

# Exhibit MG\_4

## Rates

# Use Great Caution in Design of Residential Demand Charges

*Jim Lazar*

**F**or decades, electricity prices for larger commercial and industrial customers have included demand charges, which recover a portion of the revenue requirement based on the customer's highest usage during the month. Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Great caution should be applied when considering the use of demand charges, particularly for smaller commercial and residential users. Severe cost shifting may occur. Time-varying energy charges result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. The caution applied should address the following key issues in most demand-charge rate designs:

- *Diversity:* Different customers use capacity at different times of the day, and these customers should share the cost of this capacity.
- *Impact on Low-Use Customers:* Most demand-charge rate designs have the effect of increasing bills to low-use customers,

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including the vast majority of low-income customers.

- *Multifamily Dwellings:* The utility never serves individual customer demands in apartment buildings, only the combined demand of many customers at the transformer bank.
- *Time Variation:* If demand charges are not focused on the key peak hours of system usage, they send the wrong price signal to customers.

In the recent Regulatory Assistance Project (RAP) publication *Smart Rate Design for a Smart Future*,<sup>1</sup> we looked at many attributes of rate design for residential and small commercial consumers. We identified three key principles for rate design:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Customers should pay for power supply and grid services based on how much these customers use and when they use it.
- Customers supplying power to the grid should receive full and fair compensation—no more and no less.

Applying these principles results in an illustrative rate design that constructively applies costing principles in a manner that consumers can understand and respond to. **Exhibit 1** shows the illustrative rate design, including a customer charge for customer-specific billing costs and a demand charge for customer-specific transformer capacity costs. The exhibit also includes a time-varying energy price to recover distribution

**Exhibit 1. Illustrative Rate Design**

Illustrative Residential Rate Design		
Rate Element	Based On the Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	\$4.00/month
Transformer Charge	Final Line Transformer	\$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	\$0.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	\$0.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	\$0.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	\$0.74/kWh

Source: Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Montpelier, VT: Regulatory Assistance Project. Retrieved from <http://raponline.org/document/download/id/7680>.

system capacity costs and power supply costs designed to align prices with long-run marginal costs.

Customers can and will respond to rate design. We need to make sure that their actions actually serve to maximize their value and minimize long-run electric system costs. The illustrative rate is clearly directed toward these ends.

**DEMAND CHARGES HAVE ALWAYS BEEN ONLY AN APPROXIMATION**

Demand charges are imposed based on a customer’s demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month. Demand charges are sometimes coupled with a “ratchet” provision

that charges the customer on the basis of the highest measured demand over the previous 12-month period or other multi-billing-period span of time.

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**Exhibit 2** is a typical medium commercial rate design. It includes a demand component.

Utilities often justified demand charges on the basis of two arguments. First, they were

**Exhibit 2. Illustrative Demand Charge Rate**

**Basic Tariff For Large Commercial Customer**

Rate Element	Price
Customer Charge \$/month	\$20.00
Demand Charge \$/kW/month	\$10.00
Energy Charge \$/kWh	\$0.08

**Key Terms for Demand Charges**

**CP:** coincident peak demand: the customer’s usage at the time of the system peak demand.

**NCP:** non-coincident peak demand: the customer’s highest usage during the month, whenever it occurs.

**Diversity:** the difference between the sum of customer NCP and the system CP demands.

asserted as a “fairness” rate that assured that all customers paid some share of the utilities’ system capacity costs. Second, especially when coupled with ratchets, they had the effect of stabilizing revenues.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak.

But demand charges are a shortcut, measuring each customer’s individual highest usage during a month, regardless of whether the usage was coincident with the system peak. The customer’s individual peak was used as a proxy for that customer’s contribution to system capacity costs. Demand charges were implemented in this way even though customers’ individual demands did not coincide with the peak system demand, or more accurately, with the coincident peak for the individual components of the system involved, each of which may have peaks different from the system peak. This was always a “second-best” approach. It is roughly accurate for large

commercial customers, because their highest usage *usually* (but not always) coincided with the system peak.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak. The rough accuracy that exists for using non-coincident peak (NCP) demand charges for large commercial customers is woefully inaccurate for residential consumers. But coincident-peak (CP) demand charges have other shortcomings, leaving some customers with more than their share of costs and others with none at all, as shown in **Exhibit 3**.

With data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour of usage.

