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APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY

AND

WORKPAPERS

OF

EVAN D. EVANS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

October 26, 2022

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DIRECT TESTIMONY AND WORKPAPERS OF EVAN D. EVANS

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ACRONYMS AND ABBREVIATIONS

AEP	American Electric Power Company
AMS	Advanced Metering System
CSW	Central and South West Corporation
DCRF	Distribution Cost Recovery Factor
DMS	Distribution Management System
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ETI	Entergy Texas, Inc.
FERC	Federal Energy Regulatory Commission
MDD	Maximum Diversified Demand
MISO	Midcontinent Independent System Operator, Inc.
NCP	Non-Coincident Peak or Non-Coincident Maximum Peak
NMPRC	New Mexico Public Regulation Commission
O&M	Operations and Maintenance
OMS	Outage Management System
OPUC	Office of Public Utility Counsel
PUCT	Public Utility Commission of Texas
Rider MVDR	Market Value Demand Response Rider
ROR	Rate of Return
RROR	Relative Rate of Return
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

SPS	Southwestern Public Service Company
TE	Transportation Electrification

I. WITNESS IDENTIFICATION AND SCOPE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Evan D. Evans. My business address is 101 Merlot Drive, Abilene, Texas 79602.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Office of Public Utility Counsel ("OPUC").

Q. PLEASE IDENTIFY BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am a principal and a consultant with Integrity Power Consulting, LLC. Integrity Power Consulting was established in 2003, and it provides consulting services to government agencies, and retail utility customers and customer groups. Integrity Power Consulting is also a registered electricity broker with the Public Utility Commission of Texas ("PUCT" or "Commission").

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Texas Tech University with a Bachelor of Business Administration degree in Finance in May 1980.

Upon graduation, I was employed at West Texas Utilities Company, a wholly-owned subsidiary of Central and South West Corporation ("CSW"), which was acquired by American Electric Power Company ("AEP") in June 2000. During my 20-year career with CSW and AEP, I held a variety of analytical, consultant, and management positions in the rates, regulatory services, load research, and marketing and business development areas.

In October 2000, I joined C.H. Guernsey & Company, now known as Guernsey Associates, which is an employee-owned consulting firm offering engineering, architectural, economic, and construction management services to utilities, industries, and government agencies throughout the United States and internationally. While employed with Guernsey, I managed the firm's Dallas regional office and provided consulting services to electric utility industry clients in a variety of areas, including regulatory compliance, integrated resource planning, electric utility cost of service issues, rate studies, financial analysis, economic feasibility analysis, retail electric choice, and wholesale power supply contract negotiations.

In September 2006, I left Guernsey and accepted the position of Director-Regulatory Services with El Paso Electric Company ("EPE"). I was promoted to Assistant Vice President-Regulatory Services and Rates in July 2008. While at EPE, I established the company's Regulatory Case Management and Energy Efficiency & Utilization departments. My responsibilities included direction of EPE's Energy Efficiency & Utilization, Economic & Rate Research, Regulatory Case Management, and Regulatory Accounting departments and their associated missions.

In January 2014, I began my employment with Xcel Energy as Regional Vice President – Rates and Regulatory Affairs for Southwestern Public Service Company ("SPS"). In March 2017, I became Director – Regulatory and Pricing Analysis for SPS. My responsibilities included:

- developing and implementing SPS's regulatory program to ensure SPS fulfilled all legal and regulatory requirements of the PUCT, the New Mexico Public Regulation Commission ("NMPRC"), and the Federal Energy Regulatory Commission ("FERC");
- directing the development and execution of all regulatory case filings before state commissions and the FERC;
- leading regulatory activities to establish and maintain state and federal commission relationships and overseeing the administration of regulatory rules and procedures; and
- directing the cost allocation and pricing functions for SPS.

In October 2020, I left SPS and began working as a principal and consultant with Integrity Power Consulting.

Q. HAVE YOU TESTIFIED BEFORE THIS REGULATORY COMMISSION OR ANY OTHER REGULATORY AUTHORITIES?

A. Yes. I have testified in numerous cases or dockets and on a variety of subjects before the PUCT, the NMPRC, the Georgia Public Service Commission, and the Oklahoma Corporation Commission. I have also submitted testimony before the FERC. A list of prior cases in which I submitted testimony during the last 10 years is provided in Attachment EDE-1.

II. PURPOSE AND SCOPE OF TESTIMONY

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

A. In this testimony, I will address the following areas in Entergy Texas, Inc.'s ("ETI") filed request and testimony:

- The recovery of the costs for backup generators for HEB;

- The impact of the deployment of the approved Advanced Metering System ("AMS") plan on ETI's costs;
- Allocation of distribution costs;
- The proposed distribution of the revenue increase among customer classes:
- ETI'S proposed changes to customer charges for Residential Service and Small General Service; and
- ETI's proposed Transportation Electrification ("TE") riders.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS IN THE AREAS LISTED ABOVE.

A. I make the following recommendations based upon my review of ETI's filing:

- The investment in the HEB Backup Generators, all associated costs, and the revenues associated with providing that service to HEB should be removed from ETI's cost of service;
- Consideration of the costs associated with the HEB Backup Generators should be moved to ETI's recent filing for the "Power Through" initiative, Docket No. 53992;[1]
- ETI's delayed implementation of its AMS Plan and its impact on costs should be considered in the distribution of the approved revenue increase among customer classes;
- The Commission should investigate whether ETI has delivered all of the benefits they promised would result from the implementation of their AMS Plan approved in Docket No. 47416;[2]

[1] *Entergy Texas, Inc.'s Statement of Intent and Application for Approval of Rate Schedule UODG (Utility Owned Distributed Generation)*, Docket No. 53992 (Aug. 31, 2022).

[2] *Application of Entergy Texas, Inc. for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Docket No. 47416 (Dec. 14, 2017).

- The class cost of service should be modified to only use the Maximum Diversified Demands ("MDD") and Non-Coincident Peaks ("NCP") for allocating ETI's distribution demand-related costs;
- In the alternative, the demand allocators for distribution line transformers and secondary lines should be modified to exclude NCPs for the month of February due to the unprecedented impact of Winter Storm Uri on customers' demands;
- The following directives should be followed in the final revenue distribution approved in this case:
    - Revenue increases should be assigned such that all classes are moved as close to unity as possible, without violating the other directives;
    - The proposed revenues for all classes should produce at least 0.95 times the system average rate of return ("ROR") and no class produces greater than 1.05; and
    - If possible, consistent with ETI's proposed revenue increase distribution, the increase for all classes should range from a minimum of 0.5 times the system average to a maximum of 1.5 times the system average.
- The customer charges for Residential Service and Small General Service appear to require considerable increases to recover full customer component costs. The increases to the customer charges should be moderated and should not be increased by more than 1.5 times the average increase energy charges approved for each of these classes;
- TECI-1 Rider customers should be required to reimburse the Company for the cost of construction and installation of New Facilities necessary to extend electric service to the Transportation Electrification ("TE") charging infrastructure in excess of one year's anticipated annual base revenues, instead of ETI's proposal of four years' anticipated annual base revenues;
- ETI should be required to maintain separate accounting for all investment, depreciation expense and other costs associated with the TECI-1 program and promotion of that program for consideration in ETI's next base rate case;

- All rate case expenses relative to the TECI-1 and TECDA-1 riders should be recorded separately and should not be recovered from Residential Service or other non-participating customer classes;
- If the TECDA-1 Rider is approved, the rider should expire when new rates are approved in ETI's next base rate case, unless it is approved in that base rate case;
- The under-recovered demand revenues that result from the application of the billing demand cap in the TECDA-1 Rider should not be borne by other customers; and,
- In the interest of efficiency and productivity, TE issues for all four vertically-integrated, non-ERCOT investor-owned electric utilities and the consideration of the TECI-1 Rider and the TECDA-1 Rider should be addressed in a separate case specifically to consider TE issues for the four utilities at the same time.

III. COSTS FOR BACKUP GENERATORS INSTALLED FOR HEB

Q. PLEASE DESCRIBE ETI'S REQUEST RELATIVE TO THE HEB BACKUP GENERATORS.

A. ETI is requesting the inclusion of two generation additions that were installed to provide backup generation facilities located at two separate HEB stores served by ETI. The stores are located in Beaumont, Texas and in The Woodlands, Texas. Each backup generation project includes three 400 kilowatt ("kW") natural gas generators, totaling 1.2 megawatts ("MW") of capacity each. These backup generators were installed to supply power to these HEB stores during an outage. The total investment requested by ETI for these projects is $2,504,023.[3]

[3] Direct Testimony of Stuart Barrett at 27:2 – 15.

ETI witness, Stuart Barrett, asserts that when the backup generators are not supplying power to the HEB stores during an outage they "are available to supply power to the grid to mitigate energy prices during favorable market conditions."[4] He also asserts, "Through these experimental programs, ETI is gaining experience to potentially broaden the scope and availability of backup service to a broader customer base."[5] On August 31, 2022, ETI filed Docket No. 53992, ETI's Statement of Intent and Application for Approval of Rate Schedule UODG (Utility-Owned Distributed Generation), that is an integral part of ETI's proposed "Power Through" initiative, which would include the HEB backup generators.

Mr. Barrett also states, "HEB is billed for the backup service through the Company's Additional Facilities Charge Rider."[6] ETI is requesting the investment and associated costs for the HEB backup generators to be included in their cost of service, which would be borne by all customers. Furthermore, in response to OPUC's Seventh Request for Information, OPUC RFI No. 7-21, which is provided as Attachment EDE-2, ETI stated that during outages, HEB would pay system average fuel costs and not the cost of fuel used by the backup generators to supply their load.

The revenues ETI received during the test-year from HEB pursuant to charges under the Additional Facilities Charge Rider were allocated to all customer classes.

Q. WHAT COSTS DID ETI INCLUDE IN ITS REQUESTED COST OF SERVICE RELATED TO THE HEB BACKUP GENERATOR PROJECTS?

[4] Direct Testimony of Stuart Barrett at 27:16 – 19.

[5] *Id.* at 27:16 – 22.

[6] *Ibid.*

A. As stated previously, ETI included the original investment cost of $2,504,023 for these projects. In addition, ETI included depreciation expense for the investment. OPUC witness, Ms. Constance T. Cannady, addresses these costs in her testimony. In addition, in ETI's response to OPUC's RFI No. 7-20, ETI revealed that it incurred $65,239 in expenses, including $26,920 in non-fuel Operations and Maintenance ("O&M") expenses, $26,076 in fuel costs, $4,765 in Unplanned Maintenance expenses, and $7,478 in Property Taxes.

Q. IN ITS FILING, DID ETI QUANTIFY THE VALUE OF THE BENEFITS RECEIVED FROM THE HEB BACKUP GENERATORS AND COMPARE THOSE BENEFITS TO THE COST OF THE FACILITIES?

A. I did not find anywhere in ETI's filing that they quantified the value of the benefits they have asserted from the HEB Backup Generators. I also did not find any analysis that showed the value of the benefits ETI claims are provided by the HEB Backup Generators, plus the revenues from HEB pursuant to the Additional Facilities Charge Rider that justified the cost of the investment and all expenses associated with these generators.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE INVESTMENT, ASSOCIATED COSTS AND REVENUES FOR THE HEB BACKUP GENERATORS?

A. I recommend the investment in the HEB Backup Generators, all associated costs, and the revenues associated with providing that service to HEB be removed from ETI's cost of service. ETI has not provided testimony and evidence to adequately support these costs. I recommend the consideration of these costs be moved to ETI's recent filing for the Power Through initiative, Docket No. 53992.

IV. AMS DEPLOYMENT AND IMPACT ON COSTS

Q. PLEASE SUMMARIZE THE ISSUE RELATED TO ETI'S AMS DEPLOYMENT AND ITS IMPACT ON COSTS.

A. In Docket No. 47416, ETI filed its Application for Approval of An Advanced Metering System ("AMS") Deployment Plan, AMS Surcharge, and Nonstandard-Metering-Service Fees ("ETI AMS Plan"). In that plan, ETI supported its proposal based on various promised benefits, including:

- ETI purportedly identified $33.4 million dollars in cost savings, including significant reductions in Meter Reading expenses, Meter Services expenses, and reduced Customer Receivables Write-offs.[7]
- ETI claimed, "By implementing an AMS, ETI plans to harness these technology advancements to improve our operations and customer service capabilities."[8]
- ETI addressed extensively how the AMS implementation can help customers lower their bills by providing extensive usage information, enabling ETI to offer specifically-designed customer options, and promoting load shifting by providing customers with peak event notifications.[9]
- ETI noted the implementation of the new advanced Distribution Management System ("DMS") and Outage Management System ("OMS"), which were fully implemented in November 2020,[10] combined with the data from advanced meters, means the automatic rerouting of power due to an outage should lead to shorter and fewer overall outages and interruptions.[11]

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[7] Direct Testimony of Jay A. Lewis at 11:13 – 12:2 (Docket No. 47416).

[8] Direct Testimony of Hugh Vernon Pierce at 5:30 – 31 (Docket No. 47416).

[9] *Id.* at 15:1 – 18:8.

[10] Direct Testimony of William Phillips, Jr. at 14:17 – 23.

[11] Direct Testimony of Hugh Vernon Pierce at 17:4 – 17 (Docket No. 47416).

Q. DOES IT APPEAR THE BENEFITS PROMISED IN SUPPORT OF ITS AMS DEPLOYMENT ARE BEING REALIZED?

A. It does not appear that all promised benefits listed above are being realized. In the current case, Meter Reading and Meter Services expenses have declined, but Meter Reading expense has not been essentially eliminated, as was expected in ETI's AMS Plan. Also, the total customer-related costs for the Residential and Small General Service classes have increased substantially from ETI's last base rate case, Docket No. 48371,[12] to the current case.

In addition, ETI provided no evidence the Company has been effectively using the AMS to help customers lower their bills or provide more customer-specific options. Finally, the frequency and duration of outages that ETI's customers experienced have not declined but have increased since the Company began deploying AMS.[13]

Q. HOW HAS THE CUSTOMER-RELATED COSTS FOR RESIDENTIAL SERVICE AND SMALL GENERAL SERVICE CUSTOMERS INCREASED FROM ETI'S PREVIOUS RATE CASE TO THIS CASE?

A. The customer-related costs for Residential Service customers increased from $13.64 per customer per month in ETI's filed case in Docket No. 48371,[14] to $16.96 in the current

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[12] *Entergy Texas Inc's Statement of Intent and Application for Authority to Change Rates*, Docket No. 48371 (Dec. 20, 2018).

[13] ETI's Service Quality Report for 2018 filed in Project No.49068 and ETI's Service Quality Report for 2021 filed in Project No. 52946 and provided in Attachment EDE-10, pages 6 – 11.

[14] Direct Testimony of R. Phillip Griffin at 29:1 – 2 (Docket No. 48371).

case.[15] That reflects a 24.3% increase in customer-related costs for the Residential Service class.

The customer-related costs for the Small General Service class increased from \$19.45 per customer per month in ETI's filed case in Docket No. 48371,[16] to \$24.52 in the current case. That reflects a 26.1% increase in customer-related costs for the Small General Service class.

