See Native Excel file Vongkhamchanh Direct_Exhibit KV-12.

See Native Excel file Vongkhamchanh Direct_Exhibit KV-13.

See Native Excel file Vongkhamchanh Direct_Exhibits A through D.

See Native Excel file Vongkhamchanh Direct_WP_KV-3.

See Native Excel file Vongkhamchanh Direct_WP_KV-5 and KV-6.

DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

WILLIAM PHILLIPS, JR.

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF WILLIAM PHILLIPS, JR.
2022 RATE CASE

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EXHIBIT

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is William J. Phillips Jr. My business address is 1250 Poydras Street, New Orleans, Louisiana 70113. I am currently employed by Entergy Services, LLC ("ESL") as Manager, AMI Implementation.

Q2. PLEASE DISCUSS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science degree in Mechanical Engineering in May of 2006 from Louisiana State University. In December 2014, I received a Master of Business Administration from the Flores MBA Program through Louisiana State University. I am also a registered professional engineer in the state of Louisiana.

I joined Entergy Services, Inc. (the predecessor to ESL) in July 2008. From 2008 to 2013, I held the position of gas planning engineer with responsibilities including: (i) gas pipeline design, meter set and system pressure control design; and (ii) system planning and coordination with city, state, and parish officials on proposed road design and infrastructure replacement projects; (iii) engineering field support for regulator station and gas purchase point project installations, checkout, and commissioning of new facilities; (iii) standards, compliance, and operating procedures, which included the implementation of the Distribution Integrity Management Plan; and (iv) oversight and performance of the Greg Engineering pipeline simulation tool, including hydraulic flow modeling studies on the gas distribution system. In January 2013, I was named Supervisor, Gas Field

Operations. In that capacity, I was responsible for leakage survey, valve maintenance, and gas measurement (which included the Gas Supervisory Control and Data Acquisition ("SCADA") system), odorization, and pressure control for the Entergy Gulf States Utilities portion of the gas distribution business.

In December 2016, I joined the Grid Modernization organization as Senior Project Manager on the AMI Implementation team where my primary focus was on gas AMI. Through this role, I quickly became involved in all aspects of the advanced meter systems and gained a broad view across the various workstreams of the project management organization. Beginning July 2018, I was promoted to my current position of Manager, AMI Implementation, where I lead the implementation of AMI and all supporting systems. In this position, I oversee a department of Senior Project Managers who perform a myriad of activities to support the advanced metering system ("AMS") implementation. I also have oversight of all regulatory reporting regarding AMS for all operating companies.

Q3. WHAT ARE THE PRIMARY RESPONSIBILITIES OF YOUR CURRENT POSITION?

A. I am responsible for leading the implementation of the comprehensive AMS solution. This includes the implementation of AMS systems (Meter Data Management System ("MDMS"), Head End System ("HES"), and modifications to legacy systems/applications) and the deployment of advanced meters and communication network equipment. I work collaboratively with Information Technology ("IT") leadership to ensure business case objectives are met through technology implementation. I have oversight of the Project Management Office ("PMO") activities and communications, cross-functional issue resolution, risk/issue identification and mitigation, and I function as of the point of accountability for overall program implementation.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("PUCT" OR "COMMISSION")?

A. No.

II. PURPOSE OF DIRECT TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is as follows:

- I provide an overview of this AMS reconciliation filing;
- I describe the Company's AMS Deployment Plan that was approved by the Commission in Docket No. 47416;
- I describe the Company's project management team responsible for the AMS deployment and its management of the AMS deployment;
- I describe the Company's deployment of its AMS and show that the Company has implemented that deployment consistent with the AMS Deployment Plan approved by the Commission;
- in conjunction with the Company's other AMS reconciliation witness, David Batten, I explain that the costs the Company incurred and the investments the Company made in connection with its AMS deployment through December 31, 2021 were in accordance with the approved AMS Deployment Plan and that, as a result, those costs and investments are entitled to the presumptions of reasonableness and necessity provided in 16 Texas Administrative Code ("TAC") § 25.130(k)(6);
- I describe the advanced meters installed pursuant to the Company's AMS

Deployment Plan and explain that the advanced meters' features and functionalities comply with 16 TAC § 25.130(g) and are consistent with the Deployment Plan;

- I describe the communications network costs associated with the Company's AMS Deployment Plan that was approved by the Commission in Docket No. 47416;
- I describe the actual IT systems and integration necessary to support the Company's AMS, including the Advanced Distribution Management System and Outage Management System ("DMS/OMS") described in the Deployment Plan, the associated IT systems capital costs, and related operations and maintenance ("O&M") costs;
- I describe and support the activities and costs associated with the AMS Customer Education initiative undertaken by the Company;
- I describe and support the affiliate charges included in the deployment and ongoing costs to support the Company's AMS;
- I describe and support the customer service benefits associated with the Company's AMS deployment and how those savings benefit customers;
- I describe the Company's meter-related discretionary service charges and how they have been reduced annually in accordance with the Commission's Order in Docket No. 47416; and
- I discuss the Company's plan to implement on-demand reads ("ODR") instead of home-area network ("HAN") functionality consistent with the Commission's revisions to 16 TAC § 25.130 in May 2020 and following the resolution of Docket No. 48745.

Q6. HOW IS THE COMPANY'S AMS RECONCILIATION FILING STRUCTURED?

A. The structure of the Company's reconciliation filing relies on Schedule A attached to Mr. Batten's direct testimony as Exhibit DCB-3, which is patterned on the format used in the Company's annual reports to the Commission filed in Project No. 49233. This Schedule includes a two-page summary, the first page of which summarizes the customer service benefits, O&M costs, depreciation and amortization, return, taxes, and certain other items making up the Company's revenue requirements related to the deployment of its AMS. The second page summarizes the components of the invested capital (rate base) related to the AMS deployment. Attached to and included in the Schedule are individual exhibits related to each of the items summarized on the first two summary pages of Schedule A, and additional tabs contain the workpapers with additional detail for the data presented in Schedule A.

Q7. WHAT IS THE END OF THE RECONCILIATION PERIOD FOR THE COMPANY'S FILING?

A. The Company's reconciliation period ends as of December 31, 2021.

Q8. WHAT PORTION OF THE FILING SUBMITTED AS DAVID BATTEN'S EXHIBIT DCB-3 DO YOU SPONSOR?

A. I sponsor or cosponsor the following Schedules that are a part of this filing:

Figure WJP-1

SCHEDULE A-1	
Cost/Savings Description	Exhibit
Customer Service Benefits	1-A
Meter Support	1-B
Communications Network	1-C
IT: System Integration, MDMS, DMS/OMS	1-D
Internal Support	1-E
Customer Education	1-F

SCHEDULE A-2	
Rate Base Description	Exhibit
Electric Meter Costs	2-A
Communications Network	2-B
Total IT & Implementation Expenditures	2-C

III. <u>OVERVIEW OF FILING</u>

Q9. WHY IS THE COMPANY FILING THIS REQUEST FOR AMS RECONCILIATION?

A. This filing is made to comply with 16 TAC § 25.130(k)(6) and the Commission's Order in Docket No. 47416. As part of the settlement of that case, the Company agreed to have the actual costs reviewed in a reconciliation proceeding.[1]

Q10. IS THE COMPANY SEEKING TO ADJUST THE AMS SURCHARGE IN THIS PROCEEDING?

A. No. As discussed in more detail by Company witness Mr. Batten, the Company is not seeking in this proceeding either to adjust the amount of the AMS surcharge or to modify the length of time over which the surcharge will be applied.

Q11. PLEASE DESCRIBE THE TESTIMONY OF THE OTHER WITNESS WHO SUPPORTS THE AMS RECONCILIATION.

A. As I mentioned previously, in addition to my testimony, the Company is submitting the testimony of David Batten to support the Company's request for AMS

[1] See Finding of Fact No. 35(C) of the Commission's Order in Docket No. 47416.

reconciliation. Mr. Batten addresses the Company's accounting for the actual revenues, costs, and investment associated with the Company's deployment of its AMS, including affiliate costs and the difference between certain cost estimates as established in the financial models used to set the Company's original AMS surcharges and actual costs incurred by the Company.

IV. DESCRIPTION OF APPROVED AMS DEPLOYMENT PLAN

Q12. PLEASE DESCRIBE THE COMPANY'S APPROVED DEPLOYMENT PLAN.

A. On December 14, 2017, the Commission issued its Order in Docket No. 47416 approving the Company's AMS Deployment Plan ("the Plan") consistent with the settlement agreement. The Plan is Attachment A to the Application in Docket No. 47416. The Plan provides for the Company to deploy advanced meters that provide or support the system features identified in 16 TAC § 25.130(g)(1) for residential and non-residential retail electric customers in the Company's service area, except for transmission voltage customers and customers that take non-metered service.

The Plan proposed that meter installation begin in 2019 with a projected completion date of December 31, 2021. The Plan describes the communications network and operating system that are necessary for the meter technology employed and contemplates that the Company's existing IT systems, including the OMS, will require upgrades and modifications to support the AMS deployment. The Plan also anticipates that new systems will be required, including the DMS.

Q13. PLEASE DESCRIBE HOW THE COMPANY'S AMS DEPLOYMENT IS PROGRESSING.

A. As of year-end 2021, the Company completed mass meter deployment ahead of schedule. The IT-related work necessary to support the AMS has also been completed as contemplated by the Plan, although communication network optimization and remediation is still underway. Communication network optimization and remediation is the procedure by which the layout of the network, equipment configuration, and implementation are subjected to active and passive tests to confirm that performance and redundancy meet the design specifications, and adjustments are made as necessary to meet those specifications. Optimization is executed in a specific area of the service territory when scheduled by the network installers and ETI after a sufficient number of meters have been deployed to achieve saturation of the mesh network, and it may include the provisioning of additional equipment as required for achieving the required performance and redundancy. An area is considered "optimized" when testing validates that the design specifications are satisfied.

That optimization work is estimated to be completed in December 2022.

Q14. HOW DOES THE ACTUAL CAPITAL INVESTMENT FOR THE AMS COMPARE TO THE AMOUNT ESTIMATED AT THE TIME THE PLAN WAS PREPARED?

A. As set forth in the second page of Schedule A, for some categories, the Company has incurred more than was estimated in the AMS Surcharge Model filed in Docket

No. 47416,[2] and for other categories, the Company has incurred less than was estimated. Taken as a whole, Schedule A demonstrates that the Company's actual AMS meter, communications systems, and IT infrastructure and capital investments incurred through year-end 2021 are approximately 13% more than those estimated in the AMS Surcharge Model as set forth in the following table:

Figure WJP-2

AMS Meter and IT Deployment Capital as of 12/31/2021		
Est.	**Actual**	**Diff.**
$76,178,694	$86,102,131	$9,923,437

Q15. WHAT ARE THE DRIVERS RESPONSIBLE FOR ACTUAL CAPITAL COSTS BEING MORE THAN ESTIMATED IN THE AMS SURCHARGE MODEL?

A. As explained in more detail below, the primary drivers for the variance in capital investments are due to the increased cost to implement IT infrastructure and systems due to higher complexity and longer implementation schedules than originally estimated.

[2] The Company's agreed-to AMS Surcharge Model was filed in Docket No. 47416 (Jan. 8, 2019).

Q16. HOW DOES THE ACTUAL O&M EXPENDITURE FOR THE AMS COMPARE TO THE AMOUNT ESTIMATED AT THE TIME THE PLAN WAS PREPARED?

A. The first page of Schedule A indicates that AMS O&M costs have been less than estimated in the Company's AMS Surcharge Model. The following table compares the O&M costs for meters and IT incurred through December 31, 2021:

Figure WJP-3

AMS Meter and IT Deployment O&M as of 12/31/21		
Est.	**Actual**	**Diff.**
$10,127,636	$8,594,230	$(1,533,406)

Q17. WHAT ARE THE DRIVERS RESPONSIBLE FOR ACTUAL O&M COSTS BEING LESS THAN ESTIMATED IN THE AMS SURCHARGE MODEL?

A. It is a largely a timing difference. As explained in more detail below, the difference in plant closings relative to the initial estimate resulted in a delay in incurring O&M expenses. Now that the deployment is concluded, the Company expects O&M costs will be closer to projections going forward.

Q18. HOW DO THE AMS REVENUE REQUIREMENTS INCURRED THROUGH DECEMBER 31, 2021 COMPARE TO THE LEVELS ESTIMATED IN THE AMS SURCHARGE MODEL?

A. The actual AMS revenue requirement through December 31, 2021 was more than estimated in the Company's AMS Surcharge Model as shown in the following table:

Figure WJP-4

AMS Revenue Requirement as of 12/31/21		
Est.	**Actual**	**Diff.**
$62,431,627*	$67,160,832	$4,729,205

*Net amount based on settlement.

