BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT TESTIMONY

OF

AHMAD FARUQUI

ON BEHALF OF

WESTAR ENERGY

DOCKET NO. 18 – WSEE-328 -RTS

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I. INTRODUCTION

Q. WHAT ARE YOUR NAME AND ADDRESS?

A. My name is Ahmad Faruqui. I am a Principal with the Brattle Group, an economics consulting firm. My address is 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am testifying on behalf of Westar Energy, Inc. (“Westar”).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to comment on Westar’s proposed modifications to its residential rate offering, with a focus on the proposed rate for DG customers.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into several sections:

- Section II presents my qualifications.
- Section III is an executive summary.
- Section IV is a brief summary of Westar’s residential rate proposal.
- Section V discusses the generally accepted principles of rate design.
- Section VI explains how a three-part rate satisfies these principles of rate design.
- Section VII discusses the problems with offering a two-part rate to DG customers.
- Section VIII presents quantitative analysis of the impacts of the proposed rate on DG customers.

- Section IX presents analysis of the likely response of non-DG customers to the introduction of a voluntary three-part rate, and the implications for Westar's revenues.
- Section X discusses Westar's proposal to increase the customer charge in its residential rates.
- Section XI concludes my testimony.

Several appendices are attached to my testimony, including a glossary of acronyms in Appendix B.

II. QUALIFICATIONS

Q. WHAT ARE YOUR QUALIFICATIONS AS THEY PERTAIN TO THIS TESTIMONY?

A. I am an energy economist. My consulting practice is focused on customer-related issues. My areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting.

I have worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. I have testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. Also, I have presented to governments in Australia, Canada, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents.

My research has been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. I have appeared on Fox Business News, National Public Radio and Voice of America and I have authored, co-authored, or co-editor 4 books and more than 150 articles, papers, and reports on energy matters. I have published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly.

I hold B.A. and M.A. degrees from the University of Karachi, Pakistan, an M.A. in agricultural economics and a Ph.D. in economics from the University of California at Davis.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE KANSAS CORPORATION COMMISSION?

A. Yes. I previously filed testimony on behalf of Westar Energy before the Kansas Corporation Commission (KCC) in Docket No. 15-WSEE-115-RTS ("115" docket) regarding a proposal to modify the residential rate design. I filed comments on behalf of Westar Energy in Docket No. 16-GIME-403-GIE ("403" docket) in support of creating a separate rate class for residential DG customers.

More details regarding my professional background and experience are set forth in my Statement of Qualifications, included in Appendix A.

III. EXECUTIVE SUMMARY

Q. HOW WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. To ensure that its residential rate offering is consistent with the generally accepted principles of rate design, Westar is proposing a mandatory three-part rate design for residential DG customers and a voluntary three-part rate design for non-DG customers. Each rate will consist of a basic service fee ($/month), a volumetric charge ($/kWh), and a demand charge ($/kW-month).

In my testimony, I elaborate on the following points:

- The three-part rate that Westar has proposed is consistent with well-established principles for sound rate design, including economic efficiency, equity, revenue adequacy and stability, bill stability, and customer satisfaction.

- Support for three-part rates is found throughout the industry-accepted literature on rate design.
- Three-part rates are a proven concept and have been offered to commercial and industrial customers across the U.S. for decades, as well as residential customers in several states, including Westar's residential customers (on a limited basis).
- Empirical evidence and reason suggest that customers can understand the concept of demand and will respond to three-part rates by modifying their electricity consumption patterns in economically beneficial ways.
- Demand charges also promote the adoption of beneficial energy technologies like smart thermostats and batteries.
- A portion of Westar's non-DG customers is likely to voluntarily switch to the three-part rate. Bill reductions associated with this switch could lead to revenue loss for Westar.
- Westar's proposed basic service fee of $18.50/month is within the range of those observed by other utilities in Kansas and across the Midwestern U.S.

IV. BRIEF SUMMARY OF WESTAR'S RESIDENTIAL RATE PROPOSAL

Q. WHAT IS WESTAR'S CURRENT RATE DESIGN?

A. Westar currently offers its residential customers a "two-part rate" through Schedule RS. Schedule RS is referred to as a two-part rate, because it consists of two types of charges: a basic service fee, which is a fixed charge per customer ($/month), and a volumetric charge which is based on the amount of electricity the customer has consumed (cents/kWh).

Westar also offers a three-part rate through the Residential Peak Management Electric Service rate (the “Peak Management rate”). The Peak Management rate includes a “demand charge” in addition to the basic service fee and the volumetric charge. The demand charge is based on the customer’s maximum 30-minute demand during the monthly billing cycle. The Peak Management rate is only available to customers in the North Rate Area and has been closed to new enrollment since 2006.

Schedule RS and the Peak Management Rate are summarized in Table 1.

Table 1: Westar's Current Residential Rates

Residential Standard Service

	Winter	Summer
Basic Service Fee ($/month)	14.50	14.50
Energy charge ($/kWh)		
First 500 kWh	0.076833	0.076833
Next 400 kWh	0.076833	0.076833
All additional kWh	0.062804	0.084752

Residential Peak Management Electric Service

	Winter	Summer
Basic Service Fee ($/month)	16.50	16.50
Energy charge ($/kWh)	0.046644	0.046644
Demand Charge ($/kW-month)	2.13	6.91

Riders (applicable to both rates)

	Winter	Summer
RECA ($/kWh)	0.021633	0.021633
PTS ($/kWh)	0.000892	0.000892
TDC ($/kWh)	0.017882	0.017882
EER ($/kWh)	0.000231	0.000231

Q. DOES WESTAR CURRENTLY OFFER A SEPARATE RATE SCHEDULE FOR RESIDENTIAL DG CUSTOMERS?

A. Yes. Westar implemented a separate rate schedule for DG customers in 2015. That rate schedule is designated Residential Rate Schedule Distributed Generation (RS-DG). Currently, the rate under Schedule RS-DG is the same as that for Schedule RS – the rate applicable to residential non-DG customers. In 2017, the KCC's decision in the "403" docket established that residential DG customers should remain a separate class for ratemaking purposes and that the current two-part rate design was not sufficient for fully collecting costs from these customers.[1] In its Order, the KCC cited unique load characteristics and costs of service of residential DG customers that are significantly different than that of non-DG customers. The KCC Order identified a number of alternative rate designs that could be offered to DG customers under Schedule RS-DG, including a three-part rate with a demand charge. Consistent with the Commission order in the "403" docket Westar is proposing a new rate design for residential DG customers served under Schedule RS-DG.

Q. WHAT ASPECTS OF WESTAR'S PROPOSAL IN THIS PROCEEDING WILL YOU BE ADDRESSING IN YOUR TESTIMONY?

A. I will address the following aspects of Westar's proposal:

1. Transitioning to a mandatory three-part rate for residential DG customers
2. Introducing a voluntary three-part rate for residential non-DG customers
3. Increasing the basic service fee in Schedule RS and Schedule RS-DG.

[1] "…the Commission finds the current two-part residential rate design is problematic for utilities and residential private DG customers because DG customers use the electric grid as a backup system resulting in their consuming less energy than non-DG customers, which results in DG customers not paying the same proportion of fixed costs as non-DG customers." KCC, Final Order in Docket No. 16-GIME-403-GIE, pp. 8-9.

Q. WHAT IS THE MANDATORY THREE-PART RATE THAT WESTAR HAS PROPOSED FOR RESIDENTIAL DG CUSTOMERS?

A. Westar has proposed a seasonally differentiated three-part rate for residential DG customers. The rate is designed to better reflect the cost of serving DG customers, and is based specifically on a class cost of service (CCOS) study for those customers. The proposed rate, which is an update to the current RS-DG rate, is summarized in Table 2.[2]

Table 2: Westar's Proposed Rate Design for DG Customers (RS-DG)

	Winter	Summer
Basic Service Fee ($/month)	18.50	18.50
Energy charge ($/kWh)	0.072331	0.072331
Demand Charge ($/kW-month)	3.15	9.45
Riders ($/kWh)	0.040638	0.040638

Note: The riders are RECA, PTS, TDC, and EER. They are assumed to be the same prices that are associated with Schedule RS.

Q. WHAT IS THE VOLUNTARY THREE-PART RATE THAT WESTAR HAS PROPOSED FOR RESIDENTIAL NON-DG CUSTOMERS?

A. The voluntary three-part rate for residential non-DG customers is based on the same conceptual design as the DG rate described

[2] My understanding is that the CCOS study and the associated rates have been divided into two "steps." Step 1 accounts for the full revenue requirements, and step 2 additionally recovers the effects of expiring wholesale contracts just outside the rate case window. For simplicity, throughout my testimony I rely on the Step 2 CCOS study and rates.

above, but with prices that are based on the cost requirements of serving the residential non-DG customer class. Table 3 summarizes the proposed rate, which is referred to as the Residential Peak Efficiency rate, or Schedule RPER. It would be offered in addition to Schedule RS.

Table 3: Westar's Proposed Rate Design for Non-DG Customers (RPER)

	Winter	Summer
Basic Service Fee ($/month)	18.50	18.50
Energy charge ($/kWh)	0.056234	0.056234
Demand Charge ($/kW-month)	3.15	9.45
Riders ($/kWh)	0.040638	0.040638

Note: The riders are RECA, PTS, TDC, and EER. They are assumed to be the same prices that are associated with Schedule RS.

Q. WHAT IS WESTAR'S PROPOSAL REGARDING THE CUSTOMER CHARGE IN ITS RESIDENTIAL RATES?

A. Westar is proposing to increase the basic service fee in its residential rate schedules to $18.50 per month. This increase is intended to be more in line with Westar's fixed costs of serving residential customers. The proposed customer charge does not fully reflect the fixed per-customer costs identified in Witness Amen's testimony, which are estimated to be $27.46 for residential non-DG and $28.28 for residential DG, but it moves a small step in that direction. The proposed increase in the fixed charge is accompanied by a decrease in the volumetric charge in such a way that the average customer's bill would not change. In other words, the change is revenue neutral.

V. PRINCIPLES OF RATE DESIGN

Q. IS THERE SUPPORT FOR THREE-PART RATES IN THE LITERATURE ON RATE DESIGN?

A. Yes. The principles that guide rate design and support the deployment of three-part rates have evolved over time. Many authorities have contributed to their development, beginning with the legendary British rate engineer John Hopkinson in the late 1800s.[3] Hopkinson introduced demand charges into electricity rates. Not long after, Henry L. Doherty proposed a three-part tariff, consisting of a fixed service charge, a demand charge and an energy charge.[4] The demand charge was based on the maximum level of demand which occurred during the billing period. Some versions of the three-part tariff also feature seasonal or time-of-use (TOU) variation corresponding to the variations in the costs of energy supply.[5]

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3 John R. Hopkinson, "On the Cost of Electricity Supply," Transactions of the Junior Engineering Society, Vol. 3, No. 1 (1892), pp.1-14.

4 Henry L. Doherty, Equitable, Uniform and Competitive Rates, Proceedings of the National Electric Light Association (1900), pp.291-321.

5 See, for example, Michael Veall, "Industrial Electricity Demand and the Hopkinson Rate: An Application of the Extreme Value Distribution," Bell Journal of Economics, Vol. 14, Issue No. 2 (1983).

In the decades that followed, a number of British, French and U.S. economists and engineers made further enhancements to the original three-part rate design.[6] In 1961, Professor James C. Bonbright coalesced their thinking in his canon, Principles of Public Utility Rates,[7] whose expanded second edition is co-authored with Albert Danielsen and David Kamerschen. Some of these ideas were further expanded upon by Professor Alfred Kahn in his treatise, The Economics of Regulation.[8]

Q. WHAT ARE THE GENERALLY ACCEPTED PRINCIPLES OF RATE DESIGN FOR ELECTRICITY?

A. In the first edition of his text, Bonbright propounded eight principles which were expanded into ten principles in the second edition. These are almost universally cited in rate proceedings throughout the U.S. and are often used as a foundation for designing rates. For ease of exposition, I have grouped these into five core principles: economic efficiency, equity, bill stability, customer satisfaction, and revenue adequacy and stability.

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6 The most notable names include Maurice Allais, Marcel Boiteux, Douglas J. Bolton, Ronald Coase, Jules Dupuit, Harold Hotelling, Henrik Houthakker, W. Arthur Lewis, I. M. D. Little, James Meade, Peter Steiner and Ralph Turvey.

7 James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Principles of Public Utility Rates, 2d ed. (Arlington, VA: Public Utility Reports, 1988).

8 Alfred Kahn, The Economics of Regulation: Principles and Institutions, rev. ed. (MIT Press, June 1988).

Q. WHAT IS THE PRINCIPLE OF ECONOMIC EFFICIENCY?

A. The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid, and thus the greatest benefit to electric customers as a whole.

Q. WHAT IS THE PRINCIPLE OF EQUITY?

A. There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat rate pricing structures (*i.e.*, cents/kWh). Since customers have different load profiles, "peaky" customers, who use more electricity when it is most expensive, are subsidized by less "peaky" customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of the other, and vice versa.

Q. WHAT IS THE PRINCIPLE OF BILL STABILITY?

A. Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWh's in Year 1, and the number of kWh's halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.

Q. WHAT IS THE PRINCIPLE OF CUSTOMER SATISFACTION?

A. Rates should enhance customer satisfaction. Because most residential customers devote relatively little time to reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to the rates by modifying their energy use patterns. Giving customers meaningful cost-reflective rate choices helps enhance customer satisfaction.

Q. WHAT IS THE PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?

A. Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.

Q. IS THERE AN OVERRIDING PRINCIPLE THAT SHOULD GUIDE RATE DESIGN DECISIONS?

A. Yes. The overriding principle in rate design is that of cost-causation. In other words, the rate structure should reflect the underlying cost structure. The importance of economic efficiency – and specifically on designing rates that reflect costs – is emphasized by Bonbright. In the first edition of his text, Bonbright devotes an entire chapter to cost causation. In the chapter, he states: “One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred.”[9] Later, he states “The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle

[9] James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition, Chapter IV, p. 67.

of consumer sovereignty."[10] Bonbright also cites another benefit of the cost-price standard, saying that "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to 'account' for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things."[11]

VI. HOW WESTAR'S THREE-PART RATE SATISFIES THE PRINCIPLES OF RATE DESIGN

Q. IS WESTAR'S PROPOSAL TO INTRODUCE A THREE-PART RATE CONSISTENT WITH THE ACCEPTED PRINCIPLES OF RATE DESIGN?

A. Yes. The introduction of a three-part rate for both residential DG customers and non-DG customers is consistent with the previously discussed principles of rate design. Westar's proposal further improves the alignment of its rate design with these principles.

