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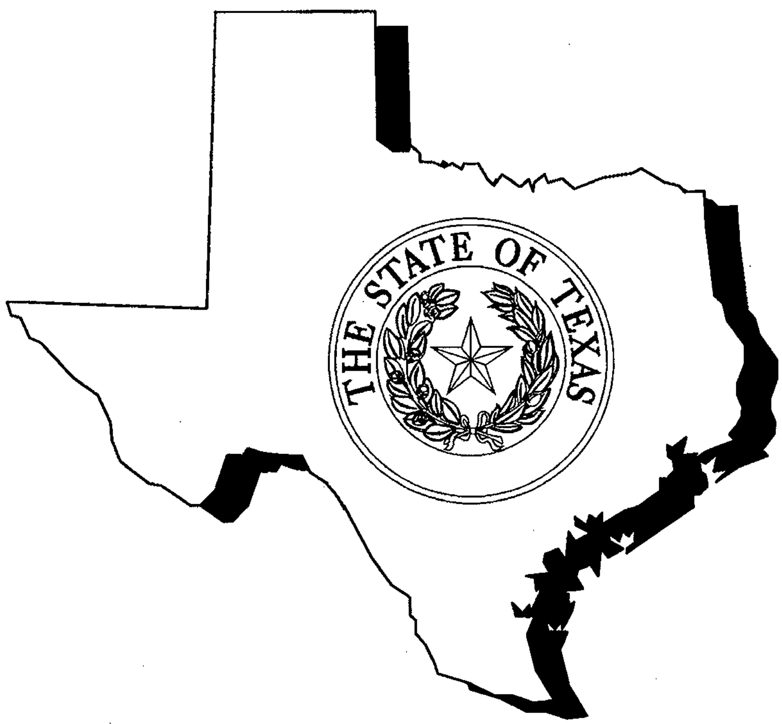
SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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



DIRECT TESTIMONY AND WORKPAPERS OF

WILLIAM B. ABBOTT

RATE REGULATION DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

OCTOBER 29, 2021

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Attachment WBA-1 Curriculum Vitae

WORKPAPERS

I. PROFESSIONAL QUALIFICATIONS

Q. Please state your name and business address.

A. William B. Abbott, 1701 N. Congress Avenue, Austin, Texas 78701.

Q. By whom are you employed and in what capacity?

A. I am employed by the Public Utility Commission of Texas (Commission) as the Director of the Tariff and Rate Analysis Section of the Rate Regulation Division.

Q. What are your principal responsibilities at the Commission?

A. In addition to the supervision and management of the Tariff and Rate Analysis Section, my principal area of responsibility involves performing analyses of issues such as utility cost allocation, rate design, and tariff filings. My specific responsibilities include: analyzing cost allocation studies, as well as revenue distribution and rate design issues, for regulated electric, water, and wastewater utilities; analyzing policy issues associated with the regulation of regulated utilities; reviewing tariffs of regulated utilities to determine compliance with Commission requirements; preparing and presenting testimony as an expert witness on rate and related issues in docketed proceedings before the Commission and the State Office of Administrative Hearings (SOAH); and working on or leading teams in contested cases, rulemaking projects, reports, and research concerning rates, pricing, and other Commission-related issues.

Q. Please state your educational background and professional experience.

A. I earned Bachelor of Science degrees in Chemistry, Psychology, and Economics with a minor in Mathematics from the University of Houston. I earned a Master of Arts degree in Economics from George Mason University while successfully completing all non-dissertation requirements for a Ph.D., with field concentrations in Law and Economics as well as Public Choice Economics. My field concentrations involved the study of the dynamics and social welfare implications of behavior in non-commercial domains such as the legal, political, legislative, and regulatory arenas. For several years as an undergraduate and post-baccalaureate student, I was employed teaching introductory and organic chemistry laboratory courses. As a graduate student, I taught several undergraduate lecture courses including Introductory Microeconomics, Introductory Macroeconomics, Money and Banking, as well as Law and Economics. After my graduate studies, and prior to my employment at the Commission, I was engaged as a freelance consultant to perform econometric analyses. In 2010, I was hired as a Rate Analyst at the Commission. In 2012, I was promoted to my current position of Director, Tariff and Rate Analysis. I have provided a summary of my educational background and professional regulatory experience in Attachment WBA-1.

Q. Have you previously testified before the Commission or SOAH?

A. Yes. Attachment WBA-1 includes a listing of my previously filed written testimony.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the purpose of your testimony in this case, PUC Docket No. 52195 and SOAH Docket No. 473-21-2606, *Application of El Paso Electric Company for Authority to Change Rates*?

A. My direct testimony regarding El Paso Electric Company's (EPE) application will address EPE's proposal to decrease the distributed generation (DG) minimum bill amounts for residential and small general service (SGS) customers. However, the fact that I remain silent on certain issues associated with the EPE's request or any issues presented by any other party to this proceeding does not imply any agreement on those issues.

Q. What is the basis for your review?

A. Public Utility Regulatory Act[1] (PURA) § 36.003(a) states that the Commission "shall ensure that each rate an electric utility or two or more electric utilities jointly make, demand, or receive is just and reasonable." PURA § 36.006 states: "In a proceeding involving a proposed rate change, the electric utility has the burden of proving that: (1) the rate change is just and reasonable, if the utility proposes the change." Under 16 Texas Administrative Code (TAC) § 25.234(a), relating to Rate Design, rates "shall not be unreasonably preferential, prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to each class of customers, and shall be based on cost."

Q. Was your testimony prepared by you or someone working under your direct supervision?

A. Yes.

Q. What items did you review to arrive at your recommendations?

A. In preparing my testimony on these issues, I reviewed portions of EPE's application, direct testimony, previous proceedings before the Commission, and certain Commission rules.

III. SUMMARY OF RECOMMENDATIONS

Q. What is your recommendation?

A. I recommend that EPE's proposal to reduce the minimum monthly bill charges for non-grandfathered DG customers be rejected. The existing levels of the minimum monthly bill

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016 (PURA).

charges are below the levels that reasonably reflects the costs to serve these customers, due to the nature of the net energy metering (NEM) applied by EPE. For affected classes facing an overall increase in base rates, exclusive of any Distribution Cost Recovery Factor (DCRF) and Transmission Cost Recovery Factor (TCRF) amounts not previously included in base rates, the monthly minimum charge for each class should be increased by the same percentage as the overall base rate increase for the class. For any affected classes facing an overall decrease in base rates, exclusive of any DCRF and TCRF amounts, the minimum monthly bill amounts should remain at their existing levels.

IV. MINIMUM BILL PROVISION FOR DG CUSTOMERS

Q. What are EPE's minimum monthly bill provisions for non-grandfathered DG customers?

A. As part of EPE's last base rate proceeding, Docket No. 46831, and in order to address the failure to properly recover a just and reasonable level of costs from NEM customers, the Commission approved a settlement providing for minimum monthly bill provisions to be applied to non-grandfathered DG customers in the residential and the small general service (SGS) classes.[2] See my previously filed testimony from Docket No. 46831, attached as workpapers to this testimony, for a more thorough discussion of the underlying cost recovery issues associated with NEM and DG.

[2] *Application of El Paso Electric Company to Change Rates,* Docket No. 46831, Final Order at Attachment A (Dec. 18, 2017).

Q. What is EPE's proposal regarding the minimum monthly bill provisions in this proceeding?

A. EPE is proposing to consolidate and reduce the minimum monthly bill charges based on (1) EPE's proposed minimum charge and (2) distribution-related system costs for both the average residential customer and the average small general service DG customers.[3] This results in a minimum charge of $24.02 for residential DG customers and $25.19 for small general service DG customers. This compares to existing minimum bill charges of $30 for residential DG customers, $26.50 for residential DG time-of-use (TOU)[4] customers, $39 for SGS DG customers, and $36.50 for SGS DG TOU customers.

Q. Is it reasonable for the residential DG minimum bill to decrease when residential rates are increasing overall?

A. No. The previously agreed level of the minimum bill represented a compromise that did not fully address the issues associated with NEM DG customers. It is unreasonable for the DG minimum bill to decrease when EPE is requesting an increase in residential rates and cost of service. If the average costs to serve residential customers has increased, then the minimum monthly bill for DG customers should increase by an equal proportion. As shown in EPE witness George Novela's testimony and my previous testimony attached as workpapers, residential DG customers are significantly different from other residential customers in several ways, including in the fact that their load factors are much lower.[5] This means that kWh billing for these NEM customers fails to account for the significantly

[3] Direct Testimony of Manuel Carrasco at bates 1633 and 1637. El Paso Electric Company's Response to Commission Staff's Tenth Request for Information at Staff 10-2 (Sep. 29, 2021).

[4] EPE is proposing to restyle "time-of-use" to "time-of-day" as part of its request in this proceeding.

[5] Direct Testimony of George Novela at bates pages 1480 -1488 and Exhibit GN-2.

higher load per kWh they impose on the system, and therefore significantly under-collects capacity-related costs such as generation, transmission, and distribution costs. In the absence of cost-based demand charges for these customers, a significant minimum bill is necessary in order to avoid unreasonably preferential rates for DG customers. EPE's reliance upon average residential distribution costs to lower the DG minimum bill charges is at odds with Mr. Novela's own analysis showing the higher-than-average demand costs, on both an absolute and on a per-kWh basis, for DG customers, as well as his analysis showing a significant reduction of DG output around the times of the system peaks.

Q. Are EPE's proposed DG minimum bill charges reasonably and fully cost-based?

A. No. EPE's proposal to base the minimum bill amounts on the proposed minimum charge and average distribution-related system costs for each class is not fully cost-based. The distribution-related system costs component for each class is based on EPE's proposed distribution cost of service for the individual class as a whole. However, as discussed in both EPE's testimonies and my own in Docket No. 46831, and in Mr. Novela's testimony in this case, DG customers have substantially different electric usage characteristics compared to other customers. It is unreasonable to expect that the distribution-related cost of service for the average customer accurately reflects the costs that DG customers impose upon EPE's distribution system. Additionally, the NEM construct as applied by EPE for DG customers results in them failing to pay a significant portion of transmission and generation costs that they cause to be incurred. EPE's proposal to lower the minimum bill for these customers, by considering only customer and average distribution costs, fails to take these facts into account.

Q. Has EPE perform any sort of analysis or study to determine the cost to serve DG customers?

A. No. EPE merely relies on average distribution and customer costs in calculating its proposed DG minimum bill charges.

Q. Do EPE's proposed DG minimum bill amounts result in fair and equitable rates?

A. No. EPE's proposed DG minimum bill amounts understate the cost to serve DG customers, and therefore inappropriately shifts costs to other residential and SGS customers.

Q. What is your recommendation regarding EPE's residential Service DG minimum bill proposal?

A. I recommend that EPE's proposal to consolidate and decrease the residential DG minimum bill amounts be rejected, and that the residential DG minimum bill amounts should each be increased by the same proportion as the overall residential class base rate change approved in this case. The class increase for this purpose should be calculated excluding any DCRF and TCRF amounts from the level of existing base rate revenues, as these distribution and transmission costs were not included in the Docket No. 46831 base rates, and the previous level of the minimum monthly bills did not consider these additional costs. In the event that the residential class faces a base rate decrease, the existing levels of the residential DG minimum bills should be maintained.

Q. What is your recommendation regarding EPE's SGS DG minimum bill proposal?

A. I recommend that EPE's proposal to consolidate and decrease the SGS DG minimum bill amounts be rejected, and the SGS DG minimum bill amounts be kept at their current levels in the event the SGS class as a whole faces an overall decrease in base rates, exclusive of any DCRF and TCRF amounts. EPE has not shown that the current level of minimum bill amounts for this class adequately addresses the cost-shifting inherent in NEM billing, and therefore has not shown that decreasing these charges results in just and reasonable rates. In fact, EPE has not presented any reasoned justification for consolidating and reducing these charges, and therefore has not met its burden of proof. In the event that the SGS class faces a base rate increase, the existing levels of the residential DG minimum bills should increase proportional to the base rate increase for the class.

V. CONCLUSION

Q. Please summarize your recommendation.

A. EPE's proposal to consolidate and reduce the minimum bill charges for non-grandfathered DG customers should be rejected. The existing residential DG minimum bill charges should be increased by the same proportion as the residential class's overall base rate increase. The SGS DG minimum bill charges should be maintained at their existing levels, unless base rates for this class are increased, in which case they should be increased based on the class percentage increase, as with the residential class.

Q. Does this complete your testimony?

A. Yes.

William B. Abbott
Public Utility Commission of Texas
1701 North Congress Avenue
Austin, TX 78701

REGULATORY EXPERIENCE:

Public Utility Commission of Texas, Rate Regulation Division

June 2010 - Present

Director, Tariff and Rate Analysis Section as of May 1, 2012

Responsible for activities related to utility cost allocation, cost unbundling, rate design, and incentive regulation in areas subject to rate regulation. Key activities include managing staff engaged in rulemaking projects, contested cases, and tariff reviews. Perform in a technical capacity similar to that of a senior economic analyst including: analysis of economic issues and cost studies; review of rate requests and specific tariffs; and participation as an expert witness in major regulatory proceedings. Maintain contact with representatives of industry and consumers, other state agencies, and other Commission staff members, and advise the Division Director regarding the status of current projects and economic perspectives on utility regulatory issues.

EDUCATION:

2008	**George Mason University** *Master of Arts: Economics* *(All requirements for Ph.D. completed, except for dissertation)*
2004	**University of Houston** *Bachelor of Science: Economics* *Minor in Mathematics*
2003	**University of Houston** *Bachelor of Science: Psychology*
2002	**University of Houston** *Bachelor of Science: Chemistry*

List of Testimony Filed at the Public Utility Commission of Texas:

Docket No. 51802 – *Application of Southwestern Public Service Company for Authority to Change Rates* – August 20 and September 14, 2021.

Docket No. 51484 – *Compliance Filing of AEP Texas Inc. for Rider TC-2 Refund – Refund of Transition Charges-2* – August 6, 2021.

Docket No. 51239 – *Application of Caroll Water Company, Inc. for Authority to Change Rates* – May 14, 2021.

Docket No. 51547 – *Joint Report and Application of Texas-New Mexico Power Company, NM Green Holdings, Inc. and Avangrid, Inc. for Regulatory Approvals Under PURA §§ 14.101, 39.262, and 39.915* – March 2, 2021.

Docket No. 50714 – *Application of Entergy Texas, Inc. to Amend its Distribution Cost Recovery Factor* – May 27, 2020.

Docket No. 49189 – *Application of the City of Austin DBA Austin Water for Authority to Change Water and Wastewater Rates* – November 15, 2019.

Docket No. 49421 – *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates* – June 12 and 19, 2019.

Docket No. 48181 – *Application of El Paso Electric Company to Expand Solar Generation Capacity and Change Rates for the Community Solar Pilot Program* – October 24, 2018.

Docket No. 48401 – *Application of Texas-New Mexico Power Company for Authority to Change Rates* – August 20 and 28, 2018.

Docket No. 48371 – *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates* - August 16, 2018.

Docket No. 48233 – *Application of Southwestern Electric Power Company to Implement a Base Rate Decrease in Compliance With Docket No. 46449* – July 19 and October 16, 2018.

Docket No. 45979 – *Review of the Rate Case Expenses Incurred by Sharyland Utilities, L.P. in Docket No. 45414* – June 27, 2018.

Docket No. 47527 – *Application of Southwestern Public Service Company for Authority to Change Rates* – May 2 and 22, 2018.

Docket No. 46602 – *Appeal of AEP Texas Central Company From an Order of the City of McAllen Regarding Complaint of L&F Distributors* – October 10, 2017.

Docket No. 46936 – *Application of Southwestern Public Service Company for Approval of Transactions with ESI Energy, LLC and Invenergy Wind Development North America, LLC, to Amend a Certificate of Convenience and Necessity for Wind Generation Projects and Associated Facilities in Hale County, Texas and Roosevelt County, New Mexico, and for Related Approvals* – October 9, 2017.

Docket No. 46831 – *Application of El Paso Electric Company to Change Rates* – June 30, July 21, and November 2, 2017.

Docket No. 46449 – *Application of Southwestern Electric Power Company for Authority to Change Rates* – May 2 and 19, 2017.

Docket No. 45414 – *Review of the Rates of Sharyland Utilities, L.P., Establishment of Rates for Sharyland Distribution & Transmission Services, L.L.C., and Request for Grant of a Certificate of Convenience and Necessity and Transfer of Certificate Rights* – March 7 and 16, 2017.

Docket No. 44941 – *Application El Paso Electric Company to Change Rates* – January 15 and April 22, 2016.

Docket No. 45084 – *Application of Entergy Texas, Inc. for Approval of a Transmission Cost Recovery Factor* – November 24, 2015.

Docket No. 44620 – *Application of Sharyland Utilities, L.P. to Revise its TCRF Class Allocation Factors and Request for Good Cause Exception From P.U.C. Subst. R. 25.193(c)* – August 21 and September 8, 2015.

Docket No. 44677 – *Application of El Paso Electric Company for Approval to Revise its Energy Efficiency Cost Recovery Factor and Request to Establish Revised Cost Cap* – July 31 and August 7, 2015.

Docket No. 44060 – *Application of Brazos Electric Power Cooperative, Inc. to Amend a Certificate of Convenience and Necessity for a 138-kV Transmission Line in Denton County* – June 15, 2015.

Docket No. 43695 – *Application of Southwestern Public Service Company for Authority to Change Rates* – June 8, 2015.

Docket No. 42370 – *Application of Southwestern Electric Power Company for Rate Case Expenses Severed From PUC Docket No. 40443* – December 12, 2014.

Docket No. 43111 – *Application of Entergy Texas, Inc. for Approval of a Distribution Cost Recovery Factor* – November 5, 2014.

Docket No. 42448 – *Application of Southwestern Electric Power Company for Approval of a Transmission Cost Recovery Factor* – July 31, 2014.

Docket No. 42449 – *Application of El Paso Electric Company for Approval to Revise its Energy Efficiency Cost Recovery Factor and Request to Establish Revised Cost Caps* – July 10, 2014.

Docket No. 42042 – *Application of Southwestern Public Service Company for Approval of a Transmission Cost Recovery Factor* – May 1, 2014.

Docket No. 41791 – *Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs* – January 17 and April4, 2014.

Docket No. 41474 – *Application of Sharyland Utilities, L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service, and Adjust Wholesale Transmission Rate* – October 28, 2013.

Docket No. 41430 – *Joint Report and Application of Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC, and Southwestern Public Service Company for Approval of Purchase and Sale of Facilities, for Regulatory Accounting Treatment of Gain on Sale, and for Transfer of Certification Rights* – August 9, 2013.

Docket No. 40627 – *Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055* – February 14, 2013.

Docket No. 40443 – *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs* – December 17, 2012.

Docket No. 39896 – *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs* – April 3, 2012.

Docket No. 39375 – *Oncor Electric Delivery Company LLC's Application for 2012 Energy Efficiency Cost Recovery Factor* – August 9, 2011.