Mr. Batten and I discuss the drivers contributing to the actual revenue requirements being different from the levels estimated in the AMS Surcharge Model. For example, it was contemplated in Docket No. 47416 that the revenues recovered under the AMS surcharges during the initial periods of deployment would exceed the Company's revenue requirement. Moreover, as Mr. Batten discusses in his testimony, in an over-recovery scenario, customers receive credit for the time value of money on the resulting difference at the Company's pretax cost of capital through the mechanisms established in Finding of Fact Nos. 58 and 59 of the Order in Docket No. 47416. As of December 31, 2021, the Company has expended on a cash basis approximately $154 million. As of that date, the Company has billed customers approximately $69.5 million through the AMS surcharge.

V. MANAGEMENT OF IMPLEMENTATION OF AMS DEPLOYMENT PLAN

Q19. WHO IS RESPONSIBLE FOR THE IMPLEMENTATION OF THE COMPANY'S APPROVED AMS DEPLOYMENT PLAN?

A. As Manager of Advanced Metering Infrastructure Implementation for ETI, I am currently responsible for the implementation of the AMS Deployment Plan. Prior to deployment, ETI put in place a project management structure to ensure that the

AMS deployment is completed effectively, efficiently, and in a manner that is consistent with the approved AMS Deployment Plan. The AMS deployment is a large capital program that is managed in compliance with ETI's capital project management structure and control environment. At the outset of the program, ESL, in conjunction with ETI, established a Project Management Office ("PMO") structure for the AMS project to manage the program design, vendor selection, and AMS deployment. The PMO is a matrix organization that consists of multiple work teams, each of which is focused on specific functional areas and project execution activities.

The PMO is governed by an Executive Steering Committee that consists of representatives from each of the participating Entergy Operating Companies ("EOCs"), including ETI (the "AMS Steering Committee"). The AMS Steering Committee is responsible for oversight and approval of PMO activities. ETI's participation on the AMS Steering Committee includes ETI's President, Eliecer Viamontes or ETI representatives acting at his direction. These ETI representatives not only participate in the decision-making for the project but also provide direct guidance and input to the PMO on issues specific to or otherwise affecting ETI's AMS deployment.

Q20. WHAT IS YOUR ROLE IN THE PMO?

A. I am the PMO lead for the AMS implementation. My responsibilities include overseeing the PMO activities and communications, managing the overall PMO logistics, resolving cross-functional issues across program work teams, and functioning as the point of accountability for the overall program implementation success.

VI. DEPLOYMENT CONSISTENT WITH APPROVED AMS DEPLOYMENT PLAN

Q21. PLEASE DESCRIBE HOW THE COMPANY'S IMPLEMENTATION OF ITS AMS DEPLOYMENT PLAN THROUGH 2021 COMPARES TO THE IMPLEMENTATION ANTICIPATED IN THE PLAN APPROVED BY THE COMMISSION.

A. As I stated previously, the Company's deployment of advanced meters has been consistent with the Plan approved by the Commission in Docket No. 47416. The Company has deployed the communications network described in the Plan. As contemplated by the Plan, the Company has modified and upgraded its IT systems to provide the necessary capabilities to support the AMS. As of March 31, 2021, the Company had completed the mass deployment of advanced meters with a total of 463,395 meters installed, whereas the Plan, which was based on projected customer growth, anticipated installing a total of 477,000 advanced meters through the end of 2021. While there are some instances where an advanced meter could not be installed during mass deployment (e.g., the customer refused access), those meters will eventually be converted to AMS, but they are no longer considered part of the AMS deployment and instead will be handled as part of normal operations.

The Company, as I mentioned previously, has also deployed the communications network to support the advanced metering system. The peer-to-peer design of the communications network accommodates a mix of paths automatically adapting and routing around obstacles connecting remote or hard-to-hear locations. The Company is deploying standard-based access points ("APs") that are primarily using cellular backhaul technology, but the network has the flexibility to use other backhaul technologies, including ethernet/fiber, and a variety of other wired and wireless options. All cellular equipment is LTE capable. The Company is also installing network relays to extend the network between the APs and the advanced meters to support multi-hop, two-way communication.

Q22. HAS THE COMPANY DEVELOPED THE IT SYSTEM TO SUPPORT AMS THAT WAS CONTEMPLATED IN THE AMS DEPLOYMENT PLAN APPROVED BY THE COMMISSION?

A. Yes. As contemplated in the Plan, and as I discuss later in my testimony, the Company has upgraded and modified its IT systems as necessary to support the deployment of advanced meters.

Q23. HAS THE COMPANY IMPLEMENTED THE DMS/OMS THAT WAS CONTEMPLATED IN THE PLAN?

A. Yes. The Company upgraded the OMS and implemented a DMS (Distribution Management System). The new system went into full production in November of 2020, and it replaced the legacy OMS for the management of outages. The new DMS/OMS is an off-the-shelf system integrated with the AMS meters and the SCADA system, which provides faster outage detection and response. Going forward, the Company is working to utilize the new DMS/OMS to streamline switching order development and execution. The Company is also working to implement new functionality that is facilitated by the DMS, examples of which include Fault Locating (FL) and Fault Isolation Service Restoration (FISR) technologies, sometimes also referred to in combination as FLISR, Conservation Voltage Reduction (CVR), and Volt-Var Optimization (VVO).

Q24. HAS THE COMPANY SUBMITTED ANY MODIFICATION OF THE PLAN?

A. No, although the Company, as has been described in the monthly 16 TAC § 25.130(d)(9) reports for some time, anticipates modifying the Plan to remove the home-area network feature in lieu of on-demand read functionality following the conclusion of Docket No. 48745. This topic is discussed in further detail in Section X, below.

VII. COSTS INCURRED IN ACCORDANCE WITH THE APPROVED PLAN

Q25. PLEASE DESCRIBE THE COSTS THAT THE COMPANY INCURRED IN THE AMS DEPLOYMENT THROUGH YEAR-END 2021.

A. As I mentioned above, Schedule A provides the cumulative O&M costs that the Company has incurred and the capital investments it has made in deploying the AMS. Schedule A-1 provides a synopsis of the O&M costs for the AMS deployment through the end of 2021 as well as total depreciation, total return, total taxes, and total revenue requirement. Schedule A-2 provides the rate base associated with the AMS deployment, including the total expenditures for advanced meters, communications network, IT systems, and regulatory assets. Following those two pages, there is a separate exhibit for each line item included in the first two pages, and each exhibit contains a description of the cost category and a calculation of the difference between the amount estimated in the Company's AMS Surcharge Model and the actual costs incurred for the investments made through December 31, 2021 in connection with the AMS deployment.

Q26. HAS THE COMPANY PRODUCED THE VENDOR CONTRACTS UNDERLYING THE COSTS THAT HAVE BEEN INCURRED?

A. Yes, HSPM Exhibit RGW-4, which was attached to the Direct Testimony of Company witness Rodney W. Griffin in Docket No. 47416, included all of the vendor contracts for the deployment that had been executed at the time. As is customary in a capital project of this scope, various change orders and addenda were executed during the deployment. Those documents are included in HSPM Exhibit WJP-1.

Q27. WERE THE COSTS THE COMPANY INCURRED AND THE INVESTMENTS THE COMPANY MADE THROUGH DECEMBER 31, 2021 IN ACCORDANCE WITH THE AMS DEPLOYMENT PLAN APPROVED BY THE COMMISSION IN DOCKET NO. 47416?

A. Yes. As demonstrated by the testimony of the Company's witnesses in this case, the costs the Company incurred and the investments the Company made in connection with the deployment of advanced meters through December 31, 2021 were in accordance with the Plan approved by the Commission in Docket No. 47416. The Company's testimony demonstrates that through December 31, 2021 it:

1. deployed the advanced meters contemplated by the Plan that have the features and functionalities required by 16 TAC § 25.130(g)(1);
2. implemented a communications network and operating systems that are necessary to support the meter technology as contemplated in the Plan;
3. implemented new IT systems and modified existing IT systems to support the AMS deployment and the web portal;
4. implemented the new DMS/OMS as identified in the Plan; and
5. implemented the customer education program as identified in the Plan.

Since the costs the Company has incurred and the investments the Company has made to deploy AMS are consistent with what was contemplated in the AMS Deployment Plan, these costs are entitled to the presumption of reasonableness described in 16 TAC § 25.130(k)(6).

Q28. WERE THE COSTS INCURRED AND THE INVESTMENTS MADE BY THE COMPANY FOR THE DEPLOYMENT OF AMS REASONABLE AND NECESSARY?

A. Yes. The costs incurred and the investments made by the Company in deploying its AMS as described in its approved AMS Deployment Plan are reasonable and necessary. The supporting testimony submitted in Docket No. 47416 and this case provides specific evidence of the reasonableness and necessity of the costs incurred and the investments made by the Company in its AMS deployment. To the extent capital or O&M costs were incurred for services provided by another Entergy affiliate, I support the reasonableness and necessity of the capital and O&M costs for construction and operation of the AMS system as well as the reasonableness and necessity of the IT and network-related affiliate capital and O&M costs.

A. <u>Advanced Meters</u>

Q29. PLEASE DESCRIBE HOW THE FEATURES AND FUNCTIONALITIES OF THE COMPANY'S INSTALLED ADVANCED METERS COMPARE WITH THE REQUIREMENTS OF 16 TAC § 25.130.

A. The advanced meters that the Company has installed have all of the features and functionalities that are required by 16 TAC § 25.130(g),[3] except where a variance was expressly allowed by the Order in Docket No. 47416. For an example, loads that currently have poly-phase service or are greater than class 200 (200-amp rating) meters do not have an internal remote service switch, which is specifically permitted under Findings of Fact No. 29 and 34 in the Order in Docket No. 47416. In addition, the Order in Docket No. 47416 recognized that certain requirements

[3] The features and functionalities contained in 16 TAC § 25.130(g) were revised by the Commission in May 2020, which was subsequent to the Order in Docket No. 47416. Accordingly, ETI's Plan, and the order approving the Plan, were based on the earlier version of the rule.

are only applicable in a deregulated market where retail electric providers provide retail electric service, and that those requirements do not apply to ETI's Plan.[4]

Q30. HOW DID THE TIMING OF THE INSTALLATION OF ADVANCED METERS THROUGH THE END OF 2021 COMPARE WITH WHAT WAS ASSUMED IN THE AMS SURCHARGE MODEL?

A. While the surcharge model assumed for purposes of calculating the surcharge and operational benefits that meter deployment would begin in January 2019 and maintain a steady deployment schedule, as explained by Company witness Rodney W. Griffith in his July 2017 Direct Testimony in Docket No. 47416, the detailed meter deployment schedule had yet to be developed, and he explained that it would be developed by the end of 2017. Consistent with that plan, the AMS deployment team worked with the meter installer during the fall of 2017 to develop a detailed deployment plan, which resulted in meter deployment beginning in Texas in March 2019. In addition to starting deployment a few months later than assumed for modeling purposes, meter deployment was not as steady as assumed, due in large part to the COVID-19 pandemic, which affected the physical availability of meter installers needed to maintain the pace assumed in modeling. In addition, ETI and other the EOCs were affected by a number of hurricanes and the threat of hurricanes between 2019 and 2021, which also resulted in temporary meter deployment slowdowns as resources were redeployed for storm preparation and

[4] Order at Finding of Fact No. 28.

restoration activities. Those conditions affected the communications and IT system deployments as well.

Despite those challenges, full meter deployment was ultimately completed ahead of schedule.[5] However, the timing difference between the start date and the pace of deployment assumed for modeling versus actual affected monthly asset closing projections compared to the model. Those differences produce variances in both the capital and O&M expenses between the model and actual. Those variances are explained below and by Mr. Batten.

1. Advanced Meters Capital Costs

Q31. PLEASE DESCRIBE HOW THE ACTUAL INVESTMENT IN THE ADVANCED METERS INSTALLED THROUGH THE END OF 2021 COMPARES TO THE ORIGINALLY ESTIMATED CAPITAL COSTS OF THE ADVANCED METERS IN THE COMPANY'S AMS SURCHARGE MODEL.

A. As shown in Exhibit 2-A to this reconciliation, the actual capital investment made in advanced meters through December 31, 2021, including the cost of meter hardware, meter installation, and project management oversight, was $66,633,983. This is $106,460 lower than the $66,740,443 estimated in the AMS Surcharge Model, which is a result of the actual number of meter installations being lower than meter population growth estimated in the plan.

[5] As noted earlier, there were some instances where AMS meters could not be installed during mass deployment. Examples include customers who refused access or extremely remote locations. While those meters will eventually be converted to AMS, they are handled through the Company's normal operations and are no longer considered to be part of the AMS deployment.

