natural Monopoly Regulation," Sanford Berg and John Tschirhart, 1988; "The Economics of Public Utility Regulation," Crew and Kleindorfer (1979); and, "The Theory of Public Utility Pricing," Brown and Sibley (1986).

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limited to criticizing the practice of applying the demand charge to a customer's maximum demand regardless of when it occurs during the month (known as the customer's "non-coincident peak demand") as opposed to applying the demand charge to the customer's load at the time the system experiences its peak (known as the customer's "coincident peak demand").[6]

Actual regulatory practices and procedures constrain what is theoretically obtainable regarding optimal utility pricing. In practice, regulated rates must be "just and reasonable" and not "unduly discriminatory." "Just" rates are those that give the privately owned utility a reasonable opportunity to a fair profit while "reasonable" rates are those that are based on prudently incurred costs required to provide safe and reliable service. Finally, rates that are not "unduly discriminatory" follow standards of horizontal equity (customers who impose similar costs on the system should face the same set of prices) and vertical equity (customers who impose different costs on the system should face different sets of prices). The determination of "just and reasonable" and "non-unduly discriminatory" rates occurs in a rate case. The class cost-of-service study (COSS) phase of a traditional electricity rate case is a standard analytical process that allocates utility costs to each rate class of customers. The notion of cost causation is crucial to the COSS, which is the systematic process of determining what activity has caused a specific category of costs to occur. Cost causation is to a class cost-of-service study as allocative efficiency is to the derivation of optimal prices in the academic realm.[7]

Within the COSS, the total annual costs the utility is allowed to recover (referred to as "revenue requirements") are classified as being one of three general types: customer-related, energy-related, or demand-related. Customer-related costs refer to costs that vary only with the number of customers regardless of a customer's demand and usage. Metering and billing costs are good examples of customer-related costs. Energy-related costs vary by the amount of kilowatt-hours (kWh) consumed by customers. Energy-related costs are all related to the generation of kWh and are primarily purchased power costs and fuel expenses as well as some variable operations and maintenance expenses such as lubricants and pollution abatement additives. Demand-related costs (also known as capacity-related costs) are sensitive to the maximum loads (measured as kW of instantaneous demand) placed on the system, which affect the amount of generation and line capacity required to satisfy these loads. These classified costs are then assigned to the various rate classes based on a variety of allocation methods. Both demand-related and customer-related costs are sometimes conventionally viewed as being "fixed" in that they are not sensitive to the production of energy (kWh). While this may be true, these two cost classifications, however, are sensitive to completely different services provided by the utility; therefore, it is inappropriate to simply comingle them into the same "fixed-cost" category and essentially treat them as the same type of cost for rate-design purposes. Demand-related costs are sensitive to the utility serving customers' maximum loads while customer-related costs are sensitive to simply connecting a customer to the network irrespective of the customer's load. Customer-related costs are positive even when kW demand and kWh are zero.

Once allocated to a particular rate class, such as the residential rate class, these classified costs must be converted into rates based on the rate design selected. A fundamental rate design option includes a fixed monthly customer charge, an energy charge applied to the kWh usage during the month, and a demand charge applied to the maximum kW demand during the month.[8] As mentioned above, the academic literature has criticized the practice of applying the demand charge to a customer's maximum demand regardless of when it occurs during the month (known as the customer's "non-coincident peak demand") as opposed to applying the demand charge to the customer's load at the time the system experiences its peak (known as the customer's "coincident peak demand").[9] This criticism is only partially justified, as it is only relevant when considering transmission and peak-load generation facilities. Simply put, total system-peak demand is not the primary cost driver associated with the capacity required for distribution and baseload generation facilities. Capacity costs for distribution facilities are more sensitive to customers' non-coincidental peak loads rather than their loads at the time of the entire system peak. Distribution transformers, for example, are sized based on the maximum loads of the customers downstream from the transformer, which occur at different times than the total system peak and is also a small subset of the total system peak demand. Second, because they are run at capacity 24/7, large baseload generation facilities are sized based on total system average (or even minimum) load. Large coal-fired steam plants and nuclear-steam plants are good examples of baseload generation.