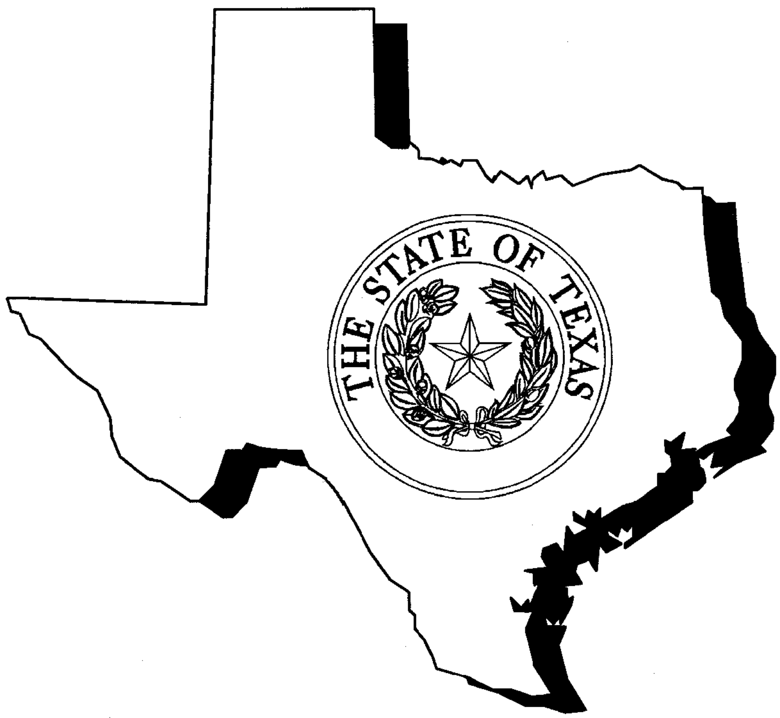
Docket No. 39366 – *Application of Entergy Texas, Inc. for Authority to Redetermine Rates for the Energy Efficiency Cost Recovery Factor Tariff and Request to Establish a Revised Energy Efficiency Goal and Cost Caps* – July 26, 2011.

Docket No. 39363 – *Application of CenterPoint Energy Houston Electric, LLC for Approval of an Adjustment to its Energy Efficiency Cost Recovery Factor* – July 22, 2011.

WORKPAPERS

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

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



CROSS-REBUTTAL TESTIMONY OF

WILLIAM B. ABBOTT

RATE REGULATION DIVISION

PUBLIC UTILITY COMMISSION OF TEXAS

JULY 21, 2017

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I. PROFESSIONAL QUALIFICATIONS

Q. Please state your name and business address.

A. William B. Abbott, 1701 N. Congress Avenue, Austin, TX 78711-3326.

Q. By whom are you employed and in what capacity?

A. I am employed by the Public Utility Commission of Texas ("PUC" or "Commission") as the Director of the Tariff and Rate Analysis Section of the Rate Regulation Division.

Q. What are your principal responsibilities at the Commission?

A. In addition to the supervision and management of the Tariff and Rate Analysis Section, my principal area of responsibility involves performing analyses of issues such as utility cost allocation, rate design, and tariff filings. My specific responsibilities include: analyzing cost allocation studies as well as revenue distribution and rate design issues for regulated electric utilities; analyzing policy issues associated with the regulation of the electric industry; reviewing tariffs of regulated utilities to determine compliance with Commission requirements; preparing and presenting testimony as an expert witness on rate and related issues in docketed proceedings before the Commission and the State Office of Administrative Hearings ("SOAH"); and, working on or leading teams in contested cases, rulemaking projects, reports, and research concerning rates, pricing, and other Commission-related issues.

Q. Please state your educational background and professional experience.

A. I have provided a summary of my educational background and professional regulatory experience in Attachment WBA-1 to my direct testimony in this proceeding.

Q. Have you previously testified before the Commission or SOAH?

A. Yes. A listing of my previously filed written testimony is also included in Attachment WBA-1 of my direct testimony in this proceeding.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the purpose of your cross-rebuttal testimony in this case, P.U.C. Docket No. 46831 and SOAH Docket No. 473-17-2686, *Application of El Paso Electric Company to Change Rates?*

A. My cross-rebuttal testimony regarding the application of El Paso Electric Company ("EPE" or "Company") to change base rates will primarily address arguments raised by various intervenors regarding EPE's distributed generation ("DG") proposal, including EPE's request to establish a new Residential DG Service rate class for residential customers with DG as well as EPE's proposed rate design for this class.[1] As the testimony of these intervenors regarding EPE's DG proposal primarily favors the interests of the solar equipment and sales industry as well as customers with DG, I will refer to this group of intervenors as "Solar Intervenors."

My cross-rebuttal testimony will address a portion of each of the following issues from the Commission's Preliminary Order (as numbered therein):

> 38. What are the just and reasonable rates calculated in accordance with PURA and Commission rules? Do the rates comport with the requirements in PURA § 36.003?

[1] Testimony opposing EPE's request was filed by several intervenors, including the Direct Testimony of: Clarence L. Johnson on Behalf of The City of El Paso ("Clarence Direct"), Diane Munns on Behalf of Eco El Paso ("Munns Direct"), Kevin Lucas on Behalf of The Solar Energy Industries Association (SEIA) ("Lucas Direct"), Justin R. Barnes on Behalf of Energy Freedom Coalition of America (EFCA) ("Barnes Direct"), David Nemir on Behalf of Vincent Perez ("Nemir Direct"), and William Perea Marcus on Behalf of the Office of Public Utility Counsel (OPUC) ("Marcus Direct").

39. What are the appropriate rate classes for which rates should be determined?

46. Are EPE's proposed rate and tariff changes applicable to distributed-generation customers just and reasonable and not unreasonably preferential, prejudicial, or discriminatory?

Other Staff witnesses may also address aspects of the above issues.

Q. What items did you review to arrive at your recommendations?

A. In preparing my cross-rebuttal testimony, I reviewed portions of EPE's application, certain discovery responses, and the direct testimonies of several intervenors. I also reviewed portions of a Massachusetts Institute of Technology study ("MIT Study") relevant to solar DG,[2] and the more recent NARUC Manual on Distributed Energy Resources Rate Design and Compensation ("NARUC DER Manual").[3]

III. SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. Contrary to the claims of the Solar Intervenors, DG customers have substantially different electric usage characteristics compared to other customers with regard to the relationship between the costs they impose upon the system and their net-metered kilowatt-hour (kWh) usage. The status-quo residential classification and rate design, involving a two-part volumetric rate design (per-kWh) in combination with net energy metering ("NEM"), results in a misalignment between costs and rate recovery for NEM DG customers, and inequitably results in these customers avoiding significant capacity costs that they cause,

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[2] *The Future of Solar Energy, an Interdisciplinary MIT Study* (2015). Excerpts attached as Attachment WBA-CR-1. Full report available at https://mitei.mit.edu/futureofsolar.

[3] *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Commissioners (2016).

to the ultimate detriment of other ratepayers. The unreasonable shifting of costs inherent in the status-quo is unsustainable as it will grow in magnitude over time as more customers install DG with NEM. Delay in adequately addressing the situation is likely to increase the need for, and frequency of, rate case proceedings for EPE, and thus the magnitude of rate case expenses to be collected from EPE's customers. Delay is also likely to increase the future customer impacts, and hence the difficulty, of resolving the issue in the future. Compared to the status-quo, EPE's proposal better aligns rates and costs, is more consistent with cost-causation, and is fairer and more equitable. EPE's proposal is not unreasonably discriminatory or prejudicial towards DG customers, and is consistent with decades of established Commission ratemaking treatment for all but the smallest non-residential customers. In light of this, the Commission should reject the recommendations made by the Solar Intervenors, and approve EPE's DG proposal regarding the establishment of a separate Residential DG rate class that includes a three-part rate design with a demand charge, as well as mandatory demand charges for non-residential DG customers.

Proposals to "grandfather" existing DG customers should be rejected; however, if the Commission determines that grandfathering is warranted, I recommend that:

1. It would be reasonable for the Commission to establish that grandfathering only be applied to customers who had submitted a DG interconnection agreement with EPE as of the date of notice in Docket No. 44941 (October 1, 2015); and
2. Any grandfathering be limited to a period of five to ten years.

Proposals to eliminate EPE's demand ratchets conflict with well-established Commission precedent, and should be rejected.

Recommendations to set DG class rates below cost conflict with PURA and should be rejected.

Q. What are your general responses to the claims of the Solar Intervenors?

A. Regarding claims that EPE's proposal is unreasonably discriminatory because DG customers are not substantially different from non-DG customers:

The Solar Intervenors' claim on this point is wrong, and the argument is logically inconsistent. While by some metrics DG and non-DG customers may be similar, there is a clear difference in the relationship between customer load and NEM usage between the two groups. There is also a clear difference in the relationship between the class demands used to allocate costs and NEM usage. Furthermore, even if it were the case that there was no substantive difference between DG and non-DG customers, then EPE's proposal would have no impact on the average DG customer bill (compared to the status-quo), and would result in lower electric bills for a large proportion of the DG customers.

Regarding claims that EPE's proposal is unreasonably discriminatory and prejudicial because EPE is not proposing similar treatment for groups of customers that adopt energy efficiency ("EE") measures or those with different air conditioning technologies:

The Solar Intervenors have not provided evidence that the usage or load differences that these groups may exhibit leads to a misalignment between costs and rate recovery anywhere near the magnitude of the misalignment that exists for the DG customers. Furthermore, to the degree that any such misalignment may exist for these groups, EPE's proposed rate design is a partial step towards addressing such issues. The Solar Intervenors have also failed to show that any of these other customer groups are being meaningfully subsidized by other customers under the status-quo.

Regarding claims that EPE's proposed demand charges are inconsistent with cost-causation and accepted ratemaking principles:
This argument is incorrect, and also demonstrates that the Solar Intervenors making these claims have little understanding of Commission ratemaking practice. If accepted, the Solar Intervenors' claims would upend decades of Commission precedent, and conflict with the ratemaking treatments reflected in every currently existing Commission-approved retail tariff.

Regarding claims that residential customers cannot understand or respond to demand charges:
Understanding the basic differences between demand and energy is well within the grasp of most customers. Furthermore, there is a fundamental "chicken-or-the-egg" issue here, in that, to the degree that residential customers do not understand demand charges that is largely because they have no incentive to understand them under the status-quo, but customers will have no incentive to understand demand charges unless they are subject to demand charges. EPE's alternative proposal to gradually phase in the demand charge reasonably addresses this concern.

Regarding the claims that DG provides benefits that justify the status-quo:

The Solar Intervenors fundamentally misunderstand how rates are established by the Commission. Most of the alleged benefits claimed are not relevant to the base-rate setting process, and do not justify setting rates for non-DG customers above cost in order to subsidize customers with DG. Those alleged benefits that are relevant to the base-rate setting process are appropriately accounted for under EPE's proposal. Furthermore, the Solar Intervenors ignore the fact that DG, especially as it become more widely deployed, can lead to increased utility costs.

IV. GENERAL POLICY CONCERNS

<u>Concentrated Benefits and Diffuse Costs</u>

Q. How would you characterize the general policy issue surrounding EPE's DG proposal and the Solar Intervenors' positions?

A. EPE's proposal represents a solution to a problem that can be accurately characterized as one of "concentrated benefits and diffuse costs." To the degree that the status-quo customer classification and NEM rate design benefits DG customers at the expense of other ratepayers, the benefits of the status-quo are concentrated in that they accrue primarily to DG customers and DG providers. The Solar Intervenor's recommendation to continue the status-quo would diffuse the costs of subsidizing DG across a much larger population of customers compared to the beneficiaries.

Q. What is the fundamental policy concern associated with such a recommendation?

A. Policies or projects that involve concentrated benefits and diffuse costs are highly susceptible to producing outcomes that are harmful to social welfare and contrary to the public interest. The concentration of benefits among a small group gives the members of that group a strong private incentive to advocate for such a policy or project, as each member can expect a relatively large share of the benefits. The diffusion of costs across a larger group results in significantly weaker private incentives for the members of the larger group to oppose the policy or project, as only a relatively small portion of the costs would fall upon any individual member. The significant asymmetry involved in such a situation makes it ripe for an outcome where the diffuse costs are greater than the concentrated benefits – and the public interest is therefore harmed by the adoption of a policy or project with costs greater than the benefits.

Q. Can you provide a simplified hypothetical example?

A. Yes. Consider a policy or project that would solely benefit a small group of 10,000 people, which group lies within a state with a population of 10,000,000 people. The group values the benefit at $100,000 while the cost of the policy or project is $1,000,000. On a cost-benefit basis, the policy would be a waste of resources, as the costs significantly outweigh the benefits. If the group were required to fund the policy on their own, the policy would likely not be undertaken, as each person in the group would stand to gain $10 of benefit while paying $100 in costs. If the group is able to "uplift" or "socialize" the costs of the policy across the entire state, the resulting cost per person would be 10 cents. Members of the group would then have a strong incentive to organize and advocate for the policy, as they each stand to gain benefits equal to $10 while only paying $0.10 – a benefit-to-cost ratio of 100 to 1. Citizens of the state outside of the group would be highly unlikely to undertake organized opposition to the project, as the individual private costs of organizing and opposing the policy are likely to exceed the $0.10 cost of the policy they would be subject to if the policy were implemented. By "uplifting" or "socializing" the cost of the policy, the problem of concentrated benefits and diffuse costs is introduced, and the likelihood increases that there will be an outcome that is not in the broader public interest.

Under the situation where the hypothetical policy had a favorable overall benefit-to-cost ratio, then the group should have been willing to undertake the actions without uplifting or socializing the costs. Therefore failing to uplift or socialize the costs would not have stood in the way of an outcome that was on net beneficial – it would only discourage policies or projects that were not beneficial on net.

Q. How can the problem of concentrated benefits and diffuse costs be mitigated or avoided?

A. The problem can be avoided or mitigated by not allowing for costs to be uplifted or socialized where such treatment is not required. In a situation where case-by-case judgement is necessary, the problem can be mitigated by requiring that a very high standard be met before allowing any costs to be uplifted or socialized. In this case, rejecting the Solar Intervenors' recommendations would mitigate the problem. Requiring that the DG customers properly pay for the costs to serve them properly aligns the incentives – if the customers do value the benefits to DG more than the costs, then the customers would come out ahead and should be willing to pay those costs. Uplifting the costs of providing utility service to DG customers significantly increases the likelihood that costs will be incurred that are less than the benefits that accrue.

General Net Energy Metering Policy

Q. Has the Commission addressed the issue of NEM outside of EPE's service territory?

A. Yes. In Project No. 34890 ("NEM Rulemaking"), the Commission adopted a rule to eliminate NEM across the state and established a six-month deadline to implement new metering.[4]

Q. How is the Commission's decision in the NEM Rulemaking relevant in this case?

A. The Commission's decision in the NEM Rulemaking indicates that NEM in combination with DG presents important issues that need to be addressed. EPE's DG proposal is a just and reasonable way to address cost-shifting issues associated with DG NEM while still retaining NEM for these customers.

V. NET METERING IN EL PASO ELECTRIC'S SERVICE TERRITORY

Q. Is EPE subject to distinctive metering requirements, compared to utilities elsewhere in Texas?

A. Yes. 16 Tex. Admin. Code ("TAC") § 25.213(c) implements Public Utility Regulatory Act ("PURA") § 39.554(e) and requires that EPE provide DG customers with the option to take service using a meter that runs forwards and backwards.[5] 16 TAC § 25.213(c)(4) implements PURA § 39.554(f) and requires that an EPE DG customer's energy production be applied to offset that customer's energy consumption for that billing period. For the transmission and distribution utilities ("TDU") in the Electric Reliability Council of Texas

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[4] *Rulemaking Proceeding Relating to Net Metering and Interconnection of Distributed Generation*, Project No. 34890, Order Adopting New §25.217 and Amendment to §25.242 as Approved at the December 18, 2008, Open Meeting (Dec. 18, 2008).

[5] It is my understanding that, per PURA § 39.551, PURA Chapter 39, Subchapter L, which contains § 39.554, applies only to EPE.

("ERCOT") region, DG customers are not allowed a net metering option, but are required to have either two separate meters to measure consumption and generator output separately, or a single meter capable of separately measuring consumption and output; ERCOT TDUs are likewise not required to offset a DG customer's energy consumption with energy production.[6]

Q. Does net metering present any unusual complications for just and reasonable utility cost recovery?

A. Yes. Distributed energy production amounts to customer-supplied *wholesale* energy. However, *retail* electric energy rates for residential customers typically, and for EPE, include significant costs other than wholesale energy. A net-metered DG customer's monthly usage is registered as their gross usage less their gross production, potentially resulting in three different net usage situations (net consumption, net zero, or net production) demonstrated in the hypothetical scenarios below:

Table WBA-CR-1

	Hypothetical Net Usage Scenario		
	Customer 1 (Net Consumer)	Customer 2 (Net Zero)	Customer 3 (Net Producer)
Gross Usage	1500 kWh	1000 kWh	1000 kWh
Gross Production	1000 kWh	1000 kWh	1100 kWh
Net Usage	**500 kWh**	**0 kWh**	**-100 kWh**

Due to net metering, all three customers receive 1000 kWh credit offset at the *retail* level of rates, with Customer 3 receiving an additional 100 kWh credit at *wholesale* energy level of rates, for their net monthly production. Under the status-quo single class, two-part rate

[6] 16 TAC § 25.213(b), implementing PURA §39.916(f).

design, this situation ultimately results in the inequitable situation wherein NEM DG customers shift non-wholesale energy costs onto other customers. The fundamental complication and inequity that arises here is present under net metering where retail kWh rates include costs other than wholesale energy costs. The MIT Study also addresses this:

> Net metering compensates these [distributed] generators at the retail price for electricity they supply to the grid, not at the wholesale price received by grid-scale generators… When a residential customer installs a rooftop PV [Photovoltaic] generator, that customer's distribution charge payments are reduced. But there is no corresponding reduction in the distribution utility's distribution system costs… the subsidy is the corresponding reduction in the utility's revenues, which may be made up by increasing the retail price paid by all customers.[7]

Given the net-metering requirements to which it is subject, EPE's DG proposal is a reasonable means of reducing the inequity and producing more just and reasonable rates for all of EPE's customers.

VI. EPE'S DISTRIBUTED GENERATION PROPOSAL

Proposal

Q. What is EPE's proposal regarding residential distributed generation customers?

A. There are two main components to EPE's request. First, EPE is proposing to establish a new rate class, Residential DG Service, populated by those residential customers that generate a portion of their own energy requirements, primarily solar DG customers. Second, EPE is proposing a "three-part" rate design including a demand charge for the Residential DG rate class, in contrast to the status-quo "two-part" volumetric rate design for residential customers. As it does for any other class, EPE's application also allocates

[7] *MIT Study* at 219, see Attachment WBA-CR-1, page 10.

costs in order to establish a Residential DG class revenue requirement, and EPE calculates rates within the Residential DG class to recover the class revenue requirement. Each of these components of EPE's request are reasonable and should be approved. If one of the components is rejected by the Commission, the other component could, and should, be adopted.

Q. What is EPE's proposal regarding Small General Service distributed generation customers?

A. For these customers, EPE is proposing only one of the above treatments. EPE is not proposing a separate class, but rather that these customers be subject to a mandatory three-part rate design that includes a demand charge. While I will primarily address the Residential DG proposal, almost all of my testimony on that proposal is also applicable to the Small General Service ("SGS") DG proposal.