Q. HOW DOES WESTAR'S PROPOSAL SATISFY THE PRINCIPLE OF ECONOMIC EFFICIENCY?

A. The cost-based price signals in the three-part rates proposed by Westar provide customers with the financial incentive to make

[10] Op. cit., p. 69.

[11] Op. cit., p. 70.

investments in technologies or otherwise change their behavior in ways that are most beneficial to the system. Technologies and behaviors that reduce a customer's peak demand should ultimately lead to a more efficient use of the grid, reduced system costs, and bill savings.

Q. HOW DOES WESTAR'S PROPOSAL SATISFY THE PRINCIPLE OF EQUITY?

A. Each customer imposes costs on the system, some of which are fixed and the rest of which are demand-driven and energy-driven. Under purely volumetric tariffs, customers with high demand but low monthly consumption would not be paying their fair share of the cost of maintaining, upgrading, and expanding the utility's generation, transmission and distribution system. Instead, lower-demand customers would be covering the deficit and paying more than their fair share. Westar's proposed three-part rates more closely match demand, fixed, and variable costs with demand, fixed, and variable charges and will reduce this inequity so that all customers will pay their fair share of the costs associated with the generation of electricity, its delivery through utility's transmission and distribution system, and customer service.

Q. HOW DOES WESTAR'S PROPOSAL SATISFY THE PRINCIPLE OF BILL STABILITY?

A. Westar's current rates recover significant amounts of fixed costs through volumetric charges. The result is an overstated volumetric charge. This subjects a disproportionate amount of a customer's bill to month-to-month fluctuations in usage, and as a result, bills are more variable and unpredictable than they would be if the rates were designed more appropriately. In a variable climate like Kansas, this can result in high seasonal bills relative to other times of the year.

Q. HOW DOES WESTAR'S PROPOSAL SATISFY THE PRINCIPLE OF CUSTOMER SATISFACTION?

A. I believe residential DG customers are likely to find the three-part rate design more attractive than other rate designs that would be necessary to fully recover costs from the residential DG customer segment such as significantly increasing the basic service fee. With a three-part rate, customers have the ability to reduce their bills by managing their electricity demand; it provides them with an option that other rate designs do not.

From a customer standpoint, the three-part rate strikes a reasonable balance between cost-reflectivity and simplicity. A "pure" cost-based rate would require multiple demand charges (based on the timing of transmission and distribution system peaks), sub-hourly volumetric rates to capture fluctuations in marginal energy costs, and possibly location-specific variation. Westar's proposed three-part rate is a simplification of such a design, and should be easier for customers to understand and respond to.

Q. HOW DOES WESTAR'S PROPOSAL SATISFY THE PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?

A. The proposed rates will not change Westar's revenues. Rather, they will more accurately collect revenue from those customers who are imposing costs on the power system.

It is worth noting that, while Professor Bonbright says that rates should be stable and predictable, he does not say that rate structures should remain frozen in time. In the U.S., there is an ineluctable movement towards cost-reflective rates brought about by the rollout of advanced metering infrastructure (AMI) and by the increased availability and customer adoption of a wide range of digital end-use technologies such as smart appliances, smart thermostats, home energy management systems, battery storage systems, electric vehicles and rooftop solar panels. Westar's three-part rate proposal is designed to provide stability in this new environment.

Q. IS THERE REGULATORY PRECEDENT FOR OFFERING THREE-PART RATES IN KANSAS?

A. Yes, there is extensive industry experience with three-part rates. They have been offered to commercial and industrial (C&I) customers for decades, and are the norm for these customer classes. In Kansas, demand charges are offered by all major utilities.[12] In fact, all of these utilities offer three-part rates to at least a portion of the C&I customers on a mandatory basis.[13] Five of the utilities, which serve the vast majority of C&I customers in the state, offer demand charges on a mandatory basis to even the smallest commercial and industrial customer segment.

Q. ARE THREE-PART RATES OFFERED TO RESIDENTIAL CUSTOMERS IN OTHER JURISDICTIONS?

A. Yes. Three-part rates are currently offered by utilities to residential customers, though on a more limited basis than for

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[12] For relevance, I excluded small utilities serving less than 10,000 customers. There are 12 utilities in Kansas above this size threshold. The list includes investor-owned utilities, cooperatives, and public utilities. See Appendix E for details.

[13] This is also common practice at many utilities throughout the US.

C&I customers. Their availability is increasing in part as technical barriers are removed through the deployment of AMI.

There are at least 42 utilities in 21 states that offer a three-part rate to residential customers.[14] Three of these utilities are in Kansas, including Westar's Peak Management rate.[15] Arizona Public Service (APS) has the most highly subscribed residential three-part rate in the US, with nearly 120,000 of its customers voluntarily choosing to enroll. Similar to Westar's proposal, Salt River Project (SRP) recently instituted a mandatory three-part rate for all residential customers who chose to install a new grid-connected distributed generation (DG) photovoltaic system after January 1, 2015.[16,17] Mid-Carolina Electric Cooperative (South Carolina) and Butler Rural Electric Cooperative (Kansas) include demand charges as a mandatory feature of their residential rate

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14 The Brattle Group survey was conducted in November 2017. A list of utilities is provided in Appendix D.

15 At its peak enrollment, the rate had around 15,600 participants. My understanding is that there were 6,463 customers on the rate as of June 2017, because it has not been open to new enrollment for several years and attrition has occurred as customers have left the service territory. The other Kansas utilities are Midwest Energy and Butler Rural Electric Cooperative.

16 SRP website. http://www.srpnet.com/prices/home/customergenerated.aspx.

17 Peak demand management could be another driver. Although many three-part rates are driven by DG, it is not the only motivation behind the rate. In Maryland and Missouri where utilities' ability to design rates specifically for DG is restricted, the focus is on the demand management benefit.

offerings to all customers. I provide a list of utilities offering residential three-part rates in Appendix D.

Q. DO YOU AGREE WITH WESTAR'S DEFINITION OF THE PEAK PERIOD IN THE PROPOSED THREE-PART RATE?

A. Yes. Westar has established a period for measuring peak demand which extends from 2 pm to 7 pm on non-holiday weekdays.[18] This period aligns with the timing of Westar's system peak, which is the driver of the majority of the costs being recovered through the demand charge. The period captured more than 75 percent of the top 100 system load hours in 2016 (test year) data.

The peak period definition is also customer friendly. The five-hour duration is short enough to provide customers with the opportunity to shift load outside of the peak period. And, by ending the period at 7 pm, a portion of the "high activity" evening hours of many households will not affect the billable demand charge.

VII. THE PROBLEM WITH A TWO-PART RATE FOR DG CUSTOMERS

Q. COULD COSTS ALTERNATIVELY BE RECOVERED FROM DG CUSTOMERS THROUGH A TWO-PART RATE?

[18] The demand charge applies to the maximum one hour of demand during that period.

A. Since DG customers are a separate class with its own revenue requirement, theoretically it would be possible to recover costs from this class through a two-part rate. However, this approach would have several distinct disadvantages and, accordingly, Westar does not advocate for these changes.

Q. WHAT WOULD BE THE DISADVANTAGES OF RECOVERING COSTS FROM DG CUSTOMERS THROUGH A TWO-PART RATE?

A. Residential DG customers have very low load factors. In other words, their net monthly energy consumption is low relative to their peak demand. As a result, in spite of low net energy consumption, residential DG customers impose significant costs on the system by requiring supporting infrastructure. If the basic service fee were held at its proposed level of $18.50 per month, the volumetric charge of a two-part rate would have to be increased to an extremely high level in order to fully recover costs from residential DG customers.

Based on the findings of Witness Amen’s CCOS study, I estimate that the average volumetric rate would need to be more than $0.20/kWh on average in order to fully recover costs from DG customers under these circumstances. That is a multiple of nearly three relative to the average energy charge in the current rate. Such a distorted price signal does not reflect the underlying variable costs and would lead to a number of problems, such as uneconomic investments in energy efficiency.

Q. ALTERNATIVELY, COULD THE BASIC SERVICE FEE IN A TWO-PART RATE BE INCREASED?

A. In an alternative scenario, the basic service fee could be increased rather than increasing the volumetric charge. Using the CCOS study results and assuming that the Schedule RS volumetric charge remains unchanged, I have estimated that the customer charge in a two-part rate would need to increase roughly from the current $14.50 to approximately $52 per month. Such a rate would not provide customers with a price signal to manage demand by time-of day.

The three-part rate avoids the problems described above by more closely reflecting the structure of underlying cost drivers. It provides customers with an efficient signal to manage their energy demand in a way that will reduce system costs and, ultimately, customer bills.

VIII. IMPACTS OF THE THREE-PART RATE ON DG CUSTOMERS

Q. HOW WILL DG CUSTOMER BILLS BE IMPACTED UNDER WESTAR'S PROPOSED TRANSITION TO A MANDATORY THREE-PART RATE?

A. There are two distinct bill impacts that will result from Westar's proposal. The first is the impact associated with moving to a rate that is specifically based on the CCOS study for DG customers. This transition will increase bills for all residential DG customers not otherwise grandfathered under the current rate structure[19], in order to correct the existing cross-subsidy from residential non-DG customers.[20]

The second impact is the change in *rate design* associated with moving from a two-part rate to a three-part rate. The change in rate design alone will reduce bills for some customers and increase bills for others. Those residential DG customers with load profiles that are flatter than the DG class average will benefit from the three-part rate design, whereas those with peakier load shapes will experience a bill increase.

It is important to differentiate between these two impacts. Otherwise, bill increases may be associated with the change in rate design when in fact that is not the primary driver.

[19] Residential customers who installed DG prior to October 28, 2015 will continue to remain on the currently applicable tariff, rather than being subject to the proposed tariff.

[20] This cross-subsidy is discussed at length in the direct comments that I filed on behalf of Westar in Docket No. 16-GIME-403-GIE.

Q. HAVE YOU QUANTIFIED THE BILL IMPACTS FOR DG CUSTOMERS?

A. Yes. Westar provided me with 15-minute load data for 155 of its residential customers that currently have DG.[21] The data spans the period from July 2016 to June 2017. There is a full year of load data for 31 of these customers.[22] Using the currently applicable rates and the proposed rates, I calculated the bill changes that would be experienced by each of the 31 DG customers in the sample for which there is a full year of load data.

Q. WHAT IS THE BILL IMPACT OF MOVING TO A REVENUE REQUIREMENT THAT IS SPECIFIC TO RESIDENTIAL DG CUSTOMERS?

A. I have estimated that Schedule RS-DG, as it exists today, would collect an average of $893 in annual revenue per customer across the sample of 31 DG customers. Alternatively, the results of Westar's CCOS study for this filing indicate that $1,341 per customer should be recovered annually from these DG customers. This would result in a necessary average rate increase of 50 percent across all DG customers. This would

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[21] DG customers who would be grandfathered under the existing rate were not included in the sample.

[22] One of the 31 customers is missing a very small number of observations (i.e., less than 1 percent of the year). The remaining 124 DG customers in the sample typically installed rooftop solar PV too recently to establish a full year of load observations. Please see Appendix I for further details on the load research data and the adjustments made for the purpose of my analysis.

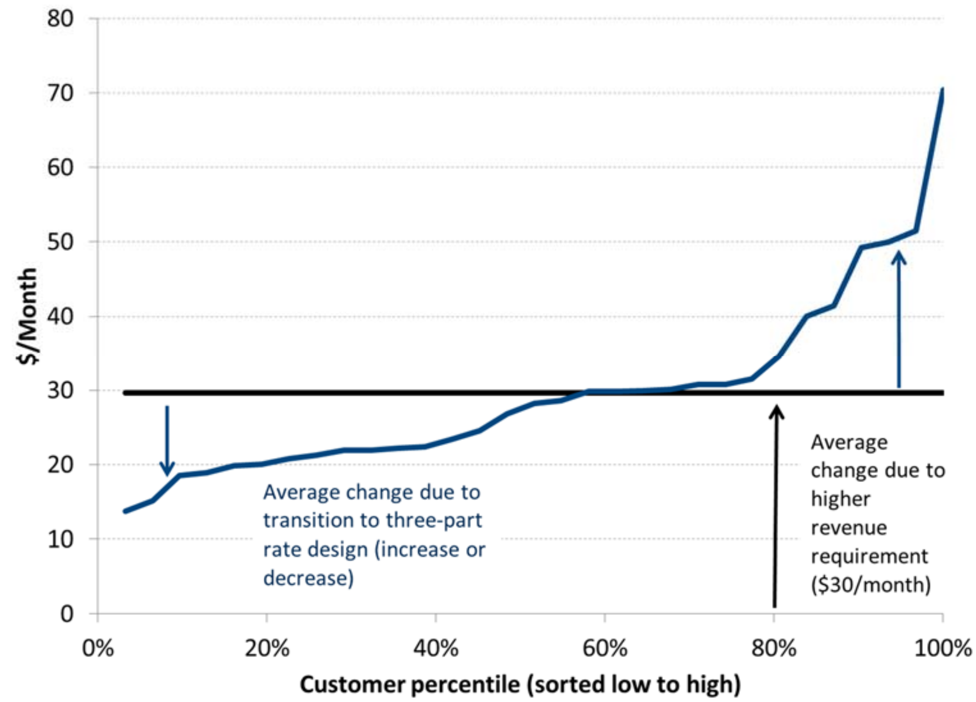
reflect the removal of a subsidy to residential DG customers that resulted from setting rates for DG customers equal to those charged to the broader residential class.

Q. SUBSEQUENTLY, WHAT IS THE BILL IMPACT OF CHANGING FROM A TWO-PART RATE TO A THREE-PART RATE?

A. Westar's proposed three-part rate design is revenue neutral. In other words, in the absence of any change in customer load shapes, the three-part rate would collect the same revenue as a two-part rate that is based on the DG customer-specific revenue requirement. Some customer bills will increase by less than the class average as a result of the change in rate design, and some will increase by more. On average, the rate design change will not lead to a change in revenues (*i.e.*, average rates).

Figure 1 illustrates the distribution of bill impacts associated specifically with the change in rate design from a two-part rate to a three-part rate. It separates the impact of the change of revenue requirement from the revenue neutral change in rate design. Note that this analysis assumes that residential DG customers do not change their load profile in response to the price signals in the three-part rate.