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**Exhibit 3.** Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

of usage. This more precise usage data makes demand charges a largely antiquated approach for all customer classes—and particularly inappropriate for residential consumers.

### **DIVERSE USER PATTERNS VARY GREATLY**

Residential customers use system capacity at different times of the day and year. Some people are early-risers, and others stay up late at night. Some shower in the morning, and some in the evening. Some have electric heat, and others have air conditioning.

This variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs. Demand charges are not very useful for this purpose.

A half-century ago, Garfield and Lovejoy discussed how system capacity costs should be reflected in rates.<sup>2</sup> Their observations, summarized in Exhibit 3, are as relevant today as when they were published. We compare the performance of three rate-design approaches to these criteria.

Variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs.

Following this guidance, capacity costs need to be recovered in every hour, with a concentration of these charges in system peak hours. The illustrative rate design in Exhibit 1 does this effectively. The typical commercial rate design in Exhibit 2, loading system capacity costs to an NCP demand charge, does not, because it recognizes only one hour of customer-specific demand.

Churches and stadiums illustrate this problem with demand charges. Churches have peak demands on days of worship—most often Wednesday nights and Sunday mornings, and stadium lights are used only a few hours per month, in the evening hours in the fall and winter. None of this usage is during typical peak periods.

Applying demand charges to recover system capacity costs based on non-coincident peak demand to churches and stadiums has long been recognized as inappropriate. Such charges have the effect of imposing system capacity costs on customers whose usage patterns contribute little, if anything, to the capacity design criteria of an electric utility system at the same rate as customers using that capacity during peak periods. The same problem applies for residential consumers.

On a typical distribution system, multiple residential consumers share a line transformer, and hundreds or thousands share a distribution feeder. The individual non-coincident demands of individual customers are not a basis for the sizing of the distribution feeder; only the combined demands influence this cost. Even at the transformer level, some level of diversity is assumed in determining whether to install a 25-kilovolt-amp or 50-kilovolt-amp transformer to serve a localized group of perhaps a dozen customers.

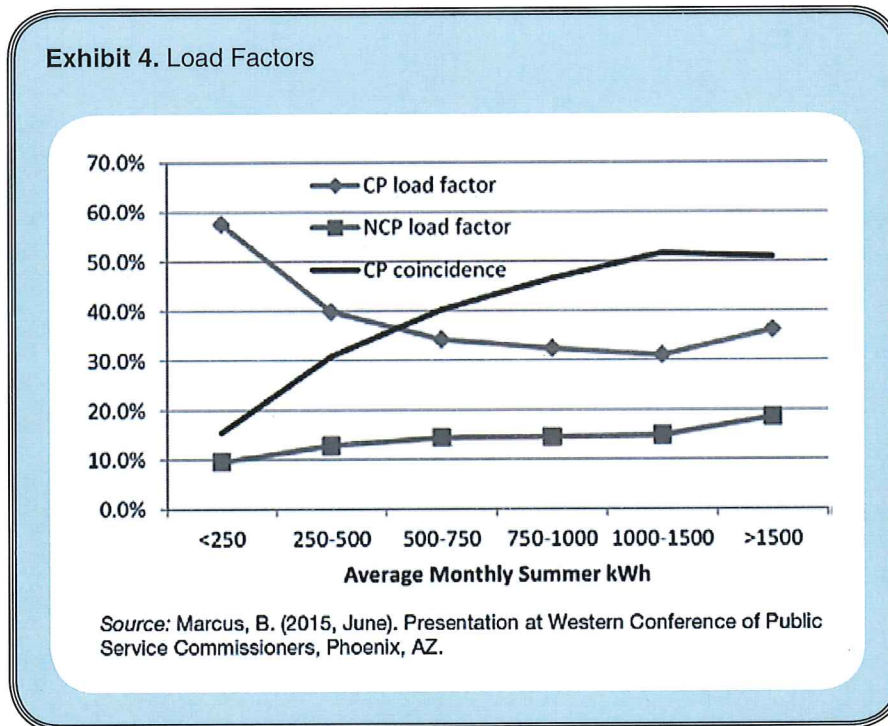
Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month.

Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month. Some customers (think of a doughnut shop and nightclub) use capacity only in the morning or evening, and can share capacity, while others (think of a 24-hour mini-mart) use capacity continuously and preempt this capacity from use by others. Modern rate design needs to distinguish between different characteristics in the usage of capacity and ensure all customers make an appropriate contribution to system capacity costs.