<u>Relevant Terms</u>

Q. What is a "two-part" rate design?

A. In the context of this case, a two-part rate design consists of a rate structure for a class that is composed of two overall rates: a "customer charge" and an "energy charge." A customer charge is a fixed dollar amount that is charged on each monthly bill regardless of customer usage or load.[8] An energy charge is a rate per kilowatt-hour ("kWh"), with the monthly amount of the charge being the product of the per-kWh rate times the kWh consumption

[8] A customer charge can also be called a "fixed charge," a "service connection charge," or a "minimum monthly charge." The customer charge components may be disaggregated into multiple fixed charges in a rate structure, such as both a fixed customer charge and a fixed metering charge. However, for the purposes of my testimony, I will consider all fixed monthly charges to be subsumed into a single customer charge.

for the billing period.[9] Such a two-part rate design is the status-quo rate design for most residential customers and for most of the smallest non-residential customers in Texas.[10]

Q. What is a "three-part" rate design?

A. In the context of this case, a three-part rate design consists of a rate structure that is composed of a customer charge, an energy charge, and a "demand charge." A demand charge is a rate per kilowatt ("kW"), with the monthly amount of the charge being the product of the per-kW rate times some specified measure of kW demand over the billing period.[11] Three-part rate design is the status-quo rate design for most mid-sized or larger non-residential customers in Texas.[12]

Q. Can you provide an analogy to help illustrate the difference between energy and demand?

A. Yes. Energy is a "volumetric" measure, similar to gallons of water. Demand is a measure of how fast energy is being delivered, similar to gallons-per-minute. A 60-foot long, ½-inch diameter garden hose might be capable of delivering 10 gallons-per-minute, whereas a 60-foot long, 2-inch diameter galvanized steel pipe might be capable of delivering 380

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[9] An energy charge can also be called a "volumetric," a "consumption," or a "usage" rate. As with the customer charge, there may be multiple energy charge components that comprise the overall per-kWh rate for a class; for simplicity, in my testimony I will generally consider all energy charges for a class to be subsumed into a single energy charge.

[10] As can be seen in a recent snapshot of Commission-approved rates for the utilities within ERCOT, which can be seen in my Attachment WBA-CR-2, or online at:
http://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf

[11] The existence of a demand charge is typically the primary distinguishing feature of three-part rate design when compared to the typical two-part rate design, and it is not unusual for discussions related to the imposition of three-part rate design in such a situation to characterize such a rate design change as one involving the imposition of demand charges. Note, there can be multiple types of demand charges based upon different measures of demand, resulting in "four-part" or "five-part" rate designs, but for simplicity I will refer to all such rate designs as "three-part" despite the fact that there can be multiple customer, demand, and energy charges, which technically result in more than three parts to the rate design.

[12] As can also be seen in attachment WBA-CR-2 or online at:
http://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf

gallons-per minute. To deliver 380 units of volume, it would take the garden hose 38 minutes, while the pipe could deliver it in one minute. In this example, the pipe has 38 times the "capacity" as the hose, and unsurprisingly the pipe is expected to cost significantly more than the hose.

As another example, if a 100-watt (or 0.1 kW) lightbulb were to be switched on for 10 hours, it would consume 1 kWh of energy (0.1 kW * 10 hours = 1 kWh). A 50-watt (0.05 kW) lightbulb, imposing half the demand of the 100-watt bulb, would need to remain on for 20 hours to consume 1 kWh of energy (0.05 kW * 20 hours = 1 kWh).

Q. Are there different measures of demand that are relevant to the rate-setting process?

A. Yes, it is often the case that some of the discussion of "peak" demand or load can be less than precise. In order to facilitate clear evaluation of the issues, I would clarify some relevant aspects of "demand."

- <u>System Peak Demand</u> – refers to the maximum demand (or load) placed by customers as a whole upon the utility system during a specified time window. In warm weather climate zones such as in Texas, an electric utility typically hits its annual system peak demand on a hot summer weekday afternoon, say around 4 pm on a weekday in August, when most businesses are operational and yet many residential customer air conditioning compressors are operating at the same time. System peak demand drives the need for much of the investment in generation and transmission capacity – a utility must have enough generation resources available to supply the maximum system peak demand, and there must be sufficient transmission capacity available to deliver that power from the generation resources to the load on the system. Almost all of the generation and transmission costs considered in a base rate proceeding such as this one are incurred to serve system peak demand.

- Coincident Peak Demand (“CP”) – refers to the demand placed by a customer, or class of customers, on the system at the time of the system peak. So, for example, the residential home with the air conditioning on and teenagers playing loud music and video games while they run the washer and dryer might impose relatively significant demand on the system at 4 pm on a hot weekday in August, and therefore have significant coincident peak demand. However a concert venue that imposes a very high load on the system at 11 pm on a Friday night may be entirely shut down and impose miniscule load at 4 pm in the afternoon, and therefore have almost zero coincident peak demand. Cost causation, and Commission precedent, would dictate that significant portions of the generation and transmission capacity costs should be allocated based on some measure of coincident peak demand.
- Non-Coincident Peak Demand (“NCP”) – refers to the maximum demand placed by a customer, or a class of customers on the system, regardless of when that maximum demand occurs. The NCP for a class of customers as a whole can also be referred to by other terms, such as Class NCP, Maximum Diversified Demand (“MDD”), or Maximum Class Demand (“MCD”). Note that the sum of all the individual customer NCP demand for the members of a class (sometimes called “sum of customer NCP”, or simply “NCP”) will generally be different from, and greater than, the MDD for a class, because not all customers in the class will be imposing their individual maximum demand upon the system at the time of the

class maximum demand.[13] Measures of NCP demand are the relevant drivers for distribution capacity investments, because distribution serves more localized loads that may have significant peak demands at times other than the system peak. For example, a substation or distribution line feeding a nighttime entertainment district may have relatively low demand at the system peak at 4 pm, when there is little activity, yet may be subject to high demand later in the evening on a weekend.

VII. SOLAR INTERVENOR TESTIMONY

Q. What are the positions of the Solar Intervenors?

A. The Solar Intervenors object to EPE's DG proposal on several grounds. In general, they make the following arguments:

1. Residential DG customers are not distinctly different from other residential customers and thus should not be separated into their own class.
2. A three-part rate design with a NCP demand charge conflicts with cost-causation.
3. Residential customer cannot understand demand charges or respond to them.
4. EPE's proposal is inconsistent with good ratemaking practice.
5. The NARUC DER Manual opposes EPE's proposal.
6. There are benefits provided by solar DG that justify the status-quo two-part volumetric rate design.
7. EPE has encouraged DG by offering incentives.

[13] Note that confusion sometimes occurs because parties can use "NCP" to refer to either "Class NCP" or some variant of "sum of customer NCP."

VIII. RESIDENTIAL DG CUSTOMERS AS A SEPARATE CLASS

DG Customers Have Substantially Different Characteristics

Q. What do the Solar Intervenors claim regarding the difference between DG and non-DG customers?

A. Several of the Solar Intervenors maintain that DG customers do not have substantially different electric usage characteristics than non-DG customers. SEIA witness Kevin Lucas devotes many pages to analyzing some electric usage characteristics, and claims that DG customers are similar to non-DG customers for these characteristics.[14] OPUC witness William Marcus also maintains that the electric usage characteristics are similar.[15] City of El Paso witness Clarence Johnson notes that the existing group of residential customers with distributed generation has similar load characteristics to high usage residential customers.[16]

Q. Do residential DG customers have substantially different electric usage characteristics compared to non-DG residential customers?

A. Yes. While the Solar Intervenors purport to show that *some* of the electric usage characteristics are similar between DG and non-DG customers, they fail to address the core relevant difference: that <u>the relationship between the load (demand) a customer imposes on the system and the energy the customer is billed for is substantially different between DG and non-DG customers.</u>

[14] Lucas Direct at 75-82.

[15] Marcus Direct at 37.

[16] Johnson Direct at 41.

Q. How does the relationship between demand and net energy usage compare between DG and non-DG customers?

A. Logic would dictate that where NEM exists, the load factor (or kWh per kW) would be much lower for DG customers, because their billed kWh is relatively low due to "rollback" NEM, which significantly affects billed kWh but does not proportionally affect most measures of demand. The empirical evidence supports this. In response to a discovery request, EPE provided monthly demand and net kWh values for three years for all residential DG and non-DG customers for which it had data.[17] Using this information, I removed the annual data for customers where there was incomplete annual data, and I calculated the average monthly net kWh and average monthly kW demand for the two groups of customers:

Table WBA-CR-2		
	DG	Non-DG
Average Monthly kW	5.54	5.30
Average Monthly net kWh	362	944
Ratio of kWh / kW	65.3	178

As the table shows, DG customers impose about 5% more demand compared to non-DG customers on average (5.54 vs 5.30).[18] The key issue though is that the DG customers have

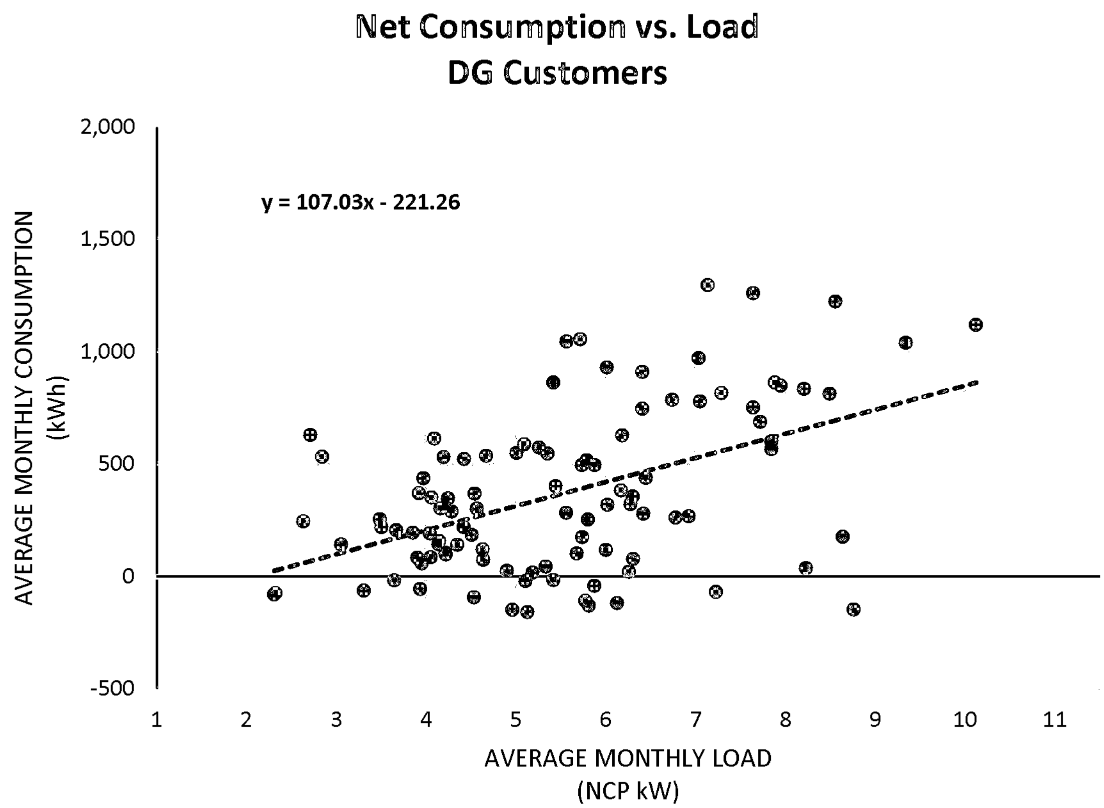
[17] El Paso Electric Company's Response to Commission Staff's Eleventh Request for Information, Question Nos. Staff 11-7 and Staff 11-8.

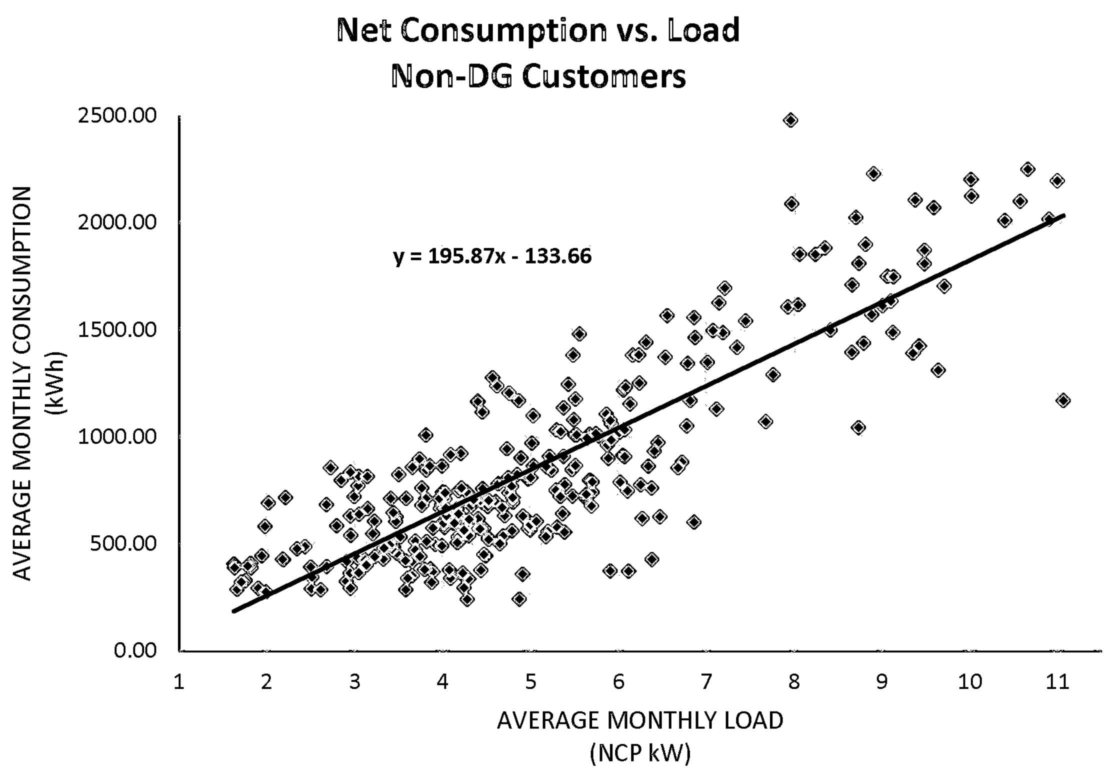
[18] This is consistent with Mr. Johnson's and EPE's claims that DG customers tend to be larger customers than average residential customers.

much lower levels of net kWh, despite imposing more demand on the system. As the ratio of kWh / kW shows, on average, for each kW of demand that DG customers are imposing, they are only being billed for 37% of the kWh as non-DG customers (65.3/178). The relationship between a customer's demand and their consumption is vastly different for DG customers compared to non-DG customers - the DG customers have much lower load factors.

This difference not only manifests itself when looking at the average for each group, but also when comparing the average for each customer. The graphs below show the kWh to kW relationships by customer for each group (with outliers removed).[19]

[19] The data for these graphs excludes the top and bottom 10% of customers by demand and energy to remove outliers. This treatment is more favorable to the Solar Intervenors' arguments than including the outliers.


Net Consumption vs. Load
DG Customers
y = 107.03x - 221.26
2,000
1,500
1,000
500
0
-500
1
2
3
4
5
6
7
8
9
10
11
AVERAGE MONTHLY CONSUMPTION
(kWh)
AVERAGE MONTHLY LOAD
(NCP kW)


Net Consumption vs. Load
Non-DG Customers
y = 195.87x - 133.66
2500.00
2000.00
1500.00
1000.00
500.00
0.00
1
2
3
4
5
6
7
8
9
10
11
AVERAGE MONTHLY CONSUMPTION
(kWh)
AVERAGE MONTHLY LOAD
(NCP kW)

Comparing the two groups, even after conservatively removing outlying data points, we can see on the lower graph that for non-DG customers there is a tighter relationship between customer load and a customer's kWh consumption, and also that each kW of demand corresponds to approximately **196 kWh** of monthly usage on average.[20] DG customers, on the other hand, are much more scattered, with some high load customers showing negative kWh consumption on average. Furthermore, the average relationship between kW and kWh is much lower for these DG customers, at **107 kWh** per kW.

This difference is even clearer when both groups are graphed on a single graph, as can be seen in Attachment WBA-CR-3. As this attachment shows, the vast majority of DG customer are below the average kWh to kW relationship displayed by non-DG customers (as represented by the solid line). Only a handful of DG customers have kWh / kW values above the average non-DG value. Similarly, only four of the non-DG customer data points fall below the average ratio for DG customers (show by the dashed line). These two customer groups clearly show differences between customer demand (kW) and net usage (kWh).

Q. Why is this relationship between customer demand and customer usage the core issue when comparing DG to non-DG customers?

A. A customer's electric bill includes two distinct categories of charges: base rate charges and fuel charges. The rates at issue in this proceeding affect the base rate portion of customers' bills. Base rate costs are predominantly capacity-related costs – the costs to build and maintain the generation units, the transmission lines, the distribution substations,

[20] As discussed later in my testimony, this is consistent with the Commission's past determinations that for non-DG customers, and absent the metering capable of NCP billing, an energy charge is a "reasonable proxy' for cost causation. The same conditions do not hold for DG customers, therefore kWh billing is not a reasonable proxy for cost causation under NEM.

transformers and distribution lines. These costs are primarily driven by the demand that customers place on the system, measured in kW, and not by the energy that customers use, measured in kWh. SEIA witness Lucas acknowledges this in his direct testimony: "the low load factor means that, relative to the class's energy use, its demand is higher than average. But it is the high demand itself, not the low load factor, that incurs costs."[21] Because DG customers have comparable or higher demand, but substantially lower net energy usage, the normal relationship between load and net energy usage for residential customers does not hold for DG customers. As it is demand that incurs costs, under the status-quo, DG customers pay much less than non-DG customers for imposing the same or greater costs. Since the overall level of rates is set at cost, this means that non-DG customers end up paying for the costs to serve DG customers. Including both types of customers in a single rate class under the status-quo rate design with NEM leads to the shifting of costs between the DG and non-DG customers.

Q. How has the Commission allocated base rate costs in recent proceedings?

A. The table below shows the Commission-approved allocations:

Table WBA-CR-3
Commission-Adopted Class Allocation Treatments

Function	SPS Docket No. 43695 Commission-adopted class cost allocation basis	SWEPCO Docket No. 40443 Commission-adopted class cost allocation basis	ETI Docket No. 39896 Commission-adopted cost allocation basis
Production capacity costs	Production AED 4CP demand	Production AED 4CP demand	Production AED 4CP demand
Production energy costs	Energy at source	Energy at source	Energy at source
Transmission capacity costs	Transmission AED 4CP demand	Transmission AED 4CP demand	Transmission AED 4CP demand

[21] Lucas Direct at 81.