Q. HOW HAS ETI PERFORMED RELATIVE TO PROMOTING CUSTOMER SAVINGS AS A RESULT OF THE AMS PROVIDING CUSTOMERS WITH MORE ACCESS TO EXTENSIVE USAGE INFORMATION AND PROVIDING PEAK NOTIFICATION ALERTS?

A. I do not believe ETI has performed well in this area. In the current case, ETI is only proposing one new rate or service option that could take advantage of the availability of this information. This proposed new rate option is the Market Value Demand Response Rider ("Rider MVDR"). This rider defines the parameters under which customers or customer aggregators can participate in the Midcontinent Independent System Operator, Inc.'s ("MISO") demand response markets. However, because it simply defines how customers can participate in what is essentially a curtailable service program, this program has limited applicability and is not an option that I expect will attract a large number of participants.

[15] Direct Testimony of Crystal K. Elbe at 33:17 – 19.

[16] Direct Testimony of R. Phillip Griffin at 29:27 - 29 (Docket No. 48371).

In addition, ETI currently offers Time-of-Day rate options to Residential Service, General Service, Large General Service, and Large Industrial Power Service customers. At the end of the test-year, ETI had the following customer participation by rate:

- Residential Service - 32 out of 422,815, or 0.008%;
- General Service – 4 out of 20,085, or 0.020%;
- Large General Service – 2 out of 4658, or 0.043%; and
- Large Industrial Power Service – 8 out of 124, or 6.452%

The participation levels for all of the classes, except the Large Industrial Power Service class, are very low and indicate that very few customers are served under a rate that provides them with the ability to lower their costs by shifting their usage to off peak hours. Therefore, it appears that only 46 of ETI's customers have any real prospect of lowering their rate because of the increased usage information afforded by the AMS system. Furthermore, there is no indication in this rate case that ETI is pursuing creative pricing or service options that would increase the number of customers that could benefit from the increased usage information and lower their bills accordingly.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT THE FREQUENCY AND DURATION OF OUTAGES THAT ETI'S CUSTOMERS HAVE EXPERIENCED HAS INCREASED SINCE IT BEGAN DEPLOYING AMS?

A. This statement was based on a review of the Service Quality Report ETI filed for 2018,[17] the year before ETI began deploying AMS, and the Service Quality Report ETI filed for

[17] Entergy Texas, Inc. Service quality Report for 2018 Reporting Year, Project No. 49068.

2021,[18] the most recent year available. In the Service Quality Reports, utilities provide information on their System Average Interruption Frequency Index ("SAIFI"), which is the average frequency of outages that customers experience in a year, and System Average Interruption Duration Index ("SAIDI"), which is the average cumulative minutes of outage that customers experience in a year. ETI's SAIFI increased from 1.42 forced outages per year in 2018 to 1.455 forced outages per year in 2021, or a 2.5% increase in frequency of outages. ETI's SAIDI increased from 217.64 minutes of forced outages in 2018 to 220.7 minutes of forced outages in 2021, or an increase of 1.4% in forced outages.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING ETI'S AMS IMPLEMENTATION AND ITS IMPACT ON COSTS?

A. I am concerned that while Residential Service customers and Small General Service customers have been paying $2.92 per month and $4.28 per month, respectively, in AMS Surcharge fees since January 2018, over a year before ETI began deploying AMS, they are not seeing the cost savings and other benefits that ETI promised in its application.

In contrast, ETI is proposing significant increases in the customer charges for Residential and Small General Service customers. In addition, ETI has not proposed new rate options that would give Residential Service and Small General Service customers the opportunity to utilize the additional usage information provided by AMS and lower their bills. Finally, Residential Service and Small General Service customers, along with all

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[18] *CY 2021 Electric Utility Service Quality Report Under 16 TAC § 25.81*, Project No. 52946, ETI's Service Quality Report 2021 and Addendum. (Feb. 14, 2022).

other customers, have experienced a reduction in service reliability through more frequent and longer outages.

I recommend ETI's delayed implementation of its AMS Plan and its impact on costs be considered in the distribution of the approved revenue increase among customer classes. Also, now that ETI has completed deployment of its AMS meters and implemented their approved AMS Plan, I recommend the Commission investigate whether ETI has delivered all of the benefits they promised would result from the implementation of their AMS Plan approved in Docket No. 47416.

V. ALLOCATION OF DISTRIBUTION COSTS

Q. PLEASE DESCRIBE YOUR CONCERNS WITH ETI'S ALLOCATION OF DISTRIBUTION COSTS.

A. I have two concerns with ETI's allocation of distribution costs. First, although ETI uses customer and weather adjusted MDD, also called class peaks, the NCP demands ETI uses have not been adjusted to remove the effects of abnormal weather. My second concern is that ETI treats summer peak demands and winter peak demands equally in the development of its distribution demand allocators.

a. Weather Normalizing NCP Demands

Q. PLEASE EXPLAIN WHY IT IS A CONCERN THAT THE NCP DEMANDS ETI USED IN ITS DISTRIBUTION ALLOCATORS WERE NOT ADJUSTED FOR ABNORMAL WEATHER.

A. It is a fundamental principle of utility ratemaking, recognized in the Commission's rules[19] and case precedent,[20] that rates should be established reflecting normal operating conditions, or those conditions that are representative of the prevailing conditions when the approved rates are in effect. This is vitally important in this rate case because ETI's test-year includes February 2021, when Winter Storm Uri struck Texas and the ETI service territory. Areas throughout Texas, including ETI's service territory, experienced record low temperatures for extended periods of time. If the demand allocators for weather-sensitive customer classes are not normalized, then the demand allocators for those classes will be abnormally high and cause more costs to be allocated to those weather sensitive classes.

Q. WHERE DO THE COMMISSION'S RULES ADDRESS WEATHER-NORMALIZATION RELATIVE TO DISTRIBUTION RATES?

A. The Commission's Distribution Cost Recovery Factor ("DCRF") rule, 16 Texas Administrative Code ("TAC") § 25.243, sets out a clear expectation that the data used is to be weather-normalized. The "Definitions" section[21] contains the following definition:

> (5) **Weather-normalized** -- Adjusted for normal weather using weather data for the most recent ten calendar years.

In addition, the "Calculation of DCRF" section[22] states,

> $BD_{C\text{-}CLASS}$= Rate Class Billing Determinants (**weather-normalized** and adjusted to reflect the number of customers at the end of the period) for the

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[19] Including, but not limited to 16 TAC §§ 25.231(a), 25.231(b), 25.231(b)(1)(A), 25.231(c)(2)(B), 25.234(b), 25.243(b)(5), and 25.248(b)(6).

[20] Including, but not limited to Docket No. 43695, Order on Rehearing, Findings of Fact ("FOF) Nos. 238 -242 (Feb. 23, 2016) and Docket No. 51415, Final Order, FOF Nos.148 and 151 (Jan. 14, 2022).

[21] 16 TAC § 25.243(b)(5).

[22] 16 TAC § 25.243(d)(1).

> 12 months ending on the date used for purposes of determining the Current Net Distribution Invested Capital. For customer classes billed primarily on the basis of kilowatt-hour billing determinants, the DCRF shall be calculated using kilowatt-hour billing determinants. For customer classes billed primarily on the basis of demand billing determinants, the DCRF shall be calculated using demand billing determinants.

Consequently, this provides clear direction that the Commission expects weather-normalized data to be used in ratemaking for distribution rates.

Q. HOW ARE NCP DEMANDS USED IN ETI'S COST ALLOCATION?

A. ETI witness Crystal K. Elbe stated that ETI used "(A)n allocation factor that consists of a 50/50 weighting of the MDD and the Non-Coincident Maximum Demand ("NCP") of each rate class" to allocate the investment in line transformers and secondary lines.[23]

Q. WERE BOTH THE MDD AND NCP DEMANDS ETI USED IN THEIR DISTRIBUTION ALLOCATORS WEATHER-NORMALIZED?

A. No. ETI used weather-normalized MDD, but used NCP demands that were not weather-normalized in the development of its distribution allocators.

Q. HOW MANY CUSTOMER CLASSES WERE IMPACTED BY ETI'S DECISION TO USE NCP DEMANDS THAT WERE NOT WEATHER-NORMALIZED?

A. Ultimately, all retail classes served from secondary facilities were impacted by ETI's decision not to use weather-normalized NCP demands in its allocators because issues with the demand of one or more customer classes affects the allocation to all classes. In addition, ETI did not provide weather-normalized NCP demands for the test-year in its filing.

[23] Direct Testimony of Crystal K. Elbe at 18:17 – 19:11.

However, I believe the customer classes that were most impacted were those that had annual NCP demands that occurred in February. These classes include:

- Residential;
- General Service – Secondary; and
- Roadway Lighting.

Q. HAVE YOU REVIEWED THE IMPACT ON THE RESIDENTIAL SERVICE CLASS OF THE ABNORMAL WEATHER IN FEBRUARY 2021?

A. Yes. Attachment EDE-3 contains a graph of the monthly NCP demands for the Residential Service class that ETI used in the development of its demand allocator for distribution secondary investment. This graph reveals the historically cold weather in February 2021 caused the NCP for that month to be dramatically higher than the NCPs for any other months during the test-year.

Attachment EDE-4 contains a comparison of the monthly MDD for the Residential Service class for the test-year, without weather adjustments to the monthly MDD that were weather-normalized. This graph clearly reveals the impact of weather adjustments on the monthly demands for the Residential Service class. Without the weather adjustments, the maximum MDD in February was significantly larger than the MDD for any other month. However, after ETI weather-normalized the MDD, July's MDD became the annual maximum.

Consequently, one would reasonably assume that if NCP demands for Residential and other classes were weather-normalized, the annual maximum NCPs will also change.

Q. DOES ETI EXPECT THE ANNUAL NCP FOR THE RESIDENTIAL SERVICE CLASS TO TYPICALLY OCCUR IN FEBRUARY?

A. No. Schedule O-7.1, pages 6 – 7, contains ETI's forecasted monthly NCP demands at the meter and at the source for the next three calendar years, January 2023 through December 2025. Attachment EDE-5 is a graph of the forecasted monthly NCP demands at the source for Residential Service. This graph clearly shows ETI forecasts the NCPs for Residential Service for February to be one of the lower months and for the Residential Service class to have significantly larger annual NCPs in August of each year. Consequently, in designing its system, ETI plans for the Residential Service class to have its annual NCP in the summer months, and not in February.

Q. IS IT REASONABLE FOR ETI TO HAVE NOT NORMALIZED THE NCP DEMANDS IN THIS RATE CASE?

A. No. It cannot be denied that February 2021's Winter Storm Uri was an extraordinary and historic event that was anything but "normal." Consequently, the extraordinarily high demands that occurred during that period should not be used in developing allocators or in setting rates, as ETI has proposed. ETI advocates for normalization throughout its filed base rate case, including in its other demand allocators, but failed to normalize the class NCP allocators.[24] It is not reasonable to allocate ETI's distribution costs using NCP demands that have not been weather-normalized.

b. Recognizing Seasonal Impacts in Demand Allocators

Q. PLEASE EXPLAIN THE CONCERN WITH ETI TREATING SUMMER AND WINTER LOADINGS EQUALLY.

[24] Schedule P-7.2, pages 25 – 26.

A. Electric utilities design and construct their distribution systems and facilities to serve the forecasted annual peak loads for those systems and facilities. For investor-owned utilities in Texas, it is unusual for distribution substations, primary lines, and secondary lines to peak in the winter months. In addition, due to the lower ambient temperatures and higher typical wind speeds that prevail in winter months, distribution substations, conductors and line transformers can typically have higher ampacity, or current carrying capability, during winter months. That means that distribution transformers and conductors can be loaded higher in the non-summer months without approaching their peak operating temperature ratings. Distribution personnel typically consider that attribute in planning and designing their distribution systems and facility expansions.

In addition, the vast majority of distribution substations and distribution lines are designed to serve customers from multiple customer classes. As shown in Schedule O-7.1, pages 6 and 7, ETI forecasts the monthly NCP demands for Residential and Commercial customer classes to be significantly higher during the summer months of June through September than in any other months.

Q. HOW SHOULD THE SUMMER AND WINTER MONTH DEMANDS BE TREATED IN ALLOCATING DISTRIBUTION DEMAND COSTS?

A. It would be reasonable to weight the summer demands higher than winter demands in a manner that reflects the typical difference in the current carrying capabilities of distribution facilities between seasons and to reflect the percentage of facilities that were designed based upon forecasted summer or winter peak demands. In the alternative, if that information is not available, it would be reasonable to only use the MDDs and NCPs for summer months for each of the customer classes served at distribution.

Q. WHAT MODIFICATIONS DO YOU RECOMMEND FOR ETI'S DISTRIBUTION DEMAND ALLOCATORS?

A. Due to the fact that I did not have the information available to develop the seasonal weights for ETI's demands, I recommend the class cost of service should be modified to only use the MDDs and NCPs for summer months for each customer class for allocating ETI's distribution demand-related costs. This would reasonably resolve ETI's failure to weather-normalize its NCP demands and to reflect the fact that distribution facilities have higher current carrying capability during the non-summer months and are typically designed to meet summer peak demands. These modified allocators are presented in Attachment EDE-6.

In the alternative, at a minimum, I recommend that the demand allocators for distribution line transformers and secondary lines be modified to not include NCPs for the month of February due to the unprecedented impact of Winter Storm Uri on customers' demands. These alternative allocators are presented in Attachment EDE-7.

VI. REVENUE DISTRIBUTION

Q. PLEASE DISCUSS ETI'S PROPOSED REVENUE DISTRIBUTION.

A. ETI's revenue distribution, as reflected in Schedule Q-7, appears to move all classes close to system average rates of return between 1.5 times the system average base rate increase, including rider revenues, and no less than 0.5 times the system average increase.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING PROPOSED REVENUE DISTRIBUTION?

A. Based on the adjustments recommended by OPUC's witness, Ms. Cannady, I expect the overall base rate revenue requirement that is finally approved in this rate case will be substantially less than the level ETI has requested. I also know that cost allocation using an historical test-year is not an exact science that precisely allocates costs among customer classes such that the revenues actually recovered from each customer class will match their allocated costs. Therefore, I recommend the following directives be followed in the final revenue distribution approved in this case:

- Revenue increases should be assigned such that the proposed revenues for all classes will produce as close to system average ROR as possible, without violating the other directives;
- The proposed revenues for all classes should produce at least 0.95 times the system average rate of return ("ROR"), with no class producing greater than 1.05; and
- If possible, consistent with ETI's proposed revenue increase distribution, the increase for all classes should be less than 1.5 times the system average and greater than 0.5 times the system average increase.

VII. ETI'S PROPOSED CHANGES TO CUSTOMER CHARGES FOR RESIDENTIAL SERVICE AND SMALL GENERAL SERVICE

Q. PLEASE DESCRIBE ETI'S PROPOSED CHANGES TO THE MONTHLY CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE AND SMALL GENERAL SERVICE CLASSES?

