RECEIVED
2017 JUN 23 PM 2:55
PUBLIC UTILITY COMMISSION
FILING CLERK

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

REDACTED

DIRECT TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF

THE ENERGY FREEDOM COALITION OF AMERICA

Justin R. Barnes
EQ Research LLC
401 Harrison Oaks Blvd., Suite 100
Cary, North Carolina 27513

June 23, 2017

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

REDACTED

DIRECT TESTIMONY OF JUSTIN R. BARNES

TABLE OF CONTENTS

EXHIBITS

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

REDACTED

DIRECT TESTIMONY OF JUSTIN R. BARNES

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. Justin R. Barnes, 401 Harrison Oaks Blvd Suite 100, Cary, North Carolina, 27513. My current position is Director of Research with EQ Research LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years, where I worked on the Database of State Incentives for Renewables and Efficiency (DSIRE) project, and several other projects related to state renewable energy and efficiency policy.

In my current position I coordinate EQ Research's various research projects for clients, directly manage and perform research for an electric industry regulatory policy tracking service, contribute as a researcher to other standard policy service offerings such as a general rate case tracking service, and perform customized research. I have testified before the Public Service Commission of South Carolina, the Oklahoma Corporation Commission, the Colorado Public Utilities Commission, the Utah Public Service Commission, and the Public Utility Commission of Texas ("PUCT" or "Commission") as an expert in distributed generation policy and rate design. My curriculum vitae is attached as Exhibit JRB-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE PUCT?

A. Yes. I submitted testimony in El Paso Electric's 2016 rate case, Docket No. 44941.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Energy Freedom Coalition of America ("EFCA"). EFCA consists of full-service distributed rooftop solar providers. They serve customers throughout the state of Texas. EFCA members also have solar facilities installed and currently serve customers in the El Paso Electric Company's ("EPE") service territory.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The primary purpose of my testimony is to describe why the Commission should deny El Paso Electric Company's ("EPE", "the Company", or "the utility") proposal to establish a separate partial requirements rate class for residential customers with distributed generation ("DG") and its proposal to subject all DG customers to rates with demand charges. I also address the Company's use of demand ratchets in the rates applicable to larger non-residential customers. More specifically, I discuss:

1. The fatal flaws in EPE's analysis and conclusion that residential DG customers should be considered a separate class of customer;
2. Why EPE's proposed partial requirements rate is out of step with traditional ratemaking principles and is unreasonably discriminatory;
3. EPE's lack of consideration of the long-term value of DG resources to EPE's ratepayers;
4. Specific issues associated with EPE's residential DG rate proposal, and in particular the lack of relationship of EPE's proposed rates to cost causation;
5. Concerns with imposing mandatory rates on any residential customer, specifically mandatory demand charges and mandatory TOU.
6. Ratemaking practices and rate designs that more appropriately address the issues that EPE alleges are present in the current rates charged to DG customers;

7. The considerable drawbacks of demand ratchets, including but not limited to the adverse effects they have on customer incentives to reduce demand on the electric grid and the impacts of demand ratchets on energy storage viability; and

8. To the extent the Commission accepts EPE's proposed DG rate design, the lack of grandfathering for existing DG customers.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission:

1. Reject the Company's proposal to establish a separate class for residential DG customers.

2. Reject the Company's proposal to subject residential and small general service DG customers to different rates than those otherwise available to customers in the respective rate classes.

3. Reject the Company's proposed interconnection application fees and consider a review of application fees in order to ensure methodological consistency in any future fees and to identify process inefficiencies that could be improved upon.

4. Conduct a thorough investigation of DG costs and benefits and appropriate rate design prior to adopting any rate changes for DG customers.

5. Direct EPE to pilot new residential rate designs, in order to gauge acceptance, response, and the impact that new rate designs would have on cost recovery.

6. Proceed gradually with any future rate design modifications with a focus on providing multiple rate options for customers and unlocking the value of advanced DG technologies such as energy storage.

7. To the extent that the Commission adopts separate rates for DG customers, grandfather existing DG customers on their present rate structure for a term of 25 years from the date of the final order in this proceeding.

8. Consider establishing a default grandfathering policy, regardless of the outcome of this proceeding, in order to provide certainty and predictability to future DG customers.

9. Eliminate EPE's current demand ratchets for General Service and Large Power Service customers, or in the alternative, provide customers on these rates that install energy storage with an option to choose a rate that does not contain a demand ratchet.

10. Direct EPE to modify its procedures for moving customers between the General Service and Large Power Service rates to provide them with an opportunity modify their energy use to maintain the same rate, and time to adapt to their new rates should a move occur.

II. EPE'S PROPOSAL FOR DG CUSTOMERS

Q. PLEASE SUMMARIZE EPE'S PROPOSAL FOR DG CUSTOMERS.

A. The Company's proposal with respect to DG customers has two main elements, as follows:

1. Define residential DG customers as a separate class of customer and thus, removed from the residential customer class where these customers currently are.

2. Require all DG customers, including both residential and small general service DG customers, to take service under rates featuring time of use ("TOU") energy charges and non-coincident demand charges.

The Company proposes to apply these proposed rates to all DG customers regardless of when the customer installed DG. In other words, EPE does not propose to "grandfather" any of the existing DG customers into the rate structure in place when those customers elected to install DG at their premises. In addition the Company proposes to impose interconnection application fees of $139 for residential and small commercial DG systems and $377 for larger commercial systems.

Q. HOW IMPORTANT IS THE IS GRANDFATHERING AS AN ISSUE IN THIS PROCEEDING?

A. It is critically important. As I discuss in greater detail below, grandfathering has been a core component of proceedings related to potential changes to DG rate structures in other states, with an implicit recognition by regulators across the country that customers deserve protection against changes that could not have been anticipated at the time a DG investment was made. In several jurisdictions, the rationale to provide grandfathering is based, in part, on the signal provided by utility-sponsored incentive programs that encouraged ratepayer investments in DG, such as EPE's own Solar Photovoltaic Pilot Program, which provided over $1.5 million in incentives to customers from 2010 to 2015.[1] A lack of grandfathering would be highly punitive and unfair to existing customers who made significant investments in an environment where incentives actively encouraged them to do so.

Moreover, from a forward-looking perspective, the lack of a firm grandfathering policy creates a cloud of perpetual uncertainty that makes decisions on investments requiring a long-term outlook highly difficult. For instance, if the PUCT were to adopt EPE's present proposal, a future DG customer that is considering energy storage as a way to manage their demand has no way of knowing whether future significant changes to the current rate structure could devalue that investment. These customers are providing valuable assets to the grid, and the Commission should encourage customers to continue to do so.

Q. DOES EPE PUT FORTH ANY OTHER RATE OPTIONS OR PROPOSALS FOR DG CUSTOMER RATES?

A. Yes. EPE requests that if its proposal to establish a separate class for residential DG customers is not approved, that these customers be required to take service on a new

[1] EPE 2014 Energy Efficiency Plan & Report. PUCT Project No. 42264, *2014 Energy Efficiency Plans and Reports Pursuant to Subst. R. § 25.181(n)*, at p. 9, including the statement: "The high up-front cost of installing solar generation systems is a barrier to customers installing energy-efficient solar generation. The EPE Solar PV Pilot MTP encourages customers to install solar PV distributed generation systems at their homes or businesses by offering an incentive of $0.75/watt dc of solar generation to off-set a portion of the up-front cost."

residential demand rate. That rate would be optional for other residential customers within the Schedule No. 1, but would be mandatory for residential DG customers.

Q. PLEASE SUMMARIZE THE DIFFERENCES BETWEEN THE PROPOSED RESIDENTIAL DG RATE AND THE PROPOSED STANDARD RESIDENTIAL RATE.

A. The proposed residential DG rate (Schedule No. 3) contains the following differences from the proposed standard residential rate (Schedule No. 1):

1. The proposed DG rate contains a fixed charge of $18.15 per month, compared to a proposed fixed charge of $10.85 per month under the standard residential rate.
2. The proposed DG rate includes a demand charge of $6.20/kW based on a customer's maximum monthly 60-minute demand, whereas the standard residential rate does not feature a demand charge.
3. The proposed DG rate utilizes a TOU-based structure with a June – September peak period from 12 PM – 6 PM, whereas the standard residential rate uses a tiered, seasonal energy charge.

Q. PLEASE SUMMARIZE THE DIFFERENCES BETWEEN THE GENERALLY APPLICABLE SMALL GENERAL SERVICE RATE AND THE COMPANY'S RATES PROPOSAL FOR SMALL GENERAL SERVICE DG CUSTOMERS.

A. EPE's proposed small general service rate (Schedule No. 2) contains three customer options. One option contains seasonal energy charges, another uses a TOU-based energy rates structure, and the third uses both TOU energy rates and a non-coincident demand charge. EPE proposes that DG customers be required to take service under the demand rate option, which features a rate of $5.22/kW based on a customer's maximum monthly 30-minute demand. The customer charges for the TOU option and demand-rate option are $1.50/month higher than those under the seasonal energy-rate option. The TOU energy rates under the demand rate option are also roughly 2.3 cents/kWh lower than those proposed for the non-demand TOU rate option.

Q. WHAT IS THE COMPANY'S RATIONALE FOR ESTABLISHING RESIDENTIAL DG CUSTOMERS AS A SEPARATE CLASS AND UTILIZING A DEMAND RATE DESIGN FOR THAT CLASS?

A. At a high level, as discussed in the testimony of Mr. Schichtl, EPE argues that residential DG customer energy consumption patterns are sufficiently different from those other residential customers to merit separation into a separate class. [2] He contends that separating DG customers into a separate class will result in a more accurate allocation of costs.[3] The Company's rationale for using a demand rate design for DG customers is based on the premise that volumetric rates limit the Company's ability to recover the fixed costs of providing electric service to customers.[4] The Company also states that its proposed demand rate design relates to "matching charges with cost causation as it applies to DG customers."[5]

Q. HOW DOES THE COMPANY ATTEMPT TO JUSTIFY ITS PROPOSAL TO REQUIRE SMALL GENERAL SERVICE DG CUSTOMERS TO TAKE SERVICE UNDER A DEMAND RATE DESIGN?

A. Mr. Schichtl states that the rationale for applying a demand rate design to these customers is the same as that underlying its proposal for residential DG customers.[6] Mr. Schichtl contends that there is the potential for under-recovery of fixed costs.

Q. DO YOU AGREE WITH THE LOGIC BEHIND THE COMPANY'S DG PROPOSAL AND THE CORRESPONDING RATE DESIGN?

A. No. In subsequent sections I discuss the numerous ways in which the proposal and underlying analysis is flawed. In brief, the inadequacies include:

1. EPE's own analysis shows that residential DG customer energy-usage patterns are in fact well within the variations seen in the residential class as a whole.

---

2 Throughout the Company's application DG customers generally are referred to as "partial requirements" customers, meaning that they do not obtain their "full" electric requirements from the Company.

3 Direct Testimony and Exhibits of James Schichtl at p. 48, lines 4-17. ("Schichtl Direct")

4 *Id.* at p. 46, lines 3-10.

5 *Id.* at p. 50, line 7.

6 *Id.* at p. 45, lines 15-18.

2. The Company has not performed any analysis of small general service DG customers to support its proposal to also subject these customers to a demand rate design. As a result, the Company has failed to provide any evidence of the alleged "cost shift" the proposal is purported to address.

3. The Company has failed to perform any analysis of the benefits that DG provides to the system and to its customers, rendering its analysis of DG customer cost of service incomplete and inaccurate.

4. The Company's DG rates proposal is punitive. It will significantly inhibit the ability of customers to exercise control over their energy costs in a manner that is contrary both to state policy goals and national ratemaking trends.

5. The lack of grandfathering for existing customers is exceptionally punitive, subjecting them to a dramatic change in rates that they could have never foreseen and stranding ratepayers' significant prior investments in DG.

III. GRANDFATHERING OF EXISTING DG CUSTOMERS

A. Grandfathering is critically important for protecting significant customer investments in DG.

Q. WHAT DO YOU PROPOSE WITH REGARD TO GRANDFATHERING SHOULD THE COMMISSION APPROVE SOME FORM OF EPE'S PROPOSED DG RATE DESIGN?

A. While I recommend that the Commission reject EPE's proposed rate structure continue to allow DG customer to take service on otherwise applicable rates, I think it is important to highlight that should substantial changes to DG rates be approved, existing DG customers should be grandfathered on their existing rate structure. In other jurisdictions that have considered grandfathering, customers have been allowed to continue to take service on the discontinued rate through the date of a final order. I think that is an appropriate cut off date.

Q. PLEASE ELABORATE ON THE PRINCIPLE OF GRANDFATHERING.

A. Grandfathering refers to a decision, usually made by a state regulatory commission, to allow customers to continue to take service under a rate structure in the event that it is discontinued for new participants. In the present context, this would mean allowing existing DG customers to continue to take service on any otherwise applicable rate schedule should new rates for DG customers be adopted. It could also mean allowing "future" customers that elect to install DG after any changes are made to maintain the rate structure in place at the time the system was installed. The overall intent of grandfathering is to respect long-term customer investments made prior to the time the changes were known.