Figure 1: Distribution of Bill Impacts due to Proposed Changes in RS-DG Rate



Q. CAN CUSTOMERS RESPOND TO THE PRICE SIGNALS IN THREE-PART RATES?

A. Yes. There is a widespread misperception that customers do not respond to changing electricity prices. This is contradicted by empirical evidence derived from more than 60 pilots and full-scale rate deployments involving over 300 innovative rate offerings over roughly the past two decades. The pilots have found that customers can and do respond to new price signals by changing their consumption pattern.[23]

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[23] Some of these studies are summarized in Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A meta-analysis of time-varying rates for electricity," *The Electricity Journal*, 2017. Similar results were obtained from an earlier generation of 14 pricing pilots that were funded in the late 1970's and early 1980's by the U.S. Federal

Further, there is evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges. The following studies arrived at this conclusion after careful empirical analysis:

- Caves, D., Christensen, L., Herriges, J., 1984. “Modeling alternative residential peak-load electricity rate structures.” J. Econometrics. Vol 24, Issue 3, 249-268.
- Stokke, A., Doorman, G., Ericson, T., 2009, January. “An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector,” Discussion Paper 574, Statistics Norway Research Department.
- Taylor, Thomas N., 1982. “Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak.” Award Papers in Public Utility Economics and Regulation. Institute of Public Utilities, Michigan State University, East Lansing, Michigan.
- Taylor, T., Schwartz, P., 1986, April. “A residential demand charge: evidence from the Duke Power time-of-day pricing experiment.” Energy Journal. (2), 135–151.

APS has also examined the experience of the customers on its highly subscribed optional three-part rate and detected a significant level of price response. Specifically, 60 percent of a sample of APS’s customers on a three-part rate reduced their demand after switching to the three-part rate, with those who

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Energy Administration (later part of the Department of Energy). See Ahmad Faruqui and Bob Malko, “The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing,” *Energy*, Vol. 8, No. 10, (1983).

actively manage their demand achieving demand savings of 9 percent to 20 percent or more.[24]

For a DG customer with service under a three-part rate, the use of battery storage or other demand-reducing technologies would reduce the customer's bill. This reduction in the customer's bill is an economic value that forms the basis of the price signal created by three-part rates.

Q. HOW WOULD THE BILL IMPACTS THAT YOU HAVE ESTIMATED CHANGE AFTER ACCOUNTING FOR PRICE RESPONSE?

A. DG customer bills will decrease after responding to the price signals in the three-part rate. I have developed a model to quantify this impact. The modeling accounts for two effects. The first is the "conservation effect," which represents the reduction in total consumption that occurs because the customer's cost of electricity increases. This is consistent with the vast literature on price elasticities, which says that when the price of a product goes up, one would buy less of it (*i.e.*, demand curves are downward sloping). The second effect is the "substitution effect." It reflects the shifting of consumption away from higher demand hours to

[24] Direct Testimony of Charles A. Miessner, on Behalf of Arizona Public Service Company, In the Matter of Tucson Electric Company, Docket E-01933A-15-0322, June 24, 2016, p. 10.

lower-demand hours in order to reduce one's bill (*e.g.*, staggering the use of multiple electricity-intensive appliances like a dishwasher and an oven). Both impacts are commonly observed in customer response to new price signals.[25]

Given uncertainty regarding the extent to which DG customers will shift load away from the peak period, I considered two scenarios. In the first scenario, customers shift five percent of their load from the peak period to the off-peak period in order to reduce the demand charge portion of their bill. This scenario is based on analysis of customer response to a three-part rate in Norway. In the second scenario, customers shift 29 percent of their peak period consumption, based on the findings of a pricing pilot conducted in Wisconsin. Both cases involved a demand charge of roughly $10/kW. Appendix H includes further detail on my methodology and assumptions.

Based on this modeling, on average I would expect residential DG bills to decrease by between 2.3 and 8.6 percent,

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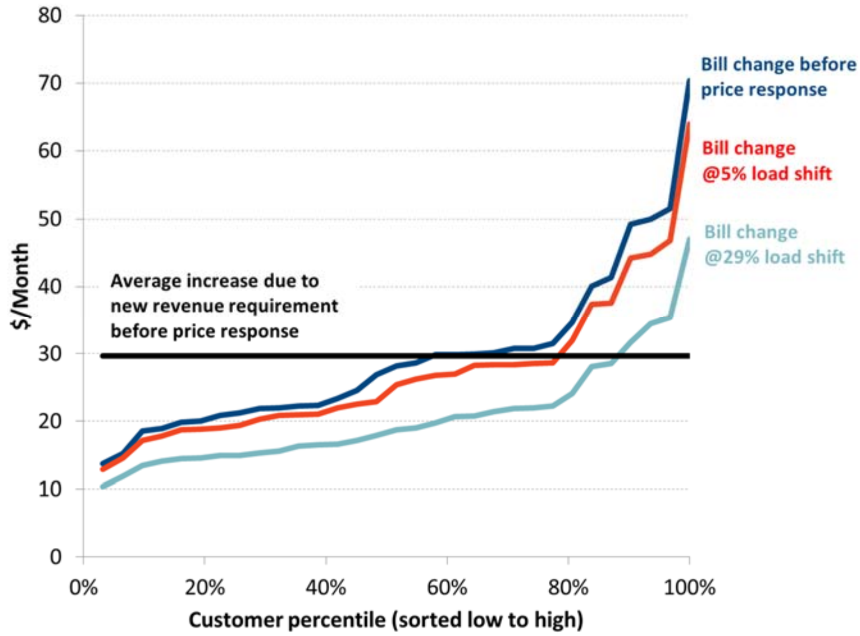
[25] These two effects are commonly incorporated into a system of two demand equations. I have used variations of this modeling framework to estimate peak load reductions in the context of AMI business cases in a variety of jurisdictions including California, Connecticut, Florida, Maryland, and Michigan. I contributed to the development of this two equation system while analyzing California's statewide pricing pilot. See Charles River Associates, "Impact Evaluation of the Statewide Pricing Pilot," March 16, 2005. https://www.smartgrid.gov/files/Impact_Evaluation_California_Statewide_Pricing_Pilot_200501.pdf.

or by between $2.44 and $8.99 per month, relative to a baseline case in which customers do not respond to the price signal. Figure 2 summarizes the change in the distribution of bill impacts resulting from price response.

Figure 2: Distribution of DG Bill Impacts after Accounting for Price Response



IX. IMPACTS OF THE VOLUNTARY THREE-PART RATE ON NON-DG CUSTOMERS

Q. DO YOU EXPECT RESIDENTIAL NON-DG CUSTOMERS TO SWITCH TO THE VOLUNTARY RPER THREE-PART RATE THAT HAS BEEN PROPOSED?

A. It is likely that some customers will choose to switch away from the standard rate and enroll in the new RPER three-part rate. This behavior, for instance, has been observed in APS's optional residential three-part rate mentioned earlier in my testimony.

Customers are most likely to switch to the new rate if they see an opportunity to reduce their bill by enrolling in the rate, or if they wish to smooth out the seasonal variation in their bills. The magnitude of the bill savings opportunity is a key factor that will determine their likelihood of adopting the new rate. It is also possible that customers will be attracted to other features of the new rates that do not directly lead to bill reductions, such as the potential for reduced bill volatility.

At the same time, there are also factors that will limit customer interest in switching to the new rates. Customers have limited resources and time available to study and react to their electricity bill. This may be because electricity represents a relatively small portion of customers' income. Other customers are risk averse and have a fear of the unknown. Even in cases where customers have a clear opportunity to reduce their bill by switching to the alternative three-part rate, they may not choose to do so. Research that I conducted with colleagues shows that most customers are likely to remain on the default rate when presented with alternatives even though they may appreciate the choice being offered to them.[26]

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[26] Ahmad Faruqui, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly*, August 2014.

Q. HAVE YOU ANALYZED THE SWITCHING BEHAVIOR OF CUSTOMERS THAT WILL OCCUR WHEN THE RPER RATE IS OFFERED?

A. Yes. I have simulated the impacts of rate switching by taking into account realistic switching behavior. My modeling accounts for uncertainty and the range of preferences that are likely to be demonstrated by customers during the actual rollout of the new RPER rate.[27]

I relied on the "Rate Choice Model" for this analysis. The Rate Choice Model is a tool I developed with a team of consultants at Brattle. It was also the basis for analysis in testimony that I filed on behalf of Westar in the "115" docket.

The Rate Choice Model is a "discrete choice model" that captures likely customer switching rates by accounting for the observation that some customers will switch to a rate that increases their bill, and some other customers will choose to remain on the current rate even when the alternative rate option could lower their bill. By varying the parameters of the model, I am able to capture a reasonable range of assumptions about the customers' likelihood of switching away from the standard rate

[27] I needed to modestly adjust the proposed RPER rate in order to make it revenue neutral specifically for my sample of load research customers. Further details are provided in Appendix G.

and their ability to accurately choose the rate that minimizes their bills. A detailed description of the model is included in Appendix F.

Q. HOW MUCH SWITCHING IS LIKELY TO TAKE PLACE?

A. The actual switching behavior of Westar's customers will depend on a number of factors, such as how effectively the new rates are marketed, how engaged the customers are in energy management, how well they understand both their bill and the new rate options, and their level of risk aversion, among other factors. Given uncertainty around these factors, I analyzed two scenarios of switching behavior.

Q. WHAT WAS THE FIRST SCENARIO YOU ANALYZED?

A. The first scenario is calibrated to observed enrollment in Westar's Peak Management rate, which was offered to customers in the North Rate Area beginning in 1981. At its peak enrollment in 1998, approximately 15,600 customers were enrolled in the rate, representing roughly five percent of Westar's total residential customer base at that time.[28]

[28] The Peak Management Rate was implemented by The Kansas Power and Light Company (Westar North) prior to the merger with Kansas Gas and Electric Company (Westar South) that created Westar Energy. The Peak Management rate was never offered in the Westar South after the merger. Westar's total North residential customer base was around 300,000 customers.

Calibrating the Rate Choice Model to roughly a five percent switching rate, I estimate that the bills of those non-DG customers who switch to the three-part rate would decrease on average by between 1.0 and 2.4 percent ($1.10/month to $3.20/month) relative to a scenario in which all customers remain on the current rate. This equates to a reduction of up to 0.1 percent in Westar’s total non-DG residential revenue. The range of impacts accounts for a range of realistic assumptions regarding the ability of switchers to accurately choose the rate that minimizes their bill.

This scenario may provide a conservative estimate of the switching that would be expected under Westar's proposals in this case.

Q. WHY DO YOU BELIEVE THAT WESTAR'S EXPERIENCE WITH CUSTOMER ENROLLMENT IN THE PEAK MANAGEMENT RATE MAY BE A CONSERVATIVE ESTIMATE OF THE SWITCHING THAT WILL OCCUR UNDER THE NEW RATE PROPOSAL?

A. I believe that to be a conservative case because the circumstances in which the Peak Management rate was offered are different from today's conditions.

First, the Peak Management rate was offered only to customers in the North Rate Area. Now, Westar has the ability to market the rate more broadly to all of its residential non-DG customers.

Second, my understanding is that Westar only marketed the rate to customers with electric heat, such as baseboard or heat pumps. My understanding from conversations with Westar is that the new proposed three-part rate is intended to be marketed to a larger residential customer base.

Third, there is evidence that today's consumers are more interested in managing their energy bills, as demonstrated by the success of home energy reports and adoption of new energy management products like the smart thermostats. To the extent that the RPER rate is seen by customers as an opportunity to manage their peak demands and reduce their energy costs by shifting their usage away from the peak period, they are more likely to enroll in that rate.

Q. WHAT WAS THE SECOND SCENARIO YOU ANALYZED?

A. The second scenario is based on higher switching rates observed at other utilities around the U.S. A combination of market research studies and utility rate deployments have demonstrated that it is possible to achieve a 20 percent switching rate through heavy marketing and customer education initiatives. For example, Oklahoma Gas & Electric has rolled out a new technology-enabled dynamic pricing rate to its customers, and enrolled around 20 percent of its customers on the rate in the first three years of the rollout. Still, this 20 percent switching rate is less than half of the 48 percent of Westar's residential customers that could automatically reduce their annual electricity bill by switching to the new RPER rate.

Calibrating my model to a 20 percent switching rate results in average bill savings that range from 0.8 percent to 1.8 percent ($0.9/month to $2.3/month). These savings pertain to customers who switch to the new rate and are measured relative to a scenario in which all customers remain on the current rate. This translates into a loss of residential revenue for Westar that ranges from 0.2 to 0.4 percent. The results of both scenarios are summarized in Table 4.

Table 4: Customer Switching Under the Likely Choice Approach

	Residential Customers Switching to New Rate	Average Bill Savings of Customer Who Switches		Change in Westar Annual Residential Revenue
	(%)	(%)	($/month)	(%)
Scenario 1: Calibrated to historical Peak Management switching behavior	4.8% to 5.3%	1.0% to 2.4%	$1.1 to $3.2	0.0% to -0.1%
Scenario 2: Calibrated to high switching rate observed at some other utilities	19.7% to 20.7%	0.8% to 1.8%	$0.9 to $2.3	-0.2% to -0.4%

Note: Range of impacts reflects a range of reasonable assumptions about switchers' ability to choose the rate that minimizes their bill

Q. WHAT DO YOU CONCLUDE ABOUT LIKELY CUSTOMER SWITCHING BEHAVIOR WHEN THE NEW THREE-PART RATE IS OFFERED?

A. Some customers are likely to switch to the new RPER three-part rate option. The extent to which the customers switch will depend partly on how heavily the three-part rate is marketed by Westar through customer outreach activities and partly on how inherently engaged Westar's customers are in managing their electricity bills. Realistic switching rates could range from being small (i.e., a few customers) to at least 20 percent of the residential customer base. On average, the option to switch could lead to bill savings of up to around 2.4 percent ($3.20/month) for those customers who switch, with some customers saving more or less than this. These bill decreases due to rate switching will equate to revenue loss for Westar.

It will be important to closely monitor customer switching behavior once the new rate is rolled out. My simulations are based on the best available data and modeling techniques of which I am aware, but these results should be refined with new analysis once there is real experience with the new rate after it is rolled out in in Westar's service territory.

X. INCREASING THE BASIC SERVICE FEE

Q. HAVE YOU REVIEWED WESTAR'S PROPOSAL TO INCREASE THE BASIC SERVICE FEE IN ITS RESIDENTIAL RATES?

A. Yes. Westar has proposed to increase the basic service fee in its residential tariffs to $18.50/month. The basic service fees in the proposed three-part rates are also $18.50/month.