Distribution substations	Class NCP demand	Class NCP demand	Class NCP demand
Distribution primary	Class NCP demand	Class NCP demand	Class NCP demand
Distribution secondary	Class NCP demand	Class NCP demand	50% Class NCP,[22] 50% Customer NCPs
Distribution line transformers	Class NCP demand	Class NCP demand	50% Class NCP, 50% Customer NCPs
Distribution service laterals	Service lateral costs	Weighted customers	Weighted customers
Distribution meters	Meter costs	Weighted customers	Weighted customers

As the table shows, the vast majority of base-rate costs are capacity related (demand), and some distribution costs are customer-related, but very little is energy-related. Note that the Average and Excess 4-Coincident Peak Demand ("AED 4CP") allocator that is used to allocate production and transmission capacity costs is a hybrid allocator that includes both peak demand and average hourly demand, which is based on non-coincident peak demands in every hour.

Q. How does the status-quo customer classification lead to the shifting of costs between DG and non-DG customers?

A. In the cost allocation phase of the ratemaking process, costs are allocated to the classes based upon cost causation principles. As discussed above, a significant portion of base rate costs are capacity related, and are consistently allocated to the classes by some measure of demand. After the revenue requirement is determined for a class, the rates are calculated by dividing by the relevant billing determinants. For residential customers, the status-quo involves most costs recovered via kWh billing determinants. Because net-metered DG customers have meters that roll backwards, the total class kWh billing units are reduced,

[22] ETI uses the term "maximum diversified demand" or "MDD" to refer to class non-coincident peak demand.

which leads to higher per-kWh rates for all customers in the class. In the hypothetical examples provided in Table WBA-CR-1 above, Customer 2 and Customer 3 pay nothing via the per-kWh energy charges, even though the demand they place on the system when they aren't producing power is causing costs to be allocated to the residential class. Those costs are recovered from other customers in the class via the higher-than-otherwise kWh rates. Under NEM, the non-DG customers end up paying higher rates to bear the costs unreasonably shifted away from the DG customers. This result is inconsistent with cost causation, and is unreasonably discriminatory and prejudicial towards non-DG customers in that it penalizes customers that do not have DG systems through relatively above-cost charges. The MIT Study also arrives at this conclusion (emphasis in original):

> In an efficient and equitable distribution system, each customer would pay a share of distribution network costs that reflected his or her responsibility for causing those costs. Instead, most U.S. utilities bundle distribution network costs, electricity costs, and other costs and then charge a uniform per-kWh rate that just covers all these costs. **When this rate structure is combined with net metering, which compensates residential PV [Photovoltaic] generators at the retail rate for the electricity they generate, the result is a subsidy to residential and other distributed solar generators that is paid by other customers on the network.** This cost shifting has already produced political conflicts in some cities and states – conflicts that can be expected to intensify as residential solar penetration increases[23]

<u>EPE's DG Proposal is Not Unreasonably Discriminatory or Prejudicial</u>

Q. Is the establishment of a separate class for DG customers unreasonably discriminatory or prejudicial?

A. No. As discussed above, there are significant differences between the relationship between the cost-causative elements of electric service and the net energy billing units for DG

[23] *MIT Study* at xviii, see Attachment WBA-CR-1, page 7.

customers compared to non-DG customers. Furthermore, establishment of DG as a separate class cannot be, in itself, unreasonably discriminatory and prejudicial to the DG customers – one must look into the details as to how the rates are established in order to determine if any unreasonable preference or penalty is being imposed. As an extreme example to illustrate this point, if DG was established as a separate class and rates were established such that DG customers paid $0.01 a year for unlimited use of the system, while residential customers paid prevailing rates, there is no question that such an outcome could not reasonably be viewed as prejudicial to DG customers. The analysis must therefore rest upon how the costs are allocated and the revenue requirements are set for the Residential and the Residential DG classes. If the same cost allocation and revenue distribution treatments are applied to the separate DG class as are applied to the separate Residential class, then it cannot credibly be claimed that establishment of the DG class is unreasonably discriminatory or prejudicial to DG customers.

Q. Is EPE proposing the same cost allocation treatment for the Residential DG class as it is for the other classes?

A. Yes. The Residential DG class is treated like the other classes in the cost allocation process. It is important to note that if one accepts the claims of the Solar Intervenors that DG customers have similar electric usage characteristics, then treating them as a separate class would not harm them – the cost-causative elements of their electric usage and the billing units would simply shift from the Residential class to the DG class.

SEIA witness Lucas acknowledges that EPE's cost allocation treats DG customers in a non-discriminatory manner, but expresses concern at the results:

> While it is correct that EPE is allocating costs using a similar methodology for both Residential and Residential DG customers, the relative proportion

> of customer, demand, and energy allocators varies substantially between the two proposed rate classes.[24]

Regarding the difference in the share of customer costs, PURA § 39.554(h) appears to mandate this treatment. Regarding the demand piece, Mr. Lucas' testimony here conflicts with his statement prior that "the overall percentage of demand-related costs are similar between the two."[25] Regarding the energy piece, the "substantial" difference Mr. Lucas suggests is problematic (the fact that energy costs are a smaller portion of the costs for the class) is a result of the fact that DG customers generate much of their own energy, and therefore buy less from the Company.[26] This would also explain why customer and demand costs are a larger portion of DG customer costs. To the degree that the breakdown of functional costs for the DG class differs from the breakdown for residential customers, that is because DG customer have substantially different usage (lower net kWh) and they are required to pay for the higher metering costs associated with NEM.

Q. Is a larger percentage rate increase for the DG class compared to the Residential class unreasonably discriminatory or prejudicial?

A. No. Both EPE's and Staff's proposed Class Cost of Service Studies ("CCOSS") involve a greater percentage increase to the Residential DG class than to the Residential class. The percentage increase from present rates, however, is not the relevant metric in determining unreasonably discriminatory treatment. Rather, the relevant metric is distance from cost. If the present rates for the DG class are further below cost than the present rates for the Residential class, then it is reasonable and fair that the DG class be subject to a greater

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[24] Lucas Direct at 84 lines 17-19.

[25] *Id.* at 84 lines 7-8.

[26] *Id.* at Table 5. Note, I have not independently verified Mr. Lucas' calculations.

percentage increase, in order to move them closer to cost. That the class cost study shows DG customers are further below cost than the Residential customers is evidence of the significant cross-subsidies embedded in the status-quo rate design. Reducing the cross-subsidy and moving towards more equitable rates necessarily involves a greater increase to the DG customers. Rather than being unreasonably discriminatory or prejudicial itself, the different percentage increases for the two classes represents movement away from the unreasonably discriminatory status-quo that favors the DG customers and prejudices other ratepayers.

Furthermore, while I am not an attorney, and do not claim to be offering a legal opinion, my plain-language reading of PURA § 39.554(h) suggests that classes that include DG customers subject to NEM may not have rates set below cost.

Q. Does the Commission's decision in Docket No. 43695 support the rejection of EPE's DG proposal?

A. No. The Solar Intervenors mischaracterize the Commission's decision in this Southwestern Public Service ("SPS") base rate case.[27] On the contrary, the Commission's decision in that case actually supports EPE's proposal.

SEIA witness Lucas states that the Commission "rejected SPS's proposal and agreed that cost allocation and rate design for residential customers should not be based on the equipment installed at the residential customers' homes."[28] OPUC witness Marcus states

[27] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing (Feb. 23, 2016).

[28] Lucas Direct at 7.

that the Commission "recently affirmed that the residential class should be unified in discussing SPS's rate case in Docket No. 43695."[29]

It is true that in Docket No. 43695 the Commission did rule, based on the particular facts in that proceeding, that one component of distribution costs should be allocated to the Residential class as a whole, and not separately to the Residential and Residential Space Heating ("RSH") subclasses; however, this corresponded with SPS's unopposed proposal to close the RSH class to new customers, as a step towards combining the two rate classes into a single class in the future.[30] These facts to not occur here. Furthermore, only distribution costs were allocated to the Residential class as a whole, for other costs the subclasses were treated separately. Not only did the Commission approve treating Residential and RSH customers differently for the allocation of most cost categories, the Commission in fact approved a separate rate design with a lower per-kWh rate for RSH customers because of their higher load factors. The Commission found:

> The Commission agrees with SPS and the SOAH ALJs that it is appropriate to increase the winter discount for customers taking service under residential service with electric space heating rider; no party refuted SPS's evidence that this group of customers has a higher load factor in the winter months and therefore their winter kWh rate can be lower than the winter kWh rate for general residential customers. In fact, eliminating or reducing the difference in the winter energy charges between the general residential service group and the residential service with electric space heating group would move both away from cost-based rates.[31]
>
> 328. It is reasonable to adopt the following classes for purposes of cost allocation and revenue distribution in this case: Residential (including both Residential Service and Residential Service with Electric Space Heating, broken out separately);
>
> 345. Higher load factors in the winter months for Residential Service With Electric Space Heating customers would unreasonably result

[29] Marcus Direct at 36.

[30] Docket No. 43695, Order on Rehearing at Findings of Fact 277A - 277B (Feb. 23, 2016).

[31] *Id.* at 15.

in moving rates for the Residential Service and Residential Service with Electric Space Heating subclasses classes further from cost causation principles if the winter discount for Residential Service with Electric Space Heating customers is not increased.

346. SPS's proposed increase in the winter discount rate for Residential Service with Electric Space Heating customers is reasonable and comports with cost causation principles.[32]

Load factor is a measure of energy usage (kWh) to demand (kW). As discussed previously, residential customers without DG have higher load factors (more kWh per kW) than DG customers under NEM. In the SPS case, because of the higher load factors for RSH customers, the Commission determined that cost causation dictates that RSH customers should be subject to lower per-kWh rates than Residential subclass customers. This finding directly supports EPE's DG proposal in this proceeding.

Q. Is the fact that EPE is not proposing separate classes based on air-conditioner type or energy efficiency measures relevant to the DG proposal?

A. No. Despite this refrain from some of the Solar Intervenors, there is no evidence that a separate class for these customer groups is warranted.[33] While there is likely meaningful differences in electric service requirements for some of these groups, it does not therefore follow that there is a meaningful difference with respect to usage characteristics and cost recovery. Again, the key issue not simply differences in some measures of electricity usage, the issue for DG customers is the mismatch between costs imposed and cost recovery. While customers with refrigerated air-conditioning systems may impose more demands on the system than other customers, they also likely consume more energy – so there is no fundamental mismatch between the cost-causative elements of their usage and their billed kWh. Similarly, most energy efficiency measures, like LED lightbulbs,

[32] *Id.* at Findings of Fact 328, 345-346.

[33] See, for example, Lucas Direct at i, or Barnes Direct at 24.

proportionally reduce both demand and energy;[34] therefore there is no mismatch between the changes to the cost-causative demand and the changes to the net energy usage, as is the case for DG customers.

Q. Is it reasonable to establish a separate rate class for residential DG customers?

A. Yes. Base rate costs are predominantly capacity-related costs – the costs to build and maintain the generation units, the transmission lines, the distribution substations, transformers and distribution lines. These costs are primarily driven by the demand that customers place on the system, measured in kW, and not by the energy that customers use, measured in kWh. Because of the significant customer-owned generation and the net energy metering required of EPE, the normal relationship between load and energy usage for non-residential customers does not hold for DG customers. To include both types of customers in a single rate class would lead to the shifting of costs between the DG and non-DG customers.

IX. THREE-PART RATE DESIGN WITH A DEMAND CHARGE

<u>General Issues</u>

Q. Is a three-part rate design generally superior to a two-part rate design?

A. Yes. Capacity costs, be they generation, transmission, or distribution, are primarily driven by some measure of demand, be it coincident or non-coincident. Because it is demand that primarily causes those costs, in general a demand charge ($/kW) of some type best reflects cost causation when it comes to capacity costs. Energy usage-related costs, such as certain generation operations and maintenance ("O&M") costs or fuel costs, are primarily driven

[34] Assuming no change in how long the lights are left on, replacing a 100 watt lightbulb with a 10 watt lightbulb results in a 90% reduction to both demand and energy usage.

by energy consumption, and so for these types of costs an energy charge ($/kWh) best reflects cost causation. So, for an integrated utility such as EPE that provides generation capacity and energy services along with transmission and distribution capacity services, a rate structure that includes both demand charges and energy charges is generally superior to one that includes only energy charges.[35] The superiority of three-part rate design with demand charges is evinced by the fact that throughout Texas, the Commission-approved rate design for almost all but the smallest non-residential customers includes customer, demand, and energy charges. In fact, for the mid-sized and larger customers within the competitive ERCOT area, the Commission-approved rate design to recover transmission and distribution base rate costs do not include energy charges, and involve cost recovery almost entirely through demand charges.[36]

Q. Why is the status-quo rate design for most residential and small non-residential customers a two-part rate design?

A. While three-part rate design is generally superior in that it allows for a better alignment of charges with cost causation, it does come at the cost of requiring a more expensive meter to record demand in addition to energy usage. For larger customers, the inefficiencies caused by a two-part rate design would lead to some combination of significantly discouraging productive economic activity as well as significantly less efficient use of the grid and ultimately higher rates for everyone. Because large customers individually cause more costs to be incurred than individual small customers do, the benefits of the three-part rate structure in aligning costs with rates far exceed the incremental metering cost.

[35] As the customer charge is present in both types of rate design, I leave it absent from my discussion.

[36] For a recent snapshot of TDU rates, see http://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf. Note that "kVA" is a measure of demand very similar to kW. Included as Attachment WBA-CR-2.

Historically speaking, and absent DG, for residential customers and the smaller non-residential customers, the incremental cost of demand-capable meters hasn't been considered to be worth the benefit gained with three-part rates. This was due, in part, to the fact that load and usage patterns for these customers was generally fairly similar and much less variable across customers than, say, large commercial or industrial customers. It was also due to the fact that historically, there has been a reasonably close relationship between energy usage and demand placed upon the system for most small customers,[37] so in the absence of net-metered DG, embedding capacity costs into a per-kWh energy charge is at least somewhat reflective of cost causation, a reasonable proxy, even if it is inferior to three-part rates with a demand charge.

Q. Are these factors supporting two-part rates for smaller customers still as compelling as they have been in the past?

A. No. Modern developments have significantly reduced the advantages of, and increased the inefficiencies of, a two-part rate structure for customers. Metering technology has advanced, and the relative costs for demand metering have dropped, making demand-capable meters less burdensome and more prevalent for residential customers. The Commission has approved the deployment, throughout Texas, of advanced, or "smart," meters for residential customers capable of measuring demand and facilitating three-part rate designs. Furthermore, the Commission has approved base rate demand charges for residential customers in the TDU service territory of Sharyland Utilities, L.P. – McAllen

[37] See the graphs on page 23 and Attachment WBA-CR-3.

("Sharyland – McAllen").[38] Additionally, as home electronic devices proliferate, larger homes are built, and a variety of energy efficiency measures become adopted by some but not others, the regularity of the relationship between a residential customer's demand and their energy usage is potentially weaker than it was in the past.

Q. Does customer-sited distributed generation also support the case for a three-part rate design with a demand charge?

A. Yes. As discussed previously, NEM customers that generate a portion of their own energy will have a significantly different relationship between the costs they cause a utility to incur and the net kWh they consume. While a three-part rate design is in general superior to a two-part design for all customers, the additional variance in net usage caused by a DG installation strongly adds to the case for implementing three-part rates. The MIT Study also supports a move away from energy charges for net-metered DG customers (emphasis in original):

> In broad terms, the economically obvious solution is to move away from the prevalent design of distribution network charges that recover fixed distribution costs via volumetric (per-kWh) charges… the ideal approach would be to recover utilities' distribution costs through a system of charges that reflect each individual customer's contribution to those costs, not their kWh consumption…
> **By enabling those utility customers who install distributed solar generation to reduce their contribution to covering distribution costs, net metering provides an extra incentive to install distributed solar generation. Costs avoided by households that install distributed solar generation are shifted to utility shareholders and/or other customers. Recovering distribution costs through a system of network charges that is more reflective of cost causation and that avoids the current direct dependence on electricity consumption would remove the extra subsidy and prevent this cost shifting.**[39]

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[38] Most recently, *Application of Sharyland Utilities, L.P. to Increase its Unbundled Rates for Residential, Secondary, Primary, and Transmission Service Pursuant to Orders in Docket Nos. 32409, 35542, and 38442*, P.U.C. Docket No. 40332, approved May 31, 2012.

[39] *MIT Study* at 220, see Attachment WBA-CR-1, page 11.

EPE's proposed three-part rate with a demand charge is more reflective of cost causation and is a reasonable way to address DG-related net-metering issues.

Q. Do other emerging trends in technology support the implementation of a three-part rate design with demand charges for residential customers?

A. Yes. In-home networked load control systems and energy storage devices are emerging technologies that could provide significant cost savings when paired with a reasonably cost-based three-part rate design. Solar DG systems themselves could be better optimized to provide system and customer benefits with the implementation of on-system-peak demand charges that reflect peak-related transmission and generation capacity costs.[40] The status-quo two-part rate design significantly limits the ability of these technologies to provide customer and system benefits by virtually eliminating any incentive to apply the technologies to reduce a customer's (coincident or non-coincident) demand at the times when doing so would provide the most savings.

Solar Intervenor Positions

Q. What to the Solar Intervenors claim with regard to EPE's proposed rate design for DG customers?

A. Some of the intervenors claim that NCP demand charges are inconsistent with cost causation. For example, SEIA witness Lucas states:

> a demand charge that is designed to collect common distribution and transmission and production costs based on an NCP billing determinant does not reflect cost causation principles. I will also describe why the use of an NCP billing determinant does not reflect the costs that an individual customer imposes on the grid.[41]

[40] Note that EPE's proposed demand charge is not such an on-system-peak transmission and generation demand charge; however it is a significant step in that direction, and would facilitate a move to such a rate design in the future. The Commission has regularly approved such on-peak transmission demand charges for mid-sized and large non-residential customers that have capable meters.

[41] Lucas Direct at 100.

OPUC witness Marcus states:

> They are not cost-based because there is a large variation in the coincidence of NCP demand for residential customers, which can be driven by random fluctuations, particularly when measured on a short interval, with coincident peak demand and the class coincident peak. In addition, small customers have a higher NCP demand (caused by randomly turning on equipment) as compared to their coincident peak (CP) demands or class MDD. This means that using a demand charge to collect CP or MDD will systematically overcharge the average residential customer.[42]

Another expressed concern is that residential and small non-residential customers may not understand demand charges.[43]

NCP Demand Charges Are Consistent With Precedent and Cost-Causation

Q. Are NCP demand charges consistent with cost causation?

A. Yes, and the Commission has clearly endorsed this position repeatedly over decades. Most importantly, NCP demand charges are far more consistent with cost causation than the status-quo energy rates. The Commission has approved NCP demand charges for most of the larger non-residential customers for decades. While it is true that NCP demand charges are not the norm for residential and small non-residential customers, the position that they are inconsistent with cost causation flies in the face of a very large body of Commission precedent.

Q. What are some relevant Commission precedents?

A. I believe it may be the case that the Commission has approved NCP demand charges in every major base rate proceeding that it has ever approved; however, I will focus on fewer proceedings. The rate summary sheet for the TDUs in ERCOT, for example, provides

[42] Marcus Direct at 47-48.

[43] See, for example, Barnes Direct at 29 or Johnson Direct at 48.

docket numbers for over twenty proceedings in which the Commission approved NCP demand charges, and shows those charges.[44] Every electric utility that the Commission regulates has Commission-approved demand charges, and all of the retail-serving utilities have NCP demand charges.