Q. HAS THE COMPANY PROPOSED TO ALLOW EXISTING DG CUSTOMERS TO BE GRANDFATHERED IN ITS APPLICATION?

A. No. Under EPE's proposal, both existing and new DG customers will need to switch to the demand-based TOU rate.

Q. DOES GRANDFATHERING HAVE THE EFFECT OF FREEZING A CUSTOMER'S RATES?

A. No; as typically implemented it only applies to rate structure, not the actual rates. Consequently, a grandfathered customer would be subject to the same periodic rate fluctuations as customers on the same rate schedule. These changes could include variable rate components, such as volumetric energy rates and fuel-cost adjustments, as well as fixed-rate components, such as a monthly service charge or minimum bill.

Q. WHY ARE ELECTRIC RATE STRUCTURES IMPORTANT TO DG CUSTOMERS?

A. DG customers make significant, long-term financial investments in DG systems. Revisions to the underlying rate structures can have dramatic impacts on these investments because retail rates are the foundation of a customer's expected savings. Expected long-term energy cost savings are an important, if not the most important, motivation behind a customer's decision to install a DG system. As I highlight in the following sections, EPE's own analysis shows that the proposed changes are expected to increase the bills of most DG customers by more than $10/month, equivalent to thousands of dollars over a typical 20-year system life.

Q. WHAT EXPECTATIONS WOULD A CUSTOMER TYPICALLY HAVE WHEN CONSIDERING WHETHER TO INSTALL A DG SYSTEM?

A. It is reasonable to assume that utility customers, including DG customers, would anticipate changes to certain rate components over time. In this respect, they are accustomed to and mostly accept that periodic, and typically gradual rate changes, will occur. That is, customers have been conditioned to expect small rate changes from year to year (i.e., typically increases) rather than dramatic changes in rates or rate structure. This expectation is in large part attributable to the fact that regulators have historically made substantial efforts to avoid "rate shock" in ratemaking decisions, employing the principle of gradualism.

Q. WHY IS IT REASONABLE FOR EXISTING DG CUSTOMERS TO BE GRANDFATHERED IN TO CURRENT RATE STRUCTURES SHOULD THOSE RATES ELEMENTS BE MODIFIED?

A. As I described previously, DG customers have made significant, long-term financial investments in DG systems that would be significantly and adversely affected by EPE's rate proposal. They did so with an expectation that the investment would pay off in the long-run based on a reasonable assumption that historic rate trends and ratemaking practices would continue, and in an environment where EPE actually encouraged them to make these investments. Without grandfathering, the changes being contemplated here are punitive for those existing DG customers, who could not have reasonably anticipated significant changes that might substantially impact their investment.

Q. HOW DID THE COMPANY ENCOURAGE CUSTOMER INVESTMENTS IN DG SYSTEMS?

A. From 2010 – 2015 the Company offered a Solar PV Pilot program that provided rebates for residential- and commercial-sited PV systems. Based on Company reports, EPE provided a total of more than $1.5 million in customer incentives over the life of the program.[7] In EPE's own words, "This program encouraged customers to install solar PV

[7] Based on historic program expenditures in EPE Energy Efficiency Plan and Report ("EEPR") in filed in PUCT Project No. 44480, *2015 Energy Plans and Reports Pursuant to P.U.C. Subst. R. 25.181(n),* ("EPE 2015 EEPR", April 1, 2015) and PUC Project No. 45675, *2016 Energy Efficiency Plans and Reports Pursuant to TAC § 25.181(n),* (2016 Report, April 1, 2016).

systems on their homes and businesses by reducing the up-front cost of these systems."[8]

Q. WHY DID THE COMPANY OFFER THIS PROGRAM AND ENCOURAGE THESE INVESTMENTS?

A. The program was part of EPE's portfolio of energy efficiency programs intended to meet state energy savings and demand-reduction goals identified in Section 39.905 of PURA.

Q. DID ALL OF EPE'S EXISTING DG CUSTOMERS PARTICIPATE IN THIS PROGRAM?

A. No; but the program was referred to as one of the utility's market transformation programs.[9] Typically, this term is used to refer to a strategy of providing support for novel, beneficial technologies in order to reduce market barriers to their adoption. A significant part of the theory of market transformation is that adoption grows as consumer knowledge and familiarity grow. In other words, consumers emulate their neighbors. The DG customers that did not directly participate in the program are nevertheless the product of its purpose and intent.

Q. WOULD GRANDFATHERING NEGATIVELY AFFECT OTHER NON-DG CUSTOMERS?

A. No. The short-term impact on the rates of other customers would be minimal and likely beneath notice because of the number of DG customers remains relatively small. EPE states that the revenue deficiency for the proposed residential DG class is roughly \$1.23 million for the test year.[10] This corresponds to a monthly bill impact on its roughly 276,000 non-DG residential customers of \$0.37/month. That figure disregards the long-term benefits that DG customers provide to ratepayers as a whole, which can have the effect of reducing rates. This value also does not account for the excessive customer costs that EPE has assigned to the proposed residential DG class, as I discuss. By contrast, impacts on most DG customers are at least 25 times larger.

---

[8] EPE 2015 EEPR, PUCT Project No. 44480, at p. 30.

[9] *Id.* Referring to the rebate as the Solar PV Pilot MTP, the designation used for market transformation programs.

[10] Direct Testimony and Exhibits of Adrian Hernandez at p. 15, Table AH-1. ("Hernandez Direct")

B. Grandfathering is universally accepted policy element in other recent regulatory decisions involving significant DG policy changes.

Q. HAVE OTHER STATE REGULATORY COMMISSIONS ADDRESSED GRANDFATHERING FOR EXISTING DG CUSTOMERS?

A. Yes; within the spectrum of recent regulatory decisions affecting net metering and DG customer rates to varying degrees, grandfathering is perhaps the single most consistent element. I have developed a table (Exhibit JRB-2) that provides an overview of how other state regulatory commissions have addressed grandfathering for existing NEM customers in their consideration of changes to NEM and/or rate structures for DG customers.[11] As Exhibit JRB-2 shows, while there are some small differences in how states have approached grandfathering, there are common conclusions as well. The dominant conclusions with respect to grandfathering are that:

1. Despite some state variations in design, as a general policy it has broad support from regulators.
2. The most common durations are in excess of 20 years, ranging upward to indefinite or complete grandfathering in many states.

Q. ARE THERE ANY SPECIFIC STATES REPRESENTED IN THIS TABLE THAT YOU WOULD LIKE TO ELABORATE ON?

A. Nevada has had an unusually complex experience with addressing grandfathering, ultimately resulting in the 20-year grandfathering period the Nevada commission approved. Through a series of decisions beginning in December 2015, the Public Utilities Commission of Nevada ("PUCN") first eliminated net metering, and adopted a system transitioning net metering customers (i.e., no grandfathering) to a new rate structure with higher fixed charges and a lower credit rate for grid exports over a four-year period.[12] Intense dissatisfaction with the abrupt policy change caused the PUCN to reconsider, resulting in a February 2016 decision that, among other things moderated the

[11] Note that Figure 1 does not include the numerous instances where proposals have simply been rejected or withdrawn, resulting in maintenance of the status quo.

[12] Public Utilities Commission of Nevada order issued December 23, 2015, in Dockets 15-07041 and 15-07042.

previous decision by extending the transition period to 12 years.[13] The February 2016 decision left in place the PUCN's initial decision to not allow grandfathering.

Shortly thereafter, Governor Brian Sandoval reconvened the state's New Energy Industry Task Force ("NEITF"), a diverse group of stakeholders that met for several months to develop recommendations on the "best energy policies for Nevada's future."[14] In its final recommendations, the Task Force advised the Nevada Legislature to consider bills in 2017 that, among other things, would require 20-year grandfathering for existing DG customers and customers with active net-metering applications as of December 31, 2015.[15]

Roughly in parallel with the NEITF proceedings, in July 2016, the state's two investor-owned utilities filed proposals with the PUCN to allow grandfathering for 20 years for NEM customers who either installed an eligible DG system or received interconnection approval prior to December 31, 2015. In September 2016, the PUCN approved a settlement directing the two utilities to provide NEM grandfathering for a 20-year period ending November 30, 2036, and instructed them to notify eligible NEM customers who had not yet interconnected a NEM system that they may opt into the grandfathered rate until February 28, 2017.[16] The PUCN subsequently extended the opt-in deadline to July 1, 2017.[17]

Finally, in December 2016, as part of its final decision in the Sierra Pacific Power Company's ("SPPC") 2016 general rate case, the PUCN directed SPPC to allow grandfathering to all new residential and small commercial ratepayers who installed NEM systems in 2016, and re-opened net metering under the grandfathered rates for an additional 6 MW of new customer-generators beginning January 1, 2017.[18] Separately,

---

[13] Public Utilities Commission of Nevada order issued February 17, 2016, in Dockets 15-07041 and 15-07042.

[14] Executive Order 2016-04, issued February 23, 2016, by Nevada Gov. Brian Sandoval.

[15] New Energy Industry Task Force Final Recommendations, issued September 30, 2016.

[16] Public Utilities Commission of Nevada order issued September 21, 2016, in Dockets 16-07028 and 16-07029.

[17] Public Utilities Commission of Nevada order issued April 7, 2017, in Docket 17-03028.

[18] Public Utilities Commission of Nevada order issued December 28, 2016, in Docket 16-06006.

on June 15, 2017 Nevada enacted legislation (Chapter 589 of 2017) restoring the availability of net metering in Nevada, cementing 20-year grandfathering for DG customers as a state policy, and establishing a system gradually reducing the NEM credit rate for new customers as capacity benchmarks are achieved.

Q. WHY ARE OTHER STATES' POLICY DECISIONS ON GRANDFATHERING FOR NEM CUSTOMERS OR DG POLICY IN GENERAL RELEVANT TO THIS PROCEEDING?

A. Despite inherent differences in underlying policies and laws, it is significant that after carefully considering the issue, regulators in diverse states have universally arrived at consistent conclusions with respect to grandfathering. Nevada's experience is particularly noteworthy because the ultimate decision on grandfathering enjoyed broad support from utilities and solar industry stakeholders, and was aligned with recommendations from a Governor's task force.

Q. WHAT IS AN APPROPRIATE TERM OR DURATION FOR GRANDFATHERING?

A. The duration arrived at in other states are primarily based on the broad principle of protecting customer expectations and preserving the value of significant investments made under reasonable assumptions. This includes consideration of customer expectations for payback, long-term electricity cost savings, system lifetimes, and contract (e.g., system lease) terms where applicable. The central theme remains the preservation of customer expectation with respect to projected savings. I recommend that the duration be set to 25 years, the approximate middle point between the typical 20-year or indefinite durations adopted in other states.

IV. RESIDENTIAL DG CUSTOMERS AS A SEPARATE CLASS OF CUSTOMER.

Q. PLEASE RESTATE WHY THE COMPANY PROPOSES TO ESTABLISH RESIDENTIAL DG CUSTOMERS AS A SEPARATE CLASS.

A. As discussed by Mr. Schichtl and Mr. Novela, the Company argues that the energy consumption patterns of residential DG customers are significantly different than those of other residential customers, enough so that they should be placed within a separate customer class.

Q. DO YOU AGREE WITH THEIR ARGUMENTS?

A. For the reasons I explain below, I disagree with their arguments.

Q. PLEASE DESCRIBE THE PARAMETERS THAT DEFINE DIFFERENT CLASSES OF CUSTOMERS.

A. At a high level, a class of customers is a group of customers with similar patterns of energy consumption. There is no standard definition or objective measure of how to differentiate between different classes. In practice, a given class typically has a significant amount of diversity in terms of annual energy consumption, different measures of demand, and how those measures vary over time. Most often the prominent characteristic that is used to define a class is customer "size" as measured by monthly energy consumption or demand, and type of use (residential vs. non-residential). In some cases, a set of customers with dramatically different energy consumption patterns are set aside in a separate class but for the most part classes tend to be broad and diverse. As I elaborate on later in my testimony, diversity within a class also reflects the practical considerations and limitations associated with minimally-populated rate classes and rate structures (i.e., feasibility).

Q. WHAT DO YOU MEAN WHEN YOU REFER TO DIVERSITY?

A. Diversity encompasses several facets. For instance, a class will have diversity in the amount of energy individual customers use, such that some customers have needs that are several times larger than other customers. Diversity also refers to usage patterns as they vary throughout the year and even the day. Those patterns are driven by how those customers use electricity, for instance, whether they have gas appliances or electric appliances, or both, how electric appliances are operated, occupancy during different times of the day or year, and behavioral determinants.

From an electric-grid perspective, diversity also refers to the coincidence of a customer's demand for electricity relative to peak demands or demand by customers within the same class. This type of diversity is a crucial consideration for system investments because most grid infrastructure is shared among customers to different degrees. Diversity allows those shared facilities to be built to meet the diversified demand of the customers they serve, which by definition must be lower than the sum of the peak demands of those same customers.