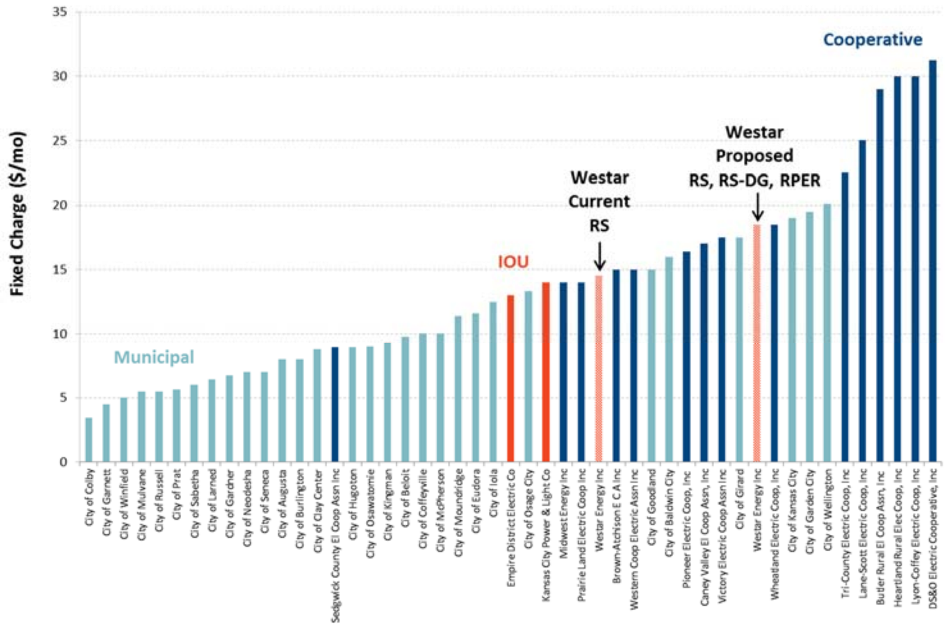
My understanding is that the basic service fees are being increased in order to better align with Westar's fixed costs. Based on my review of the CCOS study presented by Witness Amen, the proposed basic service fees still would fall well shy of fully recovering Westar's fixed costs, but they are a small step in that direction.

Q. HOW DO WESTAR'S RESIDENTIAL BASIC SERVICE FEES COMPARE TO THOSE OF OTHER UTILITIES IN KANSAS?

A. I conducted a survey of the fixed charges in residential rates offered by all electric utilities in Kansas for which I could find the necessary data. Across the 44 utilities I identified – many of which are small cooperatives or municipalities – there is significant variation. The customer charges of those utilities range from $3.45/month to $31.25/month. This variation can be explained by a number of factors, such as the density of the utility service territory, the age of its infrastructure, and the size of its customer base.

Westar's proposed basic service fee falls within the range of charges offered by the other Kansas utilities. Figure 3 provides a summary of my survey. Further methodological detail is provided in Appendix C.

Figure 3: Survey of Residential Fixed Charges Offered in Kansas



Sources: Utility tariff sheets as of November 2017, EIA Form 861
Notes: Alfafa Electric Coop, City of Holton, City of Ottawa, City of Wamego, CMS Electric Coop, Flint Hills Rural Electric Coop, Kansas Gas & Electric Co, Kaw Valley Electric Coop, Leavenworth-Jefferson Elec Coop, Radiant Electric Coop, Rolling Hills Electric Coop, Sumner-Cowley Elec Coop, and Twin Valley Electric Coop were excluded due to unavailable tariffs.

Q. HAVE YOU COMPARED WESTAR'S PROPOSED BASIC SERVICE FEES TO THOSE OF UTILITIES OUTSIDE OF KANSAS?

A. Yes. To create an additional comparison group, I also surveyed residential fixed charges offered by 20 similarly-sized investor-owned utilities in the Midwestern U.S. Both Madison Gas & Electric and Wisconsin Public Service (WPS) offer customer charges that are higher than Westar's proposed $18.50/month basic service fee. Additional detail behind my survey of basic service fees is provided in Appendix C.

XI. CONCLUSION

Q. WHAT DO YOU CONCLUDE ABOUT WESTAR'S RESIDENTIAL RATE PROPOSAL?

A. Westar has put forward cost-based three-part rate proposals that are consistent with the widely-accepted principles of rate design. I support Westar's plan to make this the standard rate for all its residential DG customers, and to create a voluntary option for non-DG residential customers. It is time to move to three-part rates which would provide proper pricing signals to customers by promoting economic efficiency and equity, facilitating the integration of distributed energy resources with the grid, and stimulating the cost-effective deployment of other innovative technologies such as customer-situated battery storage.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A: AHMAD FARUQUI RESUME

Dr. Ahmad Faruqui is an energy economist whose work is focused on the efficient use of energy. His areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents. His research been cited in *Business Week*, *The Economist*, *Forbes*, *National Geographic*, *The New York Times*, *San Francisco Chronicle*, *San Jose Mercury News, Wall Street Journal* and *USA Today*. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as *Energy Economics*, *Energy Journal*, *Energy*

Efficiency, *Energy Policy*, *Journal of Regulatory Economics* and *Utilities Policy* and trade journals such as *The Electricity Journal* and the *Public Utilities Fortnightly*. He holds BA and MA degrees from the University of Karachi, where he was awarded the Gold Medal in Economics, an MA in agricultural economics and a Ph.D. in economics from The University of California at Davis, where he was a Regents Fellow and the recipient of a dissertation grant from the Kellogg Foundation.

AREAS OF EXPERTISE

- *Expert witness.* He has testified or appeared before state commissions in Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, Illinois, Indiana, Iowa, Kansas, Michigan, Maryland, Ontario (Canada) and Pennsylvania. He has assisted clients in submitting testimony in Georgia and Minnesota. He has made presentations to the California Energy Commission, the California Senate, the Congressional Office of Technology Assessment, the Kentucky Commission, the Minnesota Department of Commerce, the Minnesota Senate, the Missouri Public Service Commission, and the Electricity Pricing Collaborative in the state of Washington.
- *Innovative pricing*. He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as three-part rates, including fixed monthly charges, demand charges and time-varying energy charges; dynamic pricing rates, including critical peak pricing, variable peak pricing and real-time pricing; time-of-use pricing; and inclining block rates.
- *Regulatory strategy.* He has helped design forward-looking programs and services that exploit recent advances in rate

design and digital technologies in order to lower customer bills and improve utility earnings while lowering the carbon footprint and preserving system reliability.

- *Cost-benefit analysis of advanced metering infrastructure*. He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.
- *Demand forecasting and weather normalization.* He has pioneered the use of a wide variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.
- *Customer choice*. He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.
- *Hedging, risk management, and market design*. He has helped design a wide range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.
- *Competitive strategy*. He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs of end-use customers, their values and decision-making practices, and their competitive

options. He has helped companies reshape and transform their marketing organization and reposition themselves for a competitive marketplace. He has also helped government-owned entities in the developing world prepare for privatization by benchmarking their planning, retailing, and distribution processes against industry best practices, and suggesting improvements by specifying quantitative metrics and follow-up procedures.

- *Design and evaluation of marketing programs.* He has helped generate ideas for new products and services, identified successful design characteristics through customer surveys and focus groups, and test marketed new concepts through pilots and experiments.
- *Academic experience.* He has given lectures at the University of California, Berkeley, University of California, Davis, Harvard University, University of Idaho, University of Karachi, Massachusetts Institute of Technology, Michigan State University, Northwestern University, University of San Francisco, San Jose State University, Stanford University, University of Virginia, and University of Wisconsin-Madison. Additionally, he has led a variety of professional seminars and workshops on public utility economics around the world. Finally, he has taught economics at the university level at San Jose State University, University of California, Davis, and the University of Karachi.

EXPERIENCE

Innovative Pricing

- **Impact Analysis for TOU Rates in Ontario.** Measured the impacts of a system-wide Time of Use (TOU) deployment in the province of Ontario, Canada, on behalf of the Ontario Power Authority. To account for the lack of a designated control group, Brattle created a quasi-experimental design that took advantage of differences in the timing of the TOU rollout.

- **Measurement and evaluation for in-home displays, home energy controllers, smart appliances, and alternative rates for Florida Power & Light (FPL).** Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviews the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discusses ways in which dynamic pricing can be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable consumers, such as those with low incomes or medical conditions requiring the use of electricity.
- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper includes an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience is international regulators in regions that are exploring the potential benefits of smart metering and innovative pricing.

- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator was expanded to include harder-to-quantify benefits such as improvements to national security and customer service.
- **Pricing and Technology Pilot Design and Impact Evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP) in the summer of 2009. PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.
- **Dynamic Pricing Pilot Design and Impact Evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years from 2008 to 2011. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact Evaluation of a Residential Dynamic Pricing Experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also tested the influence of switches that remotely adjust the duty cycle of central air conditioners.
- **Impact Simulation of Ameren Illinois Utilities' Power Smart Pricing Program.** Simulated the potential demand response of residential customers enrolled to real- time prices. Results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.

- **The Case for Dynamic Pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.
- **Analyzed the Economics of Self-Generation of Steam.** Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for the probability of self-generation switching behavior, and a module for forecasting sales and peak demand.
- **Design and Impact Evaluation of the Statewide Pricing Pilot: Three California Utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.

- **Economics of Dynamic Pricing: Two California Utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.
- **Economics of Time-of-Use Pricing: A Pacific Northwest Utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.
- **Economics of Dynamic Pricing Options for Mass Market Customers - Client: A Multi-State Utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.
- **Real-Time Pricing in California - Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Catalogued the barriers to implementing real-time pricing in California, and developed a program of research for mitigating the impacts of these barriers.
- **Market-Based Pricing of Electricity - Client: A Large Southern Utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and

automobiles. Recommended a path that could be used to transition from a regulated utility environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staffs on the new methodologies.

- **Tools for Electricity Pricing - Client: Consortium of Several U.S. and Foreign Utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share, gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.
- **Risk-Based Pricing - Client: Midwestern Utility.** Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

Demand Response

- **Combined Heat and Power Generation Study.** Investigated the economic potential for combined heat and power and regulatory policies to unlock that potential in a Middle Eastern country.

- **National Action Plan for Demand Response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress in June 2010.
- **National Assessment of Demand Response Potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress in 2009, as required by the Energy Independence and Security Act of 2007.
- **Demand response program review for Integrated Resource Plan development.** In response to legislation requiring the Connecticut utilities to jointly prepare a 10-year integrated resource plan, we conducted the analysis and helped prepare the plan. In coordination with the two leading utilities in the state, we conducted a detailed analysis of alternative resource solutions (both supply- and demand-side), drafted the report, and presented it to the Connecticut Energy Advisory Board. The analysis involved a detailed review and critique of the companies' proposed DR programs.
- **Integration of DR into wholesale energy markets.** Developed a whitepaper, "Fostering Economic Demand Response in the Midwest ISO," evaluating alternative approaches to efficiently integrating DR into its energy markets while encouraging increased participation. This work involved interviewing market participants and analyzing several approaches to economic DR regarding economic efficiency, participation rates, operational fit with other ISO rules, and susceptibility to state-level and ISO-level

implementation barriers. This work also involved an extensive survey of DR programs (qualification criteria, bidding rules, incorporation into market clearing software, measurement and verification, and settlement) in ISO/ Regional Transmission Organization (RTO) markets around the country. The project also required a detailed review of existing DR program tariffs for utilities in the RTO's service territory and development of a matrix for summarizing the various characteristics of these programs.

- **Integration of DR into resource adequacy constructs.** For the Midwest ISO, assisted in developing qualification criteria for DR as a capacity resource (we also developed estimates of likely future contributions of DR to resource adequacy, for use by their transmission planning group). For PJM, as part of our review of its capacity market, we developed recommendations on how to treat DR comparably to generation resources while accounting for the special attributes of DR. Our recommendations addressed product definition, auction rules, and penalty provisions. For the Connecticut utilities in their integrated resource planning, we evaluated future resource needs given various levels of demand response programs.
- **Evaluation of the Demand Response Benefits of Advanced Metering Infrastructure: Mid-Atlantic Utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic pricing rates that are enabled by AMI. The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.
- **Estimation of Demand Response Impacts: Major California Utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering

infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

Smart Grid Strategy

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by *Brattle* staff.
- **Cost-Benefit Analysis of the Smart Grid: Rocky Mountain Utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.
- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).
- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial government. Advised the

AUC on the smart grid, and what impacts it might have in Alberta.

- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.
- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.
- **Analysis of the benefits of increased access to energy consumption information.** For a large technology firm, assessed market opportunities for providing customers with increased access to real time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.
- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid system (including customer-facing technologies) would operate and provide benefits.

Demand Forecasting

- **Load Forecast Bottom-Up Modelling Study.** Reviewed the load forecasting methodology for a major Malaysian utility company and developed a load forecast model using a bottom-up approach.

- **Analyzed electricity consumption and maximum demand for a major electric company in Hong Kong.**
- **Forecasting Review.** Evaluated and critiqued the process conducted by an Australian utility company's electricity market forecasting, including the forecasting of electricity demand, supply, and price.
- **Comprehensive Review of Load Forecasting Methodology. PJM Interconnection.** Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.
- **Analyzed Downward Trend: Western Utility.** We conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. We developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the utility's board of directors. We also developed a time series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.
- **Analyzed Why Models are Under-Forecasting: Southwestern Utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. We ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. Demand Forecast: Edison Electric Institute.** For the U.S. as a whole, we developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. We subsequently developed forecasts that were based on EPRI's system of

end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.

- **Developed Models for Forecasting Hourly Loads: Merchant Generation and Trading Company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial, and industrial customers for three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.

- **Gas Demand Forecasting System - Client: A Leading Gas Marketing and Trading Company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

Demand Side Management

- **The Economics of Biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.

- **Assessment of Demand-Side Management and Rate Design Options: Large Middle Eastern Electric Utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.

- **Likely Future Impact of Demand-Side Programs on Carbon Emissions - Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.

- **Sustaining Energy Efficiency Services in a Restructured Market - Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that are likely to operate in a competitive market, such as third-party energy service companies (ESCOS) and utility affiliates. Assessed their objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.

- **Organizational Assessments of Capability for Energy Efficiency - Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve energy end-use efficiency in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.

- **Enhancing Profitability through Energy Efficiency Services - Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

Advanced Technology Assessment

- **Competitive Energy and Environmental Technologies - Clients: Consortium of clients, led by Southern California Edison, Included the Los Angeles Department of Water and Power and the California Energy Commission.** Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end use application, and size of product. Developed a user-friendly system for assessing the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database on more than 200 end-use technologies, and a model of customer decision making.

- **Market Infrastructure of Energy Efficient Technologies - Client: EPRI.** Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers.

TESTIMONY

Arkansas

Direct Testimony before the Arkansas Public Service Commission on behalf of Entergy Arkansas, Inc., in the matter of Entergy Arkansas, Inc.'s Application for an Order Finding the Deployment of Advanced Metering Infrastructure to be in the Public Interest and Exemption from Certain Applicable Rules, Docket No. 16-060-U, September 19, 2016.

Arizona

Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed To Develop Such Return, Docket No. E-01345A-16-0036, June 1, 2016.

Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application for UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to the its Operations Throughout the State of Arizona, and for Related Approvals, Docket No. E-04204A-15-0142, December 9, 2015.

California

Rebuttal Testimony before the Public Utilities Commission of the State of California, Pacific Gas and Electric Company Joint Utility on Demand Elasticity and Conservation Impacts of Investor-Owned Utility Proposals, in the Matter of Rulemaking 12-06-013, October 17, 2014.

Prepared testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, summer 2010.

Qualifications and prepared testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.

Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

Colorado

Rebuttal testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its Colorado PUC No.7 Electric Tariff to

Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.

Direct testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

Connecticut

Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use , Interruptible Load Response, and Seasonal Rates- Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

District of Columbia

Direct testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

Illinois

Direct testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.

Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.

Rebuttal Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company in the matter of the Petition to Approve an Advanced Metering Infrastructure Pilot Program and Associated Tariffs, No. 09-0263, August 14, 2009.

Prepared rebuttal testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Indiana

Direct testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

Kansas

Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

Louisiana

Direct testimony before the Louisiana Public Service Commission on behalf of Entergy Louisiana, LLC, in the matter of Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief in accordance with Louisiana Public Service Commission General Order dated September 22, 2009, R-29213, November 2016.

Direct testimony before the Council of the City of New Orleans, on behalf of Entergy New Orleans, Inc., in the matter of the Application of Energy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief, October 2016.

Maryland

Direct Testimony before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy, April 19, 2016.

Rebuttal Testimony before the Maryland Public Service Commission on behalf of Baltimore Gas and Electric Company in the matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates, Case No. 9406, March 4, 2016.

Direct testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure. Case no. 9207, September 2009.

Prepared direct testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

Minnesota

Rebuttal testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.

Direct testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power

Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

Mississippi

Direct testimony before the Mississippi Public Service Commission, on behalf of Entergy Mississippi, Inc., in the matter of Application for Approval of Advanced Metering Infrastructure and Related Modernization Improvements, EC-123-0082-00, November 2016.

Nevada

Prepared rebuttal testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy, in the matter of net metering and distributed generation cost of service and tariff design, Docket Nos. 15-07041 and 15-07042, November 3, 2015.

Prepared direct testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

New Mexico

Direct testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

Oklahoma

Rebuttal Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, April 11, 2016.

Direct Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, December 18, 2015.

Responsive Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Brandy L. Wreath, Director of the Public Utility Division, for Determination of the Calculation of Lost Net Revenues and Shared Savings Pursuant to the Demand Program Rider of Oklahoma Gas and Electric Company, Cause No. PUD 201500153, May 13, 2015.

Pennsylvania

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case no. M-2009-2123944, October 28, 2010.

Washington

Prefiled Direct Testimony before the Washington Utilities and Transportation Commission on Behalf of Puget Sound Energy, Dockets UE-151871 and UG-151872, February 25, 2016.

REGULATORY APPEARANCES

Arkansas

Presented before the Arkansas Public Service Commission, “The Emergence of Dynamic Pricing” at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

Delaware

Presented before the Delaware Public Service Commission, “The Demand Response Impacts of PHI’s Dynamic Pricing Program” Delaware, September 5, 2007.

Kansas

Presented before the State Corporation Commission of the State of Kansas, “The Impact of Dynamic Pricing on Westar Energy" at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

Ohio

Presented before the Ohio Public Utilities Commission, “Dynamic Pricing for Residential and Small C&I Customers" at the Technical Workshop, Columbus, Ohio, March 28, 2012.

Texas

Presented before the Public Utility Commission of Texas, “Direct Load Control of Residential Air Conditioners in Texas,” at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

PUBLICATIONS

Books

Electricity Pricing in Transition. Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2002.

Pricing in Competitive Electricity Markets. Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2000.

Customer Choice: Finding Value in Retail Electricity Markets. Co-editor with J. Robert Malko. Public Utilities Inc. Vienna. Virginia: 1999.

The Changing Structure of American Industry and Energy Use Patterns. Co-editor with John Broehl. Battelle Press, 1987.

Customer Response to Time of Use Rates: Topic Paper I, with Dennis Aigner and Robert T. Howard, Electric Utility Rate Design Study, EPRI, 1981.

Chapters in Books

"Making the Most of the No Load Growth Business Environment," with Dian Grueneich. *Distributed Generation and Its Implications for the Utility Industry*. Ed. Fereidoon P. Sioshansi. Academic Press, 2014. 303-320.

"*Arcturus*: An International Repository of Evidence on Dynamic Pricing," with Sanem Sergici. *Smart Grid Applications and Developments, Green*

Energy and Technology. Ed. Daphne Mah, Ed. Peter Hills, Ed. Victor O. K. Li, Ed. Richard Balme. Springer, 2014. 59-74.

“Will Energy Efficiency make a Difference,” with Fereidoon P. Sioshansi and Gregory Wikler. *Energy Efficiency: Towards the end of demand growth*. Ed. Fereidoon P. Sioshansi. Academic Press, 2013. 3-50.

“The Ethics of Dynamic Pricing.” *Smart Grid: Integrating Renewable, Distributed & Efficient Energy*. Ed. Fereidoon P. Sioshansi. Academic Press, 2012. 61-83.

“The Dynamics of New Construction Programs in the 90s: A Review of the North American Experience,” with G.A. Wikler. *Proceedings of the 1992 Conference on New Construction Programs for Demand-Side Management*, May 1992.

“Forecasting Commercial End-Use Consumption” (Chapter 7), “Industrial End-Use Forecasting” (Chapter 8), and “Review of Forecasting Software” (Appendix 2) in *Demand Forecasting in the Electric Utility Industry*. C.W. Gellings and P.E. Lilbum (eds.): The Fairmont Press, 1992.

“Innovative Methods for Conducting End-Use Marketing and Load Research for Commercial Customers: Reconciling the Reconciled,” with G.A. Wikler, T. Alereza, and S. Kidwell. *Proceedings of the Fifth National DSM Conference*. Boston, MA, September 1991.

"Time-of-Use Rates and the Modification of Electric Utility Load Shapes," with J. Robert Malko, *Challenges for Public Utility Regulation in the 1980s*, edited by H.M. Trebing, Michigan State University Public Utilities Papers, 1981.

"Implementing Time-Of-Day Pricing of Electricity: Some Current Challenges and Activities," with J. Robert Malko, *Issues in Public Utility Pricing and Regulation*, edited by M. A. Crew, Lexington Books, 1980.

Technical Reports

Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast, with Sanem Sergici and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.

Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs, with Toby Brown, prepared for the Australian Energy Market Commission, August 2014.

Time-Varying and Dynamic Rate Design, with Ryan Hledik and Jennifer Palmer, prepared for RAP, July 2012. http://www.raponline.org/document/download/id/5131

The Costs and Benefits of Smart Meters for Residential Customers, with Adam Cooper, Doug Mitarotonda, Judith Schwartz, and Lisa Wood, prepared for Institute for Electric Efficiency, July 2011.

http://www.smartgridnews.com/artman/uploads/1/IEE_Benefits_of_Smart_Meters_Final.pdf

Measurement and Verification Principles for Behavior-Based Efficiency Programs, with Sanem Sergici, prepared for Opower, May 2011. http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf

Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects. With R. Lee, S. Bossart, R. Hledik, C. Lamontagne, B. Renz, F. Small, D. Violette, and D. Walls. Pre-publication draft, prepared for the U. S. Department of Energy, Office of Electricity Delivery and Energy Reliability, the National Energy Technology Laboratory, and the Electric Power Research Institute. Oak Ridge, TN: Oak Ridge National Laboratory, November 28, 2009.

Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets. With Sanem Sergici and Lisa Wood. Institute for Electric Efficiency, June 2009.

Demand-Side Bidding in Wholesale Electricity Markets. With Robert Earle. Australian Energy Market Commission, 2008. http://www.aemc.gov.au/electricity.php?r=20071025.174223

Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030). With Ingrid Rohmund, Greg Wikler, Omar Siddiqui, and Rick Tempchin. American Council for an Energy-Efficient Economy, 2008**.**

Quantifying the Benefits of Dynamic Pricing in the Mass Market. With Lisa Wood. Edison Electric Institute, January 2008.

California Energy Commission. *2007 Integrated Energy Policy Report,* CEC-100-2007-008-CMF.

Applications of Dynamic Pricing in Developing and Emerging Economies. Prepared for The World Bank, Washington, DC. May 2005.

Preventing Electrical Shocks: What Ontario—And Other Provinces—Should Learn About Smart Metering. With Stephen S. George. C. D. Howe Institute Commentary, No. 210, April 2005.

Primer on Demand-Side Management. Prepared for The World Bank, Washington, DC. March 21, 2005.

Electricity Pricing: Lessons from the Front. With Dan Violette. White Paper based on the May 2003 AESP/EPRI Pricing Conference, Chicago, Illinois, EPRI Technical Update 1002223, December 2003.

Electric Technologies for Gas Compression. Electric Power Research Institute, 1997.

Electrotechnologies for Multifamily Housing. With Omar Siddiqui. EPRI TR-106442, Volumes 1 and 2. Electric Power Research Institute, September 1996.

Opportunities for Energy Efficiency in the Texas Industrial Sector. Texas Sustainable Energy Development Council. With J. W. Zarnikau et al. June 1995.

Principles and Practice of Demand-Side Management. With John H. Chamberlin. EPRI TR-102556. Palo Alto: Electric Power Research Institute, August 1993.

EPRI Urban Initiative: *1992 Workshop Proceedings (Part I)*. The EPRI Community Initiative. With G.A. Wikler and R.H. Manson. TR-102394. Palo Alto: Electric Power Research Institute, May 1993.

Practical Applications of Forecasting Under Uncertainty. With K.P. Seiden and C.A. Sabo.TR-102394. Palo Alto: Electric Power Research Institute, December 1992.

Improving the Marketing Infrastructure of Efficient Technologies: A Case Study Approach. With S.S. Shaffer. EPRI TR- I 0 1 454. Palo Alto: Electric Power Research Institute, December 1992.

Customer Response to Rate Options. With J. H. Chamberlin, S.S. Shaffer, K.P. Seiden, and S.A. Blanc. CU-7131. Palo Alto: Electric Power Research Institute (EPRI), January 1991.

Articles and Papers

"Arcturus 2.0: A meta-analysis of time-varying rates for electricity," with Sanem Sergici and Cody Warner, *The Electricity Journal*, 30:10, December 2017, pp. 64-72.

https://www.sciencedirect.com/science/article/pii/S1040619017302750

"Moving Forward with Tariff Reform," with Mariko Geronimo Aydin, *Energy Regulation Quarterly*, Volume 5, Issue 4, December 2017.

http://www.energyregulationquarterly.ca/articles/moving-forward-with-tariff-reform#sthash.ZADdmZ2h.D2l1yz9z.dpbs

"Innovations in Pricing: Giving Customers What They Want," *Electric Perspectives*, September/October 2017.

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"Moving Forward with Electricity Tariff Reform," with Mariko Geronimo Aydin, *Regulation*, Fall 2017.

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"The Public Benefits of Leasing Energy Efficient Equipment," with Neil Lessem and Henna Trewn, *The Electricity Journal*, 30:6, July 2017, pp. 8-16.

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"Rethinking Customer Research in the Utility Industry," with Henna Trewn, *Public Utilities Fortnightly*, July 2017.

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"Do Manufacturing Firms Relocate in Response to Rising Electric Rates?" with Sanem Sergici, *Energy Regulation Quarterly*, 5:2, June 2017.

http://www.energyregulationquarterly.ca/articles/do-manufacturing-firms-relocate-in-response-to-rising-electric-rates#sthash.uLnrPMwh.dpbs

"Dynamic Pricing Works in a Hot, Humid Climate," with Neil Lessem and Sanem Sergici, *Public Utilities Fortnightly*, May 2017.

https://www.fortnightly.com/fortnightly/2017/05/dynamic-pricing-works-hot-humid-climate

"The impact of advanced metering infrastructure on energy conservation: A case study of two utilities," with Kevin Arritt and Sanem Sergici, *The Electricity Journal*, 30:3, April 2017, pp. 56-63.

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"Overcoming the Over-Forecasting Bias of Pure Econometric Models: A utility case study," with Josephine Duh and Ingrid Rohmund, *Electricity Policy*, February 2017.

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"An Economist's Dilemma: To PV or Not to PV, That Is the Question," *Electricity Policy*, March 2016.

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"Response to King-Datta Re: Time-Varying Rates," *Public Utilities Fortnightly*, March 2016.

https://www.fortnightly.com/fortnightly/2016/03/response-king-datta-re-time-varying-rates

"Impact Measurement of Tariff Changes when Experimentation is not an Option – A case study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, *Energy Economics*, 52, December 2015, pp.

39-48.

"Efficient Tariff Structures for Distribution Network Services," with Toby Brown and Lea Grausz, *Economic Analysis and Policy*, 48, December 2015, pp. 139-149.

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APPENDIX B: GLOSSARY OF ACRONYMS

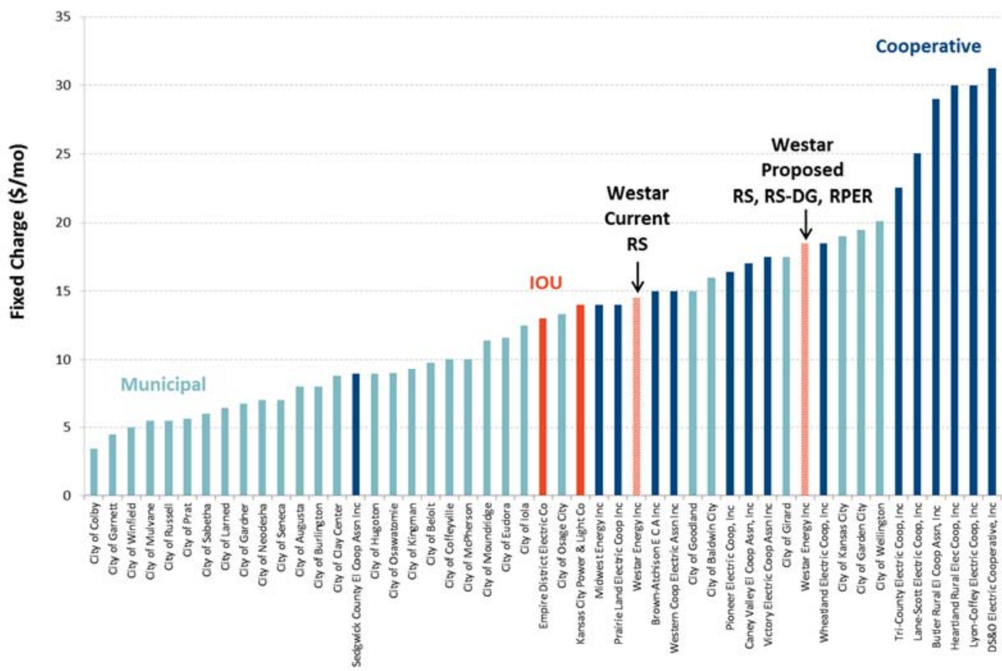
Glossary of Acronyms in Testimony

CCOS	Class Cost of Service
C&I	Commercial and Industrial
DG	Distributed Generation
EER	Energy Efficiency Rider
kW	Kilowatt
kWh	Kilowatt Hour
PTS	Property Tax Surcharge
RECA	Retail Energy Cost Adjustment (Fuel Charge)
RS	Residential Service
RS-DG	Residential Service Distirbuted Generation
RPER	Residential Peak Efficiency Rate
TDC	Transmission Delivery Charge

APPENDIX C: SURVEY OF FIXED CHARGES FOR RESIDENTIAL CUSTOMERS

This appendix provides a survey of residential fixed charges. Figure 4 presents residential fixed charges for all Kansas utilities. Figure 5 also shows residential fixed charges but only for Kansas utilities with 10,000 customers or more. Figure 6 presents residential fixed charges for 20 Midwestern IOUs that have a number of customers similar to Westar. Westar's current basic service fee and the basic service fee proposed in this proceeding are highlighted in the figures.