In establishing the standard generic customer classification and rate design for unbundled TDUs, the Commission found (emphasis added):

> The Commission agrees with the proponents of a generic rate design that **the primary principles to be considered in the design of transmission and distribution rates are cost causation, simplicity, and equity to customers within the given rate classes…**
> Also considered in these proceedings was whether the generic rate design should include a facilities/deliveries charge. The majority of the parties maintain that a facilities/delivery charge is appropriate and that the manner in which the charge is to be recovered will be contingent on the metering capabilities of each customer. Because the residential and small commercial [Secondary ≤ 10 kW] classes typically do not have demand meters in place, the majority of the parties agree that a facilities/delivery charge should be recovered on a monthly per-kilowatt-hour (kWh) basis for these customers. Many of the parties propose that demand-metered classes should be billed based on non-coincident peak (NCP) demand….
> **With respect to a facilities/delivery charge, the Commission finds that the NCP billing determinant [kW demand] should be used for non-IDR metered customers….** The interval for billing of demand charges shall be that interval which conforms to the protocols of the reliability council, power pool, or independent organization to which each utility belongs. For the majority of utilities participating in this proceeding, in accordance with Electric Reliability Council of Texas (ERCOT) protocols, a 15-minute demand interval shall be applied to demand charges. Finally, facilities/delivery charges shall be recovered on a per-kWh basis for residential and small commercial customers that do not have demand meters. The method established for the recovery of a facilities/delivery charge from each customer class, as detailed above, **appropriately reflects the best-available metering data from each class, is a reasonable proxy for cost causation,** and maintains continuity with past rate design methodology.[45]

[44] Attachment WBA-CR-2 and http://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf.

[45] P.U.C. Docket No. 22344, *Generic Issues Associated With Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule §25.344,* Order No. 40, *Interim Order Establishing Generic Customer Classification and Rate Design*, pp. 4-7 (Nov. 22, 2000).

The Commission followed up with its decision by implementing NCP demand charges for distribution costs and a portion of transmission costs for all the TDUs in ERCOT. For example, in Docket No. 22350, the Commission found (emphasis added):

> 158. Transmission costs will be allocated to distribution utilities on a 4CP basis. The Distribution utility will recover those transmission costs through a facilities/delivery charge which will be billed using 4CP billing determinants for IDR-metered customers and noncoincident peak (NCP) billing determinants for non-IDR metered customers.
>
> 161. With respect to the facilities charge, it is appropriate to use non-coincident peak (NCP) billing determinant for customers without interval data recorder (IDR) meters.
>
> 162. For those customers possessing IDR meter capabilities, it is appropriate for the transmission per- kW rate to be billed according to the Commission's transmission rule, which currently mandates a 4CP method. **In order to track cost causation, it is appropriate to bill the distribution facilities charge for IDR metered customers based on the NCP billing determinant**.[46]

The Commission clearly established a standard for ERCOT TDUs that includes a standard NCP demand charge rate design for most customer classes, and clearly expressed the superiority of, and preference for, NCP demand rates for those customer classes with meters capable of registering demand. Regarding the status-quo energy charge for residential customers, the Commission clearly indicated that an energy charge (per kWh) is "a reasonable proxy" for cost causation <u>where demand-capable metering is absent.</u> For capacity costs where demand-capable metering is available, substituting an energy charge for a demand charge is fundamentally less reflective of cost causation. Furthermore, as discussed previously, the energy charge is no longer a reasonable proxy for cost causation where DG exists under NEM.

[46] P.U.C. Docket No. 22350, *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344*, Order at Findings of Fact 158, 161-162 (Oct. 4, 2001). This approved rate design is representative of all ERCOT TDU rate designs.

Q. Do customer NCP demands appropriately reflect the class demands used to allocate costs?

A. Yes. The Solar Intervenors' testimony on this issue is highly misleading in that they focus on statistics that are either not relevant to ratemaking, or are not relevant to EPE's proposal.[47] Both Mr. Lucas and Mr. Marcus spend significant time analyzing relationships between NCP and Coincident Peak ("CP"), and report that NCP does not properly reflect CP demands. But this claim is entirely irrelevant. EPE's proposal involves collecting system-peak-related costs for DG customers through a time-of-use ("TOU") energy charge, not the NCP demand charge, so any lack of correlation between CP and NCP values is not relevant to EPE's proposal. EPE's proposed NCP charge, consistent with the Commission precedent discussed above, is calculated based almost entirely on the distribution costs, which are not caused by or allocated according to CP demand.[48] Furthermore, Mr. Lucas fails to show that NEM kWh for DG customers better correlates to CP values than does NCP – which is fundamentally necessary to support his opposition to the NCP demand charge in the first place. Mr. Marcus does this analysis, and finds that, for DG customers, NCP better reflects CP demand than kWh does: "The relationship of NCP demand to class peak was stronger than that of energy and class peak,"[49] In other words, EPE's proposed NCP demand charge better reflects CP cost-causation than the status-quo.

After his CP analysis, Mr. Lucas presents further data on NCP vs MCD (maximum class demand) and concludes:

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[47] For example, Lucas Direct at 99-105, and Marcus Direct at 45-55 and similar workpapers from Docket No. 44941.

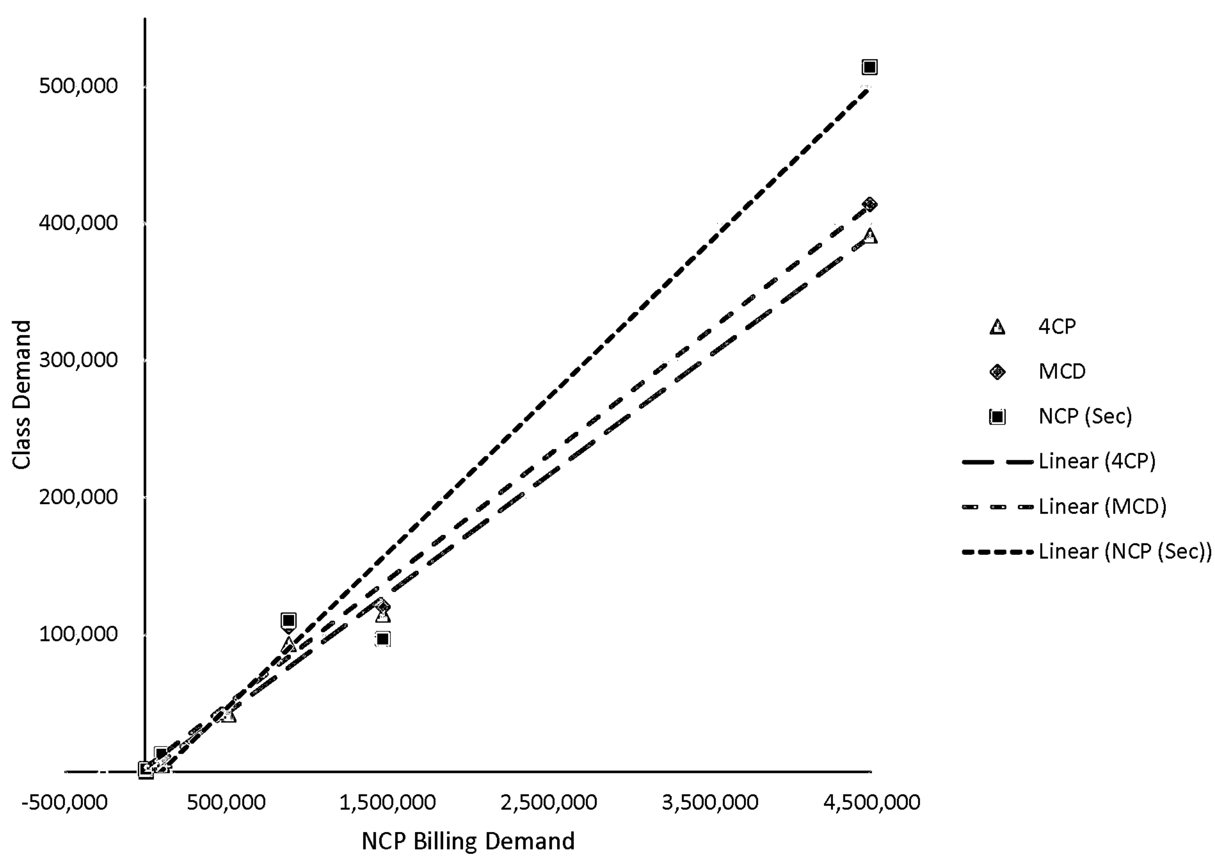
[48] See Table WBA-CR-3.

[49] Marcus Direct at 55.

> It is clear from the analysis above that an individual's monthly NCP values do not correspond in any meaningful manner to either their 4CP or MCD contributions. There is massive variability in monthly NCPs, which would result in major bill fluctuations for Residential DG customers. And Residential DG customers are massively overcharged for 4CP- and MCD-related costs relative to their contribution.[50]

This is both incorrect, inconsistent with rates approved in every major base rate proceeding before the Commission, and displays a misunderstanding of basic ratemaking. EPE's cost study shows a clear relationship between all measures of class demand and customer NCP for all of the demand-metered classes. The graph below shows this relationship:

Class Demand vs. NCP Billing Demand



[50] Lucas Direct at 105.

Clearly, there is a strong relationship between the NCP billing demand for a class and the demand categories used to allocate costs to the classes, including 4-CP, MCD, and NCP. This is not surprising, given that the Commission has determined NCP billing is consistent with cost causation, and is appropriate for recovering certain capacity-related costs.

Q. Are DG customers "massively overcharged" under EPE's proposal, as Mr. Lucas claims?

A. No. Rather, they are massively under-charged under the status-quo. While the Solar Intervenors strain to show that NCP demand is not perfect, they fail to consider that the status-quo is even worse. When one examines the various class demand values per billed kWh, a significant difference emerges between DG and non-DG customers, as can be seen in the table below.

Table WBA-CR-4

Comparison of Class Demand Per Billed kWh (Demand / kWh)						
Type of Class Demand	Allocator	Residential Service	Small General Service	Residential Distributed Generation Service	Residential DG vs. Residential	Residential DG vs. SGS
4CP Demand - Transmission	D2TRAN	0.000272	0.000278	0.000329	121%	118%
MCD Demand Less Trans/ Direct Sub	D3DIST	0.000353	0.000381	0.000589	167%	154%
MCD Demand Overhead Lines - Primary	D4DIST	0.000353	0.000381	0.000589	167%	154%
NCP Demand Overhead Lines - Secondary	D6DIST	0.000632	0.000627	0.000914	145%	146%
MCD Demand Underground Lines - Primary	D7DIST	0.000353	0.000381	0.000589	167%	154%
NCP Demand Underground Lines - Secondary	D8DIST	0.000632	0.000627	0.000914	145%	146%
NCP Demand Transformers - Primary	D5DIST-PRIM	0.000353	0.000381	0.000589	167%	154%
Poles, Towers & Fixtures - Primary	D9DIST	0.000353	0.000381	0.000589	167%	154%
Poles, Towers & Fixtures - Secondary	D10DIST	0.000632	0.000627	0.000914	145%	146%
NCP Demand Transformers - Secondary	D5DIST-SEC	0.000000	0.000000	0.000000	139%	136%
12CP Demand - Transmission	D12TRAN	0.000632	0.000627	0.000914	145%	146%
Source data from Staff's Class Cost of Service Study						

For each measure of class demand that is used to allocate costs, the demand per kWh is much higher for Residential DG customers than it is for Residential or small non-residential customers, in the range of 121% - 167%. The status-quo single-class volumetric rate design results in significantly under-charging the DG customers and over-charging the non-DG customers.

Other claims by Mr. Lucas demonstrate a clear misunderstanding of ratemaking practice. For example, he states:

> From a practical perspective, this means that customers on a demand charge billed based on NCP that collects costs that were allocated based on 4CP are being massively overcharged. For Residential DG customers, the average annual NCP value is 3.34 times higher than the average 4CP value. This means that for every 1 kW of contribution to the system peak, they are being charged for 3.34 kW. The worst affected customer would pay for more than 20 kW for each kW of their contribution to the peak. This is a clear violation of cost causation principles and is unjust and unreasonable to Residential DG customers.[51]

A similar claim is made regarding MCD.[52] Here Mr. Lucas fails to distinguish between how demand values are used in cost allocation versus how they are used in rate design.[53] The class demand values, including CP values and MCD values, are used to allocate costs to classes, which is separate and distinct from calculating the rates within each class. After the class cost is established, it is then divided by billing units to establish a rate per billing unit. So, using the example in the quote from Mr. Lucas above, the costs associated with 1kW of 4CP demand would be divided by 3.34 kW of NCP demand to set the rate. So each 1 kW of NCP demand billed to a customer would be recovering 0.299 kW of 4CP

[51] Lucas Direct at 103.

[52] *Id.* at 104.

[53] This is somewhat ironic given Mr. Lucas's claim that it is the Company that conflates cost allocation and rate design (Lucas Direct at 14).

demand costs (1 / 3.34).[54] There is no "massive" overcharging involved. It is a mathematical near-certainty that the sum of a class's customer NCP demands will exceed the sum of the class's customer CP demands, since it is vanishingly unlikely that all customers will be at their individual peak at the time of the system peak; therefore customer NCP is greater than or equal to class peak values for all classes in every rate case, and always has been.

Q. Are there other unreasonable critiques of NCP demand charges among the Solar Intervenors' testimonies?

A. Yes. Among others, Mr. Lucas suggests that NCP kW billing could increase peak demand:

> Further, EPE's use of a non-coincident demand billing determinant could create perverse incentives for customers to shift load to times that actually have an impact on system costs. Imagine a customer who comes home from work late in the evening. They turn on the air, take a shower (triggering their hot water heater), make food, and do laundry. Even though the system and class peaks have passed for the day, they get hit on their bill for their high non-coincident peak demand levels. In response to this price signal, a rational approach would be to turn on the air conditioner earlier in the day during peak hours to pre cool their house and then turn it off when they get home, even though doing this would add demand to the system at peak times, pushing up the cost of the system as a whole.[55]

This argument ignores both EPE's full proposed rate design for the Residential DG class, as well as the status-quo rate design. EPE is proposing a TOU energy rate design to recover almost all peak-related costs, while the non-peak costs are primarily in the NCP demand charge. Mr. Lucas's example conveniently ignores the strong price signal that EPE's TOU rate design provides to incentivize customers to reduce CP usage, by focusing only on the

[54] I would note again that the vast majority of peak-related costs in EPE's proposal are included in the DG energy charge, not in the NCP demand charge. The repeated attempts to use coincident-peak-related costs to impeach non-coincident-peak billing fails to seriously address EPE's proposal.

[55] Lucas Direct at 51.

demand charge. Furthermore, Mr. Lucas ignores the fact that the status-quo volumetric rate design completely ignores customer demand and provides absolutely no incentive to avoid imposing demand on the system at CP times. EPE's proposed DG rate design provides much better price signals to encourage lower system peak load, and lower costs for all ratepayers.

Understanding Demand Charges

Q. Can residential customers understand demand charges?

A. Yes. The Solar Intervenors express opposition to EPE's proposal based on concerns that residential customers do not, or cannot, understand demand charges.[56] I will acknowledge that this is the one aspect of EPE's DG proposal where the Solar Intervenors raise a legitimate concern; however, it does not rise to the level of rejecting EPE's proposal. The main behavioral response to reducing one's electric bill under NCP demand charges in the short run is simply "don't turn on multiple appliances at once." In the longer-run, it is simply a matter of paying attention to the power requirements of appliances when making purchase decisions.

Furthermore, as a practical matter, it is likely that many customers do not fully understand energy charges. To the degree that one is concerned about prioritizing understandability over cost-causation, the rate design that is easiest to understand is a fixed monthly charge; however, the Solar Intervenors are not recommending higher customer charges.

[56] Lucas Direct at 49, Johnson Direct at 45, Barnes Direct at 29, Munns Direct at 26, Marcus Direct at 55.

Q. Is EPE's proposal consistent with the fundamental goal of regulated ratemaking to mimic the effects of a competitive market?

Yes, and most customers are familiar with close analogs to demand charges in the competitive market. A close example would be internet service – it is common for internet service providers ("ISPs") to charge higher prices for higher download speeds. Customers that want to be able to stream three high-definition movies at once pay more than customers that only select the minimum speeds necessary to use email and surf the web. ISP customers pay the price corresponding to their "demand" regardless of the amount of data they download in a given month (which is analogous to energy/kWh). The status-quo NEM paradigm that the Solar Intervenors are endorsing would be roughly analogous to an internet user that uploads as much data as they download (net-zero data usage) expecting a $0 bill, or even a credit if they have uploaded more than they downloaded, funded by other customers. There is also an analog in the telecom market, where higher data speeds (demands) command higher prices – with 4G service more expensive than 3G service, which is more expensive than 2G service.

Q. Is it necessary for all residential customers to understand demand charges in order to benefit from them?

A. No. It is not even necessary that a majority of residential customers understand demand charges. Because demand charges better reflect cost-causation, even if only a handful of customers change their behavior to reduce their load, this eventually results in a lower allocation of costs to the class than would otherwise be the case – either via a reduction in the allocation of incurred costs, or an avoidance of future costs.[57]

Q. What is the best way to encourage customer familiarity with demand charges?

A. A vast majority of customers will not become familiar with demand charges unless they have a financial incentive to do so. This is the "chicken-or-the-egg" issue. While there would undoubtedly be transitional issues, customers will adapt to the new paradigm. Taken to its logical conclusion, the Solar Intervenors position would forestall the Commission from ever making improvements to rate design, because customers will always understand the status-quo better than the new rate design. This would result in significant wasted potential, especially as advanced-metering systems become more widely deployed, because it would prohibit the evolution to superior rate designs that are in the public interest.

Q. If the Commission is concerned about customers' ability to understand demand charges, what do you recommend?

A. I would recommend that the Commission order the three-part rate design with NCP demand charge to be phased in over a period of three years. The first step would establish the initial NCP demand charge at 1/4th the full rate, with the remaining energy charges being correspondingly higher to recover the full cost of service for the DG class. Each year thereafter, the demand charge would increase by 1/4th and the energy charges would correspondingly fall, until the full demand charge is reached three years after rates initially

[57] Note that the Solar Intervenors' readily point to alleged net peak demand reductions associated with DG as producing a variety of cost savings for everyone. The same logic applies to the behavioral response to a more cost-based rate design, such as the one proposed by EPE.

go into effect. Such a proposal is consistent with the alternative that EPE witness James Schichtl suggests.[58]

X. OTHER ISSUES

<u>Sound Ratemaking Structure</u>

Q. Does EPE's proposal conflict with proper ratemaking practice as described by *Bonbright*?[59]

A. No. While some of the Solar Intervenors, such as Mr. Lucas, make such claims,[60] EPE's proposal represents an improvement to the rate structure that is more consistent with good ratemaking practice.