Q. DOES THE COMPANY PROVIDE EVIDENCE SUFFICIENT TO DEMONSTRATE THAT RESIDENTIAL DG CUSTOMERS FALL OUTSIDE OF THE DIVERSITY OF THE RESIDENTIAL CLASS?

A. No. To the contrary, EPE's own load research data, as described primarily in the testimony of Mr. Novela, shows that DG customers are mostly in the middle of the spectrum in terms of multiple measures of residential energy consumption patterns. The Company's analysis of this data is skewed by inapt comparisons and selective interpretation of the data. There are several specific shortcomings:

1. Portions of the analysis focus on "total household load," which is intended to represent DG customers as they would appear without the installation of DG. Total household load is a fictional construct that is irrelevant to determining cost of service or differentiating among classes because EPE does not serve total household load.

2. Comparisons made to averages for the residential class as a whole are meaningless because the residential class is composed of customers with widely ranging usage patterns. In other words, every customer differs from the class average.

3. The analysis focuses on one single variable, the installation of DG, when in reality there are a dozen factors that influence customer energy use patterns to a lesser or greater degree. For instance, the Company lacks data and has not performed any analysis of customers that use natural gas for some of their energy needs.[19] Likewise, though it has analyzed differences associated with customers

[19] EPE's Response to EFCA RFI No. 1-3.

that use refrigerated versus evaporative cooling, it has not proposed any class separation based on this characteristic.[20]

Q. PLEASE EXPLAIN WHY "TOTAL HOUSEHOLD LOAD" IS NOT A RELEVANT CONSIDERATION FOR DETERMINING COST OF SERVICE OR ESTABLISHING RESIDENTIAL DG CUSTOMERS AS A SEPARATE CLASS?

A. Cost of service is based on the demands that a customer actually places on the system. In reality, all customer loads are inherently changeable and customers are charged for their actual use of the system, not on the basis of what they "would" have used but for some source of change in usage patterns. When a customer's energy usage pattern does change, the shared portions of the grid (i.e., most of the grid) that they historically may have used become available for use by other customers.

Similarly, with respect to the issue of class structure, residential customer loads are diverse and change over time for a variety of reasons. The fact that a customer "used to" closely resemble a certain sub-type of customer does not in itself mean that they no longer fall within the diversity of the class as a whole. Mr. Novela's comparisons of residential DG customers to residential Strata 4 (moderately high consumption) customers on the basis of total household load (i.e., ignoring DG) and delivered load (with DG) are simply not meaningful. Of course DG affects a customer's need for electricity from the utility, but so do a dozen other factors.

Q. ON WHAT SPECIFIC EVIDENCE DO YOU BASE THE ASSERTION THAT RESIDENTIAL DG CUSTOMERS FALL WITHIN THE DIVERSITY OF THE RESIDENTIAL CLASS?

A. Below are several graphs placing residential DG customers within the context of the overall residential class in terms of monthly average non-coincident peak ("NCP") demand, maximum class demand ("MCD"), and coincident peak ("CP") demand. The Strata identified below are based on average monthly energy usage with Strata 1 referring to customers with the lowest average usage and Strata 5 the highest. These Strata are defined by the Company's load research study.

[20] EPE Response to Solar Energy Industries Association ("SEIA") 1-09, Attachment 1.

Figure JRB-1

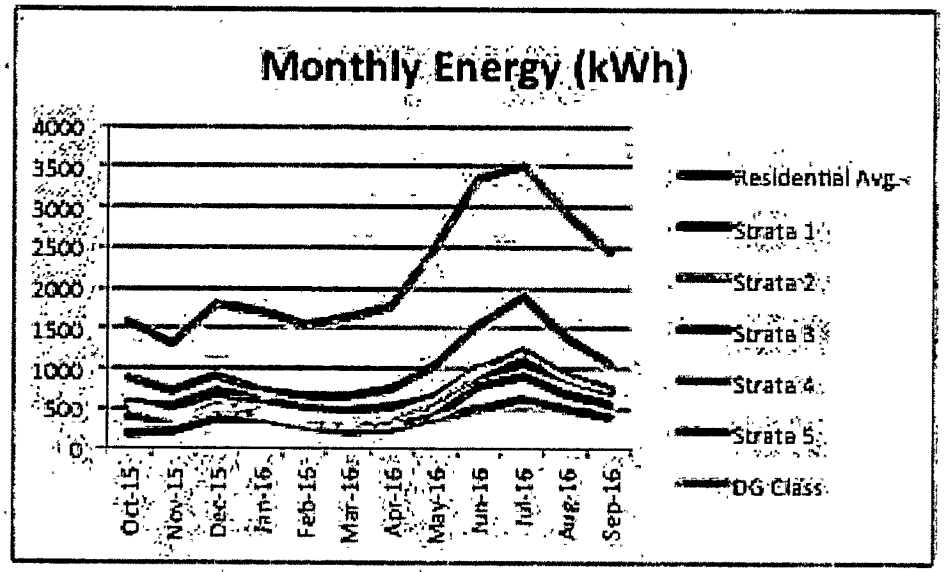


Figure JRB-2

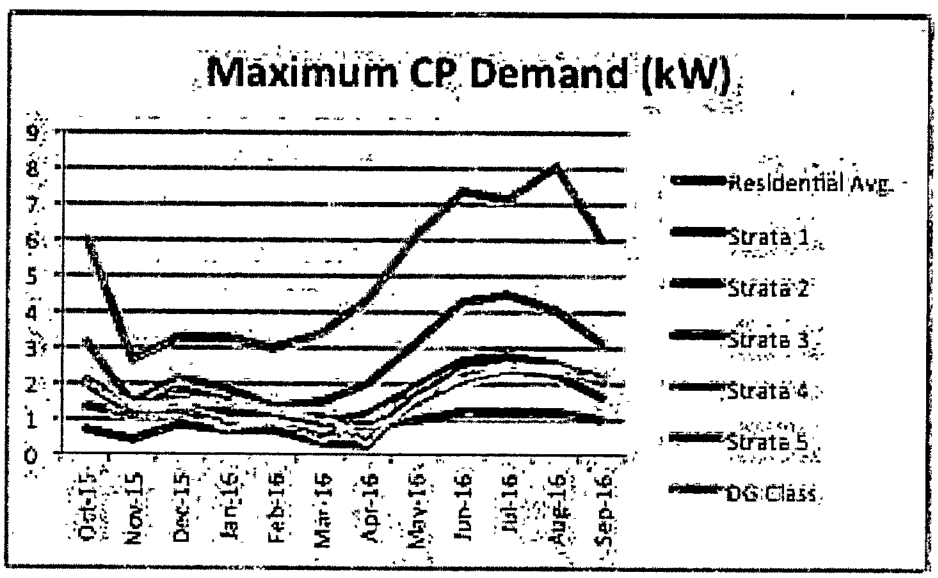


Figure JRB-3

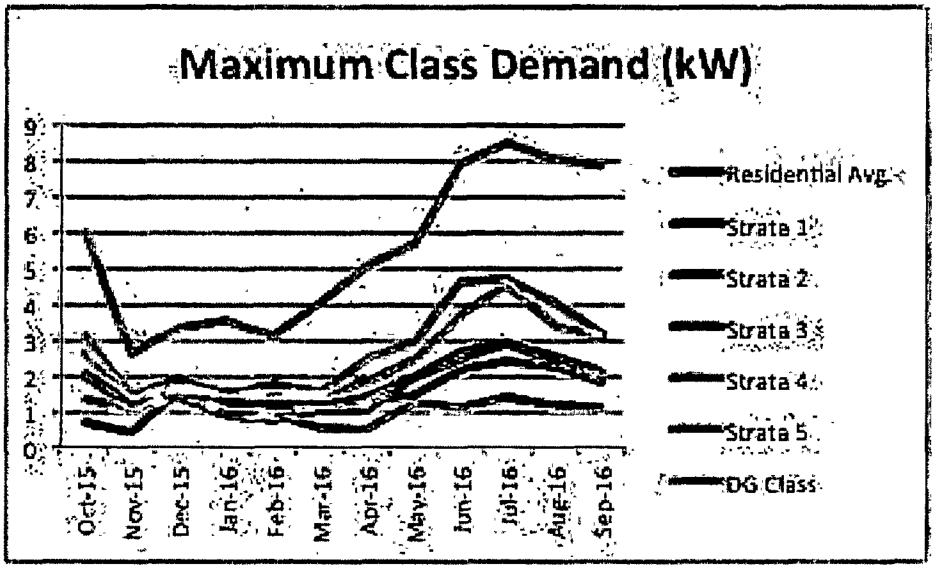
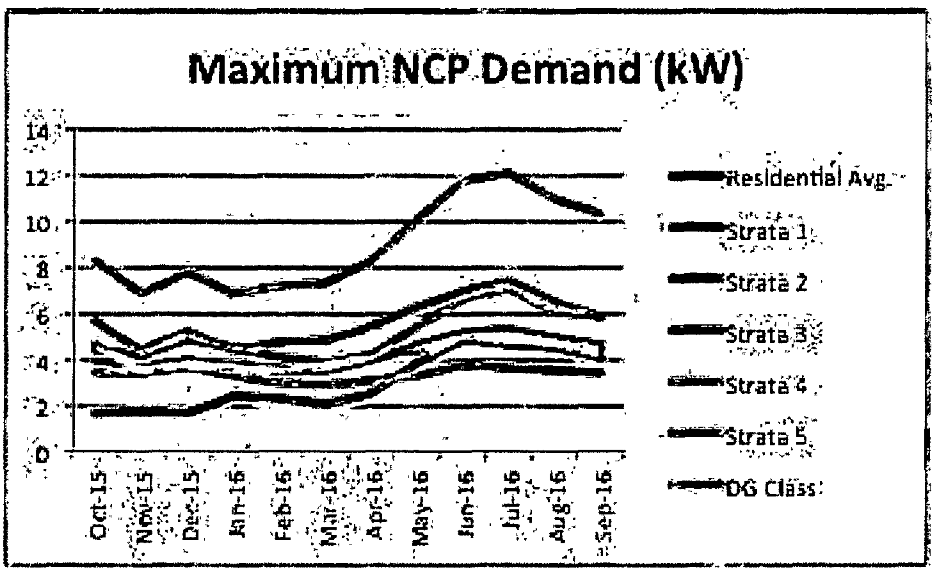


Figure JRB-4



Q. PLEASE SUMMARIZE WHAT THESE FIGURES SHOW.

A. First, they show the wide range of characteristics in the residential class, indicating that a simple departure from a residential average is not meaningful. Second, with respect to the individual measures, DG customers are generally in the range between Strata 3 and Strata 4 customers, occupying a middle portion of the graphs. In terms of monthly load shape, they also look quite similar to Strata 1 (low use) customers. Another observable feature is the range of variation in monthly energy and demand, from the largely flat

Strata 2 to the large swings in Strata 5. Again, the residential DG group falls in the middle of this variation.

Q. ARE THERE ANY NUMERICAL MEASURES SHOWING HOW MUCH RESIDENTIAL DG CUSTOMER USAGE PATTERNS VARY?

A. Yes. One way is to compare the total amount of variation over a year in to the overall annual average in each category. That is, the ratio of the annual range between the monthly maximums and minimums to the annual average, expressed as a percentage. Exhibit JRB-5 illustrates that in all of the categories; the amount of monthly variation over a year within the residential DG class is within the ranges of the residential Strata. Strata 1 shows the greatest amount of monthly variation, while the variation in the residential DG class is substantially lower. The difference between Strata 1 and the DG class is larger than the difference between the residential DG class and the residential average, Strata 4, or Strata 5 customers.

Figure JRB-5

Customer Type	Monthly Variation (% of Annual Average)			
	Energy	NCP	CP	MCD
Residential Avg.	106.66%	40.80%	108.09%	96.74%
Strata 1	172.12%	105.98%	192.86%	165.10%
Strata 2	75.35%	25.07%	86.27%	86.79%
Strata 3	88.07%	22.35%	90.24%	75.15%
Strata 4	120.14%	53.82%	118.59%	118.05%
Strata 5	102.61%	58.37%	108.76%	107.14%
DG Class	135.46%	76.39%	131.57%	127.32%

Another measure is the variation within the proposed residential DG class and how that compares to the residential class as a whole. Figure JRB-6 shows the ratio of summer to total annual energy deliveries for the respective 5 strata within both the residential and residential DG classes. Overall, the summer averages for DG and non-DG residential customers are similar while the differences between DG and non-DG customers within the same strata are mixed.

Figure JRB-6

******BEGIN CONFIDENTIAL**

[redacted]			
[redacted]	[redacted]		[redacted]
	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

END CONFIDENTIAL****

Q. ARE DAILY ENERGY CONSUMPTION PATTERNS FOR RESIDENTIAL DG CUSTOMERS MARKEDLY DIFFERENT FROM THOSE OF THE RESIDENTIAL CLASS?