A. ETI is proposing to increase the monthly customer charge for Residential Service from $10.00 to $16.96,[25] or approximately 70%. ETI is also proposing to increase the monthly customer charge for Small General Service from $14.19 to $24.52,[26] or approximately 73%.[27] In contrast, the average total non-fuel rate increase for Residential Service is 13.68% and the average total non-fuel rate increase for Small General Service is 7.12%.[28]

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE LEVEL OF INCREASES FOR THE RESIDENTIAL SERVICE AND SMALL GENERAL SERVICE CUSTOMER CHARGES?

A. Although I agree that the customer charges should be moved toward full cost, this is too drastic an increase to be made in one step. I am concerned that these large percentage increases in the customer charges will cause the lowest usage customers to bear significantly larger increases than average or larger customers. These large increases could have a wide range of unintended consequences such as causing some lower usage customers to be unable to pay their electric bills, which would lead to an increase in delinquent payments and bad debts. It could also cause customers, particularly the lower usage Small General Service customers, to cease taking service, which could cause facilities to be abandoned.

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[25] ETI's filed Schedule Q-7, page 1.

[26] *Id.* at pages 3-4.

[27] ETI's filed Schedule Q-7, pages 1 – 4.

[28] Attachment A to ETI's Application.

I am also concerned that large increases were made in these customer charges in ETI's previous rate case, Docket No. 48371, the customer charges for these rates may have been low for several rate cases or have always been low.

Finally, as mentioned earlier, I am concerned that ETI has not fully achieved the savings in meter reading costs that were expected in ETI's AMS Plan filing. In addition, the customer costs for these two classes have increased significantly, rather than decreasing, as was expected in the AMS Plan filing. Therefore, I do not believe that it would be prudent to make the drastic increases to these customer charges that ETI has proposes.

Q. WHAT IS YOUR RECOMMENDATION FOR THE CUSTOMER CHARGES FOR THE RESIDENTIAL SERVICE AND SMALL GENERAL SERVICE CUSTOMER CLASSES?

A. I recommend the customer charges for Residential Service and Small General Service be increased by 1.5 times the average increase in non-fuel rates approved for each of these classes. This approach will cause the customer charges to more fully recover the customer-related costs, without causing an inordinate percentage increase on the lowest usage customers for each class.

VIII. PROPOSED TRANSPORTATION ELECTRIFICATION RIDERS

Q. PLEASE DESCRIBE ETI'S PROPOSED TECI-1 RIDER.

A. The TECI-1 Rider is a rider that ETI seeks to offer non-residential customers the flexibility to choose the desired level of Transportation Electrification ("TE") infrastructure and equipment they would own and maintain and the level of TE equipment they would essentially lease from ETI. According to ETI's witness, Samantha F. Hill, the TECI-1 Rider is designed for non-residential customers, such as residential property developers, fleet managers, tax-exempt organizations including governmental agencies and schools, shore power ports, and business owners.[29]

According to Ms. Hill,

> ETI developed the TECI-1 Rider based on the rationale and methodology behind ETI's existing PUCT-approved AFC Rider, Option B. ETI developed the percentage-based rates under TECI-1 Rider by calculating level monthly payment percentages to be applied to the investment made by the Company using its pre-tax weighted-average cost of capital along with the insurance and property tax. The level monthly payment percentage was calculated for the Recovery Term period between 1 year and 10 years (as the Recovery Term cannot be longer than the expected book life of the infrastructure and equipment).[30]

Q. ARE THERE OTHER PROVISIONS OF THE TECI-1 RIDER IN ADDITION TO THE PROVISIONS RELATED DIRECTLY TO THE CHARGES FOR THE SPECIFIC TE INFRASTRUCTURE AND EQUIPMENT THAT WILL BE INSTALLED ON CUSTOMERS' PROPERTY?

A. Yes. Section V – Other Provisions, of the TECI-1 Rider tariff states,

> "Customers installing TE and charging infrastructure through the TECI Rider will not be required to reimburse the Company for the cost of construction and installation of New Facilities necessary to extend electric service to the TE charging infrastructure, including for the installation of underground infrastructure, as determined by the Company in its sole discretion for new TE and charging infrastructure load or incremental load for additional TE charging infrastructure, when projected Contract Revenues for the first four years of the contract term, if a

[29] Direct Testimony of Samantha F. Hill at 8:12 – 10:2.

[30] *Id.* at 17:8 – 21.

contract is required), or projected Revenues for the first four years after electric service to the TE and charging infrastructure is expected to commence (if no contract is required) is equal to or exceeds the Company's projected investment to construct and install the TE and charging infrastructure and any related infrastructure necessary to serve the TE and charging infrastructure new load."

In addition, in response to OPUC's RFI No. 8-9, which is attached as Attachment EDE-8, ETI stated the provision is intended to "extend new or upgraded service to customers without reimbursement for the costs when the projected revenue for the first four years of service for new or additional load is equal to or exceeds the Company's projected infrastructure investment."

Q. WILL THE PROVISION CONCERNING THE EXTENSION OR UPGRADE OF ETI'S FACILITIES TO SERVE NEW TE CHARGING INFRASTRUCTURE OR EXPANSION OF TE CHARGING INFRASTRUCTURE IMPACT OTHER CUSTOMERS?

A. Yes. Although ETI contends that this provision is consistent with its line extension policy, this level of unreimbursed extension of facilities would not be supported by ETI's proposed rates. Attachment EDE-9 contains an analysis of the amount of distribution rate base that is supported by ETI's proposed rates. The analysis clearly shows that ETI's proposed General Service rates only support a distribution rate base equal to 0.29 years of ETI's base revenues, which is significantly less than the four years anticipated base rate revenues that would be provided without charge pursuant to the TECI-1 Rider or ETI's current Extension Policy.[31]

[31] Schedule Q-8.8, pages 238 – 240.

Any additional investment that is not supported by additional base rate revenues will be included in ETI's rate base and will be borne by other customers. Consequently, this provision of the TECI-1 Rider will cause non-participating customers from all customer classes served at distribution voltages to bear additional costs.

Q. WHAT IS ETI'S POSITION RELATIVE TO NON-PARTICIPATING CUSTOMERS BEARING COSTS ASSOCIATED WITH THE TECI-1 RIDER?

A. ETI asserts that non-participating customers will not bear costs associated with the rider. Ms. Hill stated, "(T)he charges assessed under the TECI-1 Rider will only be charged to those customers who voluntary elect to enroll in the TECI-1 Rider, and no costs associated with the administration of the Rider will be imposed on any customers who have not elected to participate."[32]

Furthermore, in response to OPUC RFI No. 8-2, ETI stated, "The Customer Agreement attached as Exhibit SFH-3 to the Direct Testimony of Samantha F. Hill ensures that the host customer bears the responsibility for all of the infrastructure and equipment costs that it does not want to maintain, as well as the ongoing O&M costs." ETI also stated the legal liabilities, responsibilities, and obligations to pay for the costs of the TECI-1 Rider are included in the Customer Agreement entered into between ETI and the TECI-1 participating customer.[33]

Q. WILL ETI MAINTAIN A SEPARATE ACCOUNTING FOR ALL INVESTMENT IN TE INFRASTRUCTURE AND EQUIPMENT ASSOCIATED WITH THE

[32] *Id.* ar 16:1 – 6.

[33] Response of Entergy Texas, Inc. to OPUC's Eight Set of Data Requests, Question No. OPUC 8-2.

TECI-1 RIDER TO ENSURE THE INVESTMENT IS NOT INCLUDED IN ETI'S RATE BASE?

A. It appears the investment and depreciation expense will be kept separate from ETI's other rate base. ETI's response to OPUC RFI No. 8-3, seems to indicate the investment will be included in plant account 371 – Installations on Customers' Premises, and the associated depreciation will be booked to account 403 – Depreciation Expense. Also, all ongoing maintenance expenses associated with the TE infrastructure and equipment investment will be booked to distribution expense account 598 and operating expenses will be booked to distribution expense account 586. However, I am concerned that some portion of these costs would be borne by non-participating customers.

Q. DOES ETI INTEND TO RECOVER THE COSTS FOR ETI EMPLOYEES AND REPRESENTATIVES WHO CONSULT WITH POTENTIAL TECI-1 CUSTOMERS?

A. No. ETI intends to book the costs associated with representatives who consult with potential TECI-1 customers in Account 912 – Demonstration and Selling Expenses.[34] Consequently, these costs would be borne by all customers. In addition, it is not clear that ETI intends to assign to the TECI-1 program the costs incurred by representatives who draft and finalize the Customer Agreements with customers choosing to participate.

Q. DO YOU BELIEVE THAT NON-PARTICIPATING CUSTOMERS WILL BEAR COSTS ASSOCIATED WITH TECI-1?

[34] Response of Entergy Texas, Inc. to OPUC's Eight Set of Data Requests, Question No. OPUC 8-3.

A. Yes, I believe that non-participating customers will bear the costs of ETI employees and representatives who consult with potential TECI-1 customers and finalize the Customer Agreement with those customers that choose to participate in TECI-1. I also believe that non-participating customers may bear the operation and maintenance expense associated with the TE infrastructure and equipment investment. In addition, I am concerned that non-participating customers may be forced to bear any unrecovered costs when participating customers file for bankruptcy or otherwise default on paying their bills under the Rider. Finally, I am concerned that the other utilities and parties who have intervened in this docket specifically on the TE issues, will cause substantial rate case expenses that could be allocated to non-participating customer classes and customers.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE PROPOSED TECI-1?

A. Yes. I am concerned that the proposed TECI-1 Rider could limit the competitive offering of similar equipment and services in the competitive market. ETI already has contacts with most, if not all, of the potential customers and proposes to use personnel and equipment that are included in ETI's base rates to market the TECI-1 Rider. Therefore, ETI will have a regulated rate-subsidized competitive advantage over other potential participants. In addition, if ETI is permitted to have the fallback protection of recovering any costs of facilities from its electric service customers, ETI would have an additional advantage that is subsidized by its non-participating customers.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE TECI-1 RIDER?

A. I recommend the TECI-1 Rider customers be required to reimburse the Company for the cost of construction and installation of New Facilities necessary to extend electric service to the TE charging infrastructure in excess of one year's anticipated annual base revenues. That will strike a balance between ETI's proposal and the amount that is cost-justified. Also, ETI should be required to maintain separate accounting for all investment, depreciation expense and other costs associated with the TECI-1 program and promotion of that program for consideration in ETI's next base rate case. I also recommend that all rate case expenses relative to the TECI-1 Rider and the TECDA-1 Rider be separated and not allocated to Residential Service and other customer classes for which these riders are not applicable.

Q. PLEASE DESCRIBE ETI'S PROPOSED TECDA-1 RIDER.

A. The TECDA-1 Rider is designed to promote investment in the development and expansion of transportation electric charging infrastructure and shore power connections within ETI's service territory. This rider is applicable to customers who take service under ETI's General Service rate and who install separately metered charging equipment, whether the customer participates in ETI's proposed TEC-1 Rider or not.[35]

The primary component of the TECDA-1 rider is a provision that limits the amount of demand billed under Rate Schedule GS to a qualifying customer during any billing period in which the actual calculated load factor is less than 15%, so that the customer will not be billed for any demands that exceed the amount.[36] Therefore, for an average month, ETI will reduce the billing demand charges for customers who have high demands relative

[35] Direct Testimony of Samantha F. Hill at 27:5 – 9.

[36] *Id.* at 27:2 – 17.

to their kWh usage. However, ETI asserts that they only intend to offer this provision during the undefined "early adoption period" of electric vehicles.[37]

Q. WHAT IS ETI'S POSITION RELATIVE TO THE IMPACT OF THE TECDA-1 RIDER ON OTHER, NON-PARTICIPATING CUSTOMERS?

A. Ms. Hill states, "Application of the TECDA-1 Rider would not materially impact non-participating ETI customers."[38] That claim is based on a belief that the "safeguards" ETI is proposing will minimize any impact on non-participating customers.[39] The safeguards are that the TECDA-1 Rider will only be available to customers with loads less than or equal to 1500 kW and customers will only be able to use the TECDA-1 Rider for a term of five years. Furthermore, the TECDA-1 Rider will only be available to the first 30,000 kW of electric loads that enroll.[40]

However, ETI did not provide an estimate of the potential range of impacts the TECDA-1 Rider could have on non-participating customers within the General Service rate class. In addition, ETI did not limit the time period in which the TECDA-1 Rider would be available. As a result, the impact could continue indefinitely, with new participants added after the term limit for old participants is reached or they cease operations.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE PROPOSED TECDA-1 RIDER?

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[37] *Id.* at 36:2-5.

[38] *Id.* at 37:14-18.

[39] *Id.* 37:14 – 18.

[40] *Id.* at 38:1 – 7.

A. I am concerned the small commercial customers who do not participate in the TECDA-1 Rider, will be impacted by the billing demand cap provision of the TECDA-1 Rider. Therefore, I recommend that if the TECDA-1 Rider is approved, the rider will expire at ETI's next rate case, unless it is approved in that rate case. In addition, I recommend the under-recovered demand revenues that result from the application of the billing demand cap not be borne by other customers. Also, as discussed previously, I recommend that all rate case expenses relative to the TECI-1 Rider and the TECDA-1 Rider be separated and not allocated to Residential Service and other customer classes for which these riders are not applicable.

Q. DO YOU HAVE ANY COMPREHENSIVE RECOMMENDATIONS CONCERNING THE TECI-1 AND TECDA-1 RIDERS.

A. Yes, EPE and SPS have both intervened in this proceeding due to concerns specifically related to these riders and the potential impact that a decision in this case could have for all similar electric utilities. In addition, three other parties filed motions to intervene in this case, specifically related to these riders. Therefore, I do not believe the issues related to transportation electrification and the associated tariffs should be considered separately in each utility's rate case and burden each of those cases. I believe it would be more efficient and productive if these issues and the consideration of tariffs are addressed in a single case in which all of the common issues can be addressed for all four of the vertically-integrated investor-owned electric utilities in Texas: ETI, EPE, SPS and SWEPCO.

In addition, I am concerned about the potential impact of substantial rate case expenses on these issues in this rate case that could be allocated to Residential Service and other non-participating customer classes. Also, EPE and SPS should incur expenses addressing TE issues in this rate case that could be charged to Account 928 – Regulatory Commission Expenses at EPE and SPS. It would not be appropriate to recover EPE's and SPS's expenses related to TE issues in this case from residential customers in any future rate cases either EPE or SPS files because the TECI-1 and TECDA-1 riders do not apply to residential customers.

IX. CONCLUSION

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS CONTAINED IN THIS TESTIMONY.