Q. What does Mr. Lucas state regarding the criteria for cost allocation and rate design?

A. Mr. Lucas suggests that EPE witness Schichtl only consider "some" of the proper rate design aspects, and Mr. Lucas lists several criteria for cost allocation and rate design from the "full list" and discusses some of these items.[61]

Q. Is Mr. Lucas's characterization and analysis of the criteria for cost allocation and rate design complete?

A. No, it is not. Bonbright's *Principles of Public Utility Rates* does contain a list of the attributes of a sound rate structure similar to Mr. Lucas's list, however Mr. Lucas fails to acknowledge the attributes that undermine his argument to reject EPE's proposal. Further, Mr. Lucas neglects Bonbright's discussion of the *primary* criteria and objectives by which

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[58] Direct Testimony of James Schichtl for El Paso Electric Company ("Schichtl Direct") at 64.

[59] *The Principles of Public Utility Rates*, James Bonbright.

[60] See, for example, Lucas Direct at 15-16.

[61] *Id.*

to judge cost allocation and rate design, which primary criteria also undermine Mr. Lucas's arguments.

Q. What attributes of a sound rate structure undermine Mr. Lucas's recommendation to reject EPE's DG proposal?

A. The application of the following criteria would suggest against adopting his recommendation:

1. Effectiveness in yielding the revenue requirement;
2. Stability from year to year;
3. Fairness of apportionment among customer classes;
4. Avoidance of undue discrimination; and
5. Economic efficiency with respect to usage.

Q. How does Mr. Lucas's recommendation reduce the effectiveness of rates in yielding the revenue requirement and undermine rate stability?

A. Setting rates at cost is fundamental to facilitating a utility's ability to recover revenues under the fair-return standard. Customer use of a utility system is constantly changing, with the demand and energy usage of various rate classes growing or shrinking at different rates. As customer usage changes, so do the costs that customers impose on the utility system. To the degree that all rates are set to reflect cost, the revenues that a utility recovers via these rates would more closely match the costs incurred as customer usage changes. Maintaining subsidized rates for some customers, as the status-quo does for DG customers, means that the revenues recovered via the below-cost rates will be insufficient to recover the costs to serve that group of customers. Furthermore, such subsidized rates for DG customers require that the rates for other customers be set above cost. These cross-subsidies have the perverse result of artificially encouraging usage of the utility system by those customers whose rates are below-cost while artificially discouraging usage of the utility system by those customers whose rates are above-cost, leading to a growing gap between revenue recovery and costs. It would be expected that, over time, a rate structure based on such non-cost-based rates will fail to yield adequate revenues that allow a utility to recover its reasonable costs and earn a fair return. A utility with rates significantly far from cost would be expected to need to file for rate increases relatively frequently due to the failure of non-cost-based rates in yielding the required revenues over time. Failing to set rates that properly reflect cost significantly reduces the ability of the rate structure to yield the revenues necessary for the utility to recover its reasonable costs over time, and therefore undermines rate stability by necessitating frequent rate changes along with the occurrence of related rate case expenses. Mr. Lucas's recommendation to maintain the status-quo for his client's benefit is, in these respects, contrary to establishing a sound rate structure.

Q. How is Mr. Lucas's recommendation unfair in the apportionment among rate classes?

A. Under Staff's class cost of service study as well as EPE's CCOSS, the current rates for DG customers are significantly and disproportionately below cost. Perpetuating the cross-subsidies embedded in the rates requires that other customers be subject to rates that are above cost, in order to fund the subsidy that the DG customers are receiving. Mr. Lucas's recommendation is, on its face, inequitable, as it requires other customers to pay above-cost rates in order to subsidize the below-cost rates that would be charged to DG customers.

Q. How does Mr. Lucas's recommendation fail to avoid undue discrimination?

A. Mr. Lucas's recommendation effectively amounts to the argument that DG customers should be granted preferential treatment with respect to avoiding the costs they cause. By focusing on alleged potential harm that could arise if DG customers had to pay more cost-based rates, Mr. Lucas ignores the potential harm that would arise due to other customers being forced to bear above-cost rates in order to provide subsidies to DG customers. By privileging DG customers and allowing them to avoid cost-based rates, Mr. Lucas's recommendation is unduly discriminatory to the detriment of non-DG customers.

Q. What are the economic efficiency implications of Mr. Lucas's recommendation to reject EPE's proposal?

A. An economically efficient rate structure involves rates that properly reflect the costs of providing service to those consumers. Cost-based rate designs and rates for each rate class serve economic efficiency by discouraging uneconomic consumption and encouraging economic consumption of utility services. Uneconomic consumption occurs when the cost of providing that consumption is greater than the value placed on that consumption by the consumer. Uneconomic consumption occurs when prices (rates) are set below cost, as consumers will tend to consume some excess quantity of a service where the cost of providing that quantity exceeds the value of consumption to the consumer. Such a situation is harmful to social welfare because it destroys net value by using up scarce resources towards ends that are less valued than alternative uses of those resources. Uneconomic consumption is highly likely to occur when rates are set below cost. Economic consumption occurs when a quantity of a service is consumed where the value of consumption to the consumer exceeds the cost to produce that quantity. Economic consumption is value-creating and welfare-enhancing, as both the buyer and the seller benefit from the exchange. Economic consumption is discouraged when prices (rates) are set above cost, as consumers will then be unwilling to pay for some marginal quantity of a service even when the costs of providing that quantity of service is less than the value that consumers would obtain consuming it.

Mr. Lucas's recommendation to maintain below-cost rates for DG customers (and therefore to set above-cost rates for other consumers) is clearly in conflict with the economic efficiency attribute of a sound rate structure. Below-cost rates for DG customers encourages uneconomic over-consumption by those customers, while the corresponding above-cost rates for other customers leads to foregone economic consumption by those customers.

Q. What are the *primary* criteria of a sound rate structure?

A. While Mr. Lucas suggests that Mr. Schichtl failed to consider all of the attributes of a sound rate structure, Mr. Lucas fails to note that Bonbright, after discussing some of the previously mentioned attributes, indicates the *primary* objectives of sound ratemaking, which he designates so, "not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto."[62] These criteria are:

1. Capital Attraction;
2. Consumer Rationing; and
3. Fairness to Ratepayers.[63]

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[62] *Bonbright*, page 385.

[63] *Id.*

These are exactly the criteria that Mr. Schichtl discusses in his testimony as providing support for EPE's proposal.[64]

Q. How does Mr. Lucas's recommendation conflict with the Capital Attraction objective of a sound rate structure?

A. The Capital Attraction objective involves the "effectiveness in yielding the revenue requirement" criterion addressed above. For the reasons discussed previously, Mr. Lucas's recommendation to maintain the status-quo conflicts with this primary criterion of a sound rate structure.

Q. How does Mr. Lucas's recommendation conflict with the Consumer Rationing objective of a sound rate structure?

A. The Consumer Rationing objective involves the economic efficiency aspects of ratemaking addressed above. For the reasons discussed previously, Mr. Lucas's recommendation conflicts with this primary criterion of a sound rate structure.

Q. How does Mr. Lucas's recommendation conflict with the Fairness to Ratepayers objective of a sound rate structure?

A. The Fairness to Ratepayers objective involves the avoidance of arbitrary cost allocation and rate design treatments as well as the avoidance of undue discrimination. For the reasons discussed previously, Mr. Lucas's recommendation conflicts with this primary criterion of a sound rate structure.

[64] Schichtl Direct at 31.

Demand Ratchets

Q. Should the Commission adopt the recommendations of some of the Solar Intervenors to eliminate EPE's demand ratchet mechanisms?[65]

A. No. Like NCP demand charges, demand ratchets are ubiquitous in Commission ratemaking decisions, and demand ratchets are included in almost every currently-effective Commission-approved retail electric tariff. The Commission approved an 80% ratchet as being part of the standard rate design for ERCOT TDUs:

> Nearly all of the parties recommended adoption of a demand ratchet in the distribution rates. The proponents maintained that ratchets stabilize utility revenues and that ratchets are an effective method to recover fixed distribution infrastructure costs. Those that opposed ratchets argued that they are not cost justified and place an excessive burden on low load factor customers….
>
> The Commission finds that an 80% ratchet is appropriate for recovery of distribution costs from demand-metered customers. The Commission holds that although a 100% ratchet properly reflects the fixed nature of distribution costs, the 80% level more appropriately recognizes load diversity on the distribution system.[66]

Furthermore, it is important to note that eliminating demand ratchets will necessarily result in higher demand rates. If the recommendation to eliminate demand ratchets is approved, then a corresponding adjustment to increase rates to allow EPE to recover its approved costs should be made.

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[65] See, for example, Lucas Direct at 33, or Barnes Direct at 52.

[66] P.U.C. Docket No. 22344, *Generic Issues Associated With Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA §39.201 and Public Utility Commission Substantive Rule §25.344,* Order No. 40, *Interim Order Establishing Generic Customer Classification and Rate Design*, pp. 7-8 (Nov. 22, 2000).

The NARUC Distributed Energy Resources Manual

Q. What is your opinion regarding the references to the NARUC DER Manual made by the parties?

A. It is important to note that the NARUC DER Manual does not purport to provide a definitive answer to most of the contested DG issues in this proceeding:

> This Manual is organized to provide regulators with a comprehensive understanding of the question of how does DER affect regulation…. The Manual goes through them laying out the pros and cons of the option, and providing regulators with information to assist them in their consideration…. This version of the Manual is not the final word…. This Manual provides a benchmark for those discussions and solutions…. The Manual is not designed to answer questions, but to provide regulators with support.[67]

That said, in my opinion, the portions of the manual cited by Mr. Schichtl are most relevant to evaluating EPE's proposal given the Commission's preference for fair and equitable cost-based rates; and I recommend that they be given substantial weight.[68]

I would also note, that despite the claims made by several of the Solar Intervenors that the Commission can afford to wait to address the DG issue because DG adoption is so low in EPE's service territory,[69] the manual is clear that such delay is not appropriate: "Even at low levels of adoption, a jurisdiction should not be content to wait until adoption levels start to increase."[70]

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[67] *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Commissioners (2016) at 5-6.

[68] Schichtl Direct at 51-53.

[69] Lucas Direct at 115, Johnson Direct at 43, Munns Direct at 8.

[70] *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Commissioners (2016) at 6.

Q. Would it be reasonable to address the DG issue in the current proceeding rather than to delay it to some future proceeding?

A. Yes. The magnitude of the cross-subsidies would be expected to grow over time as more DG is installed on the system. This would make the customer impacts involved in unwinding the cross-subsidies in the future greater than they would be today. The MIT Study also notes this dynamic:

> As the penetration of DG goes up, customers who have installed PV [Photovoltaic] systems (thereby becoming prosumers) will consume a lower volume of electricity from the grid. Since network costs do not decrease with greater PV penetration – on the contrary, they may even increase, as we have seen – the tariff that has to be applied to each kWh consumed to recover network costs has to increase. The prosumers with PV systems, who are responsible for both the reduction in overall kWh sales and for the increase in network costs, avoid a big portion of the cost… customers without distributed generation systems fully absorb the impact of higher tariffs… Moreover, these customers will have an incentive to get their own PV system, resulting in a positive feedback mechanism that – taken to an extreme – could render the distribution business non-viable.[71]

If anything, EPE's proposal represents an excellent opportunity to get ahead of the problem before it grows larger and becomes more difficult to resolve.

<u>**Previous Incentives to Install DG**</u>

Q. Does the fact that EPE has previously provided incentives to install DG support rejection of EPE's DG proposal?[72]

A. No. Those incentives were paid for by other customers, via EPE's Commission-approved Energy Efficiency Cost Recovery Factor ("EECRF"). The EECRF program is required under PURA and the Commission rules. To maintain the status-quo would mean that

[71] *MIT Study* at 170, see Attachment WBA-CR-1, page 8.

[72] For example, Lucas Direct at 117.

customers who are paying rates to fund the EECRF incentives would also be paying higher rates to continuously subsidize the DG customers.

Q. Are the net benefits associated with the EECRF solar DG program relevant to this proceeding?[73]

A. No. The EECRF net benefits calculation was not designed or intended to inform the issues in this case. The net benefits calculation does not consider a majority of the costs, nor does it consider the specific costs avoided by EPE. It is not suitable to inform the questions in this proceeding.

<u>PUC Report on Alternative Ratemaking</u>

Q. Has a recent Commission report provided further support for EPE's proposal?

A. Yes. A recent Commission report including an analysis by Christensen Associates on alternative ratemaking was provided to the Legislature. The findings of this report strongly support EPE's DG proposal in this proceeding:

> Straight fixed-variable (SFV) rates allow utilities to recover substantially all fixed costs through fixed monthly charges (per customer-month) or peak demand charges (per peak kW) that are independent of the volumes of electrical energy consumed. Volumetric charges (per kWh) are used to recover substantially all variable costs that depend primarily upon the energy consumed. By better aligning rates with costs, SFV rates improve utility recovery of fixed costs, provide customers with energy prices that are relatively efficient, mitigate or avoid the need to adjust rates in response to load changes, remove a disincentive to utility promotion of energy efficiency, encourage lower peak demands and higher load factors, and have more stable rates and lower administrative burdens than certain other ratemaking mechanisms. Only a few states have adopted SFV rates for electric utilities. [Page v]
>
> Straight Fixed-Variable Rates
> Utilities have variable costs that depend primarily upon the volumes of electrical energy consumed, and they have fixed costs that depend primarily upon numbers of customers or peak loads. Under traditional ratemaking, large shares of fixed costs are recovered through volumetric charges (dollars

[73] *Id.* at 118.

per kWh) rather than through fixed monthly charges (dollars per customer-month) or peak demand charges (dollars per peak kW). This traditional approach leads to systematic mismatches between utility revenues and costs: growing sales cause utility revenues to rise faster than costs, while shrinking sales cause utility revenues to fall faster than costs. To foster a better match between utility revenues and costs, straight fixed-variable (SFV) rates allow utilities to recover substantially all fixed costs through fixed monthly charges or peak demand charges that are independent of the volumes of electrical energy consumed. Volumetric charges are used to recover substantially all variable costs that depend primarily upon the energy consumed. [Pages 12-13]

SFV rates have the following benefits relative to traditional rates:
• They better assure utility recovery of fixed costs, such as those of distribution system facilities.
• They provide customers with energy prices that are relatively efficient in the sense that they reflect variable costs that are related to marginal costs. Ignoring the costs of externalities such as the pollution associated with electricity generation, this may encourage more efficient use of electricity.
• Because of the better match between variable costs and volumetric revenues, they mitigate or avoid the need to adjust rates in response to changes in load growth.
• They reduce the importance of load forecasts in rate cases, potentially reducing the contentiousness of rate cases.
• They remove a disincentive to utility promotion of energy efficiency, since any revenue declines due to energy efficiency are roughly matched by reductions in variable costs.
• Because of their higher demand charges and lower energy charges, they encourage lower peak demands and higher load factors, thus increasing the use of existing electric power system facilities and potentially slowing the growth of capacity-related costs.
• Higher demand charges may facilitate investment in and use of market-based distributed resources such as load management and energy storage technologies.
• SFV rates tend to be stable relative to revenue decoupling rates.
• Compared to revenue decoupling and LRAMs, the SFV rate design imposes low administrative burdens on regulators and intervenors.
[Page 14]

Present Regulated Electricity Ratemaking Methods in Texas

…

The ERCOT investor-owned TDUs have very similar tariffs for delivery of electricity to retail consumers. For residential and small non-residential customers, cost recovery is through fixed monthly charges and energy charges. Excluding riders, energy charges constitute roughly 80% of both residential and small commercial bills. The riders increase these

> percentages. For larger non-residential customers, cost recovery is through fixed monthly charges and demand charges, with demand charges accounting for most cost recovery. Because T&D costs are largely fixed, energy usage changes result in revenue changes that are larger than the associated cost changes. The energy usage-related variability in cost recovery is more significant for the smaller customer classes than for the larger customer classes because energy consumption tends to be more variable than peak loads. [Page 48][74]

<u>Grandfathering Existing DG Customers</u>

Q. Do you recommend "grandfathering" existing DG customers?

A. No. To do so would maintain unreasonable and non-cost-based rates for existing DG customers and would not be fair to other customers for the reasons discuss previously. Based upon reports of potentially misleading sales tactics on the part of DG installers or suppliers, it is possible that the impetus for grandfathering may be more related to concerns regarding representations made by such installers or suppliers to their customers, rather than any concern for customers themselves.

Q. If the Commission decided to grandfather existing DG customers, what do you recommend?

A. I recommend that any grandfathering be limited to a period of five to ten years, after which all DG customers will be subject to the DG treatment approved by the Commission. I also recommend that it would be reasonable for the Commission to determine that the grandfathering apply only to customers who had submitted a DG interconnection agreement with EPE as of the date of notice in Docket No. 44941 (October 1, 2015). Customers subsequent to that date were on notice regarding EPE's DG proposals.

[74] *Report to the 85th Texas Legislature - Alternative Ratemaking Mechanisms*, Public Utility Commission of Texas, January 2017. Citation to included study by Christensen Associates Energy Consulting, *Alternative Electricity Ratemaking Mechanisms Adopted by Other States*, May 25, 2016. Included in Project No. 46046, *Report on Alternative Ratemaking Mechanisms*.

Other Issues

Q. Would the truth of the claim that solar DG customers produce energy at the time of the system peak and close to loads warrant rejecting EPE's DG proposal?

A. No. EPE's proposal takes any on-system-peak production by DG customers into account at both the class cost of service level and at the rate design level. At the class cost of service level, significant portions of system-peak related costs, such as transmission and generation capacity, are allocated to the classes based on measures of class coincident peak demand. To the degree that DG customers have lower demand coincident with the system peak, then that will be reflected via a reduced allocation factor, and hence reduced cost allocation, to the DG class. In this respect, EPE's proposal gives the DG class credit for any system peak reduction they are responsible for. Furthermore, this allocation treatment is consistent across all of the classes, and is therefore equitable and not unreasonably discriminatory or prejudicial. At the rate design level, EPE's proposed demand charge for the DG class is based almost entirely on the distribution costs for the class. As discussed above, distribution costs are generally caused and allocated by measures of NCP demand. Under EPE's proposal, almost all of the system-peak related generation and transmission costs are still embedded in the energy charge, therefore any customer-owned generation that is occurring around the peak will, via NEM, provide the DG customer with credit for their contribution to reducing the system peak.

Furthermore, increased solar DG on the system might actually lead to increased distribution costs, as the MIT Study notes: "when distributed PV [Photovoltaic] grows to account for a significant share of overall generation, its net effect is to increase distribution costs (and thus local rates)."[75]

Regarding generation near loads, the MIT Study notes:

> Although it seems reasonable to expect that generating electricity close to load brings energy losses down and requires less network infrastructure to carry energy from other regions, these benefits are not realized in situations where distributed generators are not controllable; where mismatches exist between load and generation, both in terms of location and time; and where networks continue to be managed in the usual way.[76]

That DG customers may produce energy around the system peak or near loads is not sufficient grounds to reject EPE's proposal.

Q. Would the truth of the claim that solar installation companies might reduce operations and employment warrant rejecting EPE's proposed DG treatment?

A. No. The status-quo does involve significant cross-subsidies that benefit the concentrated group of solar DG customers, and that likely increase profits and employment for solar companies in the short-run; however, this comes at the cost of harming a more diffuse group including other customers, businesses, and workers in the EPE service territory. As discussed previously, the asymmetry involved in such a "concentrated benefits, diffuse costs" situation makes it ripe for an outcome that is not in the public interest where the total costs exceed the total benefits, because the members of the concentrated group of beneficiaries have a strong individual incentive to lobby for subsidies, while the costs being spread over a diffuse group leaves very weak individual incentive for those who are harmed to organize and lobby in opposition, even when the overall harms significantly exceed the overall benefits.