For rate classes that either do not have metering technology capable of measuring maximum demand during the month, or may not be a good fit for the complexity inherent in demand chargesa basic demand charge cannot be used in the rate design. This limits rate design considerations to include only a customer charge and an energy charge and possibly block rates. The lack of a demand charge for these customers is arguably the source of a long-lasting debate over the magnitude of the customer charge versus the energy charge. At one extreme in this debate are those who advocate a "straight-fixed-variable" (SFV) rate design in which all "fixed" customer-related and demand-related costs are recovered through the customer charge and only the "variable" costs, such as fuel and purchased power, are recovered through the energy charge. Some electric utilities prefer the SFV rate design because it stabilizes revenue collection in the short run. At the other end of the spectrum on this debate are small-customer advocates who desire a very low customer charge because this produces lower monthly bills for low-usage households.[10] In the public utility regulatory arena, the share of demand-related (i.e., capacity-related) costs recovered from the customer charge vs. the energy charge is not typically determined in an objective cost-based manner. We provide an objective cost-based methodology to determine the best two-part tariff in the sections that follow.

2. Required billing determinants for the three-part tariff benchmark

As a starting point for our analysis, we adopt the three-part tariff with a demand charge as the preferred rate design, superior to the two-part tariff with only a customer charge and an energy charge. This presumed analytical benchmark for cost-based rates is based on the fact that: (1) capacity costs do vary in the long run by maximum customer demand; (2) maximum monthly kW demand and monthly kWh usage are statistically correlated, but not perfectly correlated,[11] and (3) these capacity costs are distinctly

6 See Wenders and Taylor (1976). An instantaneous demand on the system is also referred to as the load.

7 For excellent treatises on actual utility regulation and pricing practices and procedures, see "The Regulation of Public Utilities," Phillips, 1988); and, "The Process of Ratemaking: Volumes 1 and 2," Leonard Goodman (1998).

8 Commonly measured as the highest 15-min interval average demand. This three-part tariff design is also referred to as a "Hopkinson" tariff (see Kahn, 1971).

9 See Wenders and Taylor (1976).

10 Conservation advocates also tend to desire a low customer charge because this implies a higher energy charge.

11 For more on the correlation between kW and kWh, see Blank and Gegax (2014).

Table 1
Class Cost of Service Study Residential Population Summary.

	Actual Annual Residential Class Revenue Requirements	Actual Annual Residential Class Billing Determinants	Benchmark (hypothetical) 3-Part Tariff
Customer-Related	$96,863,780	7,084,585 customer months	$13.67 per customer per month
Demand-Related	$408,566,576	43,391,322 kW	$9.42 per kW per month
Energy-Related	$102,274,076	7,855,151,740 kWh	$0.01302 per kWh
Total	$607,704,433		

different from the customer-related costs associated with adding customers to the system such as billing and metering costs (as mentioned above, customer-related costs are positive even when kW demand and kWh are zero). In situations where demand charges are infeasible, a two-part rate design requires that demand-related costs be recovered through the energy charge, the customer charge, or a combination of the two. Note that this recovery is in addition to the energy-related costs already being recovered through the energy charge and the customer-related costs already being recovered through the customer charge.

Blank and Gegax (2014) provide results suggesting a high, statistically significant correlation between monthly household kWh usage and maximum monthly kW demand. Their analysis suggests that an energy charge may be a better substitute for a demand charge than a customer charge. That paper falls short, however, in that it does not develop a methodology for objectively determining the two-part tariff design. This article extends that research in that we prescribe an exact methodology to objectively determine the two-part tariff that most closely replicates the results of the benchmark three-part tariff with a demand charge. We apply our methodology using actual household load research data obtained from Entergy in Arkansas. Our results suggest that roughly 50% of the demand-related costs should be recovered through the customer charge, with the other 50% being recovered through the energy charge.

While it is true that most households in a typical utility's residential class of customers are not equipped with demand meters – which is why the class tariff faced by the entire population of these residential customers cannot include a demand charge – most utilities' load research efforts require that a representative *sample* of residential households be, in fact, equipped with demand meters. Load research involves using the more detailed data obtained from the residential sample of households with the more sophisticated meters to make statistically reliable inferences regarding the load profiles of the residential population as a whole. These load profiles are crucial inputs for developing demand measures and allocation methods in a class cost of service study mentioned above. In this study, we also use the results of Entergy's load research sample data to calculate the class billing determinants and the rate design analysis to objectively develop an enhanced two-part tariff. Because load research studies are commonly used by most utilities, the methodology we develop can be applied in most jurisdictions.