A. Not in all circumstances. Mr. Novela contends energy consumption by Residential DG customers is materially different from non-DG Residential customers and purports to demonstrate this assertion in Figures GN-3 and GN-4 of his direct testimony. However, he confines his analysis to a comparison of DG customers to a single stratus of the residential class (Strata 4), and in the case of GN-3, uses a single day as the basis for his comparison.[21] This is only a narrow set of data, and even so, the conclusions are more mixed than he presents.

Q. PLEASE DESCRIBE WHAT YOU OBSERVE IN THE DATA MR. NOVELA PRESENTS IN HIS EXHIBITS GN-3 AND GN-4.

A. First, let me explain a term I'll refer to: the ramp rate. The ramp rate of a customer or group of customers measures how quickly their load changes over time (i.e., change in demand from one hour to the next). Starting with Figure GN-3, the underlying data show that during the winter months, the hourly ramp from 4 PM to the respective DG and non-DG class' peaks is virtually identical, with residential DG higher by 0.02 kW/hour. This figure is arrived at by subtracting the respective average DG and Strata 4 demands at 4

[21] Direct Testimony and Exhibits of George Novela at p. 20-21. ("Novela Direct")

PM from the peak demand, and then dividing that amount by the number of hours between 4 PM and when each group peaks. If the hourly ramp is measured from the minimum afternoon demand to the peak, the average ramp is actually substantially lower for DG customers (0.13 kW/hour) because the DG customer ramp takes place over an eight-hour period instead of the four-hour period for Strata 4 customers. The DG customer profile also shows higher one-hour ramps in two hours, but also a lower rate of decline (i.e., downward ramp) during nighttime hours. In other words, the DG ramp is higher by some measures but lower by others.

During the summer months, the data underlying GN-4 show that the total daily range for residential DG customers and Strata 4 customers is identical, while the average residential DG hourly ramp is only 0.04 kW/hour higher. During the summer, it is also notable that the highest one-hour ramp for residential DG customers occurs after the system has peaked. The respective DG and non-DG ramps are offset by several hours, which has a smoothing effect on the upward and downward ramps.[22] This is an aspect of the concept of diversity that I have previously discussed and it is actually beneficial for the system. The offset reduces how quickly resources must be "ramped up" to meet the peak demand and ramped down after the peak has passed.

Q. ARE RESIDENTIAL DG CUSTOMER LOAD FACTORS OUTSIDE OF THE RANGE SEEN IN THE RESIDENTIAL STRATA?

A. No. Mr. Novela shows that DG customer load factors are lower than those of Strata 4 customers (Figure GN-5) based on maximum diversified demand. However, as shown in Figure 7, residential DG load factors are within the range of other residential strata under load factor measured as a percentage of coincident peak demand and non-coincident peak demand. Figure JRB-7 shows these load factors as a 12-month average, but the results are similar if a simple annual arithmetic average is used.

[22] See EPE's Response to EFCA RFI No. 1-1.

Figure JRB-7

Residential Strata & Residential DG Load Factors		
[redacted]	CP Load Factor	NCP Load Factor
Residential Average	55.30%	20.96%
Strata 1	59.25%	19.11%
Strata 2	56.83%	16.46%
Strata 3	58.12%	20.66%
Strata 4	54.11%	23.97%
Strata 5	61.31%	32.32%
DG Class	58.28%	17.03%

As shown in Figure JRB-7, residential DG customer load factors are higher than the NCP load-factor calculation for Strata 2 customers and close to the residential average. CP load factors for residential DG customers are likewise close to the residential average, falling in the middle of the five residential strata.

Q. ARE THE DAILY AND MONTHLY VARIATIONS ATTRIBUTABLE TO A CUSTOMER'S INSTALLATION OF DG?

A. A DG system undoubtedly affects both monthly and daily measures of customer energy-use patterns. However, it is certainly not the only variable in play. Customer usage patterns are affected by numerous factors, including but not limited to the following:

- DG system size relative to load (if applicable)
- Cooling system (evaporative or refrigerated)
- Gas vs. electric cooking appliances
- Gas vs. electric clothes drying (or none)
- Gas vs. electric heating and water heating
- Swimming pool vs. no swimming pool
- Gas and electric use for other household needs
- Family composition (e.g., children or not)
- Work schedules
- Behavioral elements, such as thermostat settings and entertainment choices.

The use of limited comparisons and averages masks the considerable amount of variation that exists among both DG and non-DG residential customers on any given day, and during any month or year.

Q. WHAT ARE THE IMPLICATIONS FOR THESE VARIATIONS IN TERMS OF IDENTIFYING AND ESTABLISHING CUSTOMER CLASSES AND RATE STRUCTURES?

A. Picking any single one as the basis for defining a class of customers ignores the diversity of the class and the fact that it is not possible to reliably isolate the effects of one variable from another. Even if it were possible, it would still be inadvisable because the result would be an unmanageable system of rates based on dozens of combinations of different customer characteristics.

Furthermore, all of these variations are subject to change over time. For instance, do customers that replace evaporative cooling with refrigerated air conditioning merit a separate class, or might they be moved into other existing classes? The implications of this approach to ratemaking go far beyond the present proposal and raise difficult questions that would be better addressed in a holistic manner.

Q. WHAT DO YOU CONCLUDE WITH REGARD TO EPE'S PROPOSAL TO CREATE A SEPARATE CLASS FOR RESIDENTIAL CUSTOMERS THAT INSTALL DG?

A. I conclude that by numerous objective measures, residential DG customers are within the variability of the broader residential class and should not be considered a separate class of customer.

V. EPE'S RATES PROPOSALS FOR DG CUSTOMERS

A. The Company's Proposal for Small General Service DG Customers is Unsupported

Q. WHAT DATA DOES THE COMPANY PROVIDE TO SUPPORT ITS PROPOSAL THAT SMALL GENERAL SERVICE DG CUSTOMERS SHOULD BE SUBJECT TO SEPARATE RATES?

A. Very little. As I have previously related, EPE's rationale is primarily based on its contention that volumetric rates are not suitable for recovering the utility's fixed costs. EPE did not perform any load research analysis related to small non-residential DG customers so it is not clear how the costs to serve those customers may vary from non-DG customers or whether they already pay those costs under present rates.

Q. IS THIS ARGUMENT SUFFICIENT TO JUSTIFY SUBJECTING SMALL GENERAL SERVICE DG CUSTOMERS TO SEPARATE RATES?

A. No. Even if one agrees that the fixed-cost, under-recovery argument is a reasonable basis for adopting a separate rate structure, the Company has not provided evidence that any under-recovery is actually occurring. For this reason alone, that portion of the Company's proposal should be rejected. There simply is not enough available data to perform a reliable analysis.

B. The Proposed Demand Rate Design for Residential and Small General Service DG Customers Is Inappropriate.

Q. WHAT ARE THE GENERAL REQUIREMENTS FOR THE ESTABLISHMENT OF UTILITY RATES IN TEXAS?

A. First, I am not an attorney and I am not offering a legal opinion. But on its face, the Public Utility Regulatory Act ("PURA") establishes a "just-and-reasonable" standard for utility rates, and states that a "rate may not be unreasonably preferential, prejudicial, or discriminatory but must be sufficient, equitable, and consistent in application to each class of consumer."[23] PURA further prohibits a utility from establishing or maintaining "an unreasonable difference concerning rates between localities or between classes of service."[24] The burden for proving that rate changes are just and reasonable falls on the utility.[25]

---

[23] Tex. Util. Code Ann. § 36.003(b).

[24] Tex. Util. Code Ann. § 36.003(c)(3).

[25] Tex. Util. Code Ann. § 36.006.

Q. WHAT IS THE MEANING OF "JUST AND REASONABLE" IN THIS CONTEXT?

A. There is no single accepted definition of this term. However, the oft-cited work of Dr. James Bonbright offers valuable guidance on the criteria that should be used in the development of a sound rate structure, listing a set of eight principles to consider. The paraphrased principles most relevant to this proceeding are:

1. The "practical" attributes of simplicity, understandability, public acceptability and feasibility of application.

2. Effectiveness in yielding total revenue requirements under the fair return standard.

3. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

4. Fairness of the rates in apportioning the total cost of service among different consumers.

5. Avoidance of undue discrimination.

6. Efficiency of the rate classes and blocks in discouraging wasteful use of service.[26]

It is generally recognized that these principles are sometimes in conflict with one another, such that rate design involves a subjective judgment of how best to balance the competing objectives. Proper rate design is therefore in large measure a policy decision on the part of regulators.

Q. IS EPE'S PROPOSAL TO IMPOSE MANDATORY DEMAND CHARGES ON RESIDENTIAL DG CUSTOMERS CONSISTENT WITH THESE RATEMAKING PRINCIPLES?

A. No. First, as I have previously described, EPE's conclusion that DG customers should be considered a separate class of customer is in error, making the proposal itself discriminatory. Second, the proposed rates violate a number of the ratemaking principles I relate above, including cost causation, simplicity and customer ease of understanding,

[26] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 291.

rate stability, and discouragement of wasteful use of service. The ultimate result of is that the tariff is unduly discriminatory.

Q. IS THIS CONCLUSION SHARED BY REGULATORS IN OTHER STATES?

A. Yes. Commissions in California (twice),[27] Idaho,[28] and Nevada[29] have rejected demand charges for residential DG customers, and proposals have been withdrawn under settlements in Georgia,[30] Kansas,[31] Montana,[32] and South Dakota.[33] On the other side, mandatory demand charges on residential DG customers have only been approved by two state Commissions. One of those examples, Black Hills Power in Wyoming, is distinguished by the fact that it arose only in a settlement and was not supported by any substantive testimony, cost-of-service analysis, or an analysis of distributed generation

---

[27] California Public Utilities Commission. Docket No. R.12-06-013. *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.* D.15-07-001. July 13, 2015.; and California Public Utilities Commission. Docket No. R.14-07-002. *Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.* D.16-01-044. February 5, 2016.

[27] Idaho Public Utilities Commission. Case No. IPC-E-12-27. *In the Matter of Idaho Power Company's Application for Authority to Modify its Net Metering Service and Increase the Generation Capacity Limit* . Order No. 32846. July 3, 2013.

[28] Idaho Public Utilities Commission. Case No. IPC-E-12-27. *In the Matter of Idaho Power Company's Application for Authority to Modify its Net Metering Service and Increase the Generation Capacity Limit* . Order No. 32846. July 3, 2013.

[29] Nevada Public Utilities Commission. Docket No. 15-07041. *Application of Nevada Power Company d/b/a NV Energy for Approval of a Cost of Service Study and Net Metering Tariffs* . Modified Final Order. February 17, 2016. This order also covers a similar application by Sierra Pacific Power in Docket No. 15-07042.

[30] Georgia Public Service Commission. Docket No. 36989. *Georgia Power's 2013 Rate Case.* Order Adopting Settlement Agreement. December 23, 2013.

[31] Kansas Corporation Commission. Docket No. 15-WSEE-115-RTS. *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.* Order Approving Stipulation and Agreement. September 24, 2015.

[32] Montana Public Service Commission. Docket No. D2015.6.51. *In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service in the State of Montana.* Order No. 7433f. March 25, 2016.

[33] South Dakota Public Utilities Commission. Docket No. EL14-026. *In the Matter of the Application of Black Hills Power, Inc. for Authority Increase its Electric Rates.* Black Hills withdrew its residential distributed generation demand charge proposal in a revised filing dated April 11, 2014.

costs and benefits.[34] The other example, the standby rates in Virginia in the service territories of Appalachian Power and Dominion Energy , are effectively required by statute, and further distinguished by the fact that they only apply to customers with DG systems of 10 kW-AC or larger.[35]

Q. HOW IS EPE'S PROPOSAL MISALIGNED WITH COST CAUSATION?

A. Only a small portion of the transmission and distribution system is designed to serve the maximum demand of an individual customer. The bulk of the system is designed to serve the maximum diversified demand of customers on a given circuit, substation, etc., not the sum of the maximum demands of individual customers. The residential class in particular is characterized by diverse, fluctuating loads, which reduce the connection between a customer's maximum demand and cost-causing conditions. Non-coincident demand rates, like those proposed by EPE, charge customers for costs caused by coincident demands on the basis of a customer's non-coincident or maximum demand. The further one travels up the system, from secondary distribution to primary distribution, and to transmission and central generation, the greater this departure from cost causation becomes. I discuss this issue further in my evaluation of the proposed demand rate itself.

Essentially, the Company is proposing to charge customers costs associated with serving peak demand, based on a customer's maximum demand, regardless of whether this customer's maximum demand occurs during the Company's costly peak hours. The fact that EPE is proposing to impose these charges on DG adds to the fact that they are not cost based, as a DG customer's peak demand for a given month is likely to occur on cloudy days or late in the evening during the hot summer months, and not during the times when EPE's grid is most constrained.[36] On the contrary, DG customers are

[34] Wyoming Public Service Commission. Case No. 13788. In The Matter Of The Application Of Black Hills Power, Inc., For A General Rate Increase Of $2,782,883 Per Annum In Its Retail Electric Service Rates.

[35] See Dominion Energy Virginia, Residential Service, Schedule No. 1.