Q32. PLEASE DESCRIBE HOW THE COMPANY HAS ENSURED THAT ACTUAL ADVANCED METER COSTS HAVE BEEN REASONABLE AND NECESSARY AND INCURRED IN ACCORDANCE WITH THE AMS DEPLOYMENT PLAN.

A. In order to provide the functionalities specified in the Commission's rules and the Order in Docket No. 47416, the Company has installed its advanced meters in accordance with the Commission-approved Plan. The advanced meters purchased by the Company from Elster Solutions, LLC, A Honeywell Company ("Honeywell"), and Landis+Gyr ("L+G") were purchased based on the per-meter pricing approved by the Commission in Docket No. 47416. The Company's advanced meter costs shown on Exhibit 2-A to this reconciliation request are, therefore, entitled to the presumption that they are reasonable and necessary under 16 TAC § 25.130(k)(6).

In implementing the Plan, the Company has used reasonable processes to procure the necessary advanced meters with the required features and functionalities, associated equipment, technology, and services. Meters were shipped directly to the contractor responsible for installing the meters in order to keep the storage, freight and handling charges to a minimum. Those processes have enabled the Company to achieve reasonable costs for the installation of advanced meters that compare favorably with the costs estimated in the AMS Surcharge Model. In addition, the Company tracks the costs associated with the meters in connection with the implementation of the Plan. For these reasons, the Company's actual advanced meter costs have been reasonably and necessarily incurred and properly allocated.

2. Advanced Meters O&M Costs

Q33. ARE THERE O&M COSTS ASSOCIATED WITH THE ADVANCED METERS INCLUDED IN THE AMS SURCHARGE?

A. Yes, there are O&M costs associated with the AMS lab, which manages the AMS meter testing and coordinates ongoing support of the AMS meters. That coordination includes meter vendor management, warranty procedures, meter troubleshooting, and new meter firmware approval process. The AMS lab costs include a lab manager, lab technicians, lab facility costs, and meter back-office software for meter testing and configuration equipment. As reflected in ETI's Exhibit 1-B, these costs are referred to as Meter Support costs.

Q34. WHAT IS THE DIFFERENCE BETWEEN THE METER SUPPORT COSTS ESTIMATED IN ETI'S AMS SURCHARGE MODEL AND THE ACTUAL METER SUPPORT COSTS INCURRED?

A. As reflected in ETI's Exhibit 1-B, the AMS Surcharge model forecasted $218,054 in meter support costs. The actual meter support costs were $60,919. This results in ETI's actual meter support being $157,135 less than estimated. The primary drivers for the variance were: (1) the AMS lab was implemented later than initially projected, resulting in incremental personnel being hired later than initially projected; and (2) a higher proportion of the initial meter support costs were capitalized compared to the original projection. The Company expects the O&M spend associated with meter support will come closer to projections going forward.

Q35. PLEASE DESCRIBE HOW THE COMPANY HAS ENSURED THAT METER SUPPORT COSTS INCURRED HAVE BEEN REASONABLE AND NECESSARY AND ARE IN ACCORDANCE WITH THE COMPANY'S APPROVED AMS DEPLOYMENT PLAN.

A. The Company has incurred meter support costs for the activities I have just discussed, which are essential for supporting the AMS meters. The Company appropriately tracked these costs and ensured that they were expended and properly allocated to the AMS initiative. The meter support costs were incurred in accordance with the Company's approved AMS Plan and are entitled to the presumption in 16 TAC § 25.130(k)(6) that those costs are reasonable and necessary.

B. Communications Network

Q36. PLEASE DESCRIBE THE COMMUNICATIONS NETWORK COSTS CONTEMPLATED IN THE AMS DEPLOYMENT PLAN.

A. The communications network costs include communication hardware and deployment. Costs also include Information Technology Systems and Infrastructure such as software, software licenses, IT hardware (and its associated vendor costs), and internal Entergy labor for the meter management software, headend system, MDMS (Meter Data Management System), and the IT portions of DMS/OMS.

The communications infrastructure is a system of communications components that provide for two-way data transfer – both from the meter and other AMS components to the Company, and from the Company to those AMS components. For purposes of ETI's AMS deployment, the communications system includes the Network Interface Card ("NIC"), a "mesh" communications network, a backhaul communications network, and the head-end system at the Company's data center.

The NIC is a modular circuit board located inside each advanced meter. It is the component that connects the advanced meter to various networks and enables remote two-way communication between the meter and the Company in a reliable and secure manner.

The mesh communications network is a wireless network made up of radio "nodes" that have the ability to communicate with each other. Each NIC and network component (e.g., access points and relays) is a separate node in the mesh network. Meter data and messages transmit from node-to-node until reaching a destination node, which can be a NIC, relay, or access point, depending on the direction the data is traveling. Data is communicated between the access points and the head-end system at the data center via the backhaul network, which primarily consists of cellular service. There are rare circumstances that require alternative backhaul solutions, e.g., Company-owned fiber.

The head-end system refers to the hardware and software components in the data center that reliably and securely: (1) receive information from field components, including meters; (2) transmit data to those components; and (3) route meter information to appropriate internal IT systems, including the MDMS. In addition, the head-end system contains basic data validation and error checking functionality in its role of collecting and passing data, information, and commands between various utility systems (e.g., the MDMS) and field components.

1. <u>Communications Network Capital Costs</u>

Q37. WERE THERE ANY CAPITAL EXPENDITURE ESTIMATES ASSOCIATED WITH THE COMMUNICATIONS NETWORK INCLUDED IN THE AMS SURCHARGE MODEL?

A. Yes. As described in Exhibit 2-B, the AMS Surcharge Model included estimated capital expenditures associated with AMS communications network at the end of 2021 totaling $17,155,843.

Q38. PLEASE DESCRIBE THE DEPLOYMENT OF THE COMMUNICATIONS NETWORK.

A. The communications network described above was implemented in phases based on meter deployment requirements and timelines included in the Company's Commission-approved AMS Plan. Through 2021, the advanced meters, aerial-mounted relays, pole-mounted APs, and associated structures used to support a fully-functional communication network have been installed to support the advanced meters. As described earlier, while the deployment of the communications network is complete, the optimization process will continue through the rest of this year.

Q39. PLEASE DESCRIBE THE ACTUAL CAPITAL EXPENDITURES ASSOCIATED WITH THE COMMUNICATIONS NETWORK IMPLEMENTED TO SUPPORT THE COMPANY'S AMS THAT HAVE BEEN INCURRED THROUGH THE END OF 2021.

A. As shown on Exhibit 2-B, as of the end of 2021, the Company has incurred capital expenditures associated with AMS communications network totaling $10,767,359. This is $6,388,483 less than the $17,155,843 estimated in the AMS Surcharge Model.

Q40. WHY ARE THE COMPANY'S ACTUAL CAPITAL EXPENDITURES DIFFERENT FROM THE ESTIMATED CAPITAL EXPENDITURES FOR AMS COMMUNICATIONS NETWORK IN THE AMS SURCHARGE MODEL?

A. The variance is a result of the optimization work on the Communication Network that is taking longer than initially estimated and the pandemic-related work constraints and major storm events that I described earlier. In addition, the contract with the communications vendor provides that payment is not fully due until optimization is complete, so additional costs will be incurred consistent with the contracts once optimization is final. Accordingly, this variance does not represent a reduction in these costs, but rather a delay in the spend associated with the

Communication Network. Optimization of Communication Network is targeted to complete by the end 2022, which is expected bring the spend in alignment with the projections.

Q41. WERE THE ACTUAL COSTS OF THE AMS COMMUNICATIONS NETWORK EXPENDED IN ACCORDANCE WITH THE COMPANY'S COMMISSION-APPROVED AMS DEPLOYMENT PLAN?

A. Yes. All actual costs associated with AMS communications network were expended in accordance with the Company's Commission-approved AMS Deployment Plan and are entitled to the presumption of reasonableness and necessity provided by 16 TAC § 25.130(k)(6).

Q42. ARE ALL ACTUAL COMMUNICATIONS NETWORK COSTS INCURRED BY THE COMPANY TO DEPLOY AMS REASONABLE AND NECESSARY?

A. Yes. All actual costs incurred by the Company associated with the AMS communications network are reasonable and are necessary to support the Company's AMS and should be recovered through the AMS surcharges.

2. <u>Communications Network O&M Costs</u>

Q43. ARE THERE O&M COSTS ASSOCIATED WITH THE COMMUNICATIONS NETWORK?

A. Yes. ESL's IT organization provides ongoing O&M services for all technology assets, which is served through both internal support and third-party provider support for application and infrastructure services. This includes communication network specific applications, supporting infrastructure, and field equipment required to operate the communications network. The O&M costs for the communication network include annual costs associated with the cellular backhaul network, the HES hardware maintenance, various software licenses, and support services contracted with the respective technology providers.

In addition, industry-standard operational services, including incident and problem management, fulfillment of business service request, and technology data maintenance activities, are provided through ESL's IT and Information Security organizations and third-party service providers. These services are provided daily and ensure secure and reliable availability of the AMS Communications Network assets to enable connectivity to AMS meters.

Q44. WHAT ARE THE PRIMARY SOFTWARE LICENSES?

A. The primary licenses are for HES base, Critical Operations Protection ("COP"), Fast Failover, and UIQ. HES base is the primary application that receives the meter data from the backhaul network. The HES includes the COP component that monitors transactions through the HES to ensure, identify, and prevent cyber security events. Fast Failover is the ability for the HES to transfer operations from the primary data center to the backup data center for redundant operations. UIQ is the HES operational user interface that is used to monitor meter status, communications, meter data, and events.

Q45. WERE THERE EXPENSE ESTIMATES ASSOCIATED WITH THE AMS COMMUNICATIONS NETWORK O&M INCLUDED IN THE AMS SURCHARGE MODEL?

A. Yes. As shown on Exhibit 1-C, as of December 31, 2021, the forecasted AMS Communications Network O&M totaled $1,378,235.

Q46. PLEASE DESCRIBE THE ACTUAL EXPENDITURES ASSOCIATED WITH THE AMS COMMUNICATIONS NETWORK O&M NECESSARY TO SUPPORT THE COMPANY'S AMS INCURRED THROUGH THE END OF 2021.

A. As shown on Exhibit 1-C, as of December 31, 2021, the forecasted AMS communications network O&M actual expenditures totaled $1,292,560, which is $85,676 less than the forecasted amount. The variance is directly attributed to the timing difference between the projected communications system hardware deployment cadence and the actual deployment and associated optimization of the network. Once network optimization is completed, the O&M costs are projected to be closer aligned with projections.

Q47. WERE THE ACTUAL AMS COMMUNICATIONS NETWORK O&M EXPENSES ASSOCIATED WITH SUPPORT OF THE AMS INCURRED IN ACCORDANCE WITH THE COMPANY'S COMMISSION-APPROVED AMS DEPLOYMENT PLAN?

A. Yes. All actual costs associated with communications network to support the Company's AMS were expended in accordance with the Company's Commission-approved AMS Deployment Plan and are entitled to the presumption of reasonableness and necessity provided by 16 TAC § 25.130(k)(6).

Q48. ARE ALL ACTUAL EXPENSES INCURRED BY THE COMPANY ASSOCIATED WITH COMMUNICATIONS NETWORK O&M IN SUPPORT OF AMS REASONABLE AND NECESSARY?

A. Yes. All actual costs incurred by the Company associated with communications network conducted in support of AMS are reasonable and necessary to support the Company's AMS and should be recovered through the AMS surcharge.

C. Information Technology Costs

Q49. PLEASE DESCRIBE THE IT-RELATED COSTS CONTEMPLATED IN THE COMPANY'S AMS SURCHARGE MODEL.

A. The Company's AMS Surcharge Model assumed that IT infrastructure and systems necessary to support the Company's AMS would be implemented and would include the necessary hardware, software customization and configuration services, system integration, and software licenses. Both infrastructure and systems are necessary to support the entire AMS deployment. The anticipated incurrence of costs in connection with modifications to the IT infrastructure and systems involved both software and hardware costs.

The estimated costs in the hardware category in the Company's AMS Surcharge Model covered the anticipated additions and changes to IT equipment such as server, network, and storage environments related to AMS. Hardware components included physical servers and network equipment, along with specialized devices, such as data security appliances, disk storage systems, and all associated cabling and hardware needed to enable the system and process AMS data. Estimated costs included in the Company's AMS Surcharge Model associated with this category were based on anticipated additions and modifications to existing hardware due to considerations like increased volume of transactions, increased security requirements, and changes to the Company's data storage solution due to the very large AMS data storage requirements.