Figure 4: Residential Fixed Charge Survey: All Kansas Utilities[29]



Sources: Utility tariff sheets as of November 2017, EIA Form 861
Notes: Alfafa Electric Coop, City of Holton, City of Ottawa, City of Wamego, CMS Electric Coop, Flint Hills Rural Electric Coop, Kansas Gas & Electric Co, Kaw Valley Electric Coop, Leavenworth-Jefferson Elec Coop, Radiant Electric Coop, Rolling Hills Electric Coop, Sumner-Cowley Elec Coop, and Twin Valley Electric Coop were excluded due to unavailable tariffs.

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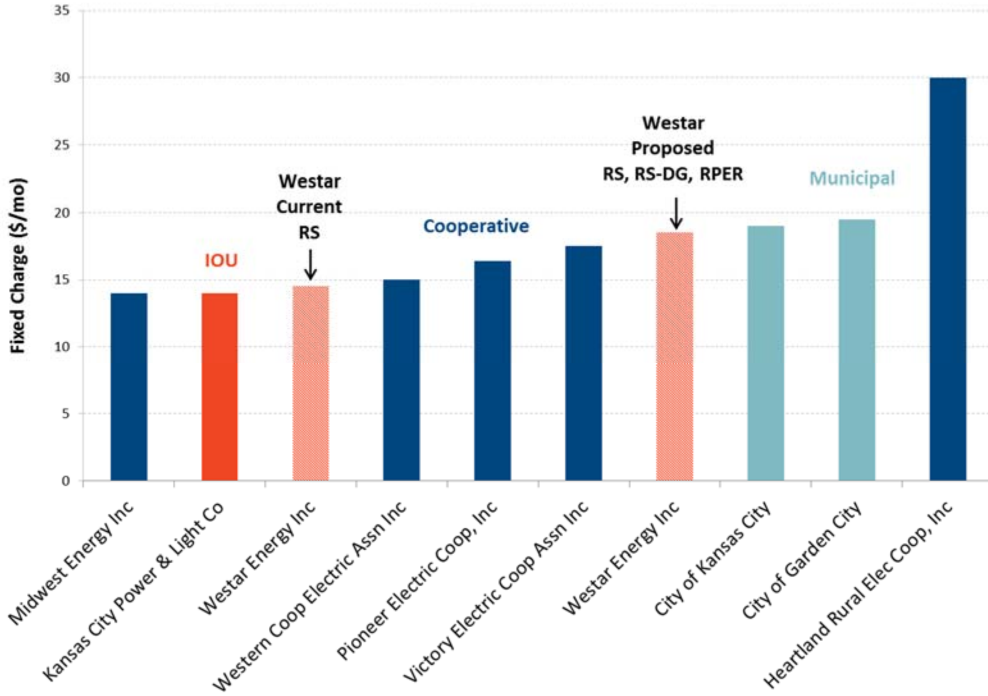
[29] The sample analyzed in Figure 4 includes all Kansas utilities (as per EIA Form 861). I collected fixed charges for each utility from its tariff sheet (found on the utilities' respective online websites or municipal code). Some utilities (see Figure 4 Notes) were

Figure 5: Residential Fixed Charge Survey:
Kansas Utilities with at least 10,000 Customers[30]



Sources: Utility tariff sheets as of November 2017, EIA Form 861
Notes: Figure includes all Kansas utilities with at least 10,000 customers. Kansas Gas & Electric Co and Rolling Hills Electric Coop were excluded due to unavailable tariffs.

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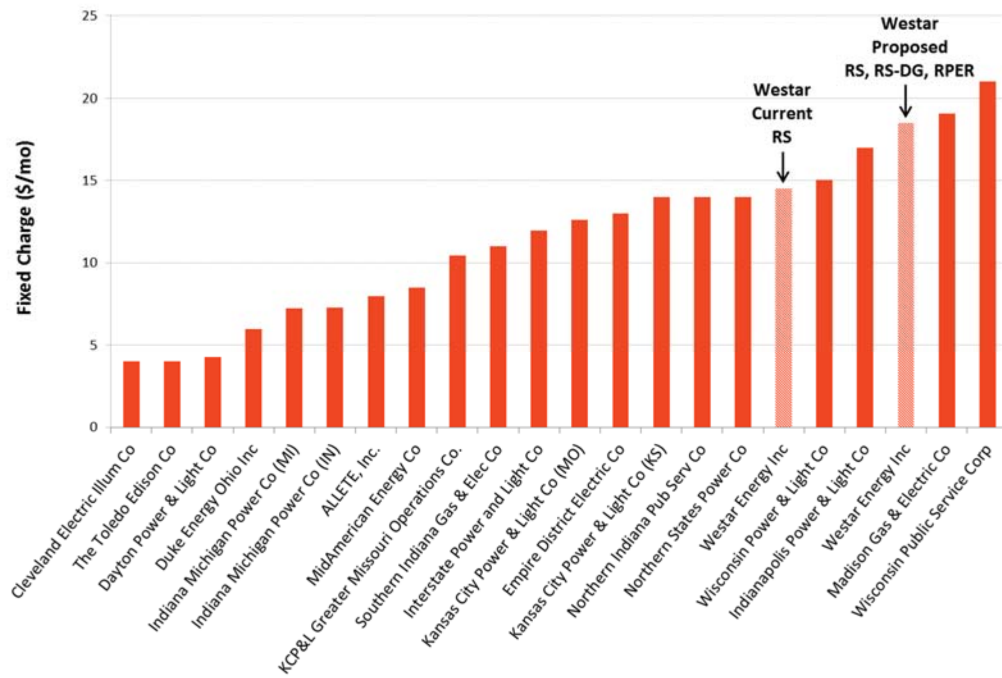
excluded because tariffs were unavailable online. I also eliminated any utilities which had fixed charges that applied to both residential and non-residential customers. For example, for some municipal utilities and cooperatives, the rate applicable to residential customers also applied to commercial or industrial customers—such rates were excluded from analysis presented in Figure 4. Lastly, some utilities reported separate fixed charges for rural customers and urban customers. In such cases, Figure 4 reports the average of the two fixed charges (rural and urban).

30 Similar to Figure 4, Figure 5 presents residential fixed charges for Kansas utilities, limiting the sample of utilities analyzed to the ones with 10,000 customers or more.

Figure 6: Residential Fixed Charge Survey:
Midwestern IOUs with a Customer Count Comparable to Westar[31]



Sources: Utility tariff sheets as of November 2017, EIA Form 861
Notes: Kansas Gas & Electric Co was excluded due to unavailable tariffs.

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[31] I identified the sample of comparable Midwestern IOUs analyzed in Figure 6 using EIA Form 861 data. First, I selected investor-owned utilities operating in the states of Iowa, Illinois, Indiana, Kansas, Michigan, Minnesota, Missouri, North Dakota, Nebraska, Ohio, South Dakota, and Wisconsin—defined as Midwestern states by the U.S. Census Bureau (see: https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf). Among these Midwestern IOUs, I selected only the closest ten utilities with total number of customers greater than that of Westar's and the closest ten utilities with total number of customers less than that of Westar's. Lastly, I collected fixed charges for each utility's standard residential rate from its tariff sheet (found on the utilities' respective online websites).

APPENDIX D: U.S. UTILITIES OFFERING A DEMAND CHARGE TO RESIDENTIAL CUSTOMERS

#	Utility	Utility Ownership	State	Residential Customers Served	Fixed charge ($/month)	Demand Charge ($/kW-month)		Timing of demand measurement	Demand interval	Combined with Energy TOU?	Applicable Residential Customer Segment	Mandatory or Voluntary
						Summer	Winter					
[1]	Alabama Power	Investor Owned	AL	1,253,875	14.50	1.50	1.50	Any time	15 min	Yes	All	Voluntary
[2]	Alaska Electric Light and Power	Investor Owned	AK	14,292	11.49	6.72	11.11	Any time	Unknown	No	All	Voluntary
[3]	Albemarle Electric Membership Corp	Cooperative	NC	11,514	27.00	13.50	13.50	Peak Coincident	15 min	Yes	All	Voluntary
[4]	Arizona Public Service	Investor Owned	AZ	1,046,989	13.02	8.40	8.40	Peak Coincident	60 min	Yes	All	Voluntary
[5]	Arizona Public Service	Investor Owned	AZ	1,046,989	13.02	17.44	12.24	Peak Coincident	60 min	Yes	All	Voluntary
[6]	Black Hills Power	Investor Owned	SD	54,809	13.00	8.10	8.10	Any time	15 min	No	All	Voluntary
[7]	Black Hills Power	Investor Owned	WY	2,085	15.50	8.25	8.25	Any time	15 min	No	All	Voluntary
[8]	Butler Rural Electric Cooperative	Cooperative	KS	6,473	29.00	5.10	5.10	Peak Coincident	60 min	No	All	Mandatory
[9]	Carteret-Craven Electric Cooperative	Cooperative	NC	35,546	30.00	11.95	9.95	Peak Coincident	15 min	No	All	Voluntary
[10]	Central Electric Membership Corp	Cooperative	NC	19,928	34.00	8.55	7.50	Peak Coincident	15 min	Yes	All	Voluntary
[11]	City of Fort Collins Utilities	Municipal	CO	61,738	6.14	2.59	2.59	Any time	Unknown	No	All	Voluntary
[12]	City of Glasgow	Municipal	KY	5,413	29.16	11.33	10.37	Peak Coincident	30 min	Yes	All	Voluntary (opt-out)
[13]	City of Kinston	Municipal	NC	9,684	14.95	9.35	9.35	Peak Coincident	15 min	No	All	Voluntary
[14]	City of Longmont	Municipal	CO	35,465	15.40	5.75	5.75	Any time	15 min	No	All	Voluntary
[15]	City of Templeton	Municipal	MA	3,500	3.00	8.00	8.00	Any time	15 min	No	All	Mandatory
[16]	Cobb Electric Membership Cooperative	Cooperative	GA	179,794	28.00	5.55	5.55	Peak Coincident	60 min	No	All	Voluntary
[17]	Dakota Electric Association	Cooperative	MN	96,153	12.00	14.70	11.10	Any time	15 min	No	All	Voluntary
[18]	Dominion Energy	Investor Owned	NC	101,620	16.39	9.76	5.66	Peak Coincident	30 min	Yes	All	Voluntary
[19]	Dominion Energy	Investor Owned	VA	2,150,818	12.00	5.68	3.95	Peak Coincident	30 min	Yes	All	Voluntary
[20]	Duke Energy Carolinas, LLC	Investor Owned	NC	1,646,664	14.13	4.97	3.69	Peak Coincident	15 min	Yes	All	Voluntary
[21]	Duke Energy Carolinas, LLC	Investor Owned	SC	470,818	9.93	8.15	4.00	Peak Coincident	30 min	Yes	All	Voluntary
[22]	Edgecombe-Martin County EMC	Cooperative	NC	10,265	34.50	8.90	8.90	Peak Coincident	Unknown	No	All	Voluntary
[23]	Fort Morgan	Municipal	CO	5,275	8.17	10.22	10.22	Unknown	Unknown	No	All	Voluntary
[24]	Georgia Power	Investor Owned	GA	2,118,033	10.00	6.64	6.64	Any time	30 min	Yes	All	Voluntary
[25]	Kentucky Utilities Company	Investor Owned	KY	423,952	12.25	7.87	7.87	Peak Coincident	15 min	No	All	Voluntary
[26]	Lakeland Electric	Municipal	FL	104,590	9.50	5.60	5.60	Peak Coincident	30 min	No	All	Voluntary
[27]	Louisville Gas and Electric	Investor Owned	KY	353,419	12.25	7.68	7.68	Peak Coincident	15 min	No	All	Voluntary
[28]	Loveland Electric	Municipal	CO	30,651	23.50	9.80	7.35	Any time	15 min	No	All	Voluntary
[29]	Mid-Carolina Electric Cooperative	Cooperative	SC	47,746	24.00	12.00	12.00	Any time	60 min	No	All	Mandatory
[30]	Midwest Energy Inc	Cooperative	KS	30,021	22.00	6.40	6.40	Any time	15 min	No	All	Voluntary
[31]	Oklahoma Gas and Electric Company	Investor Owned	AR	55,022	9.75	1.00	1.00	Any time	15 min	No	All	Voluntary
[32]	Otter Tail Power Company	Investor Owned	MN	48,026	11.00	8.00	8.00	Any time	60 min	No	All	Voluntary
[33]	Otter Tail Power Company	Investor Owned	ND	45,411	18.38	6.52	2.63	Any time	60 min	No	All	Voluntary
[34]	Otter Tail Power Company	Investor Owned	SD	8,689	13.00	7.05	5.93	Any time	60 min	No	All	Voluntary
[35]	PacifiCorp	Investor Owned	OR	492,505	13.30	2.20	2.20	Unknown	Unknown	No	All	Voluntary
[36]	Pee Dee Electric Membership Cooperative	Cooperative	SC	28,693	34.40	8.50	7.00	Unknown	Unknown	Yes	All	Voluntary
[37]	Platte-Clay Electric Cooperative	Cooperative	MO	20,691	25.38	2.50	2.50	Peak Coincident	60 min	No	All	Mandatory
[38]	Progress Energy Carolinas	Investor Owned	NC	1,107,292	14.13	4.97	3.69	Peak Coincident	15 min	Yes	All	Voluntary
[39]	Salt River Project	Political Subdivision	AZ	914,246	32.44 or 45.44	9.59 to 34.19	3.55 to 9.74	Peak Coincident	30 min	Yes	DG only	Mandatory
[40]	Santee Cooper Electric Cooperative	Cooperative	SC	40,401	50.00	6.00	6.00	Peak Coincident	30 min	Yes	DG only	Mandatory
[41]	Smithfield	Municipal	NC	3,445	17.00	5.93	5.93	Peak Coincident	15 min	Yes	All	Voluntary
[42]	South Carolina Electric & Gas Company	Investor Owned	SC	596,685	14.00	12.04	8.60	Peak Coincident	15 min	Yes	All	Voluntary
[43]	Swanton Village Electric Department	Municipal	VT	3,232	11.33	9.17	9.17	Any time	15 min	No	All	Mandatory
[44]	Tri-County Electric Cooperative	Cooperative	FL	15,975	23.00	7.00	7.00	Any time	15 min	No	All	Voluntary
[45]	Traverse Electric Cooperative, Inc.	Cooperative	MN	1,805	76.00	18.65	18.65	Peak Coincident	Unknown	No	All	Voluntary
[46]	Vigilante Electric Cooperative	Cooperative	MT	8,140	23.00	0.50 per KVA	0.50 per KVA	Any time	Unknown	No	All	Mandatory
[47]	Westar Energy	Investor Owned	KS	325,647	16.50	6.91	2.13	Any time	30 min	No	All	Voluntary
[48]	Xcel Energy (PSCo)	Investor Owned	CO	1,211,662	19.31	10.08	7.76	Any time	15 min	No	All	Voluntary
[49]	Xcel Energy (PSCo)	Investor Owned	CO	1,211,662	6.54	13.38	10.46	Peak Coincident	60 min	No	All	Voluntary

Notes accompanying table of U.S. residential demand charge offerings

Sources: Utility tariffs as of November 2017**,** and "Form EIA-861 2013 data files, EIA_861_Retail_Sales_2013.xls" (for Utility ownership and Residential Customers Served columns).
Notes:

Peak periods are applicable from Monday through Friday excluding holidays. For some utilities, the monthly fixed charge has been calculated by multiplying a daily charge by 30.5.