A. In this testimony, I recommend the following:

- The investment in the HEB Backup Generators, all associated costs, and the revenues associated with providing that service to HEB should be removed from ETI's cost of service.
- Consideration of all costs associated with the HEB Backup Generators should be moved to ETI's recent filing for the "Power Through" initiative, Docket No. 53992;
- ETI's delayed implementation of its AMS Plan and its impact on costs should be considered in the distribution of the approved revenue increase among customer classes;
- The Commission investigate whether ETI has delivered all of the benefits they promised would result from the implementation of their AMS Plan approved in Docket No. 47416;
- The class cost of service be modified to only use the summer MDDs and NCPs for allocating ETI's distribution demand-related costs;

- In the alternative, the demand allocators for distribution line transformers and secondary lines should be modified to not include NCPs for the month of February due to the unprecedented impact of Winter Storm Uri on customers' demands;
- The following directives should be followed in the final revenue distribution approved in this case:
  - Revenue increases should be assigned such that all classes are moved as close to unity as possible, without violating the other directives;
  - The proposed revenues for all classes should produce at least 0.95 times the system average rate of return ("ROR"), with no class producing greater than 1.05; and
  - If possible, consistent with ETI's proposed revenue increase distribution, the increase for all classes should range from a minimum of 0.5 times the system average to a maximum of 1.5 times the system average;
- The customer charges for Residential Service and Small General Service appear to require considerable increases to recover full customer component costs. The increases to the customer charges should be moderated and should not be increased by more than 1.5 times the average increase in energy charges approved for each of these classes;
- TECI-1 Rider customers should be required to reimburse the Company for the cost of construction and installation of New Facilities necessary to extend electric service to the TE charging infrastructure in excess of one year's anticipated annual base revenues, instead of ETI's proposal of four years' anticipated annual base revenues;
- ETI should be required to maintain separate accounting for all investment, depreciation expense and other costs associated with the TECI-1 program and promotion of that program for consideration in ETI's next base rate case;
- All rate case expenses relative to the TECI-1 and TECDA-1 riders should be recorded separately and should not be recovered from Residential Service or other non-participating customer classes;

- If the TECDA-1 Rider is approved, the rider should expire when new rates are approved in ETI's next base rate case, unless it is approved in that base rate case;
- The under-recovered demand revenues that result from the application of the billing demand cap in the TECDA-1 Rider should not be borne by other customers; and,
- It would be more efficient and productive if TE issues for all four vertically-integrated, non-ERCOT investor-owned electric utilities and the consideration of the TECI-1 Rider and the TECDA-1 Rider are addressed in a separate case specifically to consider TE issues for the four utilities at the same time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to amend and supplement my testimony based on the receipt of any outstanding supplemental responses by ETI to OPUC's requests for information.

ATTACHMENTS
AND
WORKPAPERS

List of Prior Testimony
Filed by Evan D. Evans in Last 10 Years

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2022	Public Utilities Commission of Texas (PUCT)	53601	Application of Oncor Electric Delivery Company LLC for Authority to Change Rates	Office of Public Utility Counsel (OPUC)
2022	PUCT	52828	Application of Golden Spread Electric Cooperative, Inc. to Change Wholesale Transmission Service Rates	OPUC
2021	PUCT	52451	Application of Southwestern Public Service Company for Approval of Advanced Metering System (AMS), AMS Surcharge, and Non-Standard Metering Service Fees	OPUC
2021	PUCT	52195	Application of El Paso Electric Company to Change Rates	OPUC
2021	PUCT	51802	Application of Southwestern Public Service Company for Authority to Change Rates	OPUC
2021	PUCT	51415	Application of Southwestern Electric Power Company for Authority to Change Rates	Texas Cotton Ginners' Association
2021	New Mexico Public Regulation Commission (NMPRC)	20-00222-UT	Joint Application of Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., Public Service Company of New Mexico and PNM Resources, Inc. for Approval of the Merger of NM Green Holdings, Inc. with PNM Resources, Inc.	NMPRC Utility Division Staff
2019	NMPRC	19-00315-UT	Southwestern Public Service Company's Application for Approval of Continued Use of Its Fuel and Purchased Power Cost Adjustment Clause (FPPCAC)	Southwestern Public Service Company (SPS)
2019	PUCT	49831	Application of Southwestern Public Service Company for Authority to Change Rates	SPS

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List of Prior Testimony
Filed by Evan D. Evans in Last 10 Years

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2019	NMPRC	19-00170-UT	Southwestern Public Service Company's Application for Revision of Retail Rates under Advice Notice No. 282	SPS
2018	PUCT	48718	Application of Southwestern Public Service Company for Authority to Implement a Net Refund for Overcollected Fuel Costs	SPS
2017	NMPRC	17-00255-UT	Southwestern Public Service Company's Application for Revision of Retail Rates under Advice Notice No. 272	SPS
2017	PUCT	47527	Application of Southwestern Public Service Company for Authority to Change Rates	SPS
2017	PUCT	47369	Application of Southwestern Public Service Company for Authority to Implement a Fuel Surcharge	SPS
2017	PUCT	46936	Southwestern Public Service Company's Application for Approval of CCN and Operation of Wnd Generation Facilities	SPS
2017	NMPRC	17-00044-UT	Southwestern Public Service Company's Application for Approval of CCN and Operation of Wnd Generation Facilities	SPS
2016	NMPRC	16-00291-UT	Application of Soutwestern Public Service Company for an Accounting Order Related to Back-Billed Charges by the Southwest Power Pool	SPS
2016	PUCT	46496	Application of Soutwestern Public Service Company for an Accounting Order Related to Back-Billed Charges by the Southwest Power Pool	SPS
2016	NMPRC	16-00269-UT	Southwestern Public Service Company's Application for Revision of Retail Rates under Advice Notice No. 265	SPS

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List of Prior Testimony
Filed by Evan D. Evans in Last 10 Years

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2016	NMPRC	16-00263-UT	Application for Approval of Modification of Cost Recovery Methodology under Fuel and Purchased Power Cost Adjustment Clause	SPS
2016	PUCT	46075	Application of Southwestern Public Service Company for Authority to Implement a Net Base Rate Refund	SPS
2016	PUCT	46025	Application of Southwestern Public Service Company for Authority to Reconcile Fuel and Purchased Power Costs	SPS
2016	PUCT	45524	Application of Southwestern Public Service Company for Authority to Change Rates	SPS
2015	PUCT	45291	Application of Southwestern Public Service Company For Approval of Transaction with Xcel Energy Southwest Transmission Company, LLC and Related Approvals	SPS
2015	NMPRC	15-00343-UT	Southwestern Public Service Company's Application for Authorization to Form a Subsidiary and to Contribute Certain Transmission Assets to the Subsidiary	SPS
2015	NMPRC	15-00296-UT	Application of Southwestern Public Service Company for Revision of Its Retail Rates Under Advice Notice No. 258	SPS
2015	PUCT	45141	Application of Southwestern Public Service Company for Authority to Implement a Net Refund for Overcollected Fuel Costs	SPS
2015	NMPRC	15-00139-UT	In the Matter of SPS's Application for Revision of Its Retail Rates Under Advice Notice No. 255	SPS

Attachment EDE-1
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List of Prior Testimony
Filed by Evan D. Evans in Last 10 Years

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2015	PUCT	44671	Joint Application of SPS and Oncor Electric Delivery Company LLC for Approval of Accounting Entries Associated with the Purchase and Sale of Facilities, and for True-up of the Gain-on-Sale Calculation Associated with Docket No. 41430	SPS
2015	PUCT	44609	Application of SPS for Authorization to Refund Amounts Received from Tri-County Electric Cooperative, Inc. Associated with Docket No. 42004	SPS
2015	PUCT	44289	Application of SPS for Authority for Authority to Implement Surcharge Associated with Docket No. 42004	SPS
2014	PUCT	43695	Application of SPS for Authority to Change Rates	SPS
2014	PUCT	42004	Application of SPS for Authority to Change Rates and to Reconcile Fuel and Purchased Power Costs for the Period July 1, 2012 through June 30, 2013	SPS
2014	PUCT	42042	Application of SPS for Approval of a Transmission Cost Recovery Factor	SPS
2013	PUCT	41852	Application of EPE to Reconcile Fuel Costs	El Paso Electric Company (EPE)
2013	PUCT	41763	EPE's Application for a Certificate of Convenience and Necessity for Two Additional Generating Units at Montana Power Station in El Paso County	EPE
2013	NMPRC	13-00380-UT	EPE's Application for Continued Use of Fuel and Purchased Power Cost Adjustment Clause	EPE
2013	NMPRC	13-00297-UT	EPE's Application for a Certificate of Public Convenience and Necessity to Construct, Own and Operate Two Generating Units at Montana Power Station	EPE

Attachment EDE-1
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List of Prior Testimony
Filed by Evan D. Evans in Last 10 Years

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2013	NMPRC	13-00176-UT	EPE's Application for Approval of New and Modified Energy Efficiency Programs for 2014, 2015 and 20161	EPE
2012	NMPRC	11-00218-UT	Establishment of a Reasonable Cost Threshold for Renewable Resource Procurement pursuant to the Renewable Energy Act	EPE
2012	NMPRC	12-00137-UT	EPE's Application for A Certificate of Public Convenience and Necessity to Construct, Own and Operate Two Generating Units at Montana Site in Texas	EPE
2012	PUCT	40301	EPE's Application to Amend Its Certificate of Convenience and Necessity for Two Generating Units at Montana Site in Texas	EPE
2012	PUCT	40094	Application of EPE to Change Rates and Reconcile Fuel Costs	EPE

Attachment EDE-1
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ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Seventh Set of Data Requests of Requesting Party: Office of Public Utility Counsel	Prepared By: Chris Cahal Sponsoring Witness: Stuart Barrett Beginning Sequence No. EV2311 Ending Sequence No. EV2311

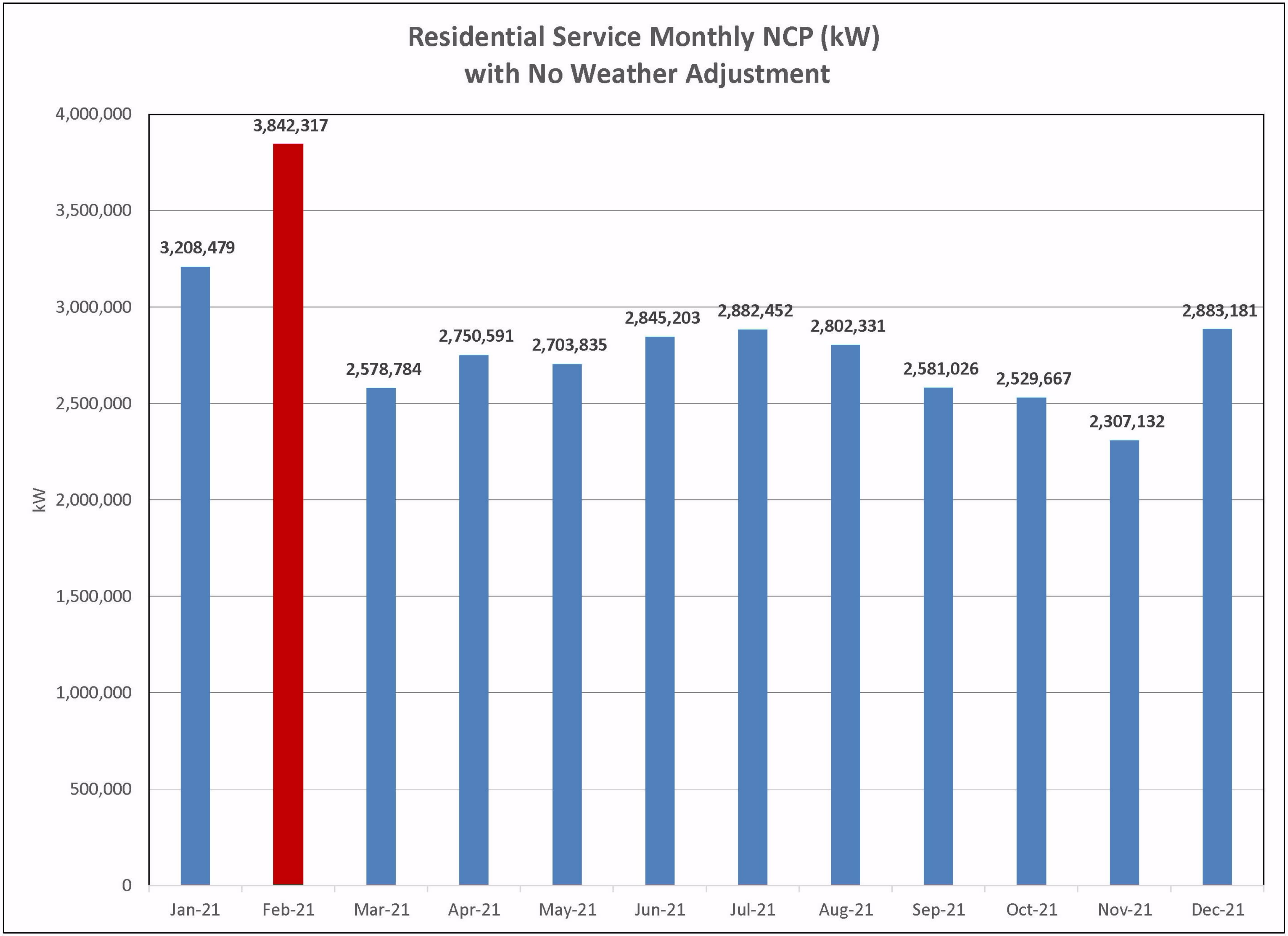
Question No.: OPUC 7-21 Part No.: Addendum:

Question:

In the instances in which outages occur and the H-E-B Backup Generators supply energy directly to the H-E-B customers' loads, do the customers pay the associated fuel cost or the system average fuel cost for the kWh generated by the backup generators?

Response:

The backup generators are electrically connected in-front-of-the-meter for the H-E-B locations. H-E-B will pay the system average fuel cost for the kWh generated as their utility meter will register electricity usage in relationship to the backup generator output.