[36] See Figure JRB-8 showing the lack of alignment between residential DG customer peaks and monthly system peaks during June – September.

contributing to reducing peak demands during these summer months because EPE's summer peak periods (12 – 6 PM) align fairly well with hours of solar generation.

Q. HOW IS EPE'S DG TARIFF PROPOSAL IN CONFLICT WITH THE PRINCIPLE OF SIMPLICITY AND UNDERSTANDABILITY?

A. Demand rate designs are wholly unfamiliar to residential customers, which the Company fully acknowledges.[37] This is especially true for EPE, as the utility currently offers no demand-based rate option to residential customers. This unfamiliar rate would contain a new and highly significant component based on a fundamentally different measure of energy use. Thus, it is more complicated and will likely be harder for customers to understand. The conceptual difference between a kW and a kWh will likely be hard for residential customers to grasp, let alone the meaning of "60-minute average maximum demand," or how each individual electric load contributes to their electric demand.

This potential lack of understanding may lead to a further drawback: the customer's inability to reliably manage electric demand and their electricity bill. It is reasonable to expect a residential customer to understand that greater use of electric appliances will lead to higher electricity bills. It is far harder for residential customers to understand and manage the coincidence of their use of electric appliances over the hundreds of hourly periods during a month. Even a knowledgeable, diligent customer who desires to reduce their electric demand could be saddled with a high electricity bill on the basis of a single hour of appliance usage in a month. The burden is likely to fall most heavily on families because as difficult as it may be for a single person to manage demand in this fashion, it is even harder to manage the actions of other users, including children.

For example, multiple family members in a home with largely electric appliances may all turn on lights, an oven or stove, a computer, a TV, the air conditioner, and a clothes dryer. While it is not difficult to imagine the combination of these appliances in use regularly during a given week, such an event, even if infrequent, would likely trigger a high demand charge regardless of whether the timing corresponds to times of actual

[37] Schichtl Direct at p. 64, line 19.

stress on the grid. A customer would likely not even know their maximum demand was triggered until they saw their bill, and at that point would likely be unable to recall what triggered the high demand in the first place, and how to avoid it in the future. To implement this rate design would at a minimum require a substantial effort on behalf of the utility to educate its customers on the effects of the changes in rate design.

Q WHAT EFFORTS DOES THE COMPANY INTEND TO MAKE TO EDUCATE CUSTOMERS OR ASSIST THEM WITH MANAGING THE PROPOSED DEMAND CHARGE?

A. The Company has stated that will provide "targeted information" through its website and billing inserts.[38] It is not clear how robust this information would actually be based on the Company's description, and EPE states that it has no intention of providing real time or interval usage data that could assist customers in identifying their peaks so that they may respond with behavioral changes.

Q. HOW DOES THE COMPANY RESPOND TO CONCERNS ABOUT CUSTOMER UNDERSTANDING OF DEMAND RATE DESIGNS AND CUSTOMER ABILITY TO REACT TO THESE CHARGES?

A. Mr. Schichtl contends that the small number of residential customers that have voluntarily enrolled in optional residential demand rates in other states indicates that residential customers are "clearly" capable of understanding and responding to a demand rate. He further states that it is reasonable to assume that DG customers are more knowledgeable simply because they have installed DG.[39]

Q. DO YOU AGREE WITH THE MR. SCHICHTL'S ASSESSMENT OF RESIDENTIAL CUSTOMERS' ABILITIES IN THIS RESPECT?

A. Absolutely not. The voluntary nature of the referenced rates makes them self-selecting, leading to a more reasonable conclusion that the very low participation rates are indicative of a lack of awareness and understanding of demand rates on the part of residential customers. Past research conducted on nine utilities with optional residential

[38] EPE's Response to EFCA RFI No. 3-8.

[39] Schichtl Direct at p. 65-66 throughout, quoted text p. 65, line 14.

demand charges indicates that with two exceptions, enrollment is "well below one percent." The two exceptions, Arizona Public Service and Black Hills Energy, showed enrollment of 10% or less of total residential customers.[40]

I further disagree that residential DG customers are fundamentally more sophisticated, or are better energy managers, than residential customers as a whole. I have never seen any evidence supporting this assumption, nor has EPE produced any in this proceeding. In reality, DG customers rely passively on a DG system to reduce energy costs, as they would with other improvements such as energy efficient lighting or HVAC systems. This does not indicate any greater level of sophistication or knowledge on their part.

Q. HOW DOES EPE'S DG TARIFF PROPOSAL VIOLATE THE PRINCIPLE OF EFFICIENCY?

A. Demand charges for residential customers directly and indirectly discourage energy conservation. Directly, the demand component reduces the volumetric components of rates, making energy savings less valuable for the customer. Indirectly, a customer that makes efforts to reduce their electricity bill but sees little change due to high demand charges is likely to conclude that further efforts are unattractive. For many residential customers, who lack the ability to understand and manage their electric demand, a demand charge is equivalent to a higher fixed charge. It therefore sends an inaccurate price signal to the customer, discouraging energy conservation and encouraging wasteful use of resources.

Q. IS THIS OUTCOME ALIGNED WITH THE EPE'S STATED GOALS FOR RATE DESIGN MORE GENERALLY?

A. No. EPE states that a number of elements in its rate application are designed to encourage energy conservation and load shifting away from peak periods. Among these are changes to TOU rate differentials and the establishment of both optional and mandatory TOU rates.[41] These goals are at odds with its DG proposal to increase fixed

[40] Hledik, R. "Rediscovering Residential Demand Charges." *The Electricity Journal*. Volume 12, Issue 7. May/September 2014. p. 85.

[41] Direct Testimony and Exhibits of Manuel Carrasco at p. 17-18. ("Carrasco Direct")

charges and establish a mandatory non-coincident demand charge for DG customers.

Q. WOULD THE PROPOSED DEMAND RATES FOR RESIDENTIAL DG CUSTOMERS PROVIDE AN INCENTIVE FOR PEAK DEMAND REDUCTION?

A. No. The proposed rates do not reward reductions in peak demand because they are based on non-coincident demand. It is possible that a customer that reduces their non-coincident demand would also incidentally reduce their peak demand, but such a result is not guaranteed, nor is the customer provided with the proper incentive (i.e., reward) for doing so. Furthermore, such an indirect outcome would only occur if residential customers had the ability to manage their non-coincident electric demand, which they do not.

In fact, a non-coincident demand charge could actually contribute to increased, on-peak demand because residential DG customers typically do not peak on the same day or at the same time as the system during the summer. Compelling them to spread their demand to avoid high demand charges, if they even can, creates the possibility that they will do so in a way that results in higher on-peak demands. Figure JRB-8 below details the levels of alignment between DG customer peaks and monthly summer system peaks by month in terms of day and timing based on the 57 residential DG customers in EPE's load research study:[42]

Figure JRB-8

Comparison of Residential DG Customer Peaks With System Peaks		
Month	Same Day	Same Day & Hour
June 2016	3 of 57 (5.3%)	0 of 57 (0%)
July 2016	2 of 57 (3.5%)	0 of 57 (0%)
August 2016	9 of 57 (15.8%)	1 of 57 (1.8%)
September 2016	2 of 57 (3.5%)	0 of 57 (0%)

These data show that residential DG customers benefit the grid on critical peak days. To avoid high demand charges caused by peaks later in the evening (i.e., when residential

[42] Derived from EPE Response to EFCA 1-1, Attachment 1, DG Delivered tab listing hourly demand for residential DG customers in EPE's load research study.

DG customers tend to peak), it would make sense for them to pre-cool their homes earlier in the day, raising their electric demand higher during the late afternoon peak hour(s). Furthermore, if a customer was aware that they had "locked in" a high demand charge during any part of the month, they have no incentive to reduce demand below that level during the remainder of a month.

Q. HOW DOES EPE'S PROPOSAL VIOLATE THE PRINCIPLE OF RATE STABILITY?

A. As shown by EPE Witness Hernandez, the total rate increase requested by the Company for the proposed residential DG class equates to a percentage increase of 125.81%. This is more than ten (10) times the 11.2% revenue increase proposed for the residential class as a whole.[43] Furthermore, EPE's own analysis shows that 96% of residential DG customers are expected to experience bill increases under the proposed new rates, 72% are expected experience increases of more than $10/month, and 26% would experience bill increases of more than $20/month or $240/yr.[44] Clearly, this amounts to the type of abrupt, seriously adverse change that Bonbright recommends against.

C. The Company's Residential DG Demand Charge Is Not Aligned With Cost Causation.

Q. HOW DOES THE COMPANY DERIVE ITS THE DEMAND RATE FOR THE PROPOSED RESIDENTIAL DG CLASS?

A. As described by Mr. Carrasco, the proposed $6.20/kW demand charge is the sum of the primary and secondary distribution unit costs, totaling $5.003/kW, and a standby transmission and production demand adder to reflect "those periods when the customers [sic] system capacity is unavailable." The adder corresponds to 10% of production and transmission demand costs, or $1.20/kW.[45] EPE calculated the monthly charge for each customer based on the customer's non-coincident peak ("NCP") demand, which as I previously discussed, is inappropriate.

---

[43] Hernandez Direct at p. 15, Table AH-1.

[44] Carrasco Direct at Exhibit MC-7.

[45] *Id.* at p. 30 line 19 through p. 31, lines 1-2.

Q. WHAT DOES THIS PROPOSED CHARGE IMPLY AS IT RELATES TO COST CAUSATION?

A. The implication is that the individual cost components of the charge are "caused" by a customer's NCP demand. This is what Mr. Schichtl referred to as "matching charges with cost causation."[46]

Q. HOW DOES THE COMPANY REFER TO COST CAUSATION IN OTHER CONTEXTS?

A. Throughout his testimony, Mr. Hernandez discusses how cost causation is reflected in the allocators used to assign costs for shared facilities to the different rate classes. As he observes, production and transmission costs are related to summer peak system demands, while distribution cost causation varies based on the voltage level, meriting different allocators for primary and secondary distribution costs.[47]

For instance, the Company uses Maximum Class Demand ("MCD"), the maximum coincident demand of the class as a whole, to allocate substation and primary distribution costs.[48] MCD is a dramatically different number than the average sum of non-coincident peak ("NCP") demands for customers within the same class. For instance, the highest monthly residential-class MCD average per customer during the test year was 2.91 kW during July 2016.[49] The average NCP during the same month on the other hand was 5.24 kW.[50] The MCD reflects diversity on the primary distribution system while NCP does not.

---

[46] Schichtl Direct at p. 50, line 7.

[47] Hernandez Direct at p. 7-9 throughout.

[48] *Id.* at p. 8, lines 5-8.

[49] Schedule Q-5.2, p. 8.

[50] *Id.* at p. 6.

Q. IS THE COMPANY'S PROPOSED RATE DESIGN CONSISTENT WITH ITS COST ALLOCATION PROCEDURES AND COST CAUSATION FOR PRIMARY DISTRIBUTION SYSTEM COSTS?

A. No. Its rates proposal assesses charges for all distribution system costs based on NCP demand. This is significant because primary distribution system costs total \$3.88/kW, or 78% of the total distribution unit cost of \$5.003/kW used to develop the proposed demand rate.[51] The remainder of the distribution unit costs (\$1.123/kW) relate to the secondary distribution system and are assigned based on the sum of customer NCP demands within a class, independent of the class peak.[52] Even if one accepts the cost causation "matching" argument made by Mr. Schichtl, the proposed rate itself is greatly mismatched.

Q. DOES DIVERSITY ALSO EXIST ON THE SECONDARY DISTRIBUTION SYSTEM?

A. Yes; even on the secondary distribution system, diversity will exist because distribution typically serves hundreds if not thousands of customers in different classes. For instance, EPE's distribution feeder with the largest number of customers ****BEGIN CONFIDENTIAL [redacted] ****END CONFIDENTIAL DG customers.[53] Even the equipment in closest proximity to the customer, line transformers, serves an average of 2.86 residential customers in a suburban setting and 10.3 residential customers in an urban setting.[54] Secondary line transformers, the portion of the secondary distribution system with the least diversity and

---

51. Schedule P-6.1, p. 3, lines 16-28. The figures above reflect sum of components identified as secondary distribution.

52 Hernandez Direct at p. 8, lines 8-10.

53 EPE Confidential Response to EFCA 3-15, Attachments 1 and 3.

54 EPE Response to EFCA 4-6. This is another example of customer diversity and a variable that is on the "slippery slope" of identifying customer classes. Accepting EPE's proposal argues in favor of establishing a customer class for customers that are in a suburban setting (where a line transformer serves only 2.86 customers) versus an urban setting (where a line transformer serves 10.3 customers), clearly not how the Commission has historically set rates.

thus the most sensitivity to individual customer peaks, carry a unit cost of only $0.421/kW for the proposed residential DG class.[55]

Q. PLEASE DESCRIBE HOW THE STANDBY "ADDER" THE COMPANY PROPOSES WAS DERIVED.

A. The 10% adder corresponds to the monthly reservation fee under Schedule No. 47 relating to back-up power service for qualifying facilities.[56]

Q. IS THE COMPANY'S PROPOSAL TO INCLUDE A STANDBY "ADDER" FOR TRANSMISSION AND PRODUCTION DEMAND COSTS IN THE PROPOSED DEMAND RATE APPROPRIATE?