Billing determinants are the measures of consumption required to calculate a rate and – after rates are determined – required to calculate customers' bills. In designing rates, billing determinants are the units by which costs are divided in order to obtain a rate. For example, the total annual expected kWh of residential energy usage are the billing determinants required to derive an energy charge ($/kWh); the total number of customer-months are the billing determinants required to derive a customer charge ($/customer per month)[12]; and the total annual billing demands are the billing determinants required to derive a demand charge ($/kW). Because total annual billing demand for the residential class can be estimated using load research methods, a benchmark residential demand charge could be calculated, which is what we did in this study. It is important to note that in practice, however, unless *all* households in the population have demand meters, a demand charge cannot be included in the standard residential tariff, because the utility requires information on each particular household's monthly maximum demand, which is then multiplied by the demand charge, in order to calculate the demand-portion of the customer's bill. However, for the sample of households that do have demand meters for the utility's load-research efforts, we can calculate a hypothetical demand-portion of these households' bills. We did exactly that here by multiplying the sample households' actual metered monthly maximum demands by the aforementioned benchmark residential demand charge.

3. The data

The load research data used here were collected by Entergy Arkansas, Inc. (EAI) for calendar year 2012. These data – along with cost and usage data for the entire residential class – were provided by EAI in their most recent Arkansas-jurisdictional rate case.[13] The sample of demand-metered households included 3511 customer months out of a total residential population of 7,084,585 customer months. The residential results of the class cost of service study from EIA's most recent Arkansas-jurisdictional rate case are summarized in Table 1.

Table 1 shows that for each classification of costs, the rate elements in the benchmark three-part tariff are obtained by dividing the classified revenue requirements (in the second column) by the respective annual class billing determinants (in the third column). The revenue- requirement values and the billing-determinant values are actuals from EIA's most recent Arkansas-jurisdictional rate case. The rate elements contained in the benchmark three-part tariff are based on these actual values. The benchmark three-part tariff is hypothetical in the sense that, in actuality, not all EIA residential households have demand meters, so it could not actually be implemented. We can, however, apply the rate elements from Table 1 to the actual energy usage and loads from the sample of demand-metered households consisting of 3511 customer months, which is what we have done here. Table 2 summarizes the billing determinants and the classified revenue requirement for the demand-metered sample only. The classified revenue requirement items are obtained by multiplying the billing

[12] Total annual customer months equal the total number of customers multiplied by 12.
[13] See Arkansas Public Service Commission Docket No. 13-028-U.

Table 2
Summary of Demand-Metered Sample.

Benchmark 3-Part Tariff		Billing Determinants		Classified Revenue Requirement	
Customer Charge	$13.67	Customer-Months	3511	Customer-Related Costs	$48,004
Energy Charge	$0.01302	Annual Energy Usage (kWh)	4,989,654	Energy-Related Costs	$64,965
Demand Charge	$9.42	Annual billing demand (kW)	27,237	Demand-Related Costs	$256,461
				Total Revenue Requirement	$369,431

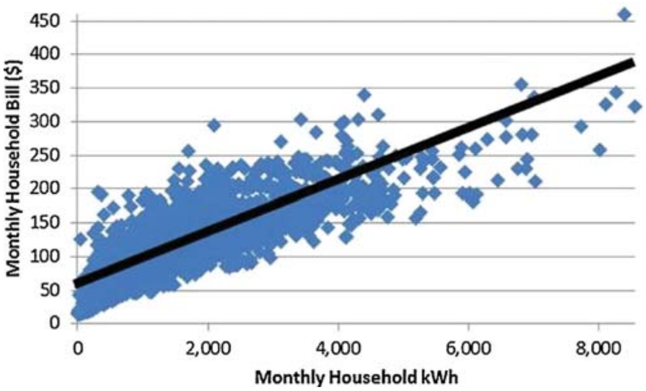

Fig. 1. Two-part tariff substitute.

determinants by the associated rate element from the benchmark three-part tariff.

The demand-metered sample had an average monthly household usage level equal to 1421 kWh and an average monthly household maximum (actual) demand equal to 7.76 kW.[14] After applying the benchmark three-part tariff rate elements to each of the 3511 customer months from the demand-metered sample, we obtain an average monthly bill of $105.22.[15] Recall that we are considering the benchmark three-part tariff as the preferred pricing scheme. The problem is that such a tariff cannot be imposed onto the entire population because, in this case, most households do not have demand meters. In other cases, such a three-part tariff may not be implemented because the regulator or utility have decided that the additional complexity is not suitable for a particular rate class. Using the same demand-metered sample of 3,511 customer months, we now turn our attention to deriving an enhanced two-part tariff, which consists only of a customer charge and an energy charge. We refer to this tariff as the "two-part tariff substitute."