The Company's AMS Surcharge Model also included estimated costs associated with multiple types of software services and systems integration that are necessary to support AMS. These included costs associated with:

1. overall system integration costs associated with overall architecture and design;
2. program management and project management, which ensure the overall program will meet system design and business requirements;
3. integration development to create application programming interfaces, which connect applications to each other in a structured

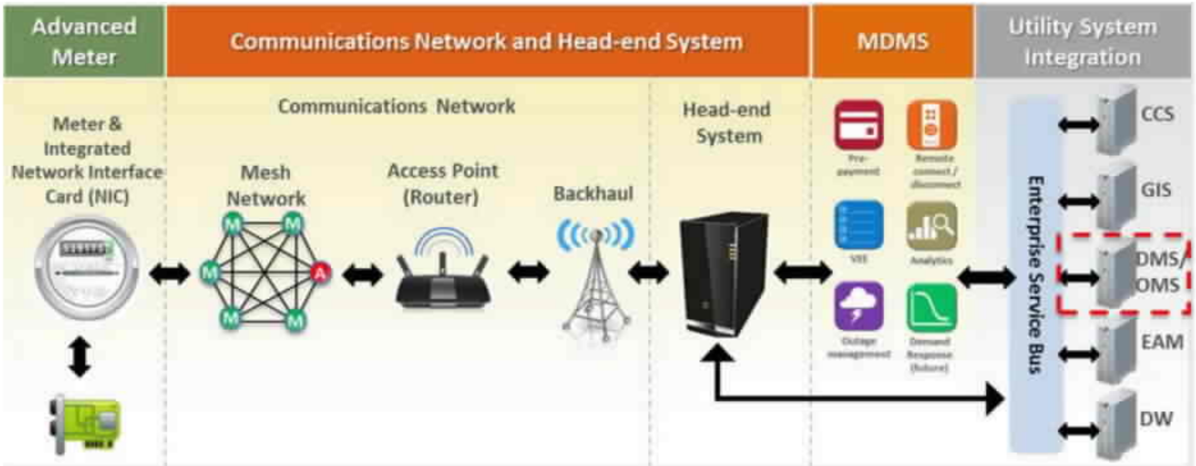
way through an Enterprise Service Bus ("ESB") ensuring proper interaction and data exchanges between these applications;

4. development costs for a web portal;
5. IT system development and enhancements to enable integration to the web portal;
6. upgrading the OMS and deploying a new DMS;
7. data warehousing and reporting enhancements; and
8. back-office enhancements to enable billing, market messaging, and service orders.

The software license costs estimated in the Company's AMS Surcharge Model included costs to purchase commercially available off-the-shelf software that forms much of the foundation of the IT needed to support the Company's AMS. The Company's AMS Surcharge Model also contemplated estimated costs associated with the software license for the Itron UIQ HES and Siemens Energy IP software that is used for interaction between the IT systems and the advanced meters, including the communication network components.

The following Figure illustrates the high level of integration necessary to support the AMS.

Figure WJP-5



Q50. DID THE COMPANY'S AMS DEPLOYMENT PLAN ANTICIPATE ANY UPGRADES OR MODIFICATIONS TO ANY EXISTING IT SYSTEM?

A. Yes, the Company's AMS Deployment Plan anticipated certain upgrades and modifications to the Company's existing IT system, and estimates for the costs of these system upgrades were included in the Company's AMS Surcharge Model.

Q51. WHAT IS THE STATUS OF THE IMPLEMENTATION OF THE AMS-RELATED IT SYSTEM MODIFICATIONS AND SYSTEM UPGRADES?

A. The foundational system implementations and modifications to support the AMS have been completed and include: (1) Itron UIQ HES software for managing the advanced meters and communications network; (2) the Siemens Energy IP MDMS for managing advanced meter reading; and (3) the TIBCO ESB to provide traceable transactional integration of the various applications. Also completed were modifications to the Company's Customer Information System — SAP Customer

Care System ("CCS") — and integration of those systems with the products described above to link the customer information and billing processes, service order processes, and CEP ("Customer Engagement Portal") processes.

Q52. HOW DID THE COMPANY DEVELOP THE NECESSARY IT SYSTEMS AND SYSTEM UPGRADES TO SUPPORT AMS?

A. The Company utilized a mixture of internal resources, several local IT firms for staff augmentation, and third-party vendors to procure, design, and configure the IT systems and system upgrades that were necessary to support the Company's AMS. The Company also selected International Business Machine Corp. ("IBM") as the systems integrator to assist with the design and program management of the AMS solution.

Q53. PLEASE DESCRIBE THE SOFTWARE SERVICES AND SYSTEM INTEGRATION NEEDED TO SUPPORT THE COMPANY'S AMS AS OF THE END OF 2021.

A. The Company's AMS is a very complex integrated solution comprised of many commercial software applications. As I mentioned, the solution currently includes the following commercial software applications: (1) Itron UIQ HES software for managing the advanced metering and communications network; (2) the Siemens Energy IP MDMS for managing advanced meter reading; and (3) the TIBCO ESB to provide traceable transactional integration of the various applications. Also involved were modifications to the Company's SAP CCS and integration of these systems with the products described above to link the customer information and billing processes, support the service order processes, and support CEP Portal processes. Key software products that are licensed to support the Company's AMS environment include:

1. Itron UIQ HES software;
2. Siemens Energy IP MDMS software;
3. database software;
4. TIBCO ESB software;
5. security-related software; and
6. other software that supports the server, storage, and appliance hardware.

1. <u>IT Capital Costs</u>

Q54. WHAT WERE THE CAPITAL COST ESTIMATES ASSOCIATED WITH THE AMS IT AND IMPLEMENTATION THAT WERE INCLUDED IN THE COMPANY'S AMS SURCHARGE MODEL?

A. As shown on Exhibit 2-C, $48,039,340 in IT capital costs were estimated to be incurred through December 31, 2021. As of December 31, 2021, the actual IT capital costs associated with IT and implementation systems, including the web portal and the DMS/OMS have been $56,136,883, which is $8,097,543 more than the estimate.

Q55. WHY ARE THE COMPANY'S ACTUAL CAPITAL EXPENDITURES DIFFERENT FROM THE ESTIMATED CAPITAL EXPENDITURES FOR IT SYSTEMS AND SYSTEM UPGRADES IN THE COMPANY'S AMS SURCHARGE MODEL?

A. The primary causes of the variance are due to: (1) expanded time frames for the upgrades and work necessary to integrate the various existing IT systems with the new AMS, including the new MDMS and head-end components; (2) delays in implementing the DMS/OMS; and (3) increased CEP development costs. In particular, the AMS core system functionality, which is primarily comprised of new systems integration, the HES, legacy systems integration, and the MDMS, was initially estimated to be completed in four "releases" by April 2019. As the system integration work commenced, it became apparent that the complexity of integrating the AMS core systems into all of the preexisting IT systems and applications that would utilize the AMS data required a more phased approach, resulting in separating the initial four AMS releases into subparts and adding a fifth release. While the overall scope of work did not significantly increase, the overall time frame required to complete the system integration increased due to the need to complete each of the multiple releases, including subparts, in sequence, which required resources working on the project longer than initially estimated. The expanded time frame to complete system integration is the primary driver of the variance seen in the actuals for the AMS core systems.

To mitigate additional cost increases associated with the IT integration work, ESL conducted a new RFP for the final two releases, and Accenture was selected over IBM to finalize the systems integration. Accenture, which had previously provided integration services under the MDMS and Legacy Systems implementation components of the overall AMS implementation, was selected to directly manage the remaining systems integrations. This eliminated the need to have a separate system integration vendor, which reduced execution complexity and simplified the overall implementation structure.

Another driver is a delay associated with holding the implementation of the DMS/OMS so that it did not occur during the hurricane season in 2018. In addition, the DMS/OMS was separated into two releases instead of one as originally planned. This allowed certain foundational aspects of the platform to be in service for the distribution operations center to manage outages in 2019, and the remainder of the platform was implemented later in 2020 to become the sole platform for distribution outage management. The reasons for splitting the release included vendor delays in next generation product development, longer than estimated product testing, and refined cybersecurity requirements.

As mentioned earlier, the IT implementation was also affected by human resource availability during the COVID-19 pandemic. Also, even the threat of a hurricane, of which there were many during the 2019-2021 timeframe, would halt implementation schedules so that IT systems would not be undergoing modifications or upgrades if a hurricane affected one of the EOC service areas.

Finally, there were some relatively minor cost increases associated with development of the CEP. While most of the CEP functionality was being tested by June 2019 and fully released to customers in September 2019, the peak event notification program was delayed until 2020, and additional costs have been incurred to address third-party data access functionality to comply with the Commission's final order in Docket No. 47416.

Q56. WERE THE ACTUAL CAPITAL COSTS ASSOCIATED WITH THE AMS IT SYSTEM AND SYSTEM UPGRADES EXPENDED IN ACCORDANCE WITH THE COMPANY'S COMMISSION-APPROVED AMS DEPLOYMENT PLAN?

A. Yes. All of the capital costs incurred in connection with the Company's AMS IT systems and system upgrades were necessary to support the implementation of AMS and were necessarily and reasonably incurred in accordance with the Company's Commission-approved AMS Deployment Plan. Accordingly, these costs are entitled to the presumption of reasonableness and necessity provided by 16 TAC § 25.130(k)(6).

Q57. HAS THE COMPANY PERFORMED THE SECURITY AUDIT CONTEMPLATED BY ORDERING PARAGRAPH NO. 5 OF THE ORDER IN DOCKET NO. 47416?

A. Yes. The security audit was completed and filed in Docket No. 51025.

Q58. DO ALL OF THE ACTUAL AMS IT SYSTEMS AND SYSTEM UPGRADES CAPITAL COSTS INCURRED BY THE COMPANY TO SUPPORT AMS QUALIFY FOR RECOVERY THROUGH THE AMS SURCHARGE?

A. Yes. All actual capital costs incurred by the Company for IT systems and system upgrades associated with AMS, as indicated in Exhibit 2-C, are reasonable, are necessary to support the Company's AMS, and should be recovered through the AMS surcharges.

2. IT O&M Expenses

Q59. WHAT O&M ACTIVITIES WERE ANTICIPATED AS NECESSARY TO SUPPORT THE COMPANY'S AMS IT SYSTEMS FOR WHICH COSTS WERE ESTIMATED IN THE AMS SURCHARGE MODEL?

A. The AMS Surcharge Model included estimated costs associated with ongoing O&M of the Company's AMS IT systems, including the DMS, OMS, and Customer Engagement Portal ("CEP"), as well as expenses associated with additional application support personnel, software license maintenance fees, and project expenses.

Q60. PLEASE DESCRIBE THE ACTUAL O&M ACTIVITIES UNDERTAKEN TO SUPPORT THE COMPANY'S AMS IT SYSTEMS.

A. As shown in the Surcharge Model, the IT related O&M activities were separated into two categories: (1) MDMS, System Integration, and DMS/OMS; and (2) Internal Support.

MDMS, System Integration, and DMS/OMS categories include hardware, software, and licensing for MDMS, ESB,[6] and the DMS/OMS. Included under the MDMS are the Advanced Meter Operations Center ("AMOC") related expenses. The AMOC is primarily responsible for ensuring the accuracy and completion of meter data delivered to the MDMS, monitoring the successful execution of remote turn-on/turn-off commands, and meter configuration management. AMOC costs include the AMOC manager and supporting operators, analysts and telecom support resources.

Internal Support includes both Business and IT resources. The business component is made up of meter services specialist to troubleshoot meter and communication network issues in the field. The IT component is comprised of the IT production support internal resources required to manage third-party contractors who provide managed services for production support (e.g., incident and problem management, fulfillment of business service request, and technology data maintenance activities) of the MDMS, DMS/OMS, and ESB software, application, and hardware infrastructure.

[6] As mentioned earlier, the Enterprise Service Bus is the middleware that provides traceable transactional integration between AMS systems and other legacy applications.

a. MDMS, System Integration, and DMS/OMS

Q61. WHAT ESTIMATED O&M COSTS WERE INCLUDED IN THE AMI SURCHARGE MODEL FOR MDMS, SYSTEM INTEGRATION, AND DMS/OMS ACTIVITIES?

A. As shown in Exhibit 1-D, $4,001,457 of IT MDMS, System Integration, and DMS/OMS O&M costs were estimated to be incurred through December 31, 2021.

Q62. WHAT WERE THE COMPANY'S ACTUAL MDMS, SYSTEM INTEGRATION, AND DMS/OMS O&M COSTS ASSOCIATED WITH THE AMS IT SYSTEMS IMPLEMENTED TO SUPPORT THE COMPANY'S AMS AS INCURRED THROUGH THE END OF 2021?