[2]: Mandatory if customer consumes more than 5,000 kWh per month for three consecutive months or has a recorded peak demand of 20 KW for three consecutive months.

[3]: The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.

[6]-[7]: Black Hills also offers an optional time-of-use rate that includes both energy and demand charges for customers owning demand controllers.

[15]: The demand charge only applies to demand measured in excess of 10 kW.

[16]: The demand rate is not mandatory for residential customers. Though, the only alternative is a flat bill.

[19]: Demand charge is the sum of the distribution demand charge and the generation demand charge. The distribution demand charge is $1.612/kW and the generation demand charge is $4.070/kW for the summer and $2.334/kW for the winter.

[23]: The timing of demand measurement and the demand interval are not explicitly identified in the publicly available information we have reviewed.

[28]: The demand rate is closed to new customers after December 31, 2014.

[30]: The demand charge is based on the greater of the highest average 15 minute kW demand measured during the period for which the bill is rendered, and 80% of the average 15 minute maximum demand for the last three summer months.

[32]-[34]: Demand is measured as the maximum winter demand for the most recent 12 months. New customers have an assumed demand of 3 kW for their first year. Fixed charge for MN is customer charge per month plus facilities charge per month. Fixed charge for ND and SD is just customer charge per month.

[35]: The demand charge is only applicable to three-phase customers

[37]: Billing demand is the greater of the current month actual demand or 50% of peak deamnd established in the preceding eleven months.

[39]: Customers below 200 amps pay a fixed charge of $32.44 per month and customers above 200 amps pay $45.44 per month. Demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). The summer demand charges shown here apply for the On-Peak Summer period. The (on-peak) summer demand charge is $9.59 for up to 3kW of demand, 17.82 for the next 7kW, and 34.19 for over 10kW. The winter demand charge is $3.55 for up to 3kW, 5.68 for the next 7kW, and $9.74 over 10kW. The utility is experimentally offering the rate plan to a limited number of non-DG customers.

[43]: The demand charge is based on the greater of the measured demand for the current month and 85% of the highest recorded demand established during the preceding eleven months. The rate is mandatory for all residential customers with monthly consumption equal to or greater than 1,800 kWh, measured on a rolling 12 month average basis.

[46]: The demand charge applies only to KVA greater than 15 KVA.

[47]: Not available to new customers since 2006.

[48]: Xcel Energy Residential Demand Service (Schedule RD).

[49]: Xcel Energy Residential Demand-Time Differentiated Rates Service (Schedule RD-TDR).

APPENDIX E: KANSAS UTILITIES OFFERING A DEMAND CHARGE TO C&I CUSTOMERS

Utility	Utility Ownership	Customers Served	Mandatory for Some C&I Customers?	Mandatory for All C&I Customers?
	[1]	[2]	[3]	[4]
Westar Energy Inc	IOU	699,690		✔
Kansas City Power & Light Co	IOU	249,183		✔
Kansas City Board of Public Utilities	Muni	64,329		✔
Midwest Energy Inc	DistCoop	50,453	✔	
Wheatland Electric Coop Inc	DistCoop	32,854		✔
Prairie Land Electric Coop Inc	DistCoop	25,389	✔	
Victory Electric Coop Association Inc	DistCoop	19,608	✔	
Pioneer Electric Coop Inc KS	DistCoop	16,952		✔
Western Coop Electric Association Inc	DistCoop	12,301	✔	
Garden City KS (City of)	Muni	11,420	✔	
Heartland Rural Electric Coop	DistCoop	11,275	✔	
Rolling Hills Electric Coop	DistCoop	11,189		✔

Sources:

[1] & [2]: EIA 2015.

[3] & [4]: Utility tariffs as of November 2017. Rolling Hills Electric Coop data from OpenEI.org.

APPENDIX F: THE RATE CHOICE MODEL

This appendix describes the Rate Choice Model (RCM), which I used to develop estimates of customer rate switching behavior in the "Likely Choice" scenario in my testimony. The model is driven by two parameters – simply called "alpha" and "beta" – which I discuss in detail below.

The RCM belongs to a family of models referred to in the economics literature as a "multinomial logit model" or a "discrete choice model."[32] When a customer is presented with a choice of two or more electricity rates, the model captures that customer's likelihood of enrolling in each rate as a function of their average monthly bill on each rate. The logic of the model rests on the intuitive presumption that a customer would be more likely to enroll in a rate that leads to a lower bill.

But while a customer is most likely to choose the rate that produces a lower bill, he/she will not choose that rate with complete certainty. There is some likelihood that the customer will choose one of the other available rate options. This could be because the customer is uncertain about his/her consumption profile and is not sure which rate will produce the lowest bill. It could also be the case that the customer has limited time and resources

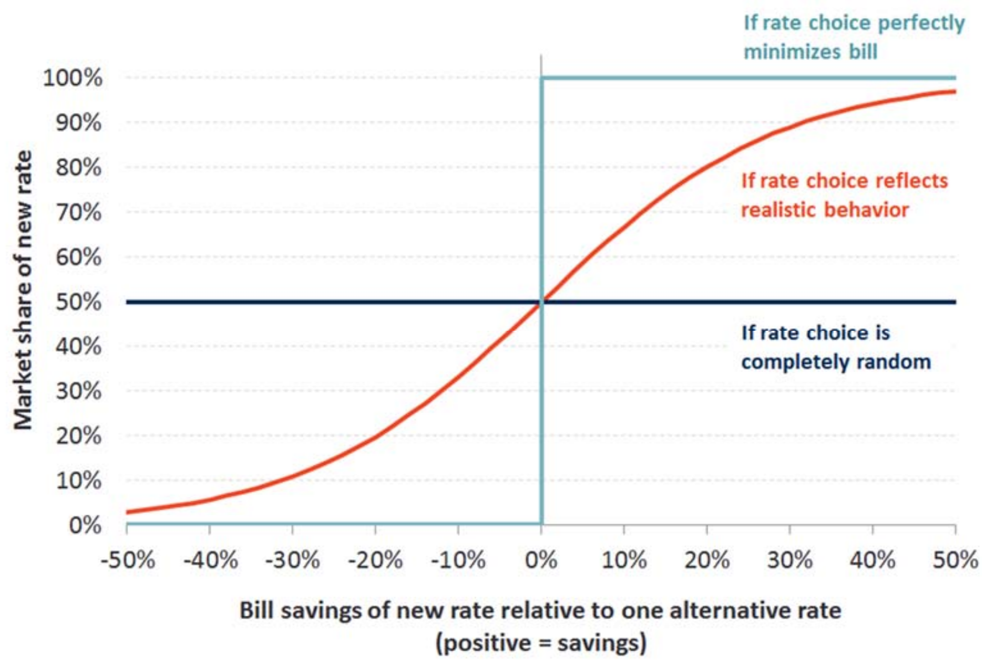
[32] Logit modeling has been used to model customer choice for decades. Nobel prize-winning economist Dan McFadden pioneered its development. See McFadden, D. (1974) "Conditional logit analysis of qualitative choice behavior" in Frontiers in Econometrics Ed. P. Zarembka New York Academic Press 105-142.

at his/her disposal to conduct the research necessary to make the optimal decision. There could also be a perception that features of the bill-minimizing rate – such as, for example, a risk of greater bill volatility – are negative attributes and would lead the customer to deliberately choose a rate that produces a higher bill that has less price volatility associated with it.

The customer's ability and willingness to choose the rate that minimizes his/her bill is represented in the model by a parameter called "beta." Beta has a negative value. The larger the negative value (i.e., the more negative the value is), the more likely the customer is to choose the rate that minimizes his/her bill. A large beta value (e.g., -1.0) means that a customer is highly likely to choose the rate that minimizes his/her bill, whereas a small beta value (e.g., -0.01) means that the customer is more likely to make a random rate enrollment choice.

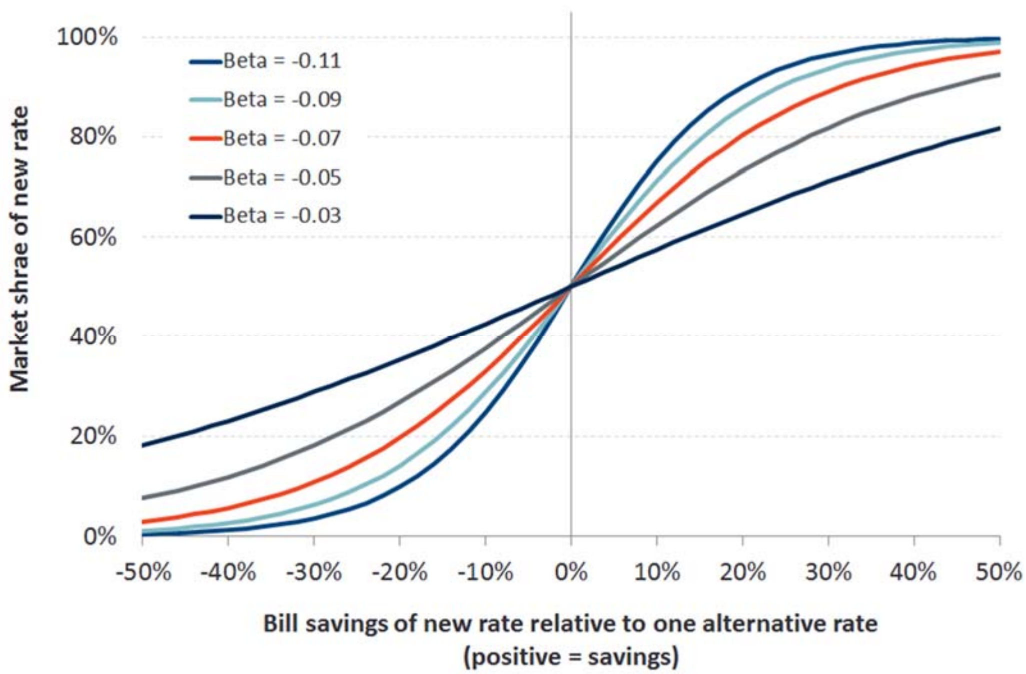
To illustrate, consider a case where a customer is faced with a choice of two rate options, both of which are new offerings. At one extreme, a price sensitive customer with perfect information would always choose to enroll in the cheapest rate, even if it saved him/her only a penny per year on his/her electricity bill. In Figure 7 below, this type of perfect least-cost behavior is represented by the light blue line. At the other extreme, a customer with no interest in his/her electricity bill would make a completely random choice of rate, regardless of the relative cost of each. This is represented by the dark blue line. In reality, the vast majority of customers will fall somewhere between these two extremes; a beta value of -0.07 represents intuitively realistic rate enrollment behavior. This is the red line. The figure illustrates a customer's likelihood of enrolling in the rate that minimizes his/her bill (the vertical axis) as a function of their monthly bill savings from enrolling in that rate (the horizontal axis).

Figure 7: Rate Adoption Curve When Choosing Between Two New Alternatives



With a beta value of -0.07, the customer's likelihood of enrolling in the cheapest rate increases with the relative bill savings associated with that rate. The customer has a 50 percent chance of enrolling in the cheapest rate if there are negligible bill savings (i.e., he/she is indifferent between the two rates). At bill savings of around 20 percent, the customer has roughly a 75 percent chance of enrolling in the cheapest rate. And if bill savings are expected to be 40 percent, the customer is more than 90 percent likely to enroll. The beta value can be adjusted by the RCM user to modify this relationship and move the curve between the two extreme cases discussed above. Figure 8 illustrates how the rate adoption curve changes with various assumed beta values.