Time-varying rates do this very well, while simple CP and NCP demand charges do not.

### **IMPACT ON LOW-USE CUSTOMERS**

Individual residences have very low individual customer load factors but quite average collective usage patterns.



**Exhibit 4** shows data from Southern California Edison Company. As is evident, while the individual customer load factors of small-use residential customers are only about 10 percent, their group coincident peak load factor is more like 60 percent, quite close to an overall system load factor. A demand charge based on NCP demand greatly overcharges these customers. Meanwhile, the high-use residential customers, who have more peak-oriented loads, would be undercharged with a simple NCP demand charge based on overall residential usage.

The evidence is that the effect is to shift costs to smaller-use customers.

Rate analysts have examined the impact of demand-charge rate designs on residential customers. The evidence is that the effect is to shift costs to smaller-use customers, with about 70 percent of small-use residential customers experiencing bill increases, and about 70 percent of large-use residential customers experiencing bill decreases, even before any shifting of load.<sup>3</sup>

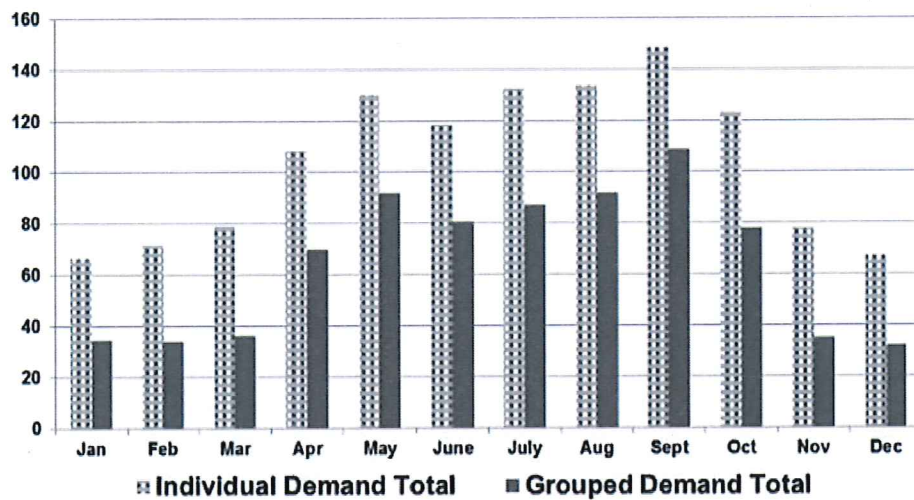
#### APARTMENT DIVERSITY

About 30 percent of American households live in some sort of multifamily dwelling. Apartments generally have the lowest cost of service of any residential customer group, because the utility provides service to many customers at a single point of delivery through a transformer bank sized to their combined loads. Because the sum of individual customer NCP demand greatly exceeds the combined group demand the utility serves, and by a greater margin than for other customer subclasses, NCP demand charges shift costs inappropriately to these multifamily customers.

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Low-income consumers are more likely to reside in apartments, and nationally, low-income household usage is about 70 percent of average household usage.<sup>4</sup> Therefore, imposing NCP demand charges on residential consumers, without separate treatment of apartments, would have a serious adverse impact on these customers, many of whom are

**Exhibit 5. Individual and Group Peaks for a 26-Unit Apartment Building**



Source: Author, from data supplied by Los Angeles-area municipal utility.

low-income households and often strain to pay their electric bills.

**Exhibit 5** shows the sum of individual customer monthly non-coincident peaks for a 26-unit apartment complex in the Los Angeles area, and the monthly group peaks of these customers actually seen by the utility at the transformer bank serving the complex. The exhibit shows that billing customers on the basis of non-coincident peak demand would dramatically overstate the group responsibility for system capacity costs.

#### TIME-VARYING COST RECOVERY

As expressed by Garfield and Lovejoy, the optimal way to recover system capacity costs is through a time-varying rate design. This can be as simple as a higher charge for usage during on-peak hours than off-peak hours, or it can be a fully dynamic hourly time-varying energy rate. What is clear is that a single demand charge, applied to a single one-hour NCP or CP measure of demand, is unfair to those customers whose usage patterns allow the shared use of system capacity.