Attachment EDE-3
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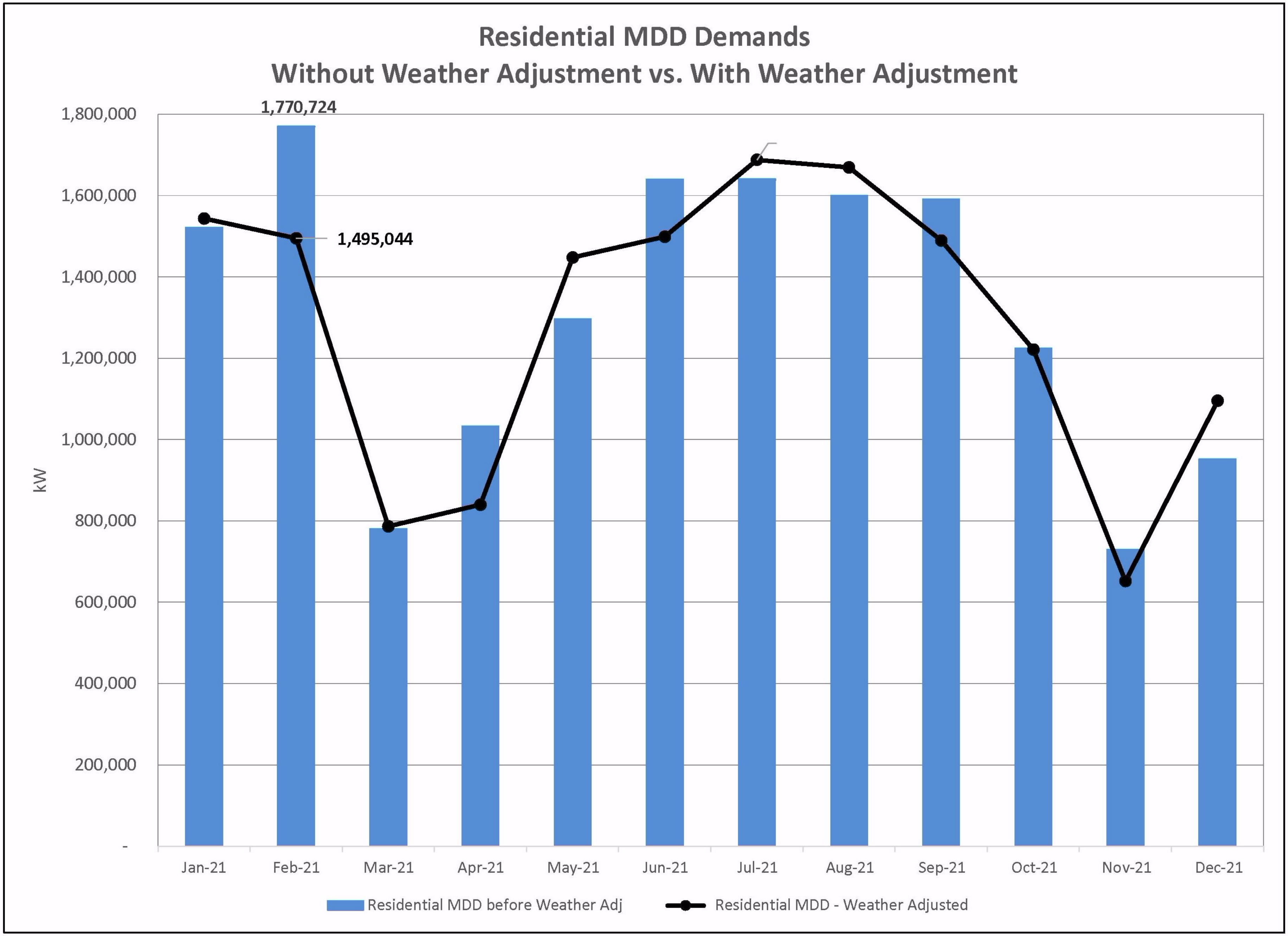
Native Files (public)

provided electronically



Attachment EDE-4
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Native Files (public)

provided electronically

Attachment EDE-5
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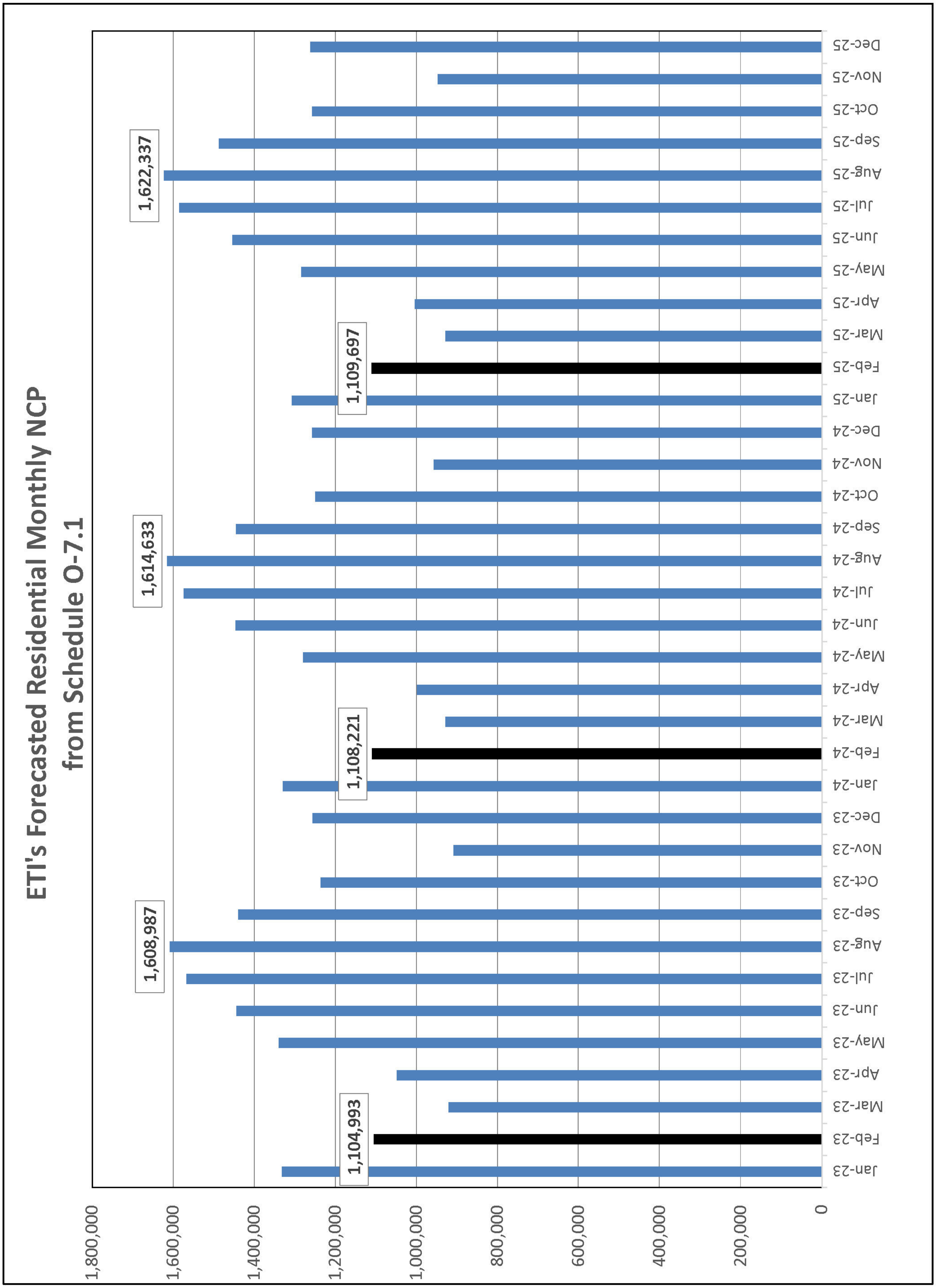

Native Files (public)

provided electronically

OFFICE OF PUBLIC UTILITY COUNSEL
Development of
Proposed Distribution Demand Allocators

Line No.	Class of Service	Class MDD @Meter kW	CLASS NCP @Meter kW	Demand Loss Factor %	Class MDD @Source kW	CLASS NCP @Source kW	Substations (MDD) kW	Primary Lines Demand (MDD) kW	Secondary Lines Demand (MDD+NCP)/2 kW	Line Transformer Demand (MDD+NCP)/2 kW
	Residential Service									
1	Secondary	1,687,852	2,882,452	7.8320%	1,820,045	3,108,206	1,820,045	1,820,045	2,464,126	2,464,126
	Small General Service									
2	Secondary	114,762	187,817	7.8320%	123,750	202,527	123,750	123,750	163,139	163,139
3	Primary	-	-	5.7220%	-	-	0	0	0	0
4	Total Small General Service	114,762	187,817		123,750	202,527	123,750	123,750	163,139	163,139
	General Service									
5	Secondary	665,591	891,941	7.8320%	717,720	961,798	717,720	717,720	839,759	839,759
6	Primary	25,938	34,757	5.7220%	27,422	36,746	27,422	27,422	N/A	N/A
7	Transmission Below 230 kV	5,854	8,988	1.0980%	5,918	9,086	N/A	N/A	N/A	N/A
8	Transmission Above 230 kV	-	-	0.2464%	-	-	N/A	N/A	N/A	N/A
9	Total General Service	697,383	935,686		751,060	1,007,630	745,142	745,142	839,759	839,759
	Large General Service									
10	Secondary	154,199	181,543	7.8320%	166,276	195,761	166,276	166,276	181,019	181,019
11	Primary	48,016	56,531	5.7220%	50,764	59,766	50,764	50,764	N/A	N/A
12	Transmission Below 230 kV	3,580	5,646	1.0980%	3,619	5,708	N/A	N/A	N/A	N/A
13	Total Large General Service	205,796	243,720		220,659	261,235	217,040	217,040	181,019	181,019
	Large Industrial Power Service									
14	Primary	82,242	110,315	5.7220%	86,948	116,628	86,948	86,948	N/A	N/A
15	Transmission Below 230 kV	626,899	758,336	1.0980%	633,783	766,662	N/A	N/A	N/A	N/A
16	Transmission 230 kV And Above	384,961	479,487	0.2464%	385,909	480,668	N/A	N/A	N/A	N/A
17	Total Large Industrial Power Service	1,094,103	1,348,138		1,106,640	1,363,958	86,948	86,948	0	0
	Roadway Lighting									
18	Secondary	8,459	8,459	7.8320%	9,122	9,122	9,122	9,122	9,122	9,122
	Non-Roadway Lighting									
19	Secondary	14,260	14,260	7.8320%	15,377	15,377	15,377	15,377	15,377	15,377
20	**Total Texas Retail**	3,822,614	5,620,531		4,046,653	5,968,055	3,017,424	3,017,424	3,672,541	3,672,541

Attachment EDE-6
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OFFICE OF PUBLIC UTILITY COUNSEL
Development of
Proposed Distribution Demand Allocators

Line No.	Class of Service	Substations %	Primary Lines Demand %	Secondary Lines Demand %	Line Transformer Demand %
	Residential Service				
1	Secondary	60.3178%	60.3178%	67.0959%	67.0959%
	Small General Service				
2	Secondary	4.1012%	4.1012%	4.4421%	4.4421%
3	Primary	0.0000%	0.0000%	0.0000%	0.0000%
4	Total Small General Service	4.1012%	4.1012%	4.4421%	4.4421%
	General Service				
5	Secondary	23.7859%	23.7859%	22.8659%	22.8659%
6	Primary	0.9088%	0.9088%	N/A	N/A
7	Transmission Below 230 kV	N/A	N/A	N/A	N/A
8	Transmission Above 230 kV	N/A	N/A	N/A	N/A
9	Total General Service	24.6946%	24.6946%	22.8659%	22.8659%
	Large General Service				
10	Secondary	5.5105%	5.5105%	4.9290%	4.9290%
11	Primary	1.6824%	1.6824%	N/A	N/A
12	Transmission Below 230 kV	N/A	N/A	N/A	N/A
13	Total Large General Service	7.1929%	7.1929%	4.9290%	4.9290%
	Large Industrial Power Service				
14	Primary	2.8815%	2.8815%	N/A	N/A
15	Transmission Below 230 kV	N/A	N/A	N/A	N/A
16	Transmission 230 kV And Above	N/A	N/A	N/A	N/A
17	Total Large Industrial Power Service	2.8815%	2.8815%	0.0000%	0.0000%
	Roadway Lighting				
18	Secondary	0.3023%	0.3023%	0.2484%	0.2484%
	Non-Roadway Lighting				
19	Secondary	0.5096%	0.5096%	0.4187%	0.4187%
20	**Total Texas Retail**	100.0000%	100.0000%	100.0000%	100.0000%

Attachment EDE-6
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OFFICE OF PUBLIC UTILITY COUNSEL
Development of
Alternative Proposed Distribution Demand Allocators

Line No.	Class of Service	Class MDD @Meter kW	CLASS NCP @Meter kW	Demand Loss Factor %	Class MDD @Source kW	CLASS NCP @Source kW	Substations (MDD) kW	Primary Lines Demand (MDD) kW	Secondary Lines Demand (MDD+NCP)/2 kW	Line Transformer Demand (MDD+NCP)/2 kW
	Residential Service									
1	Secondary	1,687,852	3,208,479	7.8320%	1,820,045	3,459,767	1,820,045	1,820,045	2,639,906	2,639,906
	Small General Service									
2	Secondary	114,762	214,548	7.8320%	123,750	231,351	123,750	123,750	177,551	177,551
3	Primary	-	-	5.7220%	-	-	0	0	0	0
4	Total Small General Service	114,762	214,548		123,750	231,351	123,750	123,750	177,551	177,551
	General Service									
5	Secondary	665,591	891,941	7.8320%	717,720	961,798	717,720	717,720	839,759	839,759
6	Primary	25,938	34,885	5.7220%	27,422	36,881	27,422	27,422	N/A	N/A
7	Transmission Below 230 kV	5,854	9,067	1.0980%	5,918	9,167	N/A	N/A	N/A	N/A
8	Transmission Above 230 kV	-	-	0.2464%	-	-	N/A	N/A	N/A	N/A
9	Total General Service	697,383	935,893		751,060	1,007,846	745,142	745,142	839,759	839,759
	Large General Service									
10	Secondary	154,199	181,543	7.8320%	166,276	195,761	166,276	166,276	181,019	181,019
11	Primary	48,016	56,531	5.7220%	50,764	59,766	50,764	50,764	N/A	N/A
12	Transmission Below 230 kV	3,580	5,809	1.0980%	3,619	5,873	N/A	N/A	N/A	N/A
13	Total Large General Service	205,796	243,883		220,659	261,400	217,040	217,040	181,019	181,019
	Large Industrial Power Service									
14	Primary	85,466	110,315	5.7220%	90,356	116,628	90,356	90,356	N/A	N/A
15	Transmission Below 230 kV	626,899	800,178	1.0980%	633,783	808,963	N/A	N/A	N/A	N/A
16	Transmission 230 kV And Above	413,064	492,573	0.2464%	414,082	493,786	N/A	N/A	N/A	N/A
17	Total Large Industrial Power Service	1,125,429	1,403,066		1,138,221	1,419,377	90,356	90,356	0	0
	Roadway Lighting									
18	Secondary	8,512	8,512	7.8320%	9,179	9,179	9,179	9,179	9,179	9,179
	Non-Roadway Lighting									
19	Secondary	14,419	14,419	7.8320%	15,548	15,548	15,548	15,548	15,548	15,548
20	**Total Texas Retail**	3,854,153	6,028,800		4,078,462	6,404,468	3,021,060	3,021,060	3,862,961	3,862,961

Attachment EDE-7
Page 1 of 3

OFFICE OF PUBLIC UTILITY COUNSEL
Development of
Alternative Proposed Distribution Demand Allocators

Line No.	Class of Service	Substations %	Primary Lines Demand %	Secondary Lines Demand %	Line Transformer Demand %
	Residential Service				
1	Secondary	60.2452%	60.2452%	68.3389%	68.3389%
	Small General Service				
2	Secondary	4.0962%	4.0962%	4.5962%	4.5962%
3	Primary	0.0000%	0.0000%	0.0000%	0.0000%
4	Total Small General Service	4.0962%	4.0962%	4.5962%	4.5962%
	General Service				
5	Secondary	23.7572%	23.7572%	21.7387%	21.7387%
6	Primary	0.9077%	0.9077%	N/A	N/A
7	Transmission Below 230 kV	N/A	N/A	N/A	N/A
8	Transmission Above 230 kV	N/A	N/A	N/A	N/A
9	Total General Service	24.6649%	24.6649%	21.7387%	21.7387%
	Large General Service				
10	Secondary	5.5039%	5.5039%	4.6860%	4.6860%
11	Primary	1.6803%	1.6803%	N/A	N/A
12	Transmission Below 230 kV	N/A	N/A	N/A	N/A
13	Total Large General Service	7.1842%	7.1842%	4.6860%	4.6860%
	Large Industrial Power Service				
14	Primary	2.9909%	2.9909%	N/A	N/A
15	Transmission Below 230 kV	N/A	N/A	N/A	N/A
16	Transmission 230 kV And Above	N/A	N/A	N/A	N/A
17	Total Large Industrial Power Service	2.9909%	2.9909%	0.0000%	0.0000%
	Roadway Lighting				
18	Secondary	0.3038%	0.3038%	0.2376%	0.2376%
	Non-Roadway Lighting				
19	Secondary	0.5147%	0.5147%	0.4025%	0.4025%
20	**Total Texas Retail**	100.0000%	100.0000%	100.0000%	100.0000%

Attachment EDE-7
Page 2 of 3

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ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Eighth Set of Data Requests of Requesting Party: Office of Public Utility Counsel	Prepared By: Samantha F. Hill Sponsoring Witness: Samantha F. Hill Beginning Sequence No. EV2334 Ending Sequence No. EV2334

Question No.: OPUC 8-9 Part No.: Addendum:

Question:

Please refer to page 2, Section V of Exhibit SFH-1 to the Direct Testimony of Samantha F. Hill. Please provide all analysis, workpapers, or other documents that support ETI's proposal to not require TECI-1 Rider customers to reimburse ETI for the cost to upgrade or extend facilities except for any amount of investment that exceeds the projected revenues for the first four years.