A. Exhibit 1-D indicates that, as of the end of 2021, the Company had spent approximately $3,622,646 in MDMS, System Integration, and DMS/OMS O&M costs associated with their AMS IT systems, which is $378,811 less than estimated.

Q63. WHY ARE THE COMPANY'S ACTUAL MDMS, SYSTEM INTEGRATION, AND DMS/OMS O&M EXPENSES DIFFERENT FROM THE ESTIMATED EXPENSES FOR O&M ASSOCIATED WITH IT SYSTEMS IN THE COMPANY'S AMS SURCHARGE MODEL?

A. Expenses were lower than estimated in the IT System Integration, MDMS and DMS/OMS. The primary contributing factor for the variance is the timing difference between projected plant closings and actuals that I described earlier. That delayed the timing of the O&M expense.

Q64. WERE THE ACTUAL AMS MDMS, SYSTEM INTEGRATION, AND DMS/OMS O&M COSTS EXPENDED IN ACCORDANCE WITH THE COMPANY'S COMMISSION-APPROVED AMS DEPLOYMENT PLAN?

A. Yes. All of the actual MDMS, System Integration, and DMS/OMS O&M expenses incurred in connection with the Company's AMS IT systems were necessary to support the implementation of AMS and were necessarily and reasonably incurred in accordance with the Company's Commission-approved AMS Deployment Plan. These costs are entitled to the presumption of reasonableness and necessity provided by 16 TAC § 25.130(k)(6).

Q65. DO ALL OF THE ACTUAL IT SYSTEM MDMS, SYSTEM INTEGRATION, AND DMS/OMS O&M COSTS INCURRED BY THE COMPANY TO OPERATE AMS QUALIFY FOR RECOVERY THROUGH THE AMS SURCHARGE?

A. Yes. All actual O&M costs incurred by the Company in the operation of the IT systems are reasonable and necessary to support the Company's AMS and should be recovered through the AMS surcharge.

b. <u>IT Internal Support Costs</u>

Q66. WHAT ESTIMATED O&M COSTS WERE INCLUDED IN THE AMS SURCHARGE MODEL FOR INTERNAL SUPPORT ACTIVITIES?

A. Yes. As shown on Exhibit 1-E, as of December 31, 2021, the forecasted AMS Internal Support O&M totaled $667,469.

Q67. PLEASE DESCRIBE THE ACTUAL EXPENDITURES ASSOCIATED WITH AMS INTERNAL SUPPORT O&M NECESSARY TO SUPPORT THE COMPANY'S AMS INCURRED THROUGH THE END OF 2021.

A. As shown on Exhibit 1-E, as of December 31, 2021, the forecasted AMS Internal Support O&M actual expenditures totaled $526,971, which is $140,497 below the forecasted amount.

Q68. WHY ARE THE COMPANY'S ACTUAL AMS INTERNAL SUPPORT O&M EXPENSES DIFFERENT FROM THEIR ESTIMATED EXPENSES?

A. Expenses were lower than estimated in the AMS Surcharge Model because of the timing effect of when plant closings actually occurred, which delayed the onset of O&M expense

Q69. WERE THE ACTUAL AMS INTERNAL SUPPORT O&M EXPENSES ASSOCIATED WITH SUPPORT OF THE AMS INCURRED IN ACCORDANCE WITH THE COMPANY'S COMMISSION-APPROVED AMS DEPLOYMENT PLAN?

A. Yes. All actual costs associated with AMS Internal Support to support the Company's AMS were expended in accordance with the Company's Commission-approved AMS Deployment Plan and are entitled to the presumption of reasonableness and necessity provided by 16 TAC § 25.130(k)(6).

Q70. ARE ALL ACTUAL EXPENSES INCURRED BY THE COMPANY ASSOCIATED WITH AMS INTERNAL SUPPORT O&M IN SUPPORT OF AMS REASONABLE AND NECESSARY?

A. Yes. All actual costs incurred by the Company associated with AMS Internal Support conducted in support of AMS are reasonable and necessary to support the Company's AMS and should be recovered through the AMS surcharge.

D. <u>AMS Customer Education</u>

Q71. PLEASE DESCRIBE THE COMPANY'S AMS CUSTOMER EDUCATION CAMPAIGN.

A. Exhibit HVP-1 of the Company's Application in Docket No. 47416 set forth the following objectives of the Company's AMS customer education campaign:

- Communicate with customers and stakeholders on the plan for meter installation and subsequent expected timing of installation of advanced meters, as well as immediate and long-term benefits of advanced meters.
- While advanced meters are being installed, continue to educate residential and commercial customers about the features and benefits and what they have to do, if anything, when their meter is replaced and how, if at all, they will be affected. Promote adoption of energy management tools as advanced meters and the web portal are activated.
- Active use of online energy management tools via web portal. Encourage all customers to use the web portal and explain how and where they can access information.
- Ongoing education on the energy management tools and how to use them is critical.

Prior to the installation of advanced meters, ETI conducted research to gauge customer perceptions, awareness, and attitudes about an AMS, including a baseline survey with customers to monitor progress made in future phases on familiarity with the technology and its benefits. ETI developed a dedicated webpage to provide information regarding ETI's AMS plan. ETI also participated in community outreach events to meet fact-to-face with customers and civic and business leaders regarding AMS. In addition, ETI held separate stakeholder engagement events in an effort to ensure external stakeholders were aware of the AMS deployment and benefits of advanced meters. Throughout the AMS deployment, ETI communicated with customers through email, SMS/text messaging, direct mail, paid media, news releases, door hangers, telephone calls, community outreach, brochures, social media, and bill inserts.

Recognizing the fact that not all customers would receive advanced meters at the same time, the Company targeted its AMS customer education campaign to the areas where advanced meters were to be installed just prior to and during the early stages of that deployment. As the deployment grew, the Company began using mass media and social media as part of the campaign.

Q72. DID THE ORDER IN DOCKET NO. 47416 IDENTIFY A SPECIFIC DOLLAR AMOUNT RELATED TO THE COMPANY'S AMS CUSTOMER EDUCATION CAMPAIGN?

A. Yes. Finding of Fact No. 64 of the Order in Docket No. 47416 provided that: "It is reasonable for ETI to spend and to include in the initial AMS surcharge an amount of approximately $4.3 million in costs associated with the customer education proposed by ETI in this application."

Q73. WHAT ARE THE ACTUAL COSTS INCURRED BY THE COMPANY FOR AMS CUSTOMER EDUCATION THROUGH THE END OF 2021?

A. Through the end of 2021, as shown in Exhibit 1-F to this reconciliation request, the Company spent $3,091,133 for customer education O&M-related expenses. The amount included in the AMS Surcharge Model for customer education O&M through December 31, 2021, was a total of $3,862,420.

Q74. WHAT EXPLAINS THE VARIANCE IN CUSTOMER EDUCATION COSTS BETWEEN THE ESTIMATE IN THE AMS SURCHARGE MODEL AND THE ACTUAL AMOUNT INCURRED THROUGH DECEMBER 31, 2021?

A. The actual customer education expense through December 31, 2021 has been $771,287 less than originally estimated. The delays explained earlier resulted in the delay of some of the planned communications and marketing efforts. Accordingly, a portion of the budgeted costs for Customer Education has shifted from 2021 into 2022 to allow time to engage customers who received AMS meters in 2021.

Q75. DID THE COMPANY INCLUDE ANY COSTS IN A REGULATORY ASSET FOR CUSTOMER EDUCATION?

A. Yes. The Company was authorized to include customer education program expenses incurred in 2016 and 2017 in a regulatory asset in the Surcharge Model.[7]

[7] Docket No. 47416 Order at Finding of Fact 62.

Those amounts totaled $212,028 and are included in the regulatory asset discussed by Mr. Batten.

Q76. PLEASE EXPLAIN HOW THE ACTUAL AMS CUSTOMER EDUCATION COSTS INCURRED BY THE COMPANY WERE REASONABLE AND NECESSARY.

A. The actual costs incurred by the Company in its AMS customer education campaign were incurred to meet a requirement in the Order in Docket No. 47416 and made in accordance with the AMS Deployment Plan approved by the Commission. Accordingly, these customer education costs were incurred in accordance with the Company's Deployment Plan, qualify for the presumption of reasonableness under 16 TAC § 25.130(k)(6), are reasonable and necessary, and should be recovered through the AMS surcharge.

E. <u>Affiliate Costs</u>

Q77. WERE ANY AFFILIATE COSTS INCLUDED IN THE AMS SURCHARGE?

A. Yes. Company witness Jay Lewis explained in his direct testimony in Docket No. 47416 that the costs for the meter hardware, meter installation, network interface cards ("NIC"), communications network devices and components, and the related internal resources and contractors would be directly incurred by ETI. Other components of the AMS deployment, including the IT systems and project support, would be shared by the EOCs because that approach results in lower overall costs to customers as compared to each EOC maintaining a separate system.

Specifically, the cost of the communications network design and the head-end component of the communications network, the MDMS, the DMS, the OMS, certain software licensing costs, the costs related to the meter testing facility, as well as the overall system integration and project support would be incurred by ESL and assigned to the EOCs based on the total number of customers located in each EOC's jurisdiction. Ongoing O&M necessary to support the AMS as I described above also includes affiliate services allocated to the EOCs. Company witness Batten sponsors Exhibit DCB-3 where the affiliate charges may be identified.

Q78. WERE THE AFFILIATE COSTS NECESSARY?

A. Yes, the affiliate costs are the result of ESL employees providing general planning, design, design engineering services, project management, and construction management necessary to deploy and support the operations of the AMS in accordance with the Deployment Plan.

Q79. WERE THE AFFILIATE EXPENSES REASONABLE?

A. Yes. Company witnesses Mr. Batten and Ryan Dumas discuss how ETI and its affiliates ensure ETI's affiliate costs are reasonable, including budgeting processes and cost controls. Additional information regarding Entergy's overall budgeting process is discussed in the testimony of Company witness Bobby Sperandeo. Those discussions are applicable to these affiliate charges as well. Moreover, these affiliate charges are made under the same cost-causative system of billing methods discussed by those witnesses. Accordingly, the affiliate charges are at-cost and at a rate no higher than the charges made to other affiliates for the same or similar services.

VIII. CUSTOMER SERVICE BENEFITS

Q80. WHAT CUSTOMER SERVICE BENEFITS WERE USED IN ETI'S AMS SURCHARGE MODEL?

A. The surcharge model includes several expected customer service benefits (described in the initial filing in Docket No. 47416 as "operational benefits") from the AMS deployment: (i) routine meter reading; (ii) meter services; (iii) reduced customer receivable write-offs; and (iv) field data collection system. As shown on Exhibit 1-A, the Company's total estimated customer service benefits total $13.89 million through year-end 2021, and actual customer service benefits were $1.97 million.

Q81. PLEASE DESCRIBE THE ROUTINE METER READING SAVINGS THAT WERE ASSUMED IN THE COMPANY'S AMS SURCHARGE MODEL.

A. The Company's AMS Surcharge Model recognized that the Company incurs expenses for contract personnel (and their vehicles) to physically travel to and read customer meters each month. The two-way communications functionality of the advanced meters along with the communications and IT infrastructure deployed with the AMS allows meters to be read remotely, and therefore eliminates the need for routine meter reading trips. As shown in the original surcharge model filed in

Docket No. 47416, the Company's estimated routine meter reading savings total $8.71 million through year-end 2021.

Q82. WHAT WERE THE COMPANY'S ACTUAL ROUTINE METER READING SAVINGS THROUGH YEAR-END 2021?

A. The components making up the routine meter reading savings categories are field labor savings, contract meter reading savings, including internal labor reductions for the back-office contract management support of the meter reading contracts, and vehicle savings. As shown on the workpapers to Exhibit 1-A, the Company achieved actual total routine meter reading benefits through year-end 2021 of $0.17 million.

Q83. WHAT IS THE DIFFERENCE BETWEEN THE ROUTINE METER READING BENEFITS ESTIMATED IN ETI'S AMS SURCHARGE MODEL AND THE ACTUAL ROUTINE METER READING BENEFITS REALIZED?

A. ETI's routine meter reading benefits are $8.54 million less than estimated. While the previously-described deployment delays and pandemic-related challenges impacted the estimated customer service benefits, ETI's advanced meter deployment has been completed as of December 2021, and all contracted meter readers have been released as of January 2022. Going forward, the Company expects the benefits to track to the annual projections.

Q84. PLEASE DESCRIBE THE METER SERVICES SAVINGS THAT WERE ASSUMED IN THE COMPANY'S AMS SURCHARGE MODEL.