Some utilities have implemented time-varying demand charges. California investor-

owned utilities impose NCP demand charges for distribution costs, and CP demand charges for generation and transmission capacity on larger commercial consumers. More recently, some utilities have imposed demand charges on smaller customers based on summer on-peak-hour demands only. All of these reflect gradual movement toward equitable recovery of system capacity costs, but full time-of-use (TOU) energy pricing is more effective, more cost-based, more equitable, and more understandable.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month. Usage during peak periods can be assigned the costs of peaking power supply resources and seldom-used distribution system capacity costs installed for peak hours. Usage during other hours can be assigned the cost of baseload resources and the basic distribution infrastructure needed to deliver that power.

The pricing can be as granular as the analyst chooses and the regulator approves—but a key element of rate design is simplicity. For that reason, most analysts shy away from rate design with more than three time periods and a few rate elements.

The illustrative rate design in Exhibit 1 shows a three-period TOU plus critical peak price for both power supply and distribution capacity cost recovery, a customer charge for billing costs, and a demand charge to recover the cost of the final line transformer. It may be as complex a rate design as most residential consumers will reliably understand.

### TRANSITIONING TO A TOU RATE DESIGN

Many customer groups are apprehensive about time-varying utility rates, because some consumers will receive higher bills and may not be able easily to change their usage patterns. This same concern would apply to implementation of a demand-charge rate design, but because that produces a less desirable result, we do not consider it a meaningful option. There are the following tools that can be used for a transition:

- *Shadow billing:* Provide consumers with *both* the current rate design and the proposed TOU rate design calculated on the bill prior to rollout.
- *Load control:* Prior to implementing a TOU rate, assist customers to install controls on their major appliances to ensure against inadvertent usage during on-peak periods.
- *Customer-selected TOU periods:* The Salt River Project in Arizona has had excellent success allowing customers to choose a three-hour “on-peak” period out of a four-hour system peak period.<sup>5</sup>

### COMMON ERRORS IN DEMAND-CHARGE DESIGN

Common errors include the following:

- *Upstream Distribution Costs:* Any capacity costs upstream of the point of customer connection can be accurately assigned to usage and recovered in time-varying prices.
- *Using NCP Demand:* NCP demand is not relevant to any system design or investment

criteria above the final line transformer, and only there if the transformer serves just a single customer.

- *Accounting for Diversity:* Diversity is greatest among small-use customers and needs to be fully accounted for.
- *Apartments:* Apartments have the lowest cost of service of any residential customer group, the highest diversity, and suffer the most when a single rate design is applied to all residential customers.

### GUIDANCE FOR COST-BASED DEMAND CHARGES

The following guidelines can be used;

- Limit any demand charges to customer-specific capacity.
- Fully recognize customer load diversity in rate design.
- Demand charges upstream of the customer connection, if any, should apply only to the customer’s contribution to system coincident peak demand.
- Compute any demand charges on a multi-hour basis to avoid bill volatility.

Modern metering and data systems make it possible to increase greatly the accuracy, and therefore the fairness, of cost allocation among a diverse customer base. Legacy concepts, such as demand charges, especially those based on NCP demand, prevent the implementation of these improvements and should be eliminated. Time-varying cost assignment is preferred, so that these new technologies can deliver their full value to customers and utilities alike. □

### NOTES

1. Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future*. Montpelier, VT: Regulatory Assistance Project. Retrieved from <http://raponline.org/document/download/id/7680>.
2. Garfield, P. J., & Lovejoy, W. F. (1964). *Public utility economics*. Englewood Cliffs, NJ: Prentice Hall; pp. 163–164.
3. Hledik, R. (2015). *The landscape of residential demand charges*. Presented at the EUCI Demand Charge Summit, Denver.
4. Testimony of John Howat, National Consumer Law Center, Indiana Utility Regulatory Commission, Cause No. 44576, 2015.
5. SRP “EZ-3” Rate. Retrieved from <http://www.srpnet.com/prices/home/ChooseYourPricePlan.aspx>.

# Exhibit MG\_5

### **C. The Minimum-System vs. Minimum-Intercept Approach**

**W**hen selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

### **D. Other Accounts**

**T**he preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step,

it is not as controversial as the classification of substations, poles, transformers, and conductors.

**1. Account 369 - Services**

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

**2. Account 370 - Meters**

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

**3. Account 371 - Installations on Customer Premises**

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

**4. Account 373 - Street Lighting and Signal Systems**

This account is generally customer-related and is directly assigned to the street customer class.