A. No. First, the use of an NCP demand charge to recover costs caused by coincident peaks on the system as a whole is in clear conflict with cost-causation principles. It conflates these two very different measures of customer demand despite their well-recognized differences and EPE's own statements regarding cost causation and appropriate cost allocation.

Second, unavailability is already reflected in the production and transmission costs allocated to the proposed residential DG class, because that allocation uses actual demand data from the DG load research sample, as well as peak energy rates. If a customer's DG system is not available during peak times, that customer would pay for electricity at the applicable rate (e.g., the on-peak electric rate under the Company's proposal). The use of the monthly 10% reservation fee from Schedule No. 47 is inapt, conflating supplemental power with back-up power. The provision of back-up power is fundamentally different, which is why the Schedule No. 47 reservation fee is only "charged in the months that Backup Power Service is not utilized by the qualifying facility."[57] In other words, it is charged when the customer does not already pay for that power under otherwise applicable rates.

[55] Schedule P-6.1, p. 3, lines 27.

[56] EPE's Response to ECO ELP RFI No. 3-39.

[57] EPE Schedule No. 47, Backup Power Service for Qualifying Facilities [emphasis added].

Third, the Company provides no evidence that system unavailability among the proposed residential DG class as a whole contributes to system peak costs.

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S RESIDENTIAL DG DEMAND CHARGE PROPOSAL?

A. I recommend that the proposal be rejected in its entirety because its design is inconsistent with cost causation, understandability, simplicity, and encouraging efficient use of service.

D. The Company's Calculation of the Proposed Residential DG Customer Charge Rates Is Inflated.

Q. HOW DOES THE COMPANY DERIVE THE CUSTOMER CHARGE FOR THE PROPOSED RESIDENTIAL DG CLASS?

A. The $18.15/month customer charge is composed of all of those costs identified as customer-specific, totaling $16.647/month, with an adder of $1.50/month to reflect the "intricacies of billing under a TOU rate."[58] The single largest component of this cost is the metering unit cost of $5.75/month, which is $2.95/month in addition to the residential class metering component of $2.80/month.[59]

Q. WHAT WOULD BE THE COLLECTIVE IMPACT ON RESIDENTIAL DG CUSTOMERS IF THE PROPOSED CUSTOMER CHARGE WAS APPROVED?

A. The incremental customer charge amounts to roughly $70 annually, and assuming an average DG system lifetime of 20 years, would total $1,400.

Q. WHAT PROBLEMS DO YOU SEE WITH THIS ASPECT OF THE PROPOSED RESIDENTIAL DG RATE?

A. I will elaborate further on individual components of the incremental charge, but in brief, the problems stem from the use of a monthly incremental metering charge to recover one-time meter costs, and excessive costs attributable to EPE's own rate proposal rather than a customer's installation of DG.

---

[58] Carrasco Direct at p. 30, lines 12-17.

[59] Schedule P-6.1, p. 3, lines 35-44.

First, the single largest component is the incremental monthly metering cost (relative to a standard residential meter) of $2.95/month, or $35.40/year. The Company has provided information indicating that the cost of a standard residential meter is *****BEGIN CONFIDENTIAL [redacted] ****END CONFIDENTIAL[60] Typical meter installation costs are $35.15 for a standard residential meter and $70.30 for a bi-directional meter.[61] This leads to a total incremental cost of *****BEGIN CONFIDENTIAL [redacted] ****END CONFIDENTIAL Over an average 20-year lifetime of a DG system, DG customers would pay an additional $708 in metering charges, *****BEGIN CONFIDENTIAL [redacted] ****END CONFIDENTIAL times the incremental cost of the bi-directional meter and installation.

Second, the incremental metering and meter installation costs are inflated because they include the cost and installation labor necessary to install a production or renewable energy credit ("REC") meter.[62] EPE acknowledges that the REC meter is not necessary for DG customer billing purposes, stating that it is used to monitor possible changes in system size and measure REC production if the customer chooses to transfer RECs to the utility.[63] Neither purpose constitutes a justification for requiring this additional equipment. Customers that do not transfer RECs to the utility clearly do not require an additional meter capable of this measurement, and other measures are available to address concerns that system modifications may be made without informing the Company.

Third, the $1.50/month adder for TOU billing is unsupported by evidence that it represents a reasonable incremental cost for TOU billing. Even if it were, it amounts to a revenue grab on the part of the Company. Effectively, the Company is engaging in an exercise of circular logic by proposing that TOU rates be mandatory for DG customers

60 EPE's Confidential Response to EFCA RFI No. 2-9, Attachment 1.

61 EPE's Response to EFCA RFI No. 2-9.

62 EPE's Response to EFCA RFI Nos. 5-5 and 5-6.

63 EPE's Response to EFCA RFI No. 5-7.

then proposing to charge customers higher rates because its own proposal makes them more costly to serve.

Finally, other incremental costs assigned to the residential DG customer class are also artifacts of the Company's proposal. Excluding the costs of meters and meter reading, incremental customer costs for the residential DG class total $1.793/month.[64] According to the Company, these cost differences are attributable to economies of scale on a per-unit basis for the residential class as a whole.[65] They are in effect "caused" by the Company's proposal to establish a separate class for residential DG customers, not by the mere fact that the customer has installed DG.

Q. DO YOU HAVE ANY CRITICISMS OF THE COMPANY'S ALLOCATION OF COSTS TO THE CUSTOMER CATEGORY MORE GENERALLY?

A. The customer-cost category should be limited only to those costs that vary directly with the number of customers. EPE's allocated cost-of-service study adheres to this principle for the most part. However, it departs by using a LABOR allocator to classify the general plant portion of its rate base.[66] Administrative and general expenses that cannot be classified into another category are likewise allocated using the LABOR allocator.[67] The LABOR allocator in turn results in roughly 31% of these general costs being classified as customer-related.[68] These costs should be removed from the customer cost category to avoid, in the words of Bonbright "using the category of customer costs as a dumping ground for costs that he [the cost analyst] cannot plausibly impute to any of his other cost categories."[69]

---

[64] Schedule P-6.1, p. 3, sum of lines 36-38 and line 43.

[65] EPE's Response to EFCA RFI No. 5-3, Attachment 1.

[66] Hernandez Direct at p. 11, lines 5-11.

[67] *Id.* at p. 13, lines 12-14.

[68] Schedules P-4 and P-5 throughout.

[69] *Principles of Public Utility Rates*, Dr. James Bonbright, Columbia University Press, 1961. p. 349

Q. IS THERE PRECEDENT FOR USING A ONE-TIME FEE STRUCTURE FOR ADDRESSING ANY DG-SPECIFIC METERING COSTS?

A. Absolutely. In fact, it is virtually universal across the United States for residential DG customers to be protected from additional monthly charges, and pay incremental metering costs as a one-time charge, if required at all, because many states do not require the customer to pay for a new meter. Texas is no exception to this. I have reviewed the web sites, tariffs and related DG interconnection materials for AEP-Texas Central, AEP-Texas North, Oncor, CenterPoint, SWEPCO, TX-NM Power, Entergy and Xcel. While most of these note the possibility that a one-time meter charge may apply, none of them state that any recurring monthly charge is used.

Q. WHAT DO YOU RECOMMEND REGARDING THE DG CUSTOMER CHARGE?

A: EPE's proposal for a higher customer charge for DG customers should be rejected because a significant portion of the Company's purported customer costs for DG customers are related to the Company's own proposal to establish a separate residential DG class and separate rates for residential DG customers. Other components are one-time in nature, making them inappropriate for recovery through recurring fees. I also note that the Company has not proposed incremental customer charges for small general service DG customers.

E. The Company's Proposed Interconnection Application Fees

Q. PLEASE RESTATE HOW THE COMPANY'S PROPOSAL REGARDING INTERCONNECTION APPLICATION FEES.

A. Currently, EPE does not charge any standard fees for processing interconnection applications. The Company proposes to establish application fees of $139 for residential and small commercial applications of 100 kW or less, and $377 for larger commercial DG applications. These fees are described as reflecting the cost of moving an interconnection customer though the application and interconnection approval process.[70]

[70] Carrasco Direct at p. 60, lines 22-25.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE PROPOSED INTERCONNECTION APPLICATION FEES?

A. Yes. It is not clear to me that the proposed fees are not duplicative of costs that the Company seeks to recover via the customer charge. I am also concerned that portions of the fee are discriminatory, charging DG customers for administrative aspects that are part of the normal course of business.

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S PROPOSED INTERCONNECTION APPLICATION FEES?

A. I recommend that the proposed fees be rejected. If the Commission determines that application fees are appropriate now or in the future, I recommend that it more closely examine the individual components of any fee to ensure that it is not discriminatory or duplicative of other charges. In doing so, I urge Commission to assemble information on any application fees charged by other utilities to ensure that the methodology for establishing a fee is consistent, and to identify areas of inefficiency that could be improved upon.

F. The Company Fails to Evaluate the Benefits that DG Provides to the Grid and to Ratepayers as a Whole.

Q. WHAT BENEFITS DOES EPE ASCRIBE TO DISTRIBUTED GENERATION?

A. The Company does not perform any true evaluation of the benefits of distributed generation; its proposal largely confines the benefits that it acknowledges to energy-related functions. Within the proposed residential DG class, the allocation of production and transmission costs on the basis of class contribution to summer peak ascribes some capacity value to residential DG in the form of a lower allocation of capacity costs.[71] This effect is not present for non-residential DG because the Company has not evaluated non-residential DG customers as a separate class.

[71] The 4CP Average & Excess methodology used for production demand diminishes this to some degree because the "excess" component utilizes NCP rather than CP to allocate costs.

Q. DOES THIS PRESENT A COMPLETE PICTURE OF THE BENEFITS THAT DG PROVIDES?

A. No. For one, the cost allocation is based on embedded costs, while future avoided costs (i.e., benefits) should be assessed on the basis of marginal costs. An embedded cost of service study is the wrong tool with which to analyze DG benefits because it examines only a test-year snapshot of costs that already have been incurred. It simply does not consider the value of future avoided costs to either EPE or ratepayers stemming from DG deployment on the grid. Moreover, it does not fully assess how DG benefits other customers by being present on the grid right now in the form of reduced deployment of interruptible load-demand reductions and reduced risk of scheduled power outages (i.e., rolling blackouts) on critical peak days.

For instance, on July 14, 2016 EPE made preparations for the possibility of rolling outages due to expected high demand.[72] Using EPE's data DG customer delivered load and total household load, I estimate that residential DG systems were producing roughly ******BEGIN CONFIDENTIAL**[redacted]**END CONFIDENTIAL****** during the peak hour on July 14 and 15, 2016.[73] This amount of capacity is the equivalent to roughly 900 residential customers reducing their demand to zero during the peak hour of July 14, 2016.

Q. WHAT IS THE PROPER WAY TO ANALYZE THE COSTS AND BENEFITS OF DG DEPLOYMENT?

A. Benefits should be evaluated using a targeted and comprehensive study, often referred to as a "Value of Solar" study. Below I summarize the list of typical categories of benefits that have been considered by regulators in other states:

---

[72] *See* for instance, ABC 7 News, KVIA "El Paso Electric says scheduled power outages are a possibility." July 14, 2016. http://www.kvia.com/news/el-paso-electric-says-scheduled-power-outages-are-a-possibility/89157156.

[73] Derived from EPE's Response to EFCA RFI No. 1-1, Attachment 1 providing sampled residential DG load data, and EPE's Response to EFCA RFI No. 3-13 providing residential DG capacity and DG customer count data. The estimate is adjusted to reflect the estimated residential DG capacity on EPE's Texas system as of June 2016.

- Avoided energy
- Avoided generating capacity
- Avoided line losses (reflected in avoided energy and capacity values)
- Avoided transmission and distribution capacity and/or deferral of associated upgrades
- Grid support and ancillary services
- Reduction in fuel price risk (i.e., power plant fuel price hedge)
- Electricity market price effects (i.e., reduction in wholesale power prices)
- Grid security, reliability and resiliency services
- Environmental benefits (i.e., avoided compliance and societal costs)
- Local economic development.[74]

Q. CAN YOU POINT TO ANY SPECIFIC BENEFITS THAT ARE NOT REFLECTED IN THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. The allocation methodology fails to account for capacity contributions and reduced line losses that occur when a DG facility is exporting power. That is, in the Company's residential DG load research study, exports are not reflected as "negative" loads, they are reflected as zero demand values. Exports from DG facilities also reduce line losses on the distribution system, benefitting all customers, because the electricity serves local customers and at a minimum avoids losses on the transmission system. The embedded cost nature of the cost of service study also disregards deferrals in investment in generation, transmission, and distribution that are made possible by load reductions on individual circuits or the system as a whole.