A. The Company incurs expenses for personnel (and their vehicles) to travel to customer premises for a variety of meter-related services, which include service starts and stops, certain meter re-reads, and service disconnections related to non-payment, as well as any subsequent reconnections. The advanced meters and related communications infrastructure will eliminate the need for the vast majority of these physical trips. As shown in the original surcharge model filed in Docket No. 47416, the Company's estimated meter services savings total \$4.81 million through year-end 2021.

Q85. WHAT WERE THE COMPANY'S ACTUAL METER SERVICES SAVINGS THROUGH YEAR-END 2021?

A. The components making up the meter services savings categories are field labor savings, contract meter services savings, including internal labor reductions for the supervision and management support of the meter services contractors, and associated vehicle savings. As shown on the workpapers to Exhibit 1-A, the Company achieved actual total meter services benefits through year-end 2021 of \$2.07 million.

Q86. WHAT IS THE DIFFERENCE BETWEEN THE METER SERVICES BENEFITS ESTIMATED IN ETI'S AMS SURCHARGE MODEL AND THE ACTUAL METER SERVICES BENEFITS REALIZED?

A. ETI's routine meter services benefits are $2.74 million less than estimated. The delays in realizing meter services savings are also attributed to the aforementioned deployment delays and pandemic-related challenges that impacted ETI's advanced meter deployment, which has since been completed. Accordingly, it is expected that going forward the Company will be more in alignment with projections for meter services savings.

Q87. PLEASE DESCRIBE THE REDUCED CUSTOMER RECEIVABLES WRITE-OFFS SAVINGS THAT WERE ASSUMED IN THE COMPANY'S AMS SURCHARGE MODEL.

A. After a disconnect ticket to suspend service for non-payment is issued to field personnel, it takes additional time to physically go to the customer premises and disconnect the service at the meter. Eliminating the lag between scheduling and dispatching a technician to disconnect electric service through use of the remote disconnect feature of advanced electric meters reduces the amount of revenue that becomes uncollectible and is ultimately reflected in rates through bad debt expense.

Q88. DID THE COMPANY REALIZE ACTUAL CUSTOMER RECEIVABLES WRITE-OFFS SAVINGS THROUGH YEAR-END 2021?

A. The Company realized negative benefits of $(0.27) million. Because of the pandemic-related moratorium on disconnects, a significant backlog of disconnect orders were incurred, which actually increased the lag on the number of days it took to enter a disconnect order. That lag negatively affected the projected write-off savings. However, the impact of the pandemic-related moratoriums would have been even greater on write-offs if the Company had not deployed advanced meters with remote disconnect capability.

Q89. PLEASE DESCRIBE THE FIELD DATA COLLECTION SYSTEM SAVINGS THAT WERE ASSUMED IN THE COMPANY'S AMS SURCHARGE MODEL.

A. There are a number of handheld electronic field data collection system ("FCS") devices used by the Company's contract meter readers to perform manual meter reads today. There are annual O&M costs associated with software and warranty necessary to provide ongoing support. Following the commissioning of the advanced meters, meter reading will be performed remotely, and these costs will no longer be required.[8]

[8] Some meter reading equipment may be retained to support readings needed for exceptional situations. However, the Company does not plan to incur O&M expense for maintaining that equipment, and it does not plan to replace it after it stops functioning.

Q90. DID THE COMPANY REALIZE ACTUAL FCS SAVINGS THROUGH YEAR-END 2021?

A. The Company recognized $0.004 million in benefits. As noted above, delays in deployment and pandemic-related challenges extended the requirement to read meters manually, which has a direct impact on the ability to reduce the cost associated with the equipment needed to perform the manual reads. Due to the extended need for manual meter reading, there were contract meter reader costs that continued to drive the variance of this benefit. However, all contracted meter readers have now been released, and this benefit is expected to be achieved in 2023 and beyond.

IX. METER-RELATED DISCRETIONARY SERVICE FEES

Q91. PLEASE DESCRIBE HOW THE COMPANY'S METER-RELATED MISCELLANEOUS ELECTRIC SERVICE CHARGES ARE BEING REDUCED IN ACCORDANCE WITH THE COMMISSION'S ORDER IN DOCKET NO. 47416.

A. Finding of Fact No. 68 of the Order in Docket No. 47416 requires the Company to file annually to reduce its meter-related discretionary service charges so that all customers in the Company's service areas will benefit from the cost savings associated with the implementation of the Company's AMS Deployment Plan. The Company has complied with this requirement by updating and reducing its meter-related discretionary service charges on an annual basis by making the required filings in Docket Nos. 49927 and 51247 to modify meter-related discretionary service fees to reflect the reduced costs in compliance with the Commission's Order in Docket No. 47416.

X. HAN

Q92. WHAT IS HAN?

A. HAN stands for "home-area network," and HAN functionality was part of the requirements in 16 TAC § 25.130(g)(1)(J) when ETI's Deployment Plan was approved. However, the Commission granted a waiver in July 2018 for the transmission and distribution utilities operating in ERCOT to cease providing HAN functionality (except for customers that already had a paired device) when the new Smart Meter Texas protocols were implemented because the Commission determined that on-demand meter reading functionality was an adequate substitute for HAN.[9] Simultaneously, the Commission initiated a new rulemaking to revise 16 TAC § 25.130, and which revisions ultimately eliminated HAN functionality in subsection (g)(1)(J) in lieu of the ability to provide on-demand reads through the graphical user interface of the web portal.[10] Those revisions became effective May 15, 2020.

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[9] *Commission Staff's Petition to Determine Requirements for Smart Meter Texas*, Docket No. 47472, Finding of Fact No. 62I, and Conclusion of Law No. 14B (July 12, 2018).

[10] *Rulemaking Relating to Advanced Metering*, Docket No. 48745, Order Adopting Amendments to §§ 25.5, 25.130, and 25.133 as approved at the April 17, 2020 Open Meeting (Apr. 20, 2020).

Q93. DID ETI'S DEPLOYMENT PLAN INCLUDE HAN FUNCTIONALITY?

A. Yes, and the AMS meters, like virtually all AMS meters of which I am aware, include a computer chip that can be provisioned to work with a HAN.

Q94. DID ETI IMPLEMENT A HAN PROVISIONING PROCESS?

A. No. Around the time that ETI's meter deployment began, it was clear from the proceedings described above that the HAN functionality requirement might, and ultimately did, change in favor of less-expensive, on-demand read functionality. In addition, since October 2018, ETI has been involved in a proceeding to develop a third-party data access solution,[11] which could utilize on-demand reads instead of HAN. Accordingly, in lieu of incurring costs to implement a HAN provisioning process, plus annual ongoing expenses, ETI has reported monthly in Docket No. 49233 that it has not implemented HAN because of the rule change and pending third-party data access docket and that ETI is considering a request for a change in the Deployment Plan to utilize on-demand reads instead of supporting HAN in accordance with the ultimate resolution of Docket No. 48745.

XI. SUMMARY AND CONCLUSION

Q95. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. In summary, my direct testimony demonstrates that the actual capital expenditures and O&M costs incurred in connection with the items listed in my testimony in

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[11] *Compliance Filing of Entergy Texas, Inc. Relating to Participation in Smart Meter Texas and Changes to its Advanced Metering System*, Docket No. 48745.

Figure WPJ-1 were made and incurred in accordance with the Company's approved AMS Deployment Plan, are properly allocated to the AMS, and are reasonable and necessary.

Q96. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF WILLIAM PHILLIPS, JR.

THE STATE OF LOUISIANA)
)
ORLEANS PARISH)

This day, William Phillips, the affiant appeared in person before me, a notary public, who knows the affiant to be the person whose signature appears below. The affiant stated under oath:

My name is William Phillips, Jr. I am of legal age and a resident of the State of Louisiana. The foregoing testimony and exhibits offered by me are true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct.

William Phillips Jr.
William Phillips, Jr.

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 22nd day of June 2022.

Andrea Erwin Potter
Notary Public, State of Louisiana

My Commission expires:
Life.

ANDREA ERWIN POTTER
NOTARY PUBLIC
LSBA NO. 35285
MY COMMISSION IS FOR LIFE.

This exhibit contains information that is highly sensitive and voluminous and will be provided under the terms of the Protective Order (Confidentiality Disclosure Agreement) entered in this case.

DOCKET NO. 53719

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
TEXAS, INC. FOR AUTHORITY TO	§	
CHANGE RATES	§	OF TEXAS

DIRECT TESTIMONY

OF

MELANIE L. TAYLOR

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF MELANIE L. TAYLOR
2022 RATE CASE

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Melanie L Taylor. My business address is 2107 Research Forest Drive, The Woodlands, Texas 77380.

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

A. I am employed by Entergy Texas, Inc. ("ETI" or the "Company") as Vice President of Reliability. As Vice President of Reliability for ETI, I am responsible for leading safety, operations, construction, reliability improvement, engineering, meter services, contract management, and emergency response and restoration for the Company's distribution and transmission systems. However, during the Test Year (January 1, 2021 through December 31, 2021), only Distribution Operations was under my area of responsibility.

Q3. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am testifying on behalf of ETI.

A. Qualifications

Q4. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Arts degree in Liberal Arts and a Master of Business Administration, both from the University of Arkansas Little Rock.

I joined Entergy Arkansas, LLC ("EAL") in 1997 in corporate communications, where I managed special projects related to employee and customer communications initiatives. In 1999, I moved into Customer Service and was responsible for managing various service-related issues with local customers while serving as the primary community contact for EAL in those areas. In 2002, I became Real Estate Manager where I was responsible for managing the real estate and facilities portfolio for EAL, including all maintenance and improvement projects related to operating the various service centers across the state. In 2003, I became the Region Customer Service Manager for EAL's Northeast Region, where I served as EAL's customer and community leader liaison. I also supervised a group of Customer Service Managers located in various communities in northeast Arkansas. In September of 2006, I moved to EAL's Distribution Operations Organization as Resource and Operations Manager. My job responsibilities included oversight of several departments, including contractor compliance, field metering, mobile data dispatch and the utility's 24-7 Distribution Operations Center. In September of 2011, I became the Customer Service Center Manager, where I assumed responsibility for EAL's call center, which provides day-to-day interaction with the Company's customers.

In December 2013, I transitioned to ETI as Corporate Communications Manager, where I was responsible for managing employee and customer communications initiatives. In April 2016, I returned to EAL and became Director of Customer Service. My job duties included oversight of distribution operations for the metropolitan Little Rock area, complaint management and resolution, community development, commercial and industrial account management, storm logistics, storm restoration, marketing of company programs, low-income initiatives, and media relations.

In August 2017, I was named Vice President of Customer Service for EAL. In that role, I was responsible for leading distribution operations and the customer service of EAL's retail customers, which built on my prior operations and customer-interfacing roles within the Company. These responsibilities included, but were not limited to, overseeing and managing customer service, safety, construction, reliability improvement, engineering, distribution dispatching, meter services, contract management, and emergency restoration for the Company's distribution systems. In August 2018, my title changed to Vice President of Distribution Operations when EAL created a separate customer service organization. My responsibilities remained the same as above except that I no longer managed customer service activities.

In August 2021, I transferred back to ETI as Vice President of Distribution Operations for ETI, with the same responsibilities as the position I held in Arkansas. In May 2022, my title changed to Vice President, Reliability - Texas, which includes the same responsibilities plus the addition of ETI's Transmission Organization.[1]

[1] Effective May 2022, the Distributions Operations and Transmission Organization groups were combined into the new Power Delivery Organization. The engineering, project management, and construction departments within those respective groups have been moved into the Capital Projects Organization. Also, the training departments within those respective groups were moved into the Operations and Development Organization.

Q5. WILL YOU BE TESTIFYING ON TRANSMISSION AS WELL AS DISTRIBUTION?

A. No. My testimony will focus on ETI's Distribution Operations because that was within the scope of my responsibility through the end of the Test Year. Khamsune Vongkhamchanh addresses ETI's Transmission Organization.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION?

A. Yes. I filed testimony in Public Utility Commission (the "Commission") of Texas Docket No. 44704 on behalf of ETI. I also testified before the Arkansas Public Service Commission in Docket Nos. 16-060-U and No. 16-036-FR on behalf of EAL.

B. Purpose of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony covers five main topics.

First, I describe ETI Distribution Operations and the Company's distribution system.

Second, I discuss the quality of service in ETI's service territory and show that ETI has provided reliable service and operated safely.

Third, I support the distribution-related capital additions to ETI's rate base. This includes discussion of capital additions closed to plant in the period beginning January 1, 2018, through the Test Year, including a reconciliation of the capital additions included in ETI's Distribution Cost Recovery Factor ("DCRF").

Fourth, I address charges to the storm reserve during the period of January 1, 2018, through the end of the Test Year.