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[75] *MIT Study* at xviii, see Attachment WBA-CR-1, page 7.

[76] *MIT Study* at 172, see Attachment WBA-CR-1, page 9.

Q. How does the status-quo cross-subsidization harm the broader public interest?

The status-quo misalignment of rates and costs for DG customers under net-metering harms the public interest in both a more immediate economic manner and in longer-run manner. In the more immediate manner, non-DG ratepayers will pay higher rates in order to subsidize DG-ratepayers. These higher rates mean that the non-DG residential ratepayers will have less disposable income for other purchases. This reduced income very likely means reduced expenditures in the local economy – a family may choose to eat out at restaurants or see movies less often, or delay a new purchase. The reduced expenditures harm other businesses in the area – a marginally profitable restaurant may become unprofitable and close, or a business may reduce employment or cancel or delay plans for expansion, employee raises, or new hiring. Furthermore, these businesses may themselves be paying higher rates in order to subsidize DG customers, further exacerbating the problem. Because the costs and harms of the cross subsidies are spread diffusely throughout an economy that is constantly in flux, it is nigh impossible to measure and point with specificity to the particular manifestations of the harmful impacts of the cross subsidies elsewhere in the economy; the harm, however, does exist. Furthermore, the misalignment of costs and rates for DG customers means that EPE's rates are less likely to adequately recover reasonable and necessary costs to provide service over time. This is especially the case since the embedded subsidies to DG artificially incentivize more rapid and uneconomic growth of DG on the system, which further exacerbates the cost recovery problem. The result of such a situation is that it is likely that EPE would have to come in for base rate proceedings more frequently than the Company otherwise would. This leads to greater rate case expenses, which are typically recovered from all ratepayers, further exacerbating the local economic harm of the embedded DG subsidies present in the status-quo. This misalignment and increased risk of inadequate cost recovery could potentially increase the cost of capital for EPE, especially as DG deployment grows, eventually resulting in higher rates for all customers via increased costs of debt or equity.

Q. Is maintaining the status-quo an efficient way to avoid fossil fuel consumption and achieve any alleged concomitant environmental benefits?

A. No. As the MIT Study notes, subsidizing residential solar DG is a grossly inefficient way of achieving such goals (emphasis in original):

> …because residential PV [Photovoltaic] generation is much more expensive than utility-scale PV generation, the subsidy cost per kWh of residential PV generation is substantially higher than the per-kWh subsidy cost of utility-scale PV generation. There is no compensating difference in benefits and thus there is simply no good reason to continue to provide more generous subsidies for residential-scale PV generation than for utility-scale PV generation…
> **Eliminating this uneconomic disparity will require replacing per-kWh distribution charges with a system for recovering utilities' distribution costs that reflect network users' impacts on those costs…**
> Net metering with per-kWh charges to cover distribution cost is an important reason why residential PV generation is more heavily subsidized than utility-scale PV generation. In addition, net metering raises equity issues: it is far from obvious that it is fair for consumers with rooftop PV generators to shift the burden of covering fixed distribution costs to renters and others without such systems[77]

Furthermore, I am unaware of any Commission decision that suggests that a just and reasonable customer classification and rate design, such as that proposed by EPE, should be rejected in pursuit of such goals.

[77] *MIT Study* at 225, see Attachment WBA-CR-1at 12.

Q. Is the status-quo harmful to lower-income residential ratepayers?

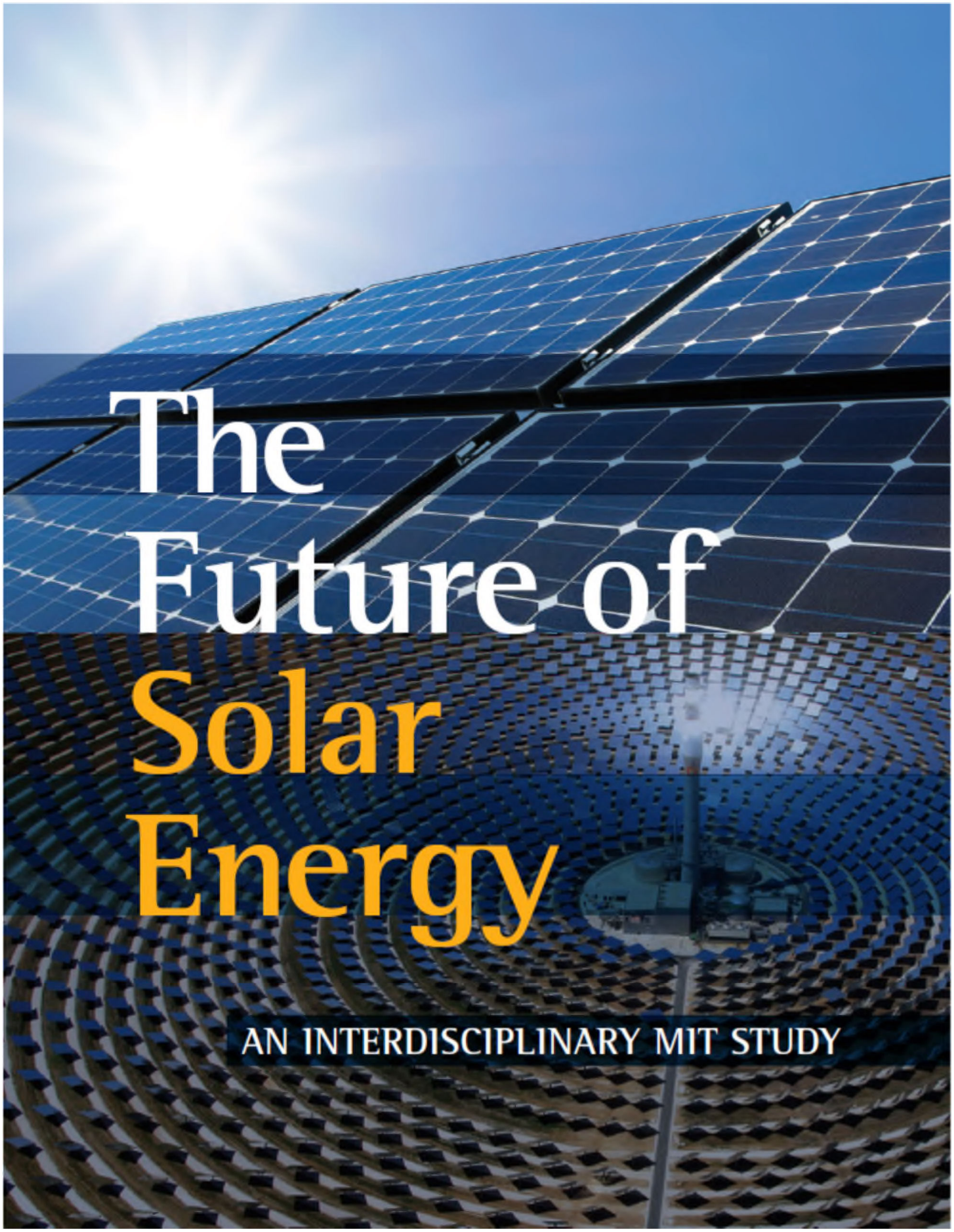
A. In general, yes. Lower-income residential customers tend to be over-represented in rental housing and other residences that are less likely to have DG. The status-quo results in DG customers shifting costs onto these customers. The MIT Study also notes this, stating that "net metering raises equity issues: it is far from obvious that it is fair for consumers with rooftop PV generators to shift the burden of covering fixed distribution costs to renters and others without such systems."[78]

XI. CONCLUSION

Q. Please summarize your recommendation.

A. EPE's proposals regarding DG customers is just, reasonable, and consistent with cost-causation, fairness, and equity; the status-quo single class two-part volumetric rate design with NEM is not. The Solar Intervenors' recommendations on this issue should be rejected, and EPE's proposal should be adopted. Alternatively, a gradual phase-in of demand charges over three years would appropriately address any concerns about demand charges.

[78] *MIT Study* at 226, see Attachment WBA-CR-1at 13.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PREPARE FOR MUCH GREATER PENETRATION OF PV GENERATION

CSP facilities can store thermal energy for hours, so they can produce dispatchable power. But CSP is only suitable for regions without frequent clouds or haze, and CSP is currently more costly than PV. PV will therefore continue for some time to be the main source of solar generation in the United States. In competitive wholesale electricity markets, the market value of PV output falls as PV penetration increases. This means PV costs have to keep declining for new PV investments to be economic. PV output also varies over time, and some of that variation is imperfectly predictable. Flexible fossil generators, demand management, CSP, hydroelectric facilities, and pumped storage can help cope with these characteristics of solar output. But they are unlikely to prove sufficient when PV accounts for a large share of total generation.

R&D aimed at developing low-cost, scalable energy storage technologies is a crucial part of a strategy to achieve economic PV deployment at large scale.

Because distribution network costs are typically recovered through per-kilowatt-hour (kWh) charges on electricity consumed, owners of distributed PV generation shift some network costs, including the added costs to accommodate significant PV penetration, to other network users. These cost shifts subsidize distributed PV but raise issues of fairness and could engender resistance to PV expansion.

Pricing systems need to be developed and deployed that allocate distribution network costs to those that cause them, and that are widely viewed as fair.

ESTABLISH EFFICIENT SUBSIDIES FOR SOLAR DEPLOYMENT

Support for current solar technology helps create the foundation for major scale-up by building experience with manufacturing and deployment and by overcoming institutional barriers. But federal subsidies are slated to fall sharply after 2016.

Drastic cuts in federal support for solar technology deployment would be unwise.

On the other hand, while continuing support is warranted, the current array of federal, state, and local solar subsidies is wasteful. Much of the investment tax credit, the main federal subsidy, is consumed by transaction costs. Moreover, the subsidy per installed watt is higher where solar costs are higher (e.g., in the residential sector) and the subsidy per kWh of generation is higher where the solar resource is less abundant.

Policies to support solar deployment should reward generation, not investment; should not provide greater subsidies to residential generators than to utility-scale generators; and should avoid the use of tax credits.

State renewable portfolio standard (RPS) programs provide important support for solar generation. However, state-to-state differences and siting restrictions lead to less generation per dollar of subsidy than a uniform national program would produce.

State RPS programs should be replaced by a uniform national program. If this is not possible, states should remove restrictions on out-of-state siting of eligible solar generation.

of federal, state, and local subsidies, the price of residential PV has now fallen below the level needed to achieve grid parity in many jurisdictions that apply net metering.

INTEGRATION INTO EXISTING ELECTRIC SYSTEMS

Distributed Solar

Introducing distributed PV has two effects on distribution system costs. In general, line losses initially decrease as the penetration of distributed PV increases. However, **when distributed PV grows to account for a significant share of overall generation, its net effect is to increase distribution costs (and thus local rates). This is because new investments are required to maintain power quality when power also flows from customers back to the network, which current networks were not designed to handle.** Electricity storage is a currently expensive alternative to network reinforcements or upgrades to handle increased distributed PV power flows.

In an efficient and equitable distribution system, each customer would pay a share of distribution network costs that reflected his or her responsibility for causing those costs. Instead, most U.S. utilities bundle distribution network costs, electricity costs, and other costs and then charge a uniform per-kWh rate that just covers all these costs. **When this rate structure is combined with net metering, which compensates residential PV generators at the retail rate for the electricity they generate, the result is a subsidy to residential and other distributed solar generators that is paid by other customers on the network.** This cost shifting has already produced political conflicts in some cities and states — conflicts that can be expected to intensify as residential solar penetration increases.

Because of these conflicts, robust, long-term growth in distributed solar generation likely will require the development of pricing systems that are widely viewed as fair and that lead to efficient network investment. Therefore, **research is needed to design pricing systems that more effectively allocate network costs to the entities that cause them.**

Wholesale Markets

CSP generation, when accompanied by substantial thermal energy storage, can be dispatched in power markets in a manner similar to conventional thermal or nuclear generation. Challenges arise, however, when PV generators are a substantial presence in wholesale power markets. In about two-thirds of the United States, and in many other countries, generators bid the electricity they produce into competitive wholesale markets. PV units bid in at their marginal cost of production, which is zero, and receive the marginal system price each hour. **In wholesale electricity markets, PV displaces those conventional generators with the highest variable costs. This has the effect of reducing variable generation costs and thus market prices. And, since the generation displaced is generally by fossil units, it also has the effect of reducing CO_2 emissions.**

This cost-reducing effect of increased PV generation, however, is partly counterbalanced by an increased need to cycle existing thermal plants as PV output varies, reducing their efficiency and increasing wear and tear. The cost impact of this secondary effect depends on the existing generation mix: it is less acute if the system includes sufficient gas-fired combustion turbines or other units with the flexibility to accommodate the "ramping" required by fluctuations in solar output. At high levels of solar penetration, it may even be

The Shortcomings of a Dominant Distribution-Cost Allocation Methodology

Determining how distribution costs should be allocated among customers is a complex issue that will not be discussed here. Rather, this discussion focuses on a problem that can arise — and that is already affecting some networks now — when regulators follow a common approach to cost allocation. This common approach has two chief elements:

- A volumetric allocation of network cost is used, in which total network cost is distributed in proportion to the kilowatt-hours of electricity consumed by each customer. The average volumetric rate (i.e., $/kWh) for the distribution component of customers' residential retail electricity bills is determined by dividing the total distribution network costs to be recovered from all residential users within each billing period by the total kilowatt-hours of electricity consumed by residential users at the end of the billing period. This per-kWh distribution network charge is bundled together with the charge for energy consumption and other regulated charges (such charges for energy efficiency and renewable energy programs, industry restructuring, etc.) that are included in the electricity bill. For some residential customers, a fraction — typically a small fraction — of the bill also includes a fixed component or, if capacity is contracted, a charge per kW for the consumption capacity contracted over the billing period.
- Net-metering is employed to determine the volume of electricity consumed by a customer. That is, a single meter is used that increases or decreases measured consumption in proportion to the net flow of power from the network to the customer. When power flows from the customer to the network, measured consumption falls. After a predefined period of time (one or two months, typically, when conventional meters are checked), the value in the meter is read, and the customer pays the corresponding $/kWh tariff multiplied by the net volume of electricity consumed.

Here we show by example what can happen in a particular network when both of the above elements are applied for purposes of cost allocation, as they often are. The first effect of this combination is shown in Figure 7.13a. As the penetration of DG goes up, customers who have installed PV systems (thereby becoming prosumers) will consume a lower volume of electricity from the grid. Since network costs do not decrease with greater PV penetration — on the contrary, they may even increase, as we have seen — the tariff that has to be applied to each kWh consumed to recover network costs has to increase. The prosumers with PV systems, who are responsible for both the reduction in overall kWh sales and for the increase in network costs, avoid a big portion of the cost, as Figure 7.13b shows. On the other end, customers without distributed generation systems fully absorb the impact of higher tariffs — an outcome that is likely to be perceived as unfair.[xiv] Moreover, these customers will have an incentive to get their own PV system, resulting in a positive feedback mechanism that — taken to an extreme — could render the distribution business non-viable.

[xiv] The results shown here assume a standard meter that is read once a year. When a shorter reading period is used, the asymmetry will be reduced because there will be periods in which PV production is lower than in other periods. For example, if monthly metering is available, the avoided network charge in winter months will be smaller.

charged according to their contribution to the factors that drive total system cost. Pérez-Arriaga and Bharatkumar (2014)[21] describe a more detailed proposal for the design of distribution network charges.

Designing DNUoS charges according to the principle of cost causality aligns with the objective of increasing economic efficiency, but presents a host of implementation challenges. The use of network utilization profiles to compute DNUoS charges leads to individualized and potentially highly differentiated charges for each distribution network user, and thus substantially departs from the common practice of network cost socialization. Regulators might therefore choose to adjust the theoretically most-efficient allocation of network costs to account for a range of other considerations and to achieve other regulatory objectives such as greater socialization of network costs and equity.

FINDING

When single bi-directional standard meters are used, volumetric network charges result in customers with PV generators partially avoiding network charges, leaving other network users and/or distribution company shareholders to assume higher costs.

Alternative approaches should aim to incentivize efficient responses by network users using a system of charges and credits that is consistent with sound principles of cost causality.

7.5 CONCLUSION

The analysis described in this chapter shows that, under current practices and existing network designs, distributed PV generation can have a significant impact on the costs associated with delivering electricity. Absent specific mitigating measures, areas with low insolation may come close to doubling their distribution costs when the annual DG contribution exceeds one-third of annual load.

Although it seems reasonable to expect that generating electricity close to loads brings energy losses down and requires less network infrastructure to carry energy from other regions, these benefits are not realized in situations where distributed generators are not controllable; where mismatches exist between load and generation, both in terms of location and time; and where networks continue to be managed in the usual way. In these situations, active network management and coordination can play a relevant role, reducing dual-peak demands over the system and minimizing losses through the exploitation of flexible demand and distributed storage, as well as through actions taken within the network itself, such as reconfiguring the network, controlling PV inverters, or regulating transformer voltage. Before active management solutions can emerge, however, adequate regulations must be implemented. For example, we have shown that common rate-setting practices such as net-metering and volumetric cost allocation do not contribute to better system management and can induce inefficient hidden subsidies. By contrast, alternative approaches should aim to incentivize efficient responses by network users using a system of charges and credits that is consistent with sound principles of cost causality.[19]

FINDING:
Investment-based subsidies, particularly those that take the form of reductions in profit taxes, are less effective per dollar of government cost at stimulating solar generation and displacing fossil fuels than price-based or output-based subsidies.

9.5 INDIRECT POLICIES

Beginning with Massachusetts and Wisconsin in 1982, 43 U.S. states plus the District of Columbia now subsidize the output from small, distributed renewable (including solar) generators by means of *net metering*; internationally, 43 other countries use this mechanism.[xxvii] The federal Energy Policy Act of 2005 requires all utilities to make net metering available to those customers who request it. Net metering compensates these generators at the retail price for electricity they supply to the grid, not at the wholesale price received by grid-scale generators. A large fraction of the cost of running a distribution system is fixed, independent of load, but much or all of this fixed cost is generally recovered from retail customers through a per-kWh distribution charge. When a residential customer installs a rooftop PV generator, that customer's distribution charge payments are reduced. But there is no corresponding reduction in the distribution utility's distribution system costs. As noted in Chapter 7, the subsidy is the corresponding reduction in the utility's revenues, which may be made up by increasing the retail price paid by all customers. For instance, in Boston in August 2014, the local distribution company, NSTAR, generally charged 9.8 ¢/kWh for electricity, reflecting average wholesale market prices, and 8.9 ¢/kWh to deliver that electricity. But electricity supplied by a rooftop PV array in Boston mainly saves NSTAR only its wholesale electricity cost; the delivery charge serves to cover NSTAR's costs to own and operate the distribution system.[xxviii] Therefore, net metering in Massachusetts involves a substantial subsidy to distributed generation — as it does elsewhere.[xxix] For at least some California retail customers, for instance, the value of the net metering subsidy apparently exceeds the value of the federal investment tax credit.[49]

Moreover, because the distribution utility pays this subsidy, it has strong incentives to make it hard to install distributed generation. So-called decoupling arrangements in some states deal with this problem by automatically increasing per-kWh distribution charges so as to maintain utility profits. But this shifts the burden of covering distribution costs from utility shareholders to those customers who do not or cannot install distributed generation, a group that is likely to be less affluent than those who benefit from net metering.[49] Even at the current relatively low penetration of residential solar, this cost shifting has become controversial in many states. It seems unlikely that the much larger cost shifts that would be induced by substantial penetration of residential solar with net metering would generally be politically acceptable.