Response:

Entergy Texas, Inc.'s ("ETI") PUCT-approved Extension of Service Policy[1] allows ETI to extend new or upgraded service to customers without a reimbursement for the costs when the projected revenue[2] for the first four years of service for new or additional load is equal to or exceeds the Company's projected infrastructure investment.

ETI designed the TECI-1 Rider to equitably apply the same policies and procedures for new or additional load. Specifically, because the TECI-1 Rider is extending service to serve new load from transportation electrification ("TE") infrastructure and equipment (for example electric vehicle chargers) or upgrading service to serve additional load from new TE infrastructure and equipment, ETI designed the TECI-1 Rider to allow for the same revenue applications as the PUCT-approved Electric Extension Policy does today for similar scenarios.

[1] *Compliance Tariff Pursuant to the Final Order in Docket No. 39896; Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 40742, Compliance Tariff at 3.1-3.4 (Item No. 22) (Nov. 21, 2012), available here https://interchange.puc.texas.gov/Documents/40742_22_742846.PDF.
[2] Projected revenue is defined in the Extension of Service Policy.

OFFICE OF PUBLIC UTILITY COUNSEL
Analysis of
Distribution Rate Base Supported by Proposed Base Rates by Customer Class

Description	Total Company Adjusted	Residential Service	Small General Service	General Service	Large General Service	Large Industrial Power	Lighting
Distribution Substations Rate Base	52,990,981	32,027,684	2,170,220	13,049,805	3,800,621	1,508,648	434,003
Distribution Primary Lines Rate Base	130,705,446	78,998,211	5,352,978	32,188,131	9,374,460	3,721,171	1,070,495
Distribution Secondary Lines Rate Base	27,809,544	19,700,085	1,169,096	5,587,244	1,190,166	-	162,953
Total Distribution Lines Rate Base	158,514,990	98,698,296	6,522,074	37,775,375	10,564,626	3,721,171	1,233,448
Distribution Line Transformers	65,517,040	46,411,809	2,754,296	13,163,097	2,803,935	-	383,903
Total Distribution Rate Base	277,023,011	177,137,788	11,446,591	63,988,277	17,169,182	5,229,818	2,051,354
Year-End Number of Customers		422,815	38,207	20,085	390	124	2,744
Dist Rate Base per Customer		$ 419	$ 300	**$ 3,186**	$ 44,024	$ 42,176	$ 748
Average Monthly Billing kW				922,426	245,218	1,375,568	
Dist Rate Base per Billing kW				**$ 69.37**	$ 70.02	$ 3.80	
ETI Proposed Rate Schedule Base Rate Revenues, Excluding Riders	$1,219,029,749	$654,138,090	$46,387,907	$218,555,806	$64,729,779	$219,104,966	$16,113,201
Distribution Rate Base Supported by $1 of Annual Base Rate Revenues	$ 0.23	$ 0.27	$ 0.25	**$ 0.29**	$ 0.27	$ 0.02	$ 0.13

Sources of Data:
1) Rate Base values by class and in total from ETI filed Schedule P-6.1.1
2) Number of customers and billing demand (kW) values from Schedule P-6.1.1
3) Proposed Base Rate Revenues, Excluding Rider Revenues from Schedule Q-7

Attachment EDE-9
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ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Frank Magee
to the Seventh Set of Data Requests	Sponsoring Witness: Allison P. Lofton
of Requesting Party: Office of Public Utility	Beginning Sequence No. EV2310
Counsel	Ending Sequence No. EV2310

Question No.: OPUC 7-20 Part No.: Addendum:

Question:

For each month since each of the H-E-B Backup Generators have been placed into service, please provide by generator the direct operations and maintenance expenses, depreciation expense, any property insurance associated with the generators, any property taxes associated with the generators, and any other costs associated with the generators.

Response:

Please see the attachments (TP-53719-00OPC007-X020-001 and TP-53719-00OPC007-X020-002).

RP-53719-00OPC007-X020-002

Attachment to ETI's Response to OPUC 7-20 Plus 2021 Totals

HEB 594				
	O&M $	Fuel $	Unplanned Maintenance $	Property Tax $
Oct-19	$418.06	$674.82		
Nov-19	$1,743.45	$1,153.47		
Dec-19	$1,644.00	$651.56		
Jan-20	$1,632.52	$553.89		
Feb-20	$1,663.95	$692.88		
Mar-20	$1,685.69	$788.84		
Apr-20	$1,736.26	$971.41		
May-20	$1,907.98	$1,884.52		
Jun-20	$1,922.91	$1,831.75		
Jul-20	$1,824.02	$1,328.76		
Aug-20	$3,104.86	$6,949.71		
Sep-20	$1,948.54	$2,393.98		
Oct-20	$1,987.75	$2,350.73		
Nov-20	$1,642.75	$942.28		
Dec-20	$1,677.65	$585.70		
Jan-21	$1,687.38	$845.94		$623.14
Feb-21	$2,990.14	$8,601.02	$587.26	$623.14
Mar-21	$1,639.74	$575.64		$623.14
Apr-21	$1,694.18	$875.16		$623.14
May-21	$1,832.38	$1,782.73		$623.14
Jun-21	$2,270.19	$4,582.90	$469.91	$623.14
Jul-21	$1,751.52	$1,463.52		$623.14
Aug-21	$1,678.41	$1,005.75	$137.75	$623.14
Sep-21	$1,258.44	$757.08	$217.91	$623.14
Oct-21	$1,680.85	$777.47	$3,352.50	$623.14
Nov-21	$1,757.49	$1,109.43		$623.14
Dec-21	$1,717.31	$698.50		$623.14
Jan-22	$1,756.61	$922.86		$687.24
Feb-22	$1,742.46	$840.50		$687.24
Mar-22	$1,824.48	$1,546.91		$687.24
Apr-22	$1,773.30	$1,205.71		$687.24
May-22	$2,065.91	$5,257.39		$687.24
Jun-22	$2,218.75	$6,888.88		$687.24
Jul-22	$2,239.94	$6,548.90		$687.24

*Oct-19 fuel related to installation and testing; no MISO market activity
*Oct-19 O&M related to being commercial 10-24-2019

HEB 048			
	O&M $	Fuel $	Property Tax $
Oct-19			
Nov-19			
Dec-19			
Jan-20			
Feb-20			
Mar-20			
Apr-20			
May-20			
Jun-20			
Jul-20			
Aug-20			
Sep-20			
Oct-20			
Nov-20			
Dec-20			
Jan-21			
Feb-21			
Mar-21			
Apr-21			
May-21			
Jun-21			
Jul-21			
Aug-21			
Sep-21		$995.79	
Oct-21	$1,639.43	$548.23	
Nov-21	$1,675.48	$876.45	
Dec-21	$1,647.04	$580.46	
Jan-22	$1,673.14	$692.18	
Feb-22	$1,665.56	$658.53	
Mar-22	$1,751.22	$1,392.95	
Apr-22	$1,691.20	$967.36	
May-22	$1,995.17	$5,168.74	
Jun-22	$2,218.14	$6,586.02	
Jul-22	$2,164.22	$6,322.76	

*Sept-21 fuel related to installation and testing

HEB 594				
	O&M $	Fuel $	Unplanned Maintenance $	Property Tax $
2021	$21,958.03	$23,075.14	$4,765.33	$7,477.73

HEB 048			
	O&M $	Fuel $	Property Tax $
2021	$4,961.95	$3,000.93	

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Eighth Set of Data Requests of Requesting Party: Office of Public Utility Counsel	Prepared By: Samantha F. Hill Sponsoring Witness: Samantha F. Hill Beginning Sequence No. EV2330 Ending Sequence No. EV2330

Question No.: OPUC 8-2 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Samantha F. Hill at 8:18 - 9:4. Please provide a detailed explanation for any proposed safeguards that will ensure that only TECI-1 Rider customers will be subject to any costs related to "the portions of the TE infrastructure and equipment that the customer does not want to own and maintain."

Response:

The Customer Agreement attached as Exhibit SFH-3 to the Direct Testimony of Samantha F. Hill ensures that the host customer bears the responsibility for all of the infrastructure and equipment costs that it does not want to maintain, as well as the ongoing O&M costs.

Please see the Company's response to OPUC 8-1 for an explanation of how the charges assessed under the TECI-1 Rider will only be charged to those customers who voluntarily elect to enroll in the TECI-1 Rider (much like Entergy Texas, Inc.'s ("ETI") existing Additional Facilities Charge ("AFC") Rider).

In order to further ensure that only the participating customer pays for the cost of the TECI-1 Rider, participating customers must meet certain eligibility requirements and their legal liabilities, responsibilities, and obligations to pay for the costs of the TECI-1 Rider are included in the Customer Agreement entered into between ETI and the participating customer. Examples of those legal provisions include the terms and conditions for contract termination and breach, duties of care, equipment casualty, customers' liabilities and responsibilities, and force majeure. Further, ETI has the right to remove and salvage any equipment owned by ETI, as covered in Part 4 Disposal of TECI Facilities.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Eighth Set of Data Requests of Requesting Party: Office of Public Utility Counsel	Prepared By: Samantha F. Hill Sponsoring Witness: Samantha F. Hill Beginning Sequence No. EV2331 Ending Sequence No. EV2331

Question No.: OPUC 8-3   Part No.:   Addendum:

Question:

Is it ETI' s intention to maintain a separate accounting for all investment in TE infrastructure and equipment that customers do not want to own and maintain? If so, please provide a detailed description of ETI's proposed accounting for that investment.

Response:

The Entergy Texas, Inc. ("ETI") owned transportation electrification ("TE") infrastructure and equipment costs would be booked in accordance with Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts to electric plant account 371 (installations on customers' premises).

Depreciation expense associated directly with the TE infrastructure and equipment investment will be booked in accordance with FERC Uniform System of Accounts to account 403 (depreciation expense).

All ongoing maintenance expenses associated directly with the TE infrastructure and equipment investment will be booked in accordance with FERC Uniform System of Accounts to account 598 (maintenance of miscellaneous distribution plant) and any operating expenses will be booked in accordance with FERC Uniform System of Accounts to account 586 (meter expenses).

Other expenses incurred such as additional property taxes will be booked to the FERC accounts currently used for similar types of expenses.

For monthly revenues received under the TECI-1 Rider, ETI proposes that those revenues be booked in accordance with FERC Uniform System of Accounts to revenue account 456 (other electric revenues) and treated as an offset against ETI's overall revenue requirement.

See also the Company's response to OPUC 8-1.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.
to the First Set of Data Requests

of Requesting Party: Office of Public Utility Counsel

Prepared By: Gareth Hutchinson
Sponsoring Witnesses: Samantha F. Hill, Crystal K. Elbe
Beginning Sequence No. PI1978
Ending Sequence No. PI1978

Question No.: OPUC 8-14 Part No.: Addendum:

Question:

For each ETI Texas retail rate class that is assessed a demand charge, please identify the number and percentage of customers that had a load factor equal to, or less than, 15% for any month during the test-year.

Response:

The table below shows the total number of customers who had load factors less than or equal to 15% for the noted number of cumulative months during the test year. Load factors were calculated using billed demands. Note that not all customers with load factors less than 15% for at least one month during the test year constitute low load factor customers, as many will return to above a 15% load factor for the majority of the year.

Please see below:

Number of Cumulative Months with Load Factor <=15	No. of General Service Customers	%	No. of Large General Service Customers	%	No. Large Industrial Power Service Customers	%
12	449	2%	3	1%	3	2%
11	621	3%	4	1%	4	3%
10	783	4%	5	1%	4	3%
9	973	5%	8	2%	5	4%
8	1,147	5%	9	2%	6	5%
7	1,376	6%	13	3%	9	7%
6	1,709	8%	17	4%	10	8%
5	2,128	10%	22	5%	12	9%
4	2,655	12%	23	6%	14	11%
3	3,406	16%	28	7%	15	11%
2	4,357	20%	31	8%	17	13%
1	5,990	28%	44	11%	32	24%

Service Quality Report

To The

Public Utility Commission of Texas

In Accordance With

Substantive Rule §25.81

2018 Reporting Year

Entergy Texas, Inc. (ETI)

Project 49068

Service Quality Report to the Public Utility Commission of Texas

Entergy Texas, Inc. (ETI)

System SAIFI	Annual	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Forced													
2018	1.42	0.13995	0.07499	0.10931	0.08801	0.11752	0.14251	0.16458	0.15927	0.13158	0.11046	0.08720	0.09799
Scheduled													
2018	0.09	0.00459	0.00667	0.00341	0.00785	0.00666	0.00938	0.00565	0.00359	0.01623	0.00746	0.01337	0.01009
Outside Causes													
2018	0.25	0.01108	0.00524	0.01411	0.01094	0.05967	0.01724	0.04532	0.03069	0.01269	0.00604	0.00217	0.03723
Major Events													
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Service Quality Report to the Public Utility Commission of Texas

Entergy Texas, Inc. (ETI)

System SAIDI	Annual	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Forced													
2018	217.64	22.5124	12.3006	24.2145	16.8409	13.8348	26.6824	23.5352	19.5070	15.9069	16.8776	11.0984	14.3305
Scheduled													
2018	7.21	0.27536	0.25006	0.28214	0.32378	0.41858	0.62531	0.60690	0.27888	1.34826	0.69066	1.01159	1.10280
Outside Causes													
2018	34.29	0.76477	0.77681	0.54060	2.85607	6.87993	1.86239	8.23351	6.81720	1.29622	0.47979	0.45460	3.32336
Major Events													
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Attachment EDE-10
Non-Native Workpapers
Page 8 of 84

OPUC 7-20 EV2369

Service Quality Report

To The

Public Utility Commission of Texas

In Accordance With

Substantive Rule §25.81

2021 Reporting Year

Project 52946

Service Quality Report to the Public Utility Commission of Texas

Entergy Texas, Inc.