4. Derivation of the two-part tariff substitute

In order to derive the two-part tariff substitute we need to determine the customer charge and energy charge that yields the smallest total variation from the (3511) customers' bills that result from the benchmark three-part tariff. The sum of the bills for the two-part tariff substitute and the benchmark three-part tariff will both equal the total revenue requirement for the demand-metered sample, which from Table 2 equals $369,431. We have now set up a simple optimization problem that all first year graduate econometrics students should recognize well: Find the line of best fit through the demand-metered sample bill data. The line of best fit is the two-part tariff line where the data to which the line is fitted are the plotted diamonds in Fig. 1, showing monthly bills (from the benchmark three-part tariff) on the Y-axis and the associated monthly household kWh usage values on the X-axis. The line of best fit, therefore, describes the two-part tariff substitute that minimizes the sum of the squared deviations between the "fitted" bills under the two-part tariff substitute and the "observed" monthly bills under the benchmark three-part tariff. The Y-intercept for the line of best fit is the enhanced two-part tariff customer charge and the slope of the line of best fit is the enhanced two-part tariff energy charge, which renders customers' bills, collectively, as close as possible to the benchmark three-part tariff.

The estimates for slope and Y-intercept for the line of best fit from the demand-metered sample of 3511 customer months were obtained by using Ordinary Least Squares. It should be noted that the goal here is not to specify a behavioral model that attempts to explain variation in household monthly kWh, but rather, to find an objectively derived two-part tariff substitute for the preferred three-part tariff. Bills under such a tariff are described by a simple linear function of monthly kWh. Therefore, it is the tariff structure that determines the "model" here – not that which best explains variation in household monthly electricity usage. The regression results (from regressing monthly bills from the three-part tariff on monthly kWh) are as follows (computed t-statistics in parentheses):

$$\hat{Y}_i = 50.5781 + 0.03845X_i$$

$$(69.54)(95.20)R^2 = 0.721$$

where $\hat{Y}_i$ denotes the fitted monthly bill value from the two-part tariff substitute for the i^{th} customer month where X_i denotes the actual monthly energy usage (kWh) for the i^{th} customer month. These results yield a customer charge equal to $50.58 per month and an energy charge equal to $0.03845 per kWh.

Applied to the demand-metered sample of 3511, the benchmark three-part tariff generated $48,004 in revenue from the customer charge ($13.6724 × 3511). This amount just covers the customer-related costs associated with the demand-metered sample as shown in Table 2. The two-part tariff substitute generates $177,580 in revenue from the customer charge ($50.58 × 3511), which is $129,576 over the actual customer-related costs associated with the sample ($177,580–$48,004 = $129,576). This $129,576 in revenue covers 50.5% of the total demand-related costs associated with the sample. The remainder of the demand-related costs is recovered through the energy charge ($0.03845 per kWh) as shown in Table 3.

[14] This compares to the average monthly household usage and average monthly household maximum (estimated) demand in the residential population of 1109 kWh and 6.13 kW respectively.

[15] The average monthly household revenue requirement across the entire residential population equals $85.78, which from Table 1 equals: ($607,704,433) ÷ (7,084,585 customer-months). With the fixed $369,431 revenue requirement as a constraint for the demand-metered sample, the average household in the sample (with 1421 kWh and 7.758 kW) will have the same $105.22 monthly bill under any of the rate designs examined in this study.

Table 3
Comparison of Benchmark Three-Part Tariff to the Two-Part Tariff Substitute.

Billing DeterminantsThis should be moved to middle of table			Benchmark Three-Part Tariff		Optimal Two-Part Tariff Substitute			
			Customer Charge	$13.6724	Customer Charge	$50.5781	Excess Revenue over Cost	% Coverage of Demand-Related Costs
			Energy Charge	$0.01302/kWh	Energy Charge	$0.03845/kWh		
			Demand Charge	$9.42/kW	Demand Charge			
Customer-Months	3511	Customer Charge Revenue	$48,004		$1,77,580		$1,29,576	50.5%
Annual Energy Usage (kWh)	49,89,654	Energy Charge Revenue	$64,965		$1,91,851		$1,26,886	49.5%
Annual Billing Demand (kW)	27,237	Demand Charge Revenue	$2,56,461		$0		-$2,56,461	
		Total Revenue	$3,69,431		$3,69,431		$0	

5. Implications for electricity rate design

In such situations wherein metering is limited to measurement of energy (kWh) consumption or a decision has been made that three-part rates are not suitable for a particular class, rate design is limited to the use of a customer charge and some type of energy charge ($/kWh) design, which may or may not vary based on a customer's total monthly kWh consumption or by season of the year. In actual utility regulation cases, the share of demand-related (i.e., capacity-related) costs recovered from the customer charge vs. the energy charge is not typically determined in an objective cost-based manner. We have provided an objective methodology for such determination.