Fifth, I support the Test Year costs for ETI Distribution Operations. These costs include both non-affiliate costs (that is, ETI's directly incurred costs) and affiliate costs for the Test Year. In regard to affiliate costs, I address two classes that support ETI Distribution Operations: the Distribution Operations Class, and the Transmission and Distribution ("T&D") Support Class.

Q8. WHY ARE YOU QUALIFIED TO ADDRESS THESE ISSUES AND TO PROVIDE THIS TESTIMONY?

A. In my role as Vice President of Reliability for ETI, I have responsibility for the activities addressed in this testimony. The affiliate activities addressed in my testimony were in support of the Distribution Operations I oversee.

Q9. FOR THE TWO CLASSES OF AFFILIATE CHARGES YOU SUPPORT, PLEASE SUMMARIZE YOUR TESTIMONY.

A. I will demonstrate that:

1. the services provided by the Distribution Operations Class and the T&D Support Class are integral to ETI's ability to provide continuous, reliable, safe, adequate, and reasonable electric service, to maintain system integrity, and to ensure operational efficiency;
2. the costs associated with those services are reasonable; and
3. as also demonstrated in Ryan Dumas's direct testimony, the prices

charged to ETI for these services are no higher than the prices charged to other affiliates for the same or similar services and represent the actual cost of the services provided.

Q10. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. I list my exhibits in the table of contents.

Q11. DO YOU SPONSOR ANY SPECIFIC RATE FILING PACKAGE ("RFP") SCHEDULES?

A. Yes. I sponsor or co-sponsor the following schedules:

Schedule H-13.1	Quality of Service Information
Schedule H-13.1a	Voltage Surveys
Schedule H-13.1b	Circuit Breaker Operations
Schedule H-13.1d	Tree Trimming Program
Schedule H-13.1e	Quality of Service Improvements
Schedule H-13.3	Continuity of Service

II. ETI DISTRIBUTION OPERATIONS

A. Overview of ETI Distribution Operations

Q12. PLEASE BRIEFLY DESCRIBE ETI DISTRIBUTION OPERATIONS.

A. ETI Distribution Operations is responsible for providing distribution voltage service to customers in ETI's service territory.

Q13. PLEASE DESCRIBE ETI'S DISTRIBUTION SYSTEM.

A. ETI's electric distribution system is the portion of ETI's electric T&D grid operating at less than 69,000 volts (69 kV). ETI owns and operates a distribution system of 413 feeders, which serve residential, commercial, and industrial customers. The feeder system spans 11,676 miles of overhead lines and 2,288 miles of underground lines to provide retail electric service to ETI's customers in Southeast Texas. The predominant operating voltages of the circuits are 13.2 kV and 34.5 kV, with a large underground 34.5 kV development in The Woodlands, Texas.

As of year-end 2021, ETI had two geographic operating regions. Figure 1 below depicts these regions—the East Region and the West Region. The East Region's headquarters are in Beaumont, Texas, and the West Region's headquarters are in The Woodlands, Texas. The heavy borders in Figure 1 identify the overall geographic bounds of the Company's facilities in each region but do not necessarily indicate service territory boundaries between ETI and other electric providers.

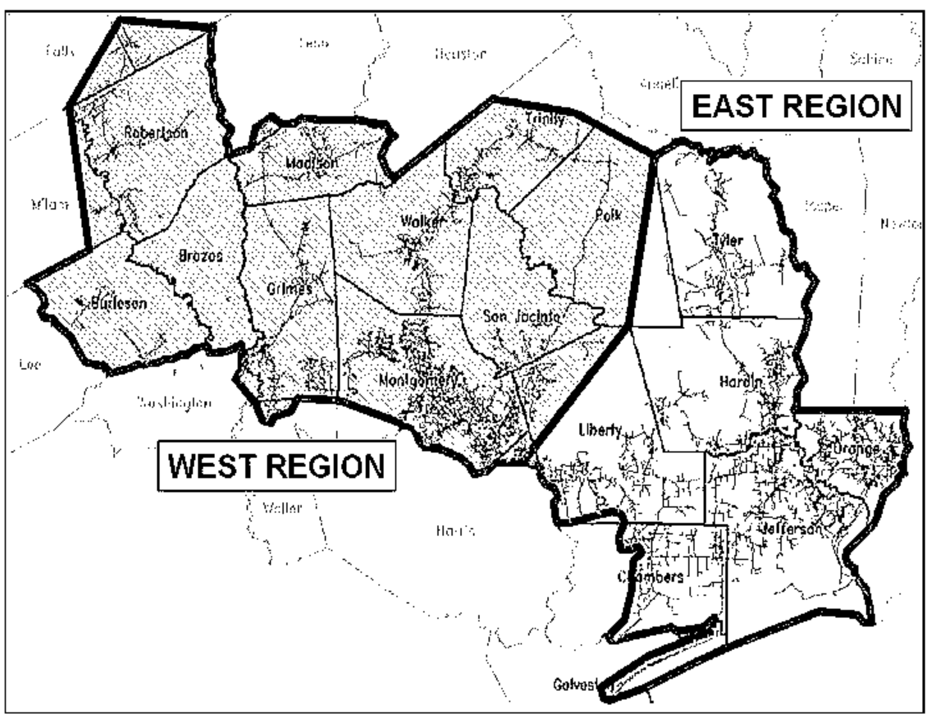

Figure 1

Q14. DID ETI MAKE ANY CHANGES TO THESE OPERATING REGIONS?

A. Yes. Beginning January 1, 2022, ETI added a third region, identified as the Central Region. Figure 2 below depicts the current configuration. The Central Region is comprised of portions of the service area experiencing rapid growth, largely driven by the expansion of the Grand Parkway and Interstate 69.

Figure 2

Q15. DOES ETI MAKE USE OF AFFILIATED ENTITIES?

A. Yes. Entergy Services, LLC ("ESL") provides essential management and corporate support services to ETI. As I explain below, the service company structure enables ETI to realize savings by using standard practices and taking advantage of economies of scale.

Q16. HOW IS DISTRIBUTION OPERATIONS ORGANIZED WITHIN ETI?

A. Figure 3 below shows the ETI Distribution Operations Organization as of December 31, 2021.

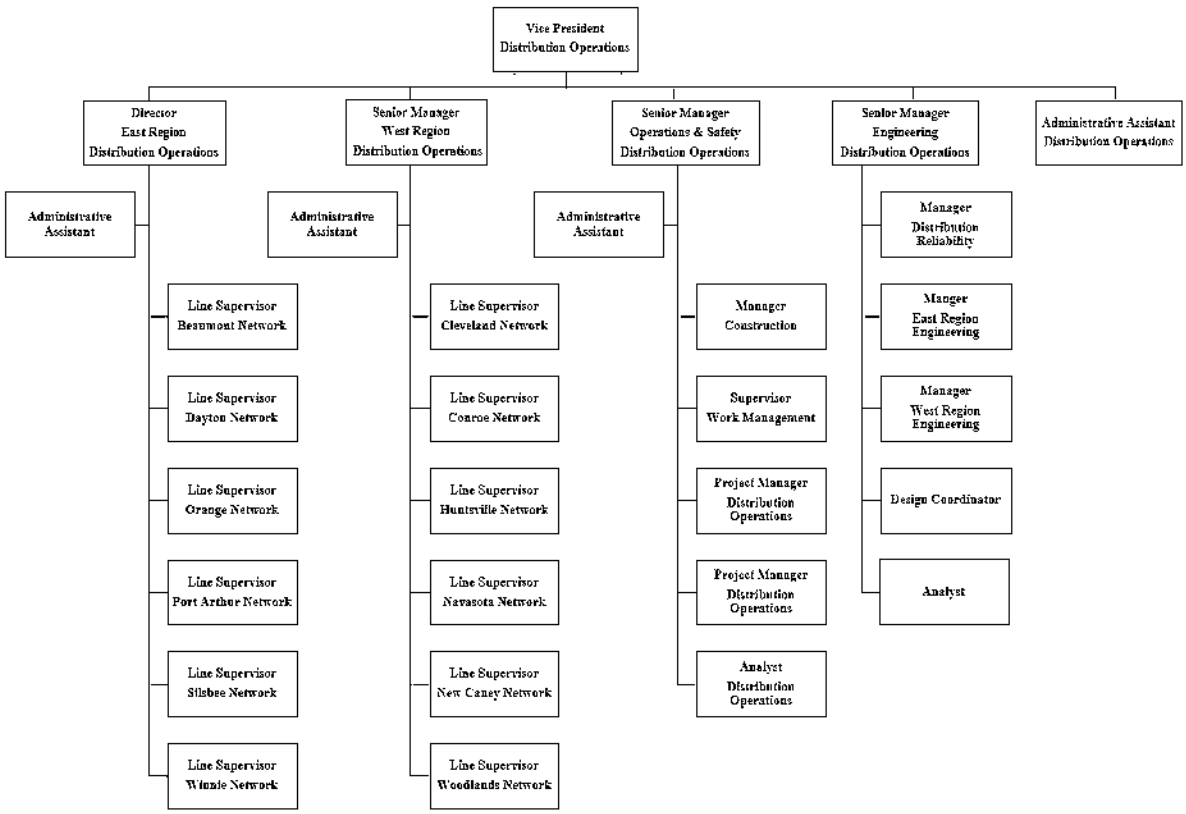

Figure 3

Q17. DID THIS ORGANIZATIONAL STRUCTURE CHANGE FOLLOWING THE ADDITION OF THE CENTRAL REGION IN 2022?

A. Yes. Similar to the East and West Regions, the Central Region organizational structure is comprised of a team of line workers, engineers, designers and support staff led by a senior region manager and engineering manager.

B. Distribution Operations Activities

Q18. WHAT ARE THE RESPONSIBILITIES OF ETI DISTRIBUTION OPERATIONS?

A. Distribution Operations is responsible for operating, planning, designing, constructing, and maintaining the electric distribution system that provides power and energy to homes, offices, businesses, industrial establishments, and governmental entities in ETI's service territory. Distribution Operations includes three ongoing core business areas: (1) operations; (2) maintenance; and (3) construction (as well as the customer support for these activities). In addition to these core business areas, Distribution Operations requires a variety of support functions such as Asset Management, Vegetation Management, Human Resources, Information Technology Services, and Safety and Skills Training, which ESL provides in whole or in part.

Q19. WHAT ACTIVITIES DOES THE OPERATIONS AREA INCLUDE?

A. The electric distribution system consists of an electric grid that supplies power to ETI's customers. The operations area monitors the distribution system load and voltage levels to ensure there is adequate capacity to meet customer needs. In addition, the operations area handles routine and emergency routing of personnel to maintain a continuous supply of electricity to customers.

Q20. WHAT ACTIVITIES DOES THE MAINTENANCE AREA INCLUDE?

A. The electric distribution system requires continuous upkeep to preserve its integrity and its ability to provide reliable service to customers. These maintenance activities are both preventive and reactive. Examples of preventive maintenance are equipment inspections and introducing new maintenance practices to enhance the overall operation and reliability of the distribution system. Reactive repairs and upkeep are required when parts of the system fail due to wind, lightning, or other types of damage.

Q21. FINALLY, WHAT ACTIVITIES DOES THE CONSTRUCTION AREA INCLUDE?

A. The purpose of the distribution system is to deliver a continuous, reliable, safe, and adequate supply of electricity to customers. In order to accommodate new customers, ETI must add facilities to serve them. These additions, both major and minor, require constructing distribution line extensions or increasing the capacity of existing facilities. The construction of new or enhanced distribution lines is part of ETI's obligation to provide continuous, reliable, safe, and adequate service to all current and prospective customers.

III. <u>QUALITY OF SERVICE</u>

Q22. PLEASE DESCRIBE HOW DISTRIBUTION OPERATIONS ADDRESSES QUALITY OF SERVICE.

A. ETI Distribution Operations strives to: (1) meet construction and service delivery commitments to customers; (2) minimize the frequency of outages; and (3) safely restore service as quickly as reasonably possible following necessary or unavoidable interruptions in customers' service. Goals (2) and (3) regarding outage frequency and duration are the two main components of the broader area that the utility industry refers to as "reliability." The frequency of outages refers to how often there is an interruption to a distribution customer's service. The main industry index used to quantify outage frequency is the System Average Interruption Frequency Index ("SAIFI"). To measure duration, the industry uses the System Average Interruption Duration Index ("SAIDI").

In addition to these three strategic operational focus areas, the Company's communications with customers through call centers, outage notifications and updates, and direct contact are also vital service quality components, which are addressed by Stuart Barrett and Paula K. Waters.

A. <u>Quality of Service & Reliability Performance Metrics</u>

Q23. PLEASE DESCRIBE ETI'S SERVICE REQUEST COMMITMENT MEASURE.