[xxvii] Source is REN21, pp. 79, 80.[7]

[xxviii] The installation of significant solar rooftop capacity will likely also require the utility to make incremental investments, as discussed in Chapter 7.

[xxix] For a positive discussion of net metering, see Duke, et al.[47] For a recent quantitative analysis of its impact, see Satchwell, Mills, and Barbose.[48]

In broad terms, the economically obvious solution is to move away from the prevalent design of distribution network charges that recovers fixed distribution costs via volumetric (per-kWh) charges.[xxx]

Over the years, governments at all levels have employed policies that attempt to expand the use of renewable energy sources by means other than incentives or regulations.

As discussed in Chapter 7, the ideal approach would be to recover utilities' distribution costs through a system of charges that reflect each individual customer's contribution to those costs, not their kWh consumption. It is not yet clear how this ideal can best be approximated in practice, however.

FINDING:

By enabling those utility customers who install distributed solar generation to reduce their contribution to covering distribution costs, net metering provides an extra incentive to install distributed solar generation. Costs avoided by households that install distributed solar generation are shifted to utility shareholders and/or other customers. Recovering distribution costs through a system of network charges that is more reflective of cost causation and that avoids the current direct dependence on electricity consumption would remove the extra subsidy and prevent this cost shifting.

Over the years, governments at all levels have employed policies that attempt to expand the use of renewable energy sources by means other than incentives or regulations. These policies, which have been termed "enabling" or "catalyzing," often involve education and information campaigns aimed more generally at building awareness and stimulating demand, as well as training programs designed to enhance supply.[xxxi] Efforts by municipalities in various regions to reduce balance-of-system costs for residential PV by, for example, simplifying and coordinating permitting, installation, and inspection; providing residential consumers with better price information; or adopting widely used standards would also fall in this category.[xxxii] Policies that require grid operators to connect to renewable generators are also present in one form or another in 43 states and the District of Columbia and have likewise been characterized as catalyzing renewables deployment, though it may be more appropriate to consider them as simply offsetting distribution utilities' incentives to resist distributed generators for the reasons discussed above.

Since July 2009, grid operators in the EU have been required to "… give priority to generating installations using renewable energy sources insofar as the secure operation of the national electricity system permits…"[54] This policy aims to provide a less uncertain revenue stream to renewable installations and, perhaps more important, to force system operators and owners of conventional generators to develop operating rules that are compatible with large amounts of renewable generation. Since electricity generated from solar energy has zero

[xxx] For a general discussion, see Kassakian and Schmalensee.[50] An alternative approach that has been discussed in some jurisdictions is to deploy two meters to value solar generation at the utility's avoided cost (which should correspond to the wholesale price) and to charge the consumer at the retail rate for all electricity consumed.[49]

[xxxi] For examples and a general discussion, see Lund.[51] See also Taylor.[52]

[xxxii] For a discussion of statewide efforts of this sort in Vermont, see North Carolina Solar Center.[53]

portfolio standards are all superior in principle to subsidizing investment via the tax system. Such subsidies are the federal government's main incentive device and are also widely used at the state and local levels. Using tax credits rather than direct expenditures reduces both transparency and generation per dollar of public expenditure. If tax credits must be used, the need for solar project developers to access the tax equity market should be reduced or eliminated, perhaps by making tax credits freely tradable.

RECOMMENDATION:

Subsidies for solar and other renewable technologies should reward generation, not investment, and should reward generation more when it is more valuable.[xxxix] Tax credits should be replaced by direct grants, which are more transparent and more effective. If this is not possible, steps should be taken to avoid dependence on the tax equity market.

State RPS regimes generally do not reward generation more when it is more valuable. Even putting this serious problem aside, the current system of multiple, incompatible state RPSs with limited interstate trading needlessly inflates nationwide costs for any level of renewable generation attained. If an output quota approach like RPS is employed, it should be employed uniformly across the nation and phased out when a comprehensive carbon policy is in place and the subsidized technology is mature. If a nationwide RPS is not feasible, state programs should permit unlimited interstate trading to avoid forcing renewable generators to be built at undesirable locations.

RECOMMENDATION:

RPS programs should be replaced by subsidy regimes that reward generation more when it is more valuable. If that is not feasible, state RPS programs should be replaced by a uniform nationwide program. If a nationwide RPS is not feasible, state RPS programs should permit interstate trading to reduce costs per kWh generated and should adopt common standards for renewable generation to increase competition.

Finally, as we have discussed at several points, because residential PV generation is much more expensive than utility-scale PV generation, the subsidy cost per kWh of residential PV generation is substantially higher than the per-kWh subsidy cost of utility-scale PV generation. There is no compensating difference in benefits and thus there is simply no good reason to continue to provide more generous subsidies for residential-scale PV generation than for utility-scale PV generation.

RECOMMENDATION:

Residential PV generation should not continue to be more heavily subsidized than utility-scale PV generation. Eliminating this uneconomic disparity will require replacing per-kWh distribution charges with a system for recovering utilities' distribution costs that reflects network users' impacts on those costs.

[xxxix] This assumes that the market power issue mentioned in Footnote x can be directly addressed by restrictions on the ownership of generation facilities.[58]

Net metering with per-kWh charges to cover distribution cost is an important reason why residential PV generation is more heavily subsidized than utility-scale PV generation. In addition, net metering raises equity issues: it is far from obvious that it is fair for consumers with rooftop PV generators to shift the burden of covering fixed distribution costs to renters and others without such systems. Chapter 7 discusses the use of reference network models to allocate distribution costs among utility customers according to how their network usage profile contributes to those costs.[58]
The discussion in Chapter 7 also notes the existence of a host of implementation issues, however, including the political acceptability of potentially very different charges for apparently similar network users. Because of the problems associated with net metering, research directed at developing a more efficient, practical, and politically acceptable system for covering fixed network costs should be a high priority.

While the current system of policies to support solar deployment in the United States is needlessly wasteful, it does not follow (and we do not believe) that such support should be ended. As noted at several points, we favor continued support of solar deployment in order to encourage industrial research and develpment and work on institutional and other barriers to greater reliance on solar energy and to produce environmental benefits. As the recommendations above make clear, however, we believe that the system of solar support policies should be reformed to increase its efficiency, so that more solar generation is produced per taxpayer and electricity-consumer dollar spent.

RECOMMENDATION:

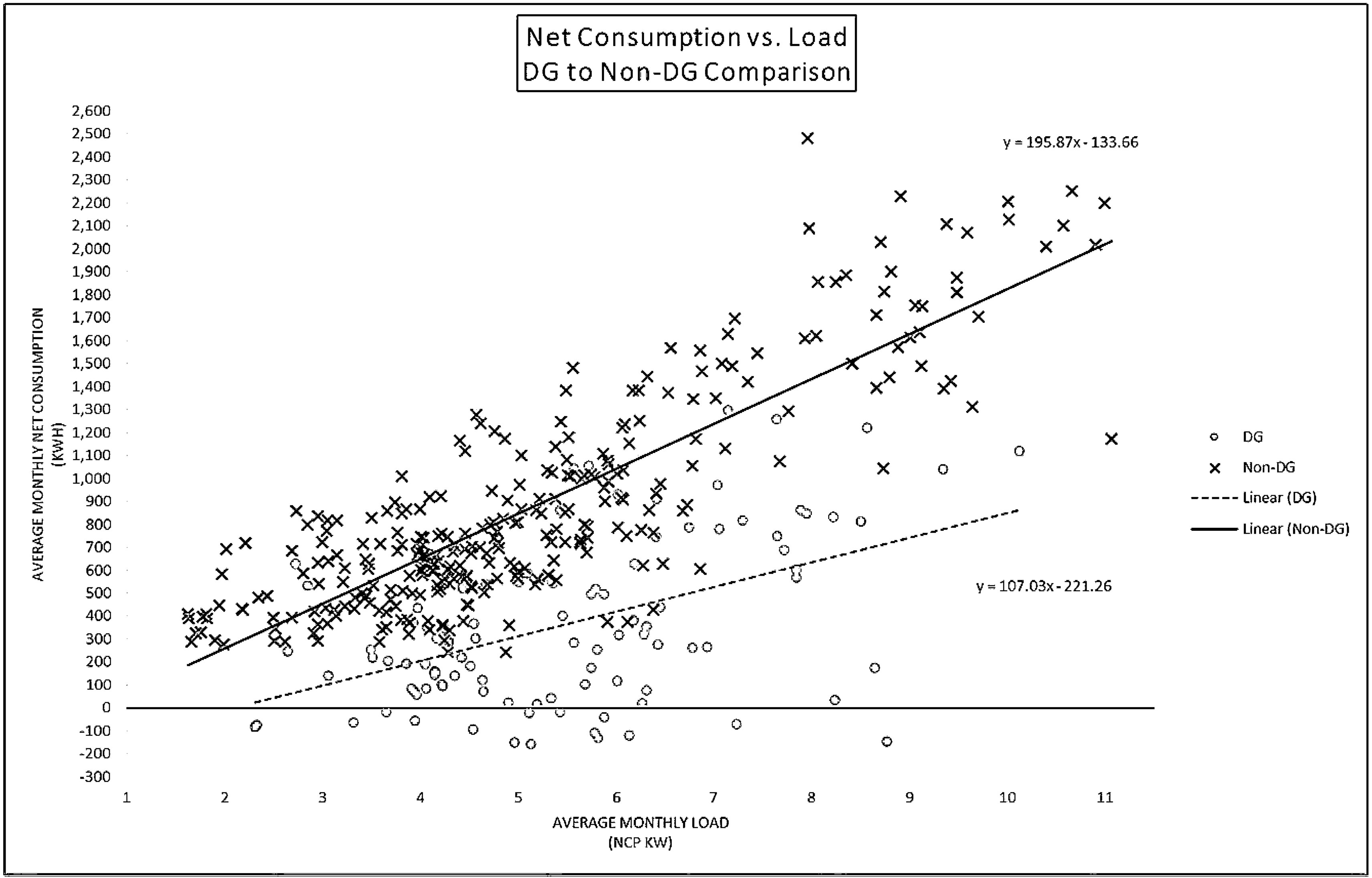
Research should be undertaken to develop workable methods for using reference network models to design pricing systems that cover fixed network costs via charges that depart from simplistic proportionality to electricity consumption and that respect the principle of cost causality.

Public Utility Commission of Texas
Comparison of Utilities' Generic T&D Rates
Updated: March 1, 2017

Generic Transmission and Distribution Rates

Class	CenterPoint - Docket 38339/41072			Oncor - Docket 38929		AEP	TCC	TNC	TNMP - Docket 38480		Sharyland - Docket 41474		Sharyland McAllen - Docket 40332	
	Charges			Charges		Charges	D-33309	D-33310	Charges		Charges		Charges	
Residential	Customer Charge (per customer)	$1.62		Customer Charge (per customer)	$0.78	Customer Charge (per customer)	$3.19	$2.94	Customer Charge (per customer)	$4.00	Customer Charge (per customer)	$5.69	Customer Charge (per customer)	$3.19
	Metering Charge (per customer)	$3.85		Metering Charge (per customer)	$2.28	Metering Charge (per customer)	$3.55	$5.24	Metering Charge (per customer)	$1.25	Metering Charge (per customer)	$4.31	Metering Charge (per customer)	$3.55
	Transmission Charge (per kWh)	$0.008439		Transmission Charge (per kWh)	$0.000000	Transmission Charge (per kWh)	$0.005190	$0.005803	Transmission Charge (per kWh)	$0.000000	Transmission Charge (per 4CP kW)	See TCRF	Transmission Charge (per 4CP kW	$1.88
	Distribution Charge (per kWh)	$0.016489		Distribution Charge (per kWh)	$0.018583	Distribution Charge (per kWh)	$0.013915	$0.019007	Distribution Charge (per kWh)	$0.017347	Distribution Charge (per kWh)	$0.062669	Distribution Charge (per kW)	$7.66
Secondary	Customer Charge (per customer)	$1.61		Customer Charge (per customer)	$1.71	Customer Charge (per customer)	$3.20	$4.25	Customer Charge (per customer)	$2.50	Customer Charge (per customer)	$9.53	Optional Residential	
≤ 10 kW	Metering Charge (per customer)	$4.41		Metering Charge (per customer)	$5.19	Metering Charge (per customer)	$3.68	$7.50	Metering Charge (per customer)	$2.20	Metering Charge (per customer)	$13.17	Customer Charge (per customer)	$3.19
(or kVA)													Metering Charge (per customer)	$3.55
(TNMP 5 kW)	Transmission Charge (per kWh)	$0.004437		Transmission Charge (per kWh)	$0.000000	Transmission Charge (per kWh)	$0.002512	$0.003148	Transmission Charge (per kWh)	$0.000000	Transmission Charge (per kWh)	See TCRF	Energy (per kWh)	$0.035988
	Distribution Charge (per kWh)	$0.012218		Distribution Charge (per kWh)	$0.020109	Distribution Charge (per kWh)	$0.015489	$0.031948	Distribution Charge (per kWh)	$0.033323	Distribution Charge (per kWh)	$0.051640		
Secondary	Customer Charge (per customer)			Customer Charge (per customer)	$6.80	Customer Charge (per customer)							Customer Charge (per customer)	$26.52
> 10 kW	Non-IDR customers	$2.26				Non-IDR customers	$3.26	$4.25	Customer Charge (per customer)	$2.56	Customer Charge (per customer)	$16.71		
(or kVA)	IDR Customers	$65.83		Metering Charge (per customer)	$22.14	IDR Customers	$26.52	$26.00					Metering Charge (per customer)	$15.81
(TNMP 5 kW)									Metering Charge (per customer)	$10.74	Metering Charge (per customer)	$24.53		
	Metering Charge (per customer)			Transmission Charge (per kW)	$0.00	Metering Charge (per customer)								
	Non-IDR customers	$18.82				Non-IDR Customers	$15.81	$18.68						
	IDR Customers	$63.07		Distribution Charge (per kW)		IDR Customers	$15.81	$35.00	Transmission Charge (per kW)		Transmission Charge	See TCRF	Transmission Charge (per 4CP kW	$1.79
				NCP ≤ 20 kW	$4.38				Non-IDR customers	$0.0000				
	Transmission Charge			NCP > 20 kW, Load Factor 0 - 10%	$6.10	Transmission Charge			IDR Customers	$0.0000				
	Non-IDR Customers (per NCP kVA	$1.4318		NCP > 20 kW, Load Factor 11 - 15	$5.47	Non-IDR Customers (per NCP kW)	$1.286	$1.245					Distribution Charge (per kW)	$6.95
	IDR Customers (per 4CP kVA)	$2.2387		NCP > 20 kW, Load Factor 16 - 20	$5.16	IDR Customers (per 4CP kW)	$1.793	$1.953	Distribution Charge (per NCP kW)		Annual Load Factor (per Disbribution Billing kW)			
				NCP > 20 kW, Load Factor 21 - 25	$5.01				Non-IDR Customers	$6.0981	0% - 25%	$13.47		
	Distribution Charge (per kVA)	$3.059429		NCP > 20 kW, Load Factor ≥ 26%	$4.38	Distribution Charge (per NCP kW)	$3.314	$3.21	IDR Customers	$5.2808	26% and above	$12.29		
Primary	Customer Charge (per customer)		Primary	Customer Charge (per customer)	$4.00	Customer Charge (per customer)			Customer Charge (per customer)	$34.50	Customer Charge (per customer)	$10.06	Customer Charge (per customer)	$28.41
	Non-IDR customers	$3.58	≤ 10 kW	Metering Charge (per customer)	$12.62	Non-IDR customers	$3.80	$4.25						
	IDR Customers	$76.73		Transmission Charge (per kWh)	$0.000000	IDR Customers	$28.41	$26.00						
				Distribution Charge (per kWh)	$0.005551				Metering Charge (per customer)	$204.98	Metering Charge (per customer)	$19.87	Metering Charge (per customer)	$154.62
	Metering Charge (per customer)		Primary	Customer Charge (per customer)	$14.95	Metering Charge (per customer)								
	Non-IDR customers	$181.35	> 10 kW	Metering Charge (per customer)	$24.69	Non-IDR Customers	$154.62	$151.75						
	IDR customers	$138.40	Distrib.			IDR Customers	$154.62	$168.65	Transmission Charge (per kW)		Transmission Charge (per kW)	See TCRF	Transmission Charge (per 4CP kW	$1.925
				Transmission Charge (per kW)	$0.00				Non-IDR customers	$0.0000				
	Transmission Charge					Transmission Charge			IDR Customers	$0.0000				
	Non-IDR Customers (per NCP kVA	$1.7033		Distribution Charge (per kW)	$3.37	Non-IDR Customers (per NCP kW)	$1.628	$1.189			Distribution Charge (per kW)	$8.70	Distribution Charge (per kW)	$5.082
	IDR Customers (per 4CP kVA)	$2.1546	Primary	Customer Charge (per customer)	$76.61	IDR Customers (per 4CP kW)	$1.925	$1.963	Distribution Charge (per NCP kW)					
			> 10 kW	Metering Charge (per customer)	$221.32				Non-IDR Customers	$4.7102				
	Distribution Charge (per kVA)	$2.002820	Substat.	Transmission Charge (per kW)	$0.00	Distribution Charge (per NCP kW)	$2.945	$1.88	IDR Customers	$5.1286				
				Distribution Charge (per kW)	$0.93									
Transmission	Customer Charge (per customer)	$154.44		Customer Charge (per customer)	$114.51	Customer Charge (per customer)	$38.84	$24.80	Customer Charge (per customer)	$214.51	Customer Charge (per customer)	$64.06	Customer Charge (per customer)	$38.84
	Metering Charge (per customer)	$1,449.82		Metering Charge (per customer)	$239.29	Metering Charge (per customer)	$1,869.15	$850.00	Metering Charge (per customer)	$1,751.67	Metering Charge (per customer)	$99.16	Metering Charge (per customer)	$1,869.15
	Transmission Charge (per 4CP kVA	$2.1188		Transmission Charge (per 4CP kW	$0.00	Transmission Charge (per 4CP kW)	$1.718	$1.356	Transmission Charge (per 4CP kVA	$0.0000	Transmission Charge (per 4CP kVA)	See TCRF	Transmission Charge (per 4CP kW	$1.718
	Distribution Charge (per 4CP kVA)	$0.463296		Distribution Charge (per kW)	$0.58	Distribution Charge (per NCP kW)	$0.199	$0.0182	Distribution Charge (per 4CP kVA	$0.0000	Distribution Charge (per kW)	$0.08	Distribution Charge (per NCP kW)	$3.153

Attachment WBA-CR-2



Attachment WBA-CR-3