Figure 8: Adoption Curve with Various Beta Value Assumptions

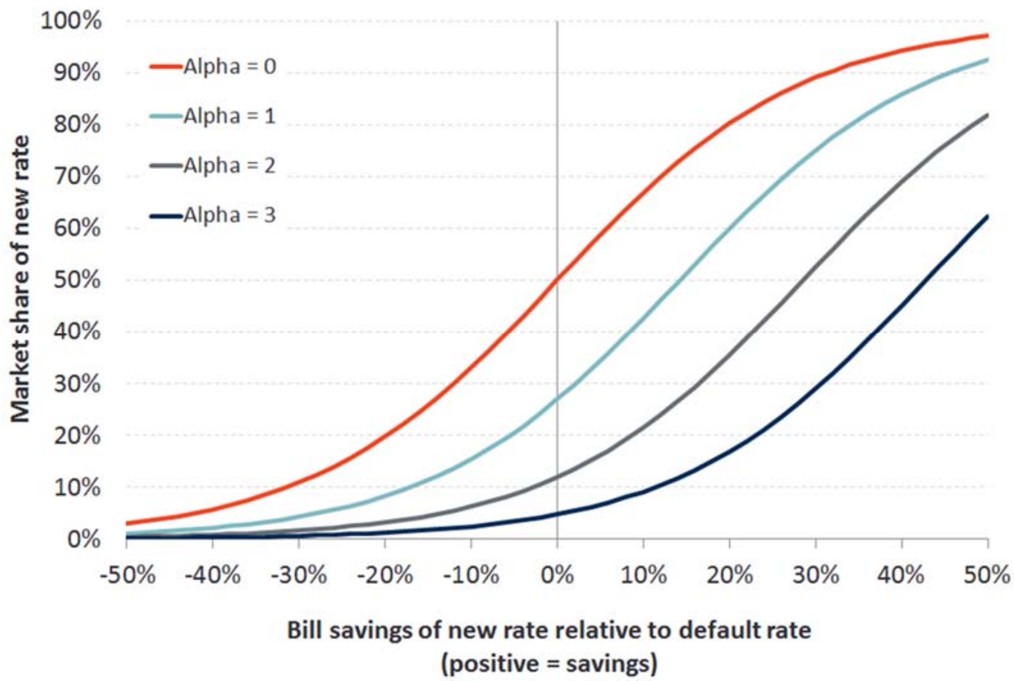


There is also a second factor that will affect a customer's decision to enroll in a new rate option. That is the presence or absence of a default rate. The example above assumes that the customer is presented with two new rate options and that the customer must choose one of those two options. In other words, in that example, the customer did not have a "default" rate in which he/she was already enrolled. When there is a default rate option (as is the case in Westar's proposal for non-DG residential customers), research has found that customers have a natural tendency to remain on the default rate. There is an inherent "stickiness" associated with the default rate; customers who could save money by switching to one of the alternative new rate options demonstrate some hesitancy in doing so.

The RCM has a parameter called "alpha" that captures the "stickiness" associated with the default rate. Alpha is a positive value, and a larger alpha value means that a customer is more likely to remain on the default rate regardless of the relative attractiveness of the alternative rates. A large alpha value (e.g., 5.0) means that a customer is highly likely to remain on the default rate, whereas a low value (e.g., 0.5) value means that the customer would treat the default rate more like one of the new alternative rate options – there is less "stickiness" with a low alpha value.

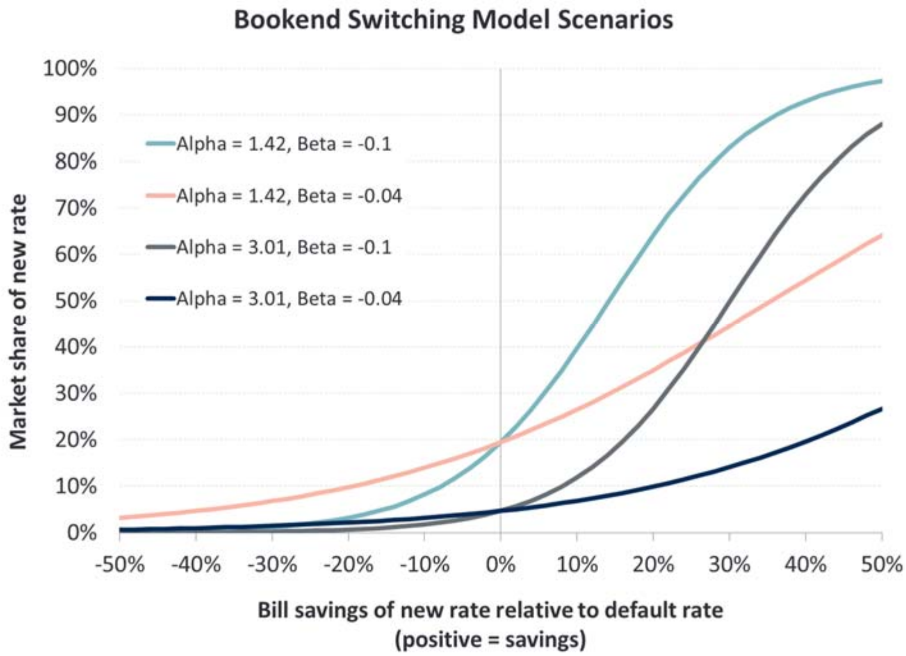
Figure 9 below illustrates how the adoption curve (with beta value of -0.07) changes with various assumptions for the value of alpha. In the figure, the customer has a choice between the default rate and one alternative new rate. With a beta value of -0.07 and an alpha of 3.0, the customer has only a 15 percent likelihood of switching to the new rate if it would provide bill savings of 20 percent and a 45 percent likelihood of switching if it provides bill savings of 40 percent.

Figure 9: Adoption Curve with Various Alpha Value Assumptions



As I described in my testimony, I analyzed two different adoption scenarios for Westar. One is anchored on roughly a 5 percent switching rate (consistent with alpha of 3.01) and the other is anchored on roughly a 20 percent switching rate (consistent with alpha of 1.42). For each of these scenarios, I tested a high beta of -0.10 and a low beta of -0.04. The adoption curves associated with each of these four cases are shown in Figure 10. The figure illustrates the choice between a default rate and one new alternative rate.

Figure 10: Four Adoption Cases Modeled in Analysis for Westar



For simplicity, the examples above illustrate a choice between just two rates. However, the RCM modeling framework can account for any number of rate choices.

In Westar's proposal, residential non-DG customers have the choice between two rate options: a default rate ("Schedule RS") and one new rate option ("Schedule RPER"). The following is a mathematical representation of the model for this scenario.

$$\text{Likelihood of Choosing Default Rate} = \frac{e^{\alpha+\beta\times \text{Bill}_d}}{e^{\alpha+\beta\times \text{Bill}_d} + e^{\beta\times \text{Bill}_a}}$$

$$\text{Likelihood of Choosing Alternative Rate} = \frac{e^{\beta\times \text{Bill}_a}}{e^{\alpha+\beta\times \text{Bill}_d} + e^{\beta\times \text{Bill}_a}}$$

Where $\alpha = \text{"alpha" value}$

β = "beta" value

$Bill_d$ = customer bill on Default Rate

$Bill_a$ = customer bill on Alternative Rate

APPENDIX G: RATE MODIFICATIONS FOR CONSISTENCY WITH RESIDENTIAL LOAD SAMPLE

It was necessary to slightly modify the proposed RPER rate provided by Westar so that it would be revenue neutral in comparison to the revenue collected from the proposed RS rate. This allows my analysis to isolate the bill impact of a change in rate design, without assuming any artificial change in the average rate level.

First, I calculated the total revenue that Westar would collect from my sample of non-DG customers, assuming they were all subject to the RS rate. Then, for each customer, I calculated the portion of the bill that would be determined by the fixed charge of $18.50 per month, the riders, and the seasonal demand charges. In other words, I calculated the non-energy portion of the bill. I summed the non-energy bills for all customers for all 12 months and then calculated the energy charge that would make up the difference between this amount and the total revenue collected under the RS rate. The energy charge under the RPER rate does not vary by season or tier. Table 5 shows the adjusted revenue-neutral RPER rate.

Table 5: Proposed RPER Rate with Modifications for Sample Load Data

	Winter	Summer
Basic Service Fee ($/month)	18.50	18.50
Energy charge ($/kWh)	0.049855	0.049855
Demand Charge ($/kW-month)	3.15	9.45
Riders ($/kWh)	0.040638	0.040638

Note: The riders are RECA, PTS, TDC, and EER. They are assumed to be the same prices that are associated with Schedule RS.

APPENDIX H: METHODOLOGY AND ASSUMPTIONS IN PRICE RESPONSE ANALYSIS

This appendix summarizes the assumptions behind the estimation of changes in customer electricity consumption patterns in response to the introduction of a three-part rate.

There are two important effects to capture when modeling customer price response. The first is what I call the "load shifting" effect (sometimes also known as the price elasticity of substitution). It captures the customer's incentive to shift consumption from the higher priced period to the lower priced period. The second effect is called the "average price" effect. It captures a customer's general reaction to a change in their overall bill – if the customer's bill (or average price) increases under the three-part rate, one would expect them to consume less electricity in response (and vice versa).

Based on a review of price elasticities from prior studies, including assumptions from a 2012 Christensen Associates rate study for the KCC, I conservatively assumed a "daily elasticity" of -0.045 to capture the average price effect, and I tested high and low elasticity cases, as discussed below.

To represent the load shifting effect, I relied on demand reductions that were observed in prior studies of customer response to three-part rates. The first study, conducted with customers in Norway, observed a demand reduction of approximately 5 percent in response to a demand charge of roughly $10/kW.[33] The second study, conducted by Wisconsin Public Service, observed a demand reduction of 29 percent in response to a demand charge that was also approximately $10/kW.[34] I am also aware of a third study, conducted by Duke Energy, which observed a demand reduction between these two values. Given the general lack of empirical data specifically related to how DG customers will change their consumption patterns in response to a three-part rate, I chose the two extreme values to represent the broadest possible range of possibilities. A summary of the three studies is provided in Figure 11.

Figure 11: Summary of Residential Demand Charge Price Response Studies

Study	Location	Utility	Year(s)	# of participants	Monthly demand charge ($/kW)	Energy charge (cents/kWh)	Fixed charge ($/month)	Timing of demand measurement	Interval of demand measurement	Peak period	Estimated avg reduction in peak period consumption
1	Norway	Istad Nett AS	2006	443	10.28	3.4	12.10	Peak coincident	60 mins	7 am to 4 pm	5%
2	North Carolina	Duke Power	1978 - 1983	178	10.80	6.4	35.49	Peak coincident	30 mins	1 pm to 7 pm	17%
3	Wisconsin	Wisconsin Public Service	1977-1978	40	10.13	5.8	0.00	Peak coincident	15 mins	8 am to 5 pm	29%

Notes:
All prices shown have been inflated to 2014 dollars
In the Norwegian pilot, demand is determined in winter months (the utility is winter peaking) and then applied on a monthly basis throughout the year.
The Norwegian demand rate has been offered since 2000 and roughly 5 percent of customers have chosen to enroll in the rate.
In the Duke pilot, roughly 10% of those invited to participate in the pilot agreed to enroll in the demand rate.
The Duke rate was not revenue neutral - it included an additional cost for demand metering.
The Wisconsin demand charge is seasonal; the summer charge is presented here because the utility is summer peaking.

[33] Stokke, A., Doorman, G., Ericson, T., 2009, January. "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector," Discussion Paper 574, Statistics Norway Research Department.

[34] Caves, D., Christensen, L., Herriges, J., 1984. "Modeling alternative residential peak-load electricity rate structures." *J. Econometrics.* Vol 24, Issue 3, 249-268.

Formulaically, each customer's price response is calculated as follows:

Average price effect

$$P_{er} = \left(\frac{R_d}{R_{std}} - 1\right) * E_d$$

Where,

P_{er} = % electricity consumption change

R_d = levelized all-in three part rate

R_{std} = levelized all-in standard two part rate

E_d = daily elasticity

New Electricity Consumption:

$$EC_1 = (1 + P_{er}) * EC_0$$

Where,

EC_1 = new electricity consumption

P_{er} = % electricity consumption change

EC_0 = original electricity consumption

The new electricity consumption is multiplied by the variable rate to calculate the change in the energy portion of the bill due to the average price effect. To avoid overstating the reduction in maximum demand, the average price effect is assumed not to incrementally change the customer's max demand; in other words, the only impact on max demand is from the load shifting effect.

The load shifting effect

Hourly on-peak consumption change (applies for hours 2pm-7pm):

$$H_1 = (1 + P_s) * H_0$$

Where,

H_1 = new hourly electricity consumption

P_s = % load shift from on-peak to off-peak (peak reduction expressed as negative)

H_0 = original hourly electricity consumption

Each customer's maximum demand, modified to account for the shift in consumption from on-peak to off-peak hours, is multiplied by the summer and winter demand rates to calculate the change in the demand portion of the customer's bill due to the load shifting effect.

I tested a range of price elasticities to account for the uncertainty in this assumption. The range is based on a review of price elasticities from prior pricing pilots conducted around the U.S. The price elasticity cases are summarized in Table 6 and Table 7.

Table 6: Average Price Effect Sensitivity Cases

	Daily Elasticity
Low	-0.030
Mid	-0.045
High	-0.060

Table 7: Load Shifting Effect Sensitivity Cases

	Average Peak Period Demand Reduction
Low	-5%
High	-29%

The reduction in the average DG customer's bill due to price response for each price elasticity case is summarized in Table 8 and Table 9.

Table 8: Reduction in Average DG Customer Bill due to Price Response (Avg. Peak Period Demand Reduction = 5%)

Avg Price Effect	Change (%)			Change ($/mo)		
Scenario	Summer	Winter	Average	Summer	Winter	Average
Low	2.8%	1.4%	2.0%	$3.79	$1.22	$2.08
Mid	3.2%	1.7%	2.3%	$4.41	$1.45	$2.44
High	3.7%	1.9%	2.7%	$5.02	$1.68	$2.79

Table 9: Reduction in Average DG Customer Bill due to Price Response (Avg. Peak Period Demand Reduction = 29%)

Avg Price Effect	Change (%)			Change ($/mo)		
Scenario	Summer	Winter	Average	Summer	Winter	Average
Low	11.7%	5.6%	8.3%	$16.10	$4.90	$8.63
Mid	12.2%	5.9%	8.6%	$16.71	$5.13	$8.99
High	12.6%	6.1%	9.0%	$17.33	$5.36	$9.35

APPENDIX I: DESCRIPTION AND ADJUSTMENTS TO LOAD RESEARCH SAMPLE DATA

This section describes the DG and non-DG residential data used in my analysis and summarizes the adjustments I made to the data for the purpose of my analysis.

<u>DG Residential Load Data</u>

Westar provided 15-min interval load data for its 155 customers that installed DG after October 2015. The dataset spans the period from July 2016 to June 2017. There is nearly a full year of load data for 31 of the 155 customers. Several these customers had a small number of missing observations. I grouped the observations by hour, and I replaced each hourly value containing at least one missing 15-minute observation with a value equal to the average hourly load for the same hour, using all the other days of the same month for the individual customer.

<u>Non-DG Residential Load Data</u>

Westar provided 15-min load data for non-DG customers grouped by stratum and Rate Area (Westar North and Westar South), as well as the sample weights of each stratum by Rate Area. The data spans the same time period as the DG data, and missing observations were replaced using the same approach used for the DG data, as described above.

To combine the North and South load research data for non-DG customers, I applied a weighting to the sample to reflect the number of customers in each of the two Areas. I then replicated entries for each customer in the dataset in a proportion that aligned with the Rate Area and strata weights.