System SAIFI	Annual	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Forced													
2021	1.455	0.089	0.098	0.101	0.079	0.031	0.067	0.085	0.222	0.196	0.180	0.148	0.157
Scheduled													
2021	0.283	0.024	0.033	0.043	0.039	0.007	0.019	0.018	0.010	0.035	0.007	0.025	0.024
Outside Causes													
2021	0.200	0.001	0.017	0.051	0.006	0.010	0.009	0.003	0.034	0.028	0.021	0.010	0.009
Major Events													
2021	1.208	0.000	0.215	0.000	0.000	0.993	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Service Quality Report to the Public Utility Commission of Texas

Entergy Texas, Inc.

System SAIDI	Annual	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Forced													
2021	220.7	15.0	10.7	12.1	12.8	4.2	7.1	10.6	40.8	26.4	25.8	21.8	33.4
Scheduled													
2021	50.7	1.4	3.6	6.5	4.8	1.3	2.1	2.9	1.3	16.8	1.1	4.0	4.8
Outside Causes													
2021	28.0	0.1	1.2	6.4	0.3	0.6	0.7	0.4	5.7	5.2	4.0	1.8	1.6
Major Events													
2021	683.6	0.0	61.7	0.0	0.0	621.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0

52946 Entergy Service Quality Report.xlsx
System-SAIDI

PUCT DOCKET NO. _____

APPLICATION OF ENTERGY	**§**	
TEXAS, INC. FOR APPROVAL OF	**§**	**PUBLIC UTILITY COMMISSION**
ADVANCED METERING SYSTEM	**§**	
(AMS) DEPLOYMENT PLAN, AMS	**§**	**OF**
SURCHARGE, AND NON-	**§**	
STANDARD METERING SERVICE	**§**	**TEXAS**
FEES	**§**	

DIRECT TESTIMONY

OF

HUGH VERNON PIERCE

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2017

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EXHIBITS

Exhibit HVP-1	Customer Education Plan
Exhibit HVP-2	Non-Standard Metering Service Costs
Exhibit HVP-3	Proposed Revised Schedule MES

I. NAME AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is H. Vernon Pierce. My business address is 350 Pine Street, Beaumont, Texas 77704.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Vice-President, Customer Service Texas and employed by Entergy Texas, Inc. ("ETI," also referred to as "the Company").

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I earned a Bachelor of Science Degree in Marketing at Mississippi State University in 1979. I joined the Mississippi Power & Light Company as a Residential and Commercial Sales Representative in 1979. I moved to the position of Credit Manager responsible for credit and collection in Central Mississippi in 1982. I became a Local Office Manager in 1983 where I was responsible for all line construction, service, accounting, meter reading, and customer relations for Attala County, Mississippi. I held various Marketing Manager positions from 1986 to 1996 in which I was responsible for sales and service activity in Central Mississippi. In 1996, I moved to Arkansas Power & Light and held the positions of Major Accounts Manager, Area Line Manager, and Network Manager in Conway, Arkansas where I was responsible for distribution operations. In 1998, I moved to Entergy Gulf States, Inc. in Texas as the Resource Manager responsible for storm outage restoration, meter services, electronic mapping, and distribution dispatch center operations. I was promoted to Director of Customer Service, Entergy Texas in December 2003 and then Vice President of Customer Service Texas in December 2013. As part of my current duties, I am responsible for all aspects of customer service, operations, and engineering activities in Texas.

Q4. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am filing my direct testimony on behalf of ETI.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of ETI's application seeking approval to deploy an Advanced Metering System ("AMS").[1] ETI's proposed AMS deployment includes:

[1] Advanced meters, two-way communications system, and related systems are also commonly referred to as advanced metering infrastructure, or "AMI."

(1) replacing almost all of its existing electro-mechanical (*i.e.*, analog) and digital retail electric meters with advanced meters that enable two-way data communication,[2]

(2) designing and building a secure and reliable communications network that supports two-way data communication, and

(3) implementing supporting systems, including a Meter Data Management System ("MDMS"), an Outage Management System ("OMS"), and a Distribution Management System ("DMS"), which ETI plans to integrate with its legacy information technology ("IT") systems.

Company witness Mr. Rodney W. Griffith provides a detailed discussion of each of these components of ETI's proposed AMS deployment.

In addition to providing an overview of ETI's application, I describe the customer benefits and operational cost savings resulting from the proposed AMS deployment, as well as the Company's plans for customer data protection, customer education, non-standard metering service, and changes to miscellaneous electric service ("MES") charges included in the Company's Schedule MES.

Q6. WHAT EXHIBITS ARE YOU SPONSORING?

A. I sponsor the exhibits listed on my table of contents.

[2] As explained in the direct testimony of Company witness Mr. Rodney W. Griffith, the deployment plan does not include meter replacement for customer accounts that receive service at transmission voltage.

III. OVERVIEW OF APPLICATION AND DIRECT TESTIMONY

Q7. WHAT IS THE PURPOSE OF ETI'S APPLICATION IN THIS PROCEEDING?

A. The purpose of ETI's application is to request that the Public Utility Commission of Texas ("PUCT" or "Commission") approve its deployment plan for installation of AMS across its service area, allow the Company to recover the costs of AMS deployment through a surcharge, and approve the non-standard metering service fees for customers who elect to opt-out of having an advanced meter.

Q8. PLEASE PROVIDE AN OVERVIEW OF THE DIRECT TESTIMONY FILED IN SUPPORT OF THE COMPANY'S APPLICATION.

A. In addition to my testimony, the Company offers three witnesses in support of its application who provide the information required by the applicable Commission Rules:

- **Rodney W. Griffith** – Mr. Griffith is the Director of AMI Implementation for Entergy Services, Inc. ("ESI").[3] Company witness Griffith sponsors the "Statement of Functionality" and "Deployment Plan" that are required by Commission Rule 25.130(d). He also affirms that ETI's AMS provides the minimum system features listed in Commission Rule 25.130(g). He provides a technical discussion of the capabilities of the AMS that ETI seeks to deploy, as well as various functionalities that will be available when advanced meters are installed, including a MDMS. He also describes the Company's plan to update its legacy OMS and to implement a new DMS to enhance overall system performance. Mr. Griffith also describes the data that the advanced meters will collect, as well as how the data will be securely collected, stored, and transmitted. Lastly, Mr. Griffith discusses how the different AMS vendors were selected, the equipment and/or services that they will provide, the proposed AMS

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[3] ESI is a subsidiary of Entergy Corporation that provides technical and administrative services to all of the Entergy Operating Companies ("EOCs"), which include Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and ETI.

implementation approach and deployment schedule, and estimated costs of the AMS design and deployment.

- **Jay A. Lewis** – Mr. Lewis is the Vice President of Regulatory Policy for ESI. He identifies and describes the requirements of the applicable statute and Commission rules, which require that ETI obtain Commission approval of its AMS deployment plan and surcharge. He also describes and quantifies operational cost savings related to an AMS. He makes specific accounting proposals related to using a seven-year life for the AMS assets, and he also addresses the unrecovered costs of the existing meters that will be removed from service. Lastly, he describes the Company's proposal for non-standard metering service and the non-standard metering service fees, and he describes how those fees were calculated, consistent with Commission Rule 25.133.

- **Richard Lain** – Mr. Lain is Manager, Regulatory Affairs for ETI. He presents the Company's proposal for recovery of the costs of the AMS deployment, including how the revenue requirement and AMS surcharge rates were calculated. He demonstrates that the Company's proposed AMS surcharge rates are calculated consistent with the requirements of Commission Rule 25.130(k). He also describes the AMS reconciliation proceeding that will eventually be initiated to review the costs recovered through the AMS Surcharge.

IV. OVERVIEW OF AMS PROJECT

Q9. WHAT IS THE PURPOSE OF THE COMPANY'S AMS PROJECT?

A. ETI believes that an AMS is the foundation of the modernized power grid and will deliver reliability, customer service and empowerment improvements to our customers. Technology advancements have fundamentally changed the way electricity is supplied and distributed today, as well as how we interact with our customers. Technology advancements have also changed customer expectations regarding how they interact with ETI and how they manage the services that are provided. By implementing an AMS, ETI plans to harness these technology advancements to improve our operations and customer service capabilities.

Q10. WHAT DO YOU MEAN WHEN YOU USE THE PHRASE "ADVANCED METERING SYSTEM"?

A. AMS is defined in Commission Rule 25.130 as "A system, including advanced meters and the associated hardware, software, and communications systems, including meter information networks, that collects time-differentiated energy usage and performs the functions and has the features specified in this section." More generally, AMS is a broad term that encompasses a range of related technologies and processes. It represents a dramatic change in how the Company will interact with its customers that is made possible by advanced meters and the associated infrastructure. The benefits of advanced meters, and their related infrastructure, have been documented by the PUCT, the Texas Legislature, and across the country. More than 48% of all meters in the U.S. are advanced meters, and, in Texas, approximately 83% of all meters are advanced meters.[4] Advanced metering technology has helped utilities around the nation put more information into their customers' hands, while paving the path for a more energy efficient future with the integration of new technology.

[4] U.S. Department of Energy, Energy Information Administration ("EIA"), Form EIA-826, statistics based on utilities providing "Advanced Metering" data as of January 2017, *available* at https://www.eia.gov/electricity/data/eia826/.

Q11. WHAT IS THE EXPECTED SCHEDULE FOR THE COMPANY'S AMS DEPLOYMENT?

A. As detailed by ETI witness Mr. Rodney W. Griffith, the Company proposes that the deployment and installation of the advanced meters and components at customers' premises would begin in early 2019 and take approximately three years to complete.

Q12. WHY IS ETI PROPOSING TO DEPLOY AN AMS AT THIS TIME?

A. In its most recent regular session, the Texas Legislature approved Senate Bill 1145, which extended mechanisms that support deployment of AMS to ETI and directed that if ETI elects to deploy AMS, it shall deploy the network as rapidly as practicable to allow customers to better manage energy use and control costs. Consistent with the support and direction of the Legislature as provided in Senate Bill 1145, ETI has chosen to deploy AMS and is submitting this application for Commission review and approval of its proposed deployment plan.

The U.S. electric utility industry is undergoing significant change driven by new technology, the pace of technology innovation, increased customer interest around self-supply and control, an emphasis on efficiency, aging infrastructure, and uncertainty surrounding evolving standards and environmental regulations. Moreover, technology and innovation are also changing customer expectations as a result of how products and services are delivered both inside and outside of the utility industry. There has been an increase in customers' expectations that they be able to access information and manage services via mobile devices like smart phones and tablets. As technology evolves, so must our capabilities to address such customer expectations.

The PUCT has already approved the deployment of AMS by CenterPoint, Oncor, AEP Texas, and Texas New Mexico Power Company, and, as noted above, advanced meters already comprise the majority of meters in Texas. The hardware, technologies, and partners needed for an AMS deployment have evolved to the point where reliability and integration are no longer cutting edge, but proven attributes. It appears that, if advanced meter deployments continue on pace with historical rates, the vast majority of all electric customers in the U.S. will have advanced meters by the time ETI finishes its AMS deployment. The Company believes it is now an appropriate time to deploy AMS given the lessons-learned from earlier utility deployments, technological improvements and cost decreases of AMS infrastructure, and evolving customer expectations.

Q13. DOES AN AMS HELP ADDRESS THE CHANGES OCURRING WITH REGARD TO CUSTOMER EXPECTATIONS?

A. Yes. As I describe in more detail below, an AMS is a fundamental step in improving ETI's ability to meet customer expectations with regard to service restoration, reliability, enabling ETI to help customers better understand and manage their utility bills and energy usage, and improving customers' experience when they interact with the Company.

Q14. AFTER THE COMPANY IMPLEMENTS ITS AMS PROPOSAL, WOULD IT ALSO BE POSITIONED TO TAKE ADDITIONAL STEPS TO MODERNIZE ITS ELECTRIC GRID?

A. Yes. With an AMS in place, ETI would be positioned to invest in new technology and infrastructure upgrades to move beyond a largely centralized, one-way distribution grid and move towards a more advanced power grid. An AMS is a foundational technology of an integrated energy network that would support additional features such as distribution automation and the further integration of distributed energy resources ("DERs").[5] In other words, an AMS is the first step towards integrating advanced technology into ETI's operations.

I discuss in more detail below some of the potential future capabilities that can be built upon an AMS. These potential future capabilities would not be possible without the communications and information technology improvements that will be part of ETI's AMS deployment.

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[5] DERs include technologies like customer-owned rooftop solar PV systems, energy storage (*e.g.*, advanced batteries), and plug-in electric vehicles ("EVs").

V. CUSTOMER BENEFITS

Q15. PLEASE PROVIDE AN OVERVIEW OF THE CUSTOMER BENEFITS FROM AN AMS.

A. An AMS offers a number of immediate and longer-term benefits to customers in addition to the quantified operational cost savings that Company witness Mr. Jay A. Lewis discusses in his Direct Testimony. For example, an AMS will better enable ETI to identify outage locations, which will allow quicker and more accurate detection of service problems and will result in overall faster outage restoration. The information and capabilities provided by an AMS will improve the accuracy and timeliness of outage and restoration communications with customers. The advanced meters and communication system also will allow for remote connection and disconnection of nearly all customers' electric service that will occur more quickly than the Company's manual process for existing electric meters, which requires a field visit.[6]

Another benefit of an AMS is that, once the advanced meters and related infrastructure and systems are activated, ETI's customers will have access to more detailed energy usage data, which will help customers better understand and manage their usage and reduce their energy bills.[7] A further benefit of the

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[6] Remote connection and disconnection will not be available for customers with service rated at greater than 200 amps or for customers with three-phase service.

[7] Customer usage data will be collected in fifteen-minute intervals for residential customers and five-minute intervals for commercial and industrial customers, and this usage data will be made available for customer access the following day (such as through the web portal that I discuss later in my testimony).

availability of this data is that ETI customer service representatives will have more timely and detailed customer energy usage data to help expedite and more effectively address customer billing questions and issues.

Overall, ETI is committed to leveraging the functionalities that an AMS provides to improve customer satisfaction and our customers' experience when they interact with the Company. To achieve this goal, an important customer-focused feature will be making customers' daily usage data available to them on the Company's web portal and educating customers about how to take advantage of that new information.

Further, as I discussed above, ETI is seeking to modernize its electric grid to meet customer expectations regarding how they interact with their service providers and the tools available for them to manage those services. To that end, an AMS is the technical foundation and platform for the modernization of ETI's electric grid that will enable future products and services for customers. I describe some examples of those potential, future products and services below.

Q16. CAN YOU ELABORATE ON THE TYPE OF INFORMATION THAT WILL BE AVAILABLE TO CUSTOMERS THROUGH THE WEB PORTAL?

A. Yes. As described by Mr. Griffith, the advanced meters will record energy usage data in fifteen-minute intervals for residential customers and five-minute intervals for commercial and industrial customers. The next day, usage information will be available on the web portal through a computer and/or mobile device, which will allow customers to access detailed energy usage information for their homes and businesses. Due to the timely accessibility of that information, customers can better and more easily track their electricity usage, analyze their historic and current usage patterns, and view an estimate of their monthly bills.