Q. DOES THE COMPANY RECOGNIZE THAT DG CAN HELP AVOID FUTURE COSTS IN OTHER CONTEXTS?

A. Yes. In calculating its planning reserve margin, the Company reflects forecasted contributions from DG as "negative" demand that reduces total system demand, allowing for deferral of new utility generating capacity or resource purchases. To place this in context, greater deployment of customer-sited DG could very well avoid the 15 MW

[74] IREC. *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* October 2013. http://www.irecusa.org/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

acquisition the Company identifies as a new resource purchase in 2020.[75] The Company also recognizes the importance of marginal capacity costs as the driver of peak costs in its TOU rates proposal, estimated at $101.74/kW-year.

Q. ARE THERE ANY SPECIFIC EXAMPLES OF DG BEING USED TO AVOID INVESTMENTS BEYOND GENERATING CAPACITY?

A. Yes. In recent years a number of states have begun evaluating distribution capacity deferrals through use of so-called "non-wires alternative" or "NWA" projects and more advanced distribution system planning methods that incorporate DG deployment forecasts. NWAs typically involve a combination of DG, energy storage, demand response, and energy efficiency to provide load reductions in local grid areas. For instance, Orange and Rockland Utilities ("ORU) in New York alone lists seven future requests for proposals ("RFPs") for load relief and reliability-related projects.[76] Other utilities in New York are engaged in similar activities.

Even absent these planned activities, there are examples of high levels of DG deployment causing deferral and potential cancellations of significant transmission investments. For instance, the California Independent System Operator ("CAISO") has opted to re-evaluate a major new high-voltage transmission line to be located in Fresno California, valued between $115 and $145 million, due to increases in forecasted DG development and shifting peak demand.[77]

With respect to distribution system planning, numerous efforts are ongoing in states including but not limited to California, Maryland, Minnesota, New York, and Rhode Island, often as part of broader "Grid 2.0" initiatives. While many states are only in the early stages of quantifying the distribution deferral value of DG, in the staff of the New York Public Service Commission ("NYPSC") estimated utility-level distribution deferral values ranging from roughly 1 cent/kWh to more than 5 cents/kWh of annual PV

[75] EPE's Response to Staff RFI No. 6-3.

[76] ORU. Non-Wires Alternatives. https://www.oru.com/en/business-partners/non-wires-alternatives.

[77] Tim Sheehan. "Solar Growth Puts Fresno High-Voltage Line on Hold". The Fresno Bee. December 20, 2016. http://www.fresnobee.com/news/local/article122063189.html.

production.[78] These estimates are based on utility-specific marginal distribution costs and reference PV output profiles during 10 system peak hours. The results of such an analysis would certainly differ for EPE, but are illustrative of distribution level DG benefits.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION APPROACH CONSIDERATION OF DG BENEFITS FROM A RATEMAKING PERSPECTIVE?

A. I recommend that the Commission reject EPE's DG rate proposals. Without the insight provided from a full evaluation of DG costs and benefits, the PUCT has no way of knowing whether any long-term subsidy exists, its magnitude, and even the direction in which it operates. To the extent that DG benefits outweigh the costs, adopting rates that would hinder DG deployment amounts to forgoing those benefits and increasing long-term ratepayer costs.

Q. IS THIS OVERALL APPROACH CONSISTENT WITH HOW REGULATORS IN OTHER STATES HAVE ADDRESSED THE ISSUE OF APPROPRIATE DG RATE STRUCTURES?

A. Yes. All of the states shown in Exhibit JRB-2 that have actually made any significant changes to net metering or DG rate structures have done so only after completing thorough cost-benefit analyses. Those states that have not completed full cost-benefit analyses or investigations (Arkansas and South Carolina), have not moved to change net metering or DG rate structures.

This approach represents a "measure twice, cut once" mentality that is reflected in National Association of Regulatory Utility Commissioners' ("NARUC") Manual on Distributed Energy Resources Rate Design and Compensation. While the NARUC Manual does not recommend a specific approach or benchmark for considering rate design changes, it does provide a decision-making framework that includes numerous questions related to DG cost-benefit analysis.[79] It further states "there should not be so

[78] NYPSC, Department of Public Service Staff. Docket No. 15-E-0751. Copy of VoD Estimate. October 28, 2015.

[79] NARUC. Manual on Distributed Energy Resources Rate Design and Compensation. 2016. See Section VI entitled "A Path Forward for Regulators."

much urgency that the decision is made without all of the appropriate information. The results from such uninformed actions could be worse than no action at all."[80]

G. The Commission Should Take a Methodical and Gradual Path in Considering Rate Structure Changes.

Q. HOW DO RECOMMEND THE COMMISSION PROCEED IN ITS CONSIDERATION OF APPROPRIATE DG RATES AND RATE STRUCTURES?

A. EPE has not provided all of the appropriate information to allow the Commission to make an informed decision on the future of DG rates in EPE's service territory. As I have discussed previously, the lack of reliable cost-benefit analysis is a significant missing piece at present. Moreover, the Company's proposal involves an abrupt shift to a dramatically new and untested rate structure and the information that the Company has presented on how it will manage customer response and acceptance is minimal. I recommend that DG rates and potential rate structures be investigated much more thoroughly and consider a variety of rate options if changes are ultimately determined to be necessary.

Q. WHAT TYPES OF NEAR TERM ACTIONS COULD THE COMMISSION TAKE TO BEGIN THIS PROCESS?

A. At this point in time it is most appropriate for EPE to pilot new residential rate designs, in order to gauge acceptance, response, and the impact that new rate designs would have on cost recovery. Pilot programs testing new rates are certainly not unusual. In fact, a number of the optional demand rates referenced by Mr. Schichtl are pilot rates subject to review and evaluation. Without this type of information, the Commission risks taking the premature actions that the NARUC Manual recommends against.

Q. DO YOU RECOMMEND THAT THE COMMISSION ADOPT THE COMPANY'S PROPOSAL WITH RESPECT TO REQUIRING DG CUSTOMERS TO TAKE SERVICE UNDER TOU RATES?

A. No. The adoption of mandatory TOU rates would likewise be premature for the same reasons. As with a shift to demand rates, an abrupt transition to mandatory TOU rates is

80 *Id.* at p. 155.

contrary to standard ratemaking principles of gradualism, rate stability, and customer understanding. Customer receptivity and response to different TOU rate structures should be thoroughly evaluated prior to any mandatory adoption. In performing this evaluation I also urge the Commission to consider the evolving technological landscape of DG (e.g., smart inverters, energy storage) and pursue rate design in a manner that is consistent with unlocking potential future benefits that advanced DG can provide.

VI. DEMAND RATCHETS IN EPE'S DEMAND RATE STRUCTURES

Q. WHAT IS A DEMAND RATCHET?

A. A demand ratchet may determine a customer's billing demand based on that customer's demand during prior months, rather than the customer's measured demand during a given billing month. The ratchet is typically expressed as a percentage of the customer's maximum demand measured over the previous year. The ratchet is "triggered" if the customer's monthly measured demand is less than the defined percentage. The term "ratchet" reflects how the minimum billed demand "ratchets" upward to settle at a new level whenever a customer exceeds a prior maximum, or ratchets down as that month is removed from the period of consideration.

Q. HOW ARE EPE'S DEMAND RATCHETS DESIGNED?

A. Demand ratchets are currently employed under the Schedule No. 24 General Service ("GS") Rate and the Schedule No. 25 Large Power Service ("LPS") rate. The GS rate determines billing demand as the highest of:

1. 15 kW (the minimum demand under the GS rate);
2. The maximum monthly demand as measured over 30 minutes; and
3. 60% of the highest measured demand established during the billing months of June – September in the 12-month period ending with the current month (i.e., the demand ratchet).

The design for the LPS rate demand ratchet is similar except that the minimum demand of 600 kW corresponds to the minimum for that rate schedule, and the ratchet percentage is set at 75% rather than 60%.

Q. DOES THE COMPANY PROPOSE ANY REVISIONS TO THESE DEMAND RATCHETS IN ITS APPLICATION?

A. No.

Q. WHAT IS A DEMAND RATE INTENDED TO ACCOMPLISH?

A. The typical rationale for demand rates is that they send price signals to customers that are consistent with how system costs are caused. That is, many costs to serve customers are related to measures of the demand they place on different parts of the system and demand charges approximate this effect. As I have previously described, this is what Mr. Schichtl refers to as "matching charges with cost causation."[81] Underlying this is a basic principle that rates should promote efficient use of the system, such that the price signal in the rate incentivizes customers to reduce their demands on the system. Time- or seasonally-differentiated demand rates reflect the time-varying nature of costs and provide an equivalent price signal to customers.

Q. ARE DEMAND RATCHETS CONSISTENT WITH PROVIDING THIS TYPE OF PRICE SIGNAL TO CUSTOMERS?

A. No. Neither the demand rate itself nor the demand ratchet fully account for the timing of a customer's maximum demand. While there is seasonal differentiation in both of these elements, they do not reflect the actual times during a day when EPE's system is the most stressed (i.e., costs are caused). For instance, during the peak summer period, EPE's peak load varies considerably throughout the day. Early morning hourly system loads expressed as a percentage of the system peak are roughly 50% lower than the average summer peak, while 10 hours average less than 70% of the peak and 18 hours average

[81] Schichtl Direct at p. 50, line 7.

less than 90% of the peak.[82] Most hours of the summer day fall well outside of the system peak periods.

While complete information is not available on distribution system peaks, ****BEGIN CONFIDENTIAL [redacted] ****END CONFIDENTIAL[83]

Q. ARE EPE'S DEMAND RATCHETS FOR THE GS AND LPS CLASS CONSISTENT WITH COST CAUSATION?

A. No. The rates themselves as well as the demand ratchet are based on non-coincident demand, creating a misalignment with costs caused by the coincident demand at different points on the system. I have discussed this issue at length in the context of the Company's proposed residential DG rate. The Company's GS and LPS costs are dominated by production and transmission demand, which comprise roughly 81% of GS demand-related costs and 82% of LPS demand related costs.[84] Both types of costs are more closely related to summer coincident demand than non-coincident demand.

Q. HAVE REGULATORS IN OTHER STATES RECENTLY CONSIDERED THE APPROPRIATENESS OF DEMAND RATCHETS?

A. While I have not undertaken a comprehensive survey of all states, I am aware of two recent examples, in Massachusetts and Arizona. In decisions by the Arizona Corporation Commission ("ACC") in August 2016 and February 2017, the ACC voiced concerns

---

[82] EPE's Response to EFCA RFI No. 1-1, Attachment 1, Figure 7

[83] EPE's Confidential Response to EFCA RFI No. 3-14, Attachment 1.

[84] Schedule P-6.1, p. 2. Percentages arrived at by dividing production and transmission demand unit costs by total demand-related unit costs for the GS and LPS classes.

about demand ratchet components in the rates of UniSource Energy Services ("UNS") and Tucson Electric Power ("TEP').

In the UNS case, the ACC declined to eliminate an existing demand ratchet for the medium general service rate class, but opined that "Demand ratchets may be characterized as a substitute for rates that actually reflect cost causation." The ACC consequently directed UNS to seriously consider rates not involving demand ratchets in its next rate case.[85]

The ACC later declined to adopt a TEP proposal to establish a new demand ratchet for the medium general service rate class based on similar concerns and directed TEP to offer a non-ratcheted alternative to LGS customers installing storage.[86]

Finally, in September 2016 the Massachusetts Department of Public Utilities ("MDPU") rejected a request by National Grid to establish a new demand ratchet, finding that it would distort price signals, reduce customer motivations to reduce demand beyond class or system peak, discourage investments in cost-effective, load-control equipment, and unfairly impose higher costs on some customers.[87]

Q. DOES EPE'S DEMAND RATCHET RAISE SIMILAR CONCERNS REGARDING A CUSTOMER'S INCENTIVE TO REDUCE DEMAND DURING PEAK TIMES?

A. Yes. EPE's demand ratchet significantly diminishes the customer incentive because a peak set outside the fairly narrow range of typical peak times sets a minimum demand that cannot be reduced inside of a year. For instance, to the extent that a customer is located on a portion of the distribution system that peaks outside of the June – September period, they remain subject to a ratchet set during the summer period. Or, if they are located in one of the more typical summer peaking locations they could set a minimum demand during the many hours that are outside of the typical afternoon peaks. The

[85] ACC Decision No. 75697 at p. 86.

[86] ACC Decision No. 75975 at p. 188.

[87] MDPU Order 15-155 at p. 456-457.

customer's incentive to reduce demand is therefore confined for a year at a time to a reduction of 25% for LPS customers and 40% for GS customers.