**III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT**

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

**A. Development of the Distribution Demand Allocators**

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

# Exhibit MG\_6

**THE NATIONAL ASSOCIATION OF  
STATE UTILITY CONSUMER ADVOCATES  
RESOLUTION 2015-1**

**OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE  
DELIVERY SERVICE CUSTOMER CHARGES**

*Whereas*, the National Association of State Utility Consumer Advocates (“NASUCA”) has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

*Whereas*, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer’s usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

*Whereas*, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are “fixed” and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

*Whereas*, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

*Whereas*, gas and electric utilities’ own embedded cost of service studies,<sup>1</sup> in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

*Whereas*, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,<sup>2</sup> in some instances; and

*Whereas*, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

*Whereas*, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

*Whereas*, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called “reportable domains,”<sup>3</sup> low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;<sup>4</sup> and

*Whereas*, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;<sup>5</sup> and

*Whereas*, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;<sup>6</sup> and

*Whereas*, data from the U.S. Department of Energy’s Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,<sup>7</sup> thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S.;<sup>8</sup> and

*Whereas*, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

*Whereas*, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer’s utility bill consisting of variable usage charges, customers’ incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

*Whereas*, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

*Whereas*, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer’s utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

*Now, therefore, be it resolved*, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

***Be it further resolved***, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

***Be it further resolved***, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

***Be it further resolved***, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

***Be it further resolved*** that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015  
Philadelphia, Pennsylvania

No Vote: Wyoming  
Abstention: Vermont

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<sup>1</sup>See, e.g., Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates*, PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company*, AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

<sup>2</sup>ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

<sup>3</sup>The U.S. Energy Information Administration’s Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as “reportable domains.”

<sup>4</sup>See Wis. Pub. Serv. Com’n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natural Gas Rates*, Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by “Reportable Domain” at 5-6.

<sup>5</sup>*Id.* at 7-8.

<sup>6</sup>U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

<sup>7</sup>See ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates*, AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

<sup>8</sup>U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

# Exhibit MG\_7

**The Alliance for Solar Choice**  
**Data Request TASC-6**  
***Cause No. PUD 201500273***

- 6-2 In reference to page 15, lines 1 through 7, Mr. Scott states that "OG&E established separate classes for DG customers."
- a. Did the Company undertake load research on distributed generation customers?
  - b. Please provide a detailed description of the methods and inputs used to create the load research study for distributed generation customers and any associated workpapers.
  - c. To the extent that the updated tariff prices for the distributed generation residential class are lower than the rates proposed in Cause No. 201500274, does this reflect the fact that the residential distributed generation class has a lower cost to serve than the general residential class?

Response\*:

- a. Yes, Load Research was performed on the distributed generation customers.
- b. Residential distributed generation (DG) customers and General Service DG customers were both treated like the other customer groups (except Lighting) by starting with the mean-per-unit (MPU) load shape and then performing several adjustments to arrive at the final load shape for that customer group. However, for DG customer groups, the energy flows two ways: in and out. The meter measures the net flowing in (Channel 1) and the net flowing out (Channel 3). The MPU is computed as follows:

For each DG customer, for each hour, Channel 3 was subtracted from Channel 1; any negative results were changed to zero. [see Subchapter 9 - Optional Net Energy Billing Purchase Rate (165:40-9-3)]. The MPU is the average of these calculations. The results were then used in the development of the Production Demand Allocator and the Transmission Demand Allocator (see WP L-13 Pg4).

The maximum of Channel 1 and Channel 3 for each DG customer, for each hour, was used to calculate another MPU. The results for this MPU were then used in the development of the Distribution Demand Allocator (see WP L-13 Pg2).

Please see **TASC 6-2\_Att** for the MPU for the Residential DG group and the General Service DG group, for both methods, and the adjustments made to these load shapes.

- c. No. The prices for the standard residential rate for the general residential class were not at issue in Cause No. 201500274.

In addition, OG&E has not performed an analysis comparing the residential DG tariff prices proposed in this Cause with those proposed in Cause No. 201500274. OG&E believes the prices it proposed in both Causes were and are cost justified within normal rate design parameters.

Response provided by: Bryan Scott  
Response provided on: March 22, 2016  
Contact & Phone No: Sheri Richard 405-553-3747

\*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.