Using 2012 load research data – along with cost and usage data for the entire residential class – provided by Entergy Arkansas in a recent Arkansas-jurisdictional rate case, we derive an enhanced two-part tariff, which serves as a substitute for the benchmark three-part tariff. The benchmark three-part tariff collects all the customer-related costs through the customer charge; all the demand-related costs through the demand charge; and all the energy-related costs through the energy charge.[16] We prescribe an exact methodology to objectively determine the two-part tariff that most closely replicates the results of the benchmark three-part tariff with a demand charge. The two-part tariff substitute is derived by finding the customer-charge/energy-charge combination that minimizes the (squared) deviations from customers' bills generated through the benchmark three-part tariff. With the EAI data used in this study, the two-part tariff substitute collects approximately half of the demand-related costs (as well as all the customer-related costs) through the customer charge and half of the demand-related costs (as well as all the energy-related costs) through the energy charge. This result greatly contradicts the conventional practice, which recovers nearly 100% of the demand-related costs (or more) through the energy charge.[17] Our analysis also suggests that the other extreme – a straight-fixed variable (SFV) approach – may not be justified based on cost. The SFV approach collects all the demand-related and customer-related costs through the fixed customer charge. The analysis here clearly shows that, in order to get household bills collectively as close as possible to a benchmark three-part tariff, a significant amount of the demand-related costs should be recovered through the energy charge. This result is consistent with Blank and Gegax (2014) that show a strong correlation between monthly household kWh usage and maximum monthly kW demand, but takes the analysis to the next level by objectively determining the amount of demand-related costs that should be recovered through an energy charge.

6. Lacunae and future research

We have identified several possible aspects of our approach that may be worthy of future research. First, our use of a hypothetical demand charge to produce our monthly bill observations ignores any household behavioral changes to reduce monthly maximum demands and possibly improve load factors. Second, for commissions that have explicit tilt policies for demand-metered customers, consistency may suggest that (for customers without demand meters) more of the demand-related costs be recovered from the energy charge than that suggested by the two-part tariff substitute. Third, commissions may consider an increasing block rate design rather than the linear energy charge derived for the two-part tariff substitute to encourage conservation. One possible option would be to move some of the cost recovery in the customer charge into the second or third block of an increasing block rate design. Fourth, the relatively high customer charge suggested by our result will cause below-average-usage customers to have higher monthly bills. This may produce an undesirable social welfare impact on below-average usage customers who are also low-income households.

Some advocates in favor of maintaining very low customer charges do so based on the belief that low usage implies low income. Although it is true that a lower customer charge reduces the monthly bills for below-average-use customers, low usage does not necessarily imply low income. There are a variety of reasons why low-income households may use above average amounts of energy such as energy inefficient residences in older apartment buildings or houses, inefficient appliances, more individuals living in the home, and more hours spent in the home each month. Indeed, a recent British study finds that 25% of households in the lowest income quintile use above-average amounts of gas and electricity.[18] Reliance on a low customer charge to help low-income households would in that case actually

[16] Technically the energy charge in the three-part tariff collects all the base energy costs. It is typically the case that a portion of the (non-base) energy-related costs (especially for fuel) are collected through an automatic adjustment mechanism, which can adjust non-base rates in response to changes in actual energy costs without the need for a rate case. Depending on the jurisdiction, the adjustment can be on either a monthly, quarterly or annual basis.

[17] It is also not unusual for some commissions in their residential tariff design to collect a portion of the customer-related costs – as well as 100% of the demand-related costs – from the energy charge. An exception to this policy has been the Ohio Public Utilities Commission, which has ordered the filing of SFV by its gas and electric utilities. See Ohio PUC (2013).

[18] White et al., 2010, p. 10.

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increase the electric bills of 25% of low-income households, which is not very efficient. Additional research is necessary on the correlation between individual household income and energy usage, and in the spirit of Eriksson et al. (1998), more research is necessary on the welfare losses associated with the use of rate design attempting to assist low-income households versus a more targeted subsidy approach for qualifying households. We suspect a similar finding in that targeted low-income subsidy programs are likely to prove less costly and more effective in helping low-income households rather than the subsidies from high-usage customers to low-usage households. Additional empirical research is required on the relationship between low income and usage and the design of low-income household rates.

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