Q. IS THIS OUTCOME ALIGNED WITH STATE AND UTILITY OBJECTIVES, AND GOALS?

A. No. As I have previously discussed, the state of Texas has set goals for reductions in demand growth. These have given rise to programs such as EPE's Load Management Program, Standard Offer Program, and Electric Solutions Program, all of which provide considerable incentives for customer demand reduction, ranging from $194/kW up to $400/kW for most measures.[88] During 2016 EPE reported demand savings of 12.79 MW translating to roughly $1 million in capacity related avoided costs for these and accompanying residential programs.[89] The Company has also recently debuted a residential and small commercial smart thermostat program specifically targeting peak demand reductions through remote operation of thermostat settings during peak periods.[90]

By limiting the demand rate savings that a customer can accrue for up to one year after the measures are installed, the demand ratchet diminishes the effectiveness of the non-residential programs resulting in foregone cost savings. Demand ratchets are also misaligned with the Company's targeting of peak demand reduction via dispatchable demand response as well as through TOU rate expansion. Furthermore, demand ratchets decrease the viability of on-site energy storage investments by customers, which is well-suited for general demand reduction, peak demand reduction, and dispatchable demand response during critical peak events.

---

[88] *See* EPE Texas Energy Efficiency Programs for Commercial and Industrial Customers. https://www.epelectric.com/tx/business/texas-energy-efficiency-programs-for-commercial-and-industial-customers.

[89] EPE Revised EEPR (April 27, 2017), p. 49. PUCT Project No. 46907, *2017 Energy Efficiency Plans and Reports Pursuant to TAC §25.181(n).*

[90] EPE, eSmart Thermostat Program. https://enrollmythermostat.com/elpasoelectric/.

Q. PLEASE EXPLAIN HOW DEMAND RATCHETS AFFECT THE DEPLOYMENT OF ENERGY STORAGE?

A. The effect is similar to the effect on any customer incentives for demand reduction, but more pronounced for several reasons. First, modern energy-storage systems (e.g., lithium ion batteries) are commonly estimated to have a lifetime of roughly 10 years. The one-year fixed nature of the demand ratchet covers 10% of this lifetime, whereas the effect is reduced for longer-lived demand reduction measures. Second, energy-storage systems are more scalable than other demand reduction measures since they are not confined to reducing demand from specific end uses; thus, they create an opportunity for the kind of deep demand reductions that are more affected by the demand ratchet. Third, because energy storage is not specifically eligible for the demand-reduction incentive programs I have noted previously, the mitigating effect of receiving a rebate or other incentive offsetting the loss of savings is not present.

Q. ARE THERE REASONS TO SUPPORT THE CUSTOMER DEMAND REDUCTIONS EVEN IF THE COMPANY IS ALREADY MEETING ITS DEMAND REDUCTION TARGETS?

A. Of course. The value of demand reduction is not diminished simply because some target benchmark has been met. This is especially true when those reductions are financed by customers, involving no outlay of ratepayer dollars for provision of demand reduction incentives. The long-term benefits of fostering energy storage deployment on EPE's systems are also potentially broader in scope and higher than those of technologies that achieve demand reduction through more constrained means. Those benefits include more flexibility and responsiveness, greater scalability, and the ability to offer additional grid services. Those additional grid services include reserves, fast responding frequency regulation, voltage support, black start capability, resource adequacy/capacity, and distribution or transmission deferral.

Q. WHAT DO YOU RECOMMEND REGARDING EPE'S DEMAND RATCHET?

A. I recommend that the existing demand ratchets be eliminated so as to base billing demand for customers on the LPS and GS rate schedules only on measured demand during a month. Lacking that, I recommend that the tariffs be revised to offer a rate without demand ratchets for customers that install energy storage.

Q. DOES THIS TYPE OF TARGETED CHANGE HAVE PRECEDENT IN EPE'S RATES?

A. Yes. The Company instituted an experimental off-peak rider within the LPS rate schedule in September 2012. The Company states that "The intent behind implementing this rider was to provide an alternative pricing option for low-load factor customers that more accurately reflects cost causation and provides these customers with a strong economic incentive, through lower bills, to avoid operating during EPE's summer peak load hours." The utility further states that the rider has been successful at achieving these goals.[91]

The LPS and GS schedules also contain a now closed thermal energy storage rider targeting peak-demand reduction and generation capacity investment deferrals. The rider, which was open from 1995 - 2010, allowed customers to avoid paying demand charges during off-peak periods where the off-peak energy was used as part of an ice-storage cooling system.[92] Both riders were designed to more effectively accommodate unique customer circumstances in a manner aligned with cost causation and supportive of peak demand reduction.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR TARIFF CHANGES RELATED TO FACILITATING ENERGY STORAGE DEPLOYMENT?

A. Yes. When a customer's demand falls outside of the parameters for either the GS or LPS class, the only form of notice that the customer receives is a letter notifying them that their rate will be switched "effective with the account's next billing statement."[93] It is not clear to me this is sufficient notice for a customer with on-site energy storage to effectively respond to the new rate. It is likely that the storage system's operating instructions would need to be modified to optimize its operation if a rate change were to

[91] EPE's Response to EFCA RFI No. 7-22.

[92] EPE's Response to EFCA RFI Nos. 7-11 and 7-12.

[93] EPE's Response to EFCA RFI Nos. 7-19 and 7-20.

occur. I recommend that these customers be provided, first, with a warning notice that they have exhibited load behavior that will qualify them for a different rate. If a customer's load falls outside of the load requirements of their given rate a second time, I recommend EPE provide them with advance notice of at least one month prior to moving the customer off of their rate. The notice should include the exact date of the switchover so that they have time to have the unit reprogrammed and know precisely when the changes should be executed.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON THE ISSUES YOU HAVE DISCUSSED IN YOUR TESTIMONY.

A. At an overarching level, I recommend that the Commission carefully consider the evolving nature of the electric grid, DG, technological advances and customer preferences in its determinations in this and future proceedings. The Commission should not be locked in to a specific proposal or approach to addressing a highly complicated and inter-related set of issues associated with this evolution. My specific recommendations to the Commission on EPE's proposal reflect this long-term, outcome-oriented outlook. With respect to the Company's proposals, I recommend that the Commission:

1. Reject the Company's proposal to establish a separate class for residential DG customers because the Company has failed to provide convincing evidence that these customers are outside the diversity of the residential class.

2. Reject the Company's proposal to subject residential and small general service DG customers to different rates than those otherwise available to customers in the respective rate classes, on the basis that the proposed rates are misaligned with cost causation and other accepted ratemaking principles.

3. Reject the Company's proposed interconnection application fees and consider establishing a review of interconnection application fees to identify the appropriate methodology for setting any future fees and to identify process inefficiencies that could be improved upon.

4. Conduct a thorough investigation of DG costs and benefits and appropriate rate design options prior to adopting any rate changes for DG customers.

5. Proceed gradually with any future rate design modifications with a focus on providing multiple rate options for customers and unlocking the value of advanced DG technologies such as energy storage.

6. To the extent that the Commission adopts separate rates for DG customers, grandfather existing DG customers on their present rate structure for a term of 25 years from the date of the final order in this proceeding.

7. Consider establishing a default grandfathering policy, regardless of the outcome of this proceeding, in order to provide certainty and predictability to future DG customers.

8. Eliminate EPE's current demand ratchets, or in the alternative, direct the Company to develop optional non-ratcheted rates for customers that install energy storage, as was recently done by the ACC in Arizona.

9. Direct EPE to modify its protocols for moving customers between the GS and LPS rates in order to allow them an opportunity to modify their usage in order to remain on the same rate and sufficient time to adapt (e.g., modify operating protocols for on-site energy storage) to new rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

DIRECT TESTIMONY OF JUSTIN R. BARNES

EXHIBIT JRB-1:

Curriculum Vitae of Justin R. Barnes

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting.
- Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and quantitative or qualitative analysis to fulfill client requests, and for internal and published reports, focused primarily on state solar market drivers such as net metering, rate design, incentives, and renewable portfolio standards.
- Provide expert witness testimony on issues related to overall DG policy, rate design, cost of service, and DG benefits.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.
- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.

- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future.* 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?.* September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments.* July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts.* December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues.* July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communtties: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri.* 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On.* 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar.* 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends.* Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets.* 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar.* 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues.* 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

- Utah Public Service Commission. Docket No. 14-035-114. June 2017.
- Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016.
- Public Utility Commission of Texas, Control No. 44941. December 2015.
- Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015.
- South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015.
- South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

SOAH DOCKET NO. 473-17-2686
PUC DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

DIRECT TESTIMONY OF JUSTIN R. BARNES

EXHIBIT JRB-2:

Summary of Grandfathering and Regulatory Decisions on DG Rate Structures and NEM

Figure 1: Summary of Regulatory Decisions on DG Rate Structures and NEM

State	Grandfathering Allowed?	Case Decided by Litigation, Settlement or Rule?	Grandfathering Term/Duration	Grandfathering Eligibility Deadline	Outcome	Next Steps?
AR[1]	Yes (if NEM revised in Phase 2)	Rule	20 years (if Phase 2 changes)	Future, application before effective date of Phase 2 structure	Core of existing NEM maintained	Explore NEM modifications in Phase 2, overall DG policy in separate proceeding
AZ[2]	Yes	Litigated	20 years from date of application[3]	Future, application before effective date of GRC decision	NEM eliminated, gradual reduction in export rates	Rate design in utility GRCs, next generation DG policies in other proceedings
CA[4,5]	Yes	Litigated	20 years from date of interconnection year	Future interconnected before 7/1/2017, or utility cap reached	Modest minimum bill, mandatory TOU, core of NEM maintained with small credit rate reduction	NEM review in 2019, multi-faceted DER and grid 2 0 efforts
CO[6]	N/A	Settled	N/A	N/A (existing NEM rate structure maintained)	Existing NEM rate structure maintained	Test new rate options; storage integration
HI[7]	Yes	Litigated	Indefinite	Application before date of Order	NEM eliminated, new DG tariffs with minimum bills	Phase 2 exploring DER market integration, enablement, grid services
IA[8]	Yes	Litigated	Indefinite	Application before effective date of any tariff changes	Expanded NEM under 3-year pilot	Review pilot outcomes, then decide next steps
LA[9]	Yes	Rule	Indefinite	Future, application before utility cap reached	NEM maintained, monthly rollover changed to avoided cost from retail	Phase II addressing effectiveness of NEM rules and broader DG policies
ME[10]	Yes	Rule	15 years	Future, in-service date before 12/31/17 (or future vintage year)	Gradual decrease in distribution component of NEM credit	Rule review when new penetration benchmark met
NV[11]	Yes (eventually)	Litigated, Settled	~20 years (through 11/30/2036)	Initially no grandfathering; upon revision, application within one week of initial NEM Order	Higher fixed charge phase-in, NEM eliminated with gradual decline in export credit rate, NEM re-opened subsequently in SPPC territory [12]	Investigate "universally-acceptable" methodology for rooftop PV valuation & NEM systems Legislation now targeting broader electricity market reforms
NY[13]	Yes	Rule	Indefinite (existing), 20 years (Phase 1 NEM)	Installed by date of Order	NEM maintained for residential (NEM Phase 1), DER tariff for others	DER tariff refinement, Phase 1 NEM through 2020 or when new caps reached, ongoing broad energy transformation initiative
SC[14]	Yes	Settled	~10 years (through 12/31/2025)	Future; Earlier of 12/31/2020 or utility cap met	NEM adopted	No specific next steps
VT[15]	N/A	Rule	10 years	Application by 1/1/2017	Core of existing NEM maintained	Ongoing broad energy transformation initiative

[1] Arkansas Public Service Commission. Order No. 10 in Docket No. 16-027-R. March 8, 2017.
[2] Arizona Corporation Commission. Decision No. 75859. Docket No. E-00000J-14-0023. January 3, 2017.

[3] Arizona Corporation Commission. Decision No. 75932. Docket No. E-00000J-14-0023. January 13, 2017.
[4] California Public Utilities Commission. D.14-03-041. Docket No. R.12-11-005. March 4, 2014.
[5] California Public Utilities Commission. D.16-01-044. Docket No. R.14-07-002. February 6, 2016.
[6] Colorado Public Utilities Commission. Decision C16-1075. Docket No. 16AL-0048E. November 23, 2016.
[7] Hawaii Public Utilities Commission. Decision No. 33258. Docket No. 2014-0192. October 12, 2015.
[8] Iowa Utilities Board. Order Directing the Filing of Net Metering Tariffs. Docket No. NOI-2014-0001. July 19, 2016.
[9] Louisiana Public Service Commission. General Order 12-08-2016. Docket No. R-33929. November 17, 2016.
[10] Maine Public Utilities Commission. Order Adopting Rule and Statement of Factual and Policy Basis, Amendments to Net Energy Billing Rule (Chapter 313). Docket No. 2016-00222. March 1, 2017
[11] Public Utilities Commission of Nevada. Order in Docket Nos. 16-07028 and 16-07029. September 16, 2016.
[12] Public Utilities Commission of Nevada. Order in Docket No. 16-06006. December 28, 2016.
[13] New York Public Service Commission. Order on Net Metering Transition, Phase One of Value of Distributed Resources, and Related Matters. Docket No. 15-E-0751. March 9, 2017.
[14] Public Service Commission of South Carolina. Order No. 2015-194. Docket No. 2014-246-E. March 20, 2015.
[15] Vermont Public Service Board. Final Proposed Rule 5.100. Secretary of State Docket No. 16P-062. January 20, 2017.