A. The service request commitment measure identifies the percentage of the time the Company provides service on or before the Company-provided date committed to the customer requesting the service. As mentioned above, the Company communicates a timeframe by which it expects to complete a service request initiated by a customer. This timeframe takes into account, and may be impacted by, a number of variables, including the type and amount of construction and labor hours required to fulfill the request, resource availability, weather, material availability, and emergency work. The Company measures its performance by the percentage of commitments ETI met by the Company-provided commit date. This metric includes, among others, projects requiring line construction, projects requiring a service connection from existing facilities to new customer facilities, and meter service requests.

Figure 4 below illustrates the percentage of time the Company provided service by the commit date in the years 2020 through 2021. Data on commit dates prior to 2020 is not comparable because ETI transitioned to a new work force management system, Enterprise Asset Management ("EAM"), in 2020, which significantly changed how commit date performance is measured. EAM was implemented to improve work planning, scheduling, and execution with improved technology in prioritizing outstanding work as well as providing a further line of sight on pending work resource optimization. As illustrated in Figure 4, the commit date percentage jumped following the learning curve associated with transitioning to the new system. During the Test Year, ETI met its service date commitments 97% of the time.

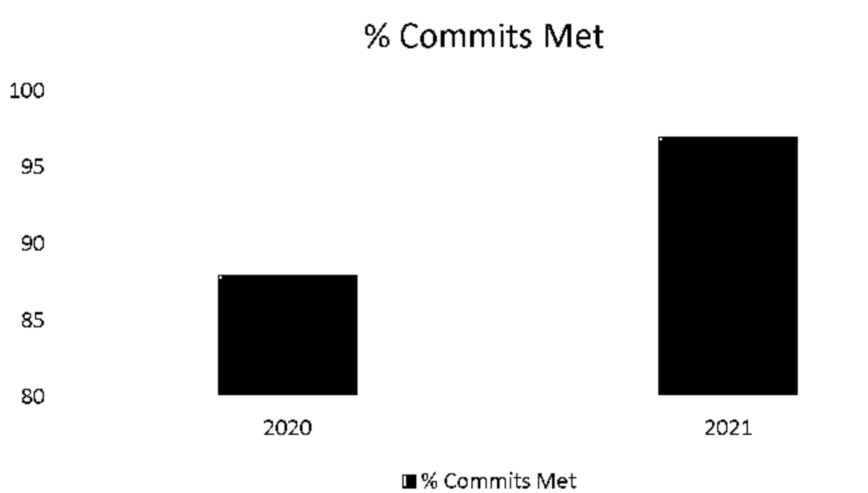

Figure 4

Q24. PLEASE EXPLAIN THE CALCULATIONS OF SAIFI AND SAIDI.

A. Each time an outage occurs, the Company records two important quantities:

- the number of Customers Interrupted ("CI"); and
- Customer Minutes Interrupted ("CM"), which is the product of the number of customers interrupted and the duration in minutes.

ETI follows the American National Standard Institute's ("ANSI") recognized calculation method, defined in Institute of Electrical and Electronics Engineers' Standard 1366 Guide for Electric Power Distribution Reliability Indices. Using CI, CM, and the number of customers served on the system under study, the indices for any given time period are calculated as follows:

$$\textbf{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

$$\textbf{SAIDI} = \frac{\sum \text{Customer Minutes Interrupted}}{\text{Total Number of Customers Served}}$$

SAIFI reflects the average number of times that a customer experiences an interruption during a specified time period. SAIDI reflects the average outage duration for the system over a specified time period. Lower numbers represent relatively better performance for both indices.

Figure 5 below show the calculations of ETI's SAIFI and SAIDI for 2021, as reported in ETI's updated 2021 Service Quality Report filed with the Commission.

SAIFI = Customer Interruptions/Customers Served
Customer Interruptions = 714,654
Customers Served = 488,747
SAIFI = 714,654 / 488,747 = 1.462

SAIDI = Customer Minutes Interrupted/Customers Served
Customer Minutes Interrupted = 108,393,639
Customers Served = 488,747
SAIDI = 108,393,639 / 488,747 = 221.8

Figure 5

Q25. USING THESE INDUSTRY-RECOGNIZED INDICES, PLEASE DESCRIBE THE COMPANY'S DISTRIBUTION RELIABILITY PERFORMANCE DURING THE TEST YEAR.

A. During 2021, for forced interruptions on the distribution system as reported in the Company's annual Service Quality Report, ETI's SAIFI was 1.462 outages, and its SAIDI was 221.8 minutes. This means that, on average, a typical customer experienced 1.462 forced distribution outages during 2021. This is 22.2% better performance than the reference target set by the Commission for ETI. In addition, ETI met the Commission's performance target for SAIFI under 16 Tex. Admin. Code ("TAC") § 25.52(f)(1).

The average total cumulative outage time experienced for those 1.462 outages was 221.8 minutes. This missed the Commission performance target by 54% in 2021. 2021 was a relatively high year because ETI experienced residual effects of Winter Storm Uri,[2] and there was an unusually high number of severe weather days, including flash floods, thunderstorms, tornados, high winds, hard freezes, and tropical storms. In addition, the months of May, June, and September 2021 were extremely active from a severe weather perspective. Those three months alone contributed 46% of the overall 2021 SAIDI performance. Excluding major event days as defined by the Institute of Electrical and Electronics Engineers ("IEEE"), ETI's service territory had 137 instances during that time frame where a Watch, Warning, or Advisory was issued by the National Weather Service.[3] The weather conditions that occurred during that time frame caused over 60,000 customer interruptions.

I discuss some of the additional circumstances that affect outage duration statistics in more detail below, including the effect of ETI implementing more rigorous safety practices.

Q26. PLEASE SHOW THE COMPANY'S SAIFI AND SAIDI AS REPORTED TO THE COMMISSION FOR THE YEARS 2010 THROUGH 2021.

A. Figure 6 and Figure 7 below show the Company's reliability performance for distribution forced outages since 2010 in both frequency and duration. These figures depict the annual targets, as per 16 TAC § 25.52(f)(1), showing that the SAIFI scores were better than the target of 1.88 by an average margin of 0.45

[2] Most of the outages that occurred during the week of February 14, 2021 were excluded from the SAIDI calculations because they were Major Event Days. However, freeze-related outages and restoration work continued for some time, and those outages are reflected in the SAIDI statistics.

[3] *See* www.weather.gov.

outages (24%), and the SAIDI scores missed the target of 143.94 by an average margin of 48 minutes (34%). As noted above, the SAIDI scores were particularly affected by unusually severe weather in 2021, and 2019 was similar in terms of unusual severe weather.

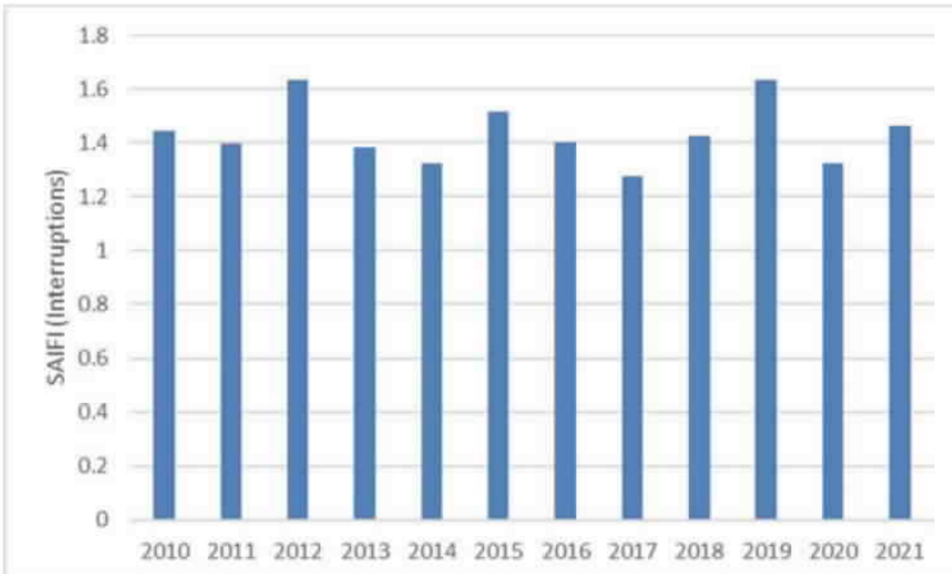

Figure 6

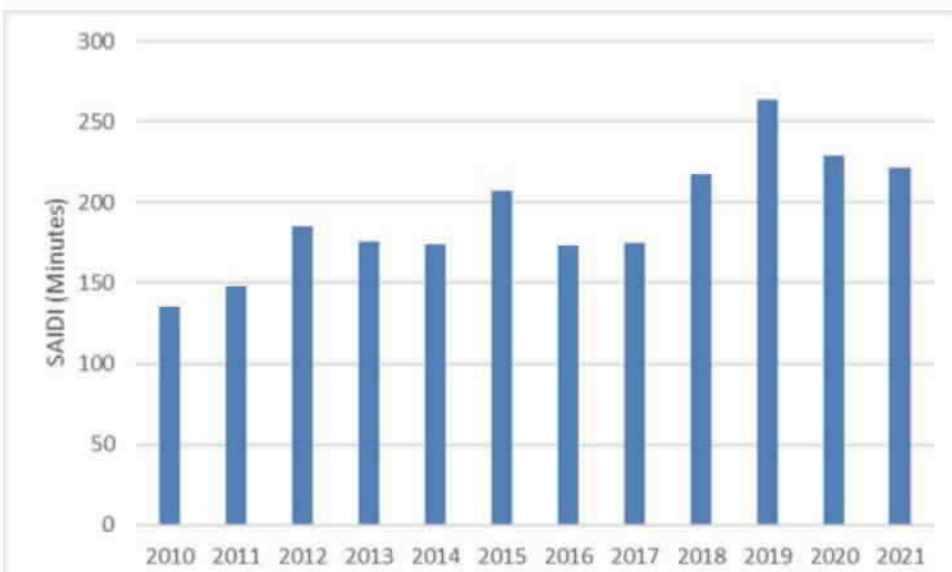

Figure 7

Q27. HOW FREQUENTLY DOES THE COMPANY UPDATE, REVIEW, AND ACT UPON THESE INDICATORS?

A. The Company's Performance Metrics group reports reliability performance each month. In addition to this monthly reliability data, the Distribution Operations Center produces both real time and previous-day outage reporting. A cross-section of the Distribution Operations Organization, including reliability engineers, perform data driven analyses to identify both short-term actions as well as longer-term projects to improve reliability and ensure data integrity in the recording process.

Q28. PLEASE ADDRESS THE COMPANY'S LONG-TERM RELIABILITY PERFORMANCE TREND.

A. Reviewing the standard indices, 2021 continued ETI's overall trend for SAIFI performance, which is 22% better than the target. Further, ETI reduced the number of customer interruptions by unknown causes by ~34%, largely due to the implementation of a standardized root cause analysis process to help ensure the true cause is identified and solutions are developed to address the cause.

SAIDI shows elevated levels in recent years largely due to adverse weather (see the example above regarding May through September 2021), uncontrollable outages (e.g., trees falling from outside right of way ("ROW") and damage caused by the public or third-party contractors), and enhanced safety measures (which require certain measures for safe work that can increase the time needed to repair an outage). Damage from trees hitting the lines often requires the replacement of one or more poles as well as other facilities, and they are usually in more rural areas, often with no road access, making both patrolling to find the issue and repairing it more time consuming. ETI's customer base is also experiencing rapid growth in certain areas, with cities like Conroe among the fastest growing in the United States multiple years in a row. With the rapid growth in residential and commercial construction, the Company has experienced a significant increase in public-inflicted damage and outages (e.g., underground conductor "dig-ins" by third party contractors and vehicles striking the Company's facilities).

In other parts of ETI's service territory, customers are located in the rural areas and are spread out geographically. The low customer density and distance between each customer in those areas have an impact on ETI's overall restoration efforts, particularly in terms of outage duration. Duration scores are further affected by the various types of challenging terrain in which ETI's customers reside. For example, hilly and swampy/flood prone areas, typically requiring special equipment and heavy machinery, are two examples that impact the amount of time required to deploy resources and safely make needed repairs to complete restoration.

Severe weather is another factor that significantly impacts both outage frequency and duration. Texas is subject to both hot and cold weather patterns, as opposed to one or the other, including tornadoes, severe thunderstorms, hurricanes, ice storms, and extended periods of extreme hot and cold temperatures. The variety of these weather-related events in particular affect

ETI's outage duration scores. For example, a thunderstorm may impact a relatively small geographic area isolating outages to a local area. However, the duration of the outages can be lengthy where there is significant damage, which is due to a large number of poles and downed conductor and the time required to safely rebuild these facilities

Finally, although ETI