By analyzing their information, customers will be able to identify their times of high usage, which can result in customer action such as changes that reduce consumption within the remainder of a billing cycle (*i.e.,* in-cycle). While such in-cycle changes can occur without an AMS, the availability of in-cycle detailed usage information and enhanced tools, such as text message alerts based on customer-specified criteria, provide additional opportunities for customers to consider changing their usage. Customers also will have in-cycle information about how usage changes can affect their bill, much the same way that cellular phone customers can track and receive notifications about their data plan usage thresholds throughout a billing cycle.

Q17. HOW WOULD CUSTOMERS ACCESS THEIR USAGE INFORMATION?

A. Customers will have access to the web portal described above by computer and by mobile device. In addition to offering energy management information, the web portal will allow customers to set personalized notification preferences regarding how they would like to receive information about their energy use. For example, customers could set up text or email alerts for ETI to notify them in the event of high usage or when a bill reaches a certain dollar amount based on the customer's pre-defined threshold. Additionally, customers will be able to download and share their data, as further described below.

Q18. WILL ETI UTILIZE THE SMART METER TEXAS WEB PORTAL?

A. No. The Smart Meter Texas web portal was developed by and is used by the transmission and distribution utilities in Electric Reliability Council of Texas ("ERCOT") that deployed AMS in recent years. Smart Meter Texas is set up for use in the unbundled retail electric service environment in ERCOT, where customer meters are assigned Electric Service Identifiers ("ESI IDS"), and retail electric providers ("REPs") compete to provide retail electric service by offering different rate packages. ETI participates in the Midcontinent Independent System Operator, Inc. ("MISO") regional transmission organization and provides bundled electric service in its service area, meaning it is the sole provider of retail electric service, and there are no REPs or ESI IDs. Accordingly, ETI's AMS Deployment Plan contemplates providing AMS data and enhanced tools to its customers via web portal developed for the Company and its customers.

Q19. HOW DOES ETI PROPOSE TO ADDRESS THIRD-PARTY ACCESS TO CUSTOMER DATA THAT IS AVAILABLE TO CUSTOMERS ON ITS WEB PORTAL?

A. The customer web portal will provide customers access to their interval data (on a day-after basis), and it will have functionality that allows customers to download their AMS data in an industry-standard file format and then share that file with whomever they choose (*e.g.*, Green Button Download My Data).[8] With respect to third-party direct access to customer AMS data, the Company is still exploring the various methods by which such access might be feasible (*e.g.*, Green Button Connect My Data), as well as studying the related privacy and data security aspects of providing third-party direct access. I understand that these issues have been the subject of considerable study and testing in the ERCOT market, which as discussed above, differs considerably from ETI's retail operating environment, and ETI requests that it similarly be afforded time to study the implications of third-party direct access with respect to its AMS deployment and associated development of its customer web portal. To the extent that the Commission's Rules are interpreted to require that ETI provide third-party direct access to customer AMS data (subject to customer consent), ETI is requesting a waiver of that requirement as is detailed in the Direct Testimony of Company witness Mr. Lewis.

Q20. WHEN WILL THE WEB PORTAL BE FUNCTIONAL?

A. The web portal will be functional by the time meter deployment begins. However, meter data may not be available on the web portal until a certain

[8] The Green Button initiative is an industry-led effort to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and nationally standardized format. *See* https://energy.gov/data/green-button.

number of meters in a geographic area have been installed and the communications network is optimized by the communications network vendor.

Q21. HOW CAN AMS HELP CUSTOMERS LOWER THEIR ENERGY BILLS?

A. Through customer education, ETI will seek to inform customers about how their usage data, which will be available in greater detail and on a more frequent basis as a result of the AMS deployment, can be used in conjunction with other energy savings tips to reduce their consumption. As a result of the incorporation of AMS data into the web portal, and through related educational efforts I discuss later in this testimony, ETI will provide customers with tools to access, track, and decide whether and/or how to adjust their energy usage. For example, ETI plans to provide interested customers with notifications of preset usage thresholds that would give them more frequent information about their usage and estimated bills. Customers will also be able to review usage patterns each day to see where opportunities to reduce or eliminate consumption may occur within each billing cycle, rather than after the billing cycle has ended.

Q22. DOES ETI ANTICIPATE OFFERING PEAK EVENT NOTIFICATIONS TO CUSTOMERS AS A PART OF AMS DEPLOYMENT?

A. Yes, ETI plans to provide customers with peak event notifications as part of its AMS deployment. This program will provide text message and/or email notifications to customers (subject to an opt-out procedure and applicable legal requirements related to such communications channels) suggesting that they take steps to reduce their usage during certain times of peak load on the overall system. Such notifications would be expected to occur on only a handful of days each year when the system load is anticipated to be at peak. Based on results experienced by other utilities, it is reasonable to expect that customers will take action to reduce consumption in response to the information and alerts they receive.

Q23. PLEASE ELABORATE ON HOW THESE EFFORTS FACILITATE PEAK LOAD SHIFTING.

A. With these efforts, customers would be educated in advance about the importance of reducing load on select days of the year in response to notifications provided by the Company. Notifications would be provided by one or more communication channels at the customer's preference (*e.g.*, text and/or email and subject to applicable law related to such channels). These notifications would inform customers in advance of an upcoming "event" day, which would be a day that the Company projects as one of the highest load days of the year. The notification would ask customers to reduce (or in some instances shift) load during the "event" period, which typically coincides with the highest load hours (*e.g.*, ~2:00 pm – 6:00 pm on a hot summer day). The notifications could also suggest various specific actions that customers could take to reduce or shift their load during the event periods. Because of the AMS, customers will be informed with more detailed usage information upon which to base their decision. The total number of "event" days would be minimized to avoid burdening customers (*e.g.*, 5-10 "events" per summer). Most importantly, as a result of the AMS, customers will receive an after-the-fact notification providing the results of their load shifting or reduction that would use data available through the AMS. Customers may, at any time, opt-out of receiving such notifications.

Q24. DOES THE PROPOSED AMS DEPLOYMENT SUPPORT ADDITIONAL FUNCTIONALITIES THAT COULD BE IMPLEMENTED IN THE FUTURE?

A. Yes. There are several other functionalities and programs enabled by an AMS that could be implemented in the future. As I noted earlier in my testimony, greater grid resiliency could be accomplished in the distribution network. By deploying additional automated devices on the distribution grid connected to the AMS communication system, and combined with the data from advanced meters, automatic rerouting of power due to an outage would allow for shorter and fewer overall outages and interruptions. Mr. Griffith provides additional discussion on this functionality in his Direct Testimony.

In addition, the AMS data, in combination with other operational asset data and advanced analytics software, could identify assets (*e.g.*, transformers) that are approaching failure, and those assets could then be replaced prior to failure, which would prevent an unplanned outage from occurring.

The availability of customer usage data at a more detailed level could also allow for specifically-designed offerings for and better assistance to customers.

For example, when a Company customer service representative is speaking with a customer about their bill questions, the representative will be able to access the detailed usage data underlying the customer's bill, which will enable more efficient and tailored discussions with the customer. There could be more flexible billing and payment options developed based on the knowledge of the customer's usage patterns.

Some of these functionalities and programs would require additional investments in infrastructure and technology at a later date in order to deploy and achieve the desired functionality. These features could provide a wide range of benefits such as customer savings, greater grid resiliency, and specifically-designed customer options, but should be accompanied by appropriate regulatory policies that are fair to both customers and the Company.

VI. OPERATIONAL COST SAVINGS

Q25. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I provide a background discussion that supports the operational cost savings of AMS deployment that are quantified by Mr. Lewis in his Direct Testimony. The benefits quantified by Mr. Lewis are then used as offsets to the costs that are included in the calculation of the annual revenue requirement that forms the basis for the AMS surcharge. The costs and savings reflected in the AMS surcharge are ultimately subject to reconciliation pursuant to Commission Rule 25.130(k)(6).

Q26. PLEASE PROVIDE AN OVERVIEW OF ETI'S CURRENT METER-RELATED OPERATIONS ACTIVITIES.

A. ETI's current meter-related operations activities include (1) meter reading and (2) meter services. For meter reading, ETI currently utilizes contract meter readers employed by firms that specialize in providing meter reading services to provide on-site meter readings. For meter services, ETI currently utilizes employees as well as contract personnel for on-site work performed at the meter, including account activation for new service at existing locations and de-activation for cancelled service, as well as disconnect/reconnect activity related to past-due billings. Because of the two-way data communication supported by an AMS, all of the meter reading and nearly all of the meter services activity will be able to be performed remotely.

Q27. CAN YOU FURTHER DESCRIBE THE METER READING PROCESS?

A. Yes. On a daily basis, meter readers are assigned a route (or routes) that include the meters to be read during the current billing cycle. Depending on the geography of the route, the meter reader navigates the route by foot or vehicle. The meter reader must be able to see the meter to obtain the value indicated by the dials for older, analog meters or the digital display in newer meters. The reading is input into an electronic handheld device. Depending on the customer's rate schedule, this input may also include the demand information displayed on the meter or require the use of a probe device that downloads periodic demand information required for customer billing.

To obtain these readings, the meter reader must sometimes navigate numerous obstacles including animals, locked gates, overgrown vegetation, and variable weather and traffic conditions. Meter readers also resort to using binoculars or monoscopes to read meters where they cannot get access or where it is more efficient to read from a distance.

Meter readers may also need to re-read a customer's meter in certain circumstances. For example, the Company's internal meter reading edit processes may indicate usage for a particular customer account is unusually high or low and a re-read is needed. As re-reads are not typically in the meter readers' current routes, they must work the re-read into the day's work schedule, creating inefficiencies in the meter reading route. Once deployed, an AMS is designed to eliminate the need for these processes.[9]

Q28. WHY DOES ETI USE CONTRACT METER READERS RATHER THAN COMPANY EMPLOYEES TO READ CUSTOMER METERS?

A. To reduce meter reading costs that are reflected in customer rates, the Company made a business decision approximately 20 years ago to switch from internal labor to third-party suppliers to perform all manual meter reading. To achieve an appropriate balance between cost and performance with the third-party suppliers,

[9] Mr. Griffith discusses how the AMS data will be collected and validated.

the Company uses competitive bidding techniques and requires a contractual high "service-level" agreement, which contains certain performance measures. The use of third-party suppliers for manual meter reading has resulted in lower costs over the years, which means the related savings from ETI's AMS deployment are expected to be lower than those of other utilities that transitioned their meter reading services from employees to remote meter reading through an AMS.

Q29. HOW ARE METER READING SERVICES MANAGED?

A. ETI's meter reading service contracts are managed by regionally based employees familiar with the requirements of the contracts and holding the skills and knowledge necessary to evaluate contractor performance. In addition, a centralized group of employees supports the technology necessary for current meter reading operations.

Meter reading contracts have been periodically put out to bid. This periodic bidding process ensures that meter reading contract pricing is reflective of current market conditions, including any efficiencies developed by vendors, new entrants into the meter reading market, and other cost changes that may affect bids (fuel costs, local labor conditions, etc.). The Company also actively monitors contractor performance on a variety of performance measures to ensure the Company, and ultimately its customers, receive accurate and cost-effective meter reading services.

Q30. ARE METER READING COSTS INCLUDED IN CUSTOMER RATES?

A. Yes, and as Mr. Lewis describes, one component of the operational cost savings of an AMS is the elimination of these costs and removal from customer rates.

Q31. WILL THE AMS ELIMINATE ALL OF ETI'S CONTRACT METER READING COSTS?

A. Yes. When fully deployed, an AMS will allow the Company to read all advanced meters remotely. It is not anticipated that readings because of exceptions (such as readings of non-standard meters or readings required in the event of a failure in the communications module in an individual meter or as part of an investigation generated by unusual meter reading results) will necessitate the need for additional meter reading services contracts because these issues will be handled by Company personnel.

Q32. PLEASE DESCRIBE THE METER SERVICES ACTIVITIES YOU NOTED ABOVE.

A. As I mentioned, there are meter services activities that take place at customers' meters. These services are performed by meter services personnel (both ETI employees and contract labor) and not by meter readers. These services include the installation, maintenance, and inspection of the existing meters. Today, meter services personnel perform the initial meter installation and any future meter changes or removals. Meter services personnel also perform the initial meter connection of service for a new customer and perform the meter disconnection when a customer asks to terminate service. Meter services personnel also perform meter disconnections as a result of non-payment of bills as well as any subsequent meter reconnection after payment is received. Finally, meter services personnel perform meter re-reads in certain circumstances (*e.g.*, there are meter access issues or a re-read is requested by a customer).

All of this meter services activity is scheduled and coordinated by the Mobile Dispatch function. These dispatchers perform the scheduling and dispatching of certain meter services work orders, such as metering equipment changes, meter reading verification, and location verification. Mobile Dispatch also assists with work management for increased efficiency by dispatching orders to both meter service personnel and service department personnel. These dispatchers also provide assistance when a problem exists with job readiness, the job location, or if a safety situation (hazard) is present at the job site.

Q33. HOW WILL THOSE FUNCTIONS CHANGE AFTER THE AMS IS DEPLOYED?

A. Personnel will be needed to support the ongoing operations, including installations, removals, and exchanges of metering equipment once the AMS is in place. There will also be new positions added in the Utility Operations Support organization of ESI to manage the communication and data aspects of the AMS deployment and ongoing operations. However, because of the capabilities of an

AMS, nearly all residential electric connections and disconnections, including temporary disconnections for non-payment of bills and subsequent reconnections following payment, will be performed remotely without requiring travel to the service location. Further, the need for physical re-reads will be virtually eliminated because (1) Company personnel can perform remote read confirmation; (2) the opportunity for error in monthly manual reads is eliminated; and (3) the analytics software that will be utilized can detect errors and confirm accuracy.

Q34. ARE METER SERVICES COSTS INCLUDED IN CUSTOMER RATES?

A. Yes, and as Mr. Lewis describes, one component of the operational cost savings is elimination of these costs and removal from customer rates.

Q35. HOW WILL THE COMPANY ADDRESS THE CURRENT METER READING AND METER SERVICES CONTRACTS?

A. The Company is managing the current meter reading and meter services contracts and any necessary extensions to align with the AMS deployment schedule to allow for the contract services to be reduced as the AMS is implemented.

Q36. ARE ANY NEW POSITIONS ASSUMED TO BE CREATED AS A RESULT OF THE AMS?

A. Yes, in addition to retaining some personnel for post-AMS deployment operations, as described above, the Company has assumed that there will be new positions created to support the AMS deployment and ongoing AMS operations. The Company is still evaluating whether these positions would be filled by contractors, employees, or a mix of the two depending on position, level of responsibility, required skill set, and duration of the role. Many of these new positions will be in the Utility Operations Support organization of ESI to manage the communication and data aspects of the AMS post-deployment.

VII. CUSTOMER EDUCATION PLAN

Q37. HOW DOES THE COMPANY PLAN TO MAKE CUSTOMERS AWARE OF ITS AMS DEPLOYMENT PLAN AND THEIR ABILITY TO ACCESS AND UTILIZE THE INFORMATION AND PROGRAMS YOU DESCRIBED?

A. In addition to the standard notice the Company is required to provide in connection with this application,[10] a comprehensive educational plan will coincide with the AMS ramp-up, infrastructure implementation, and meter deployment. This multi-phase plan is being designed to educate customers about the

[10] As described in the Company's Application, notice will be provided consistent with the notice provisions of 16 TAC § 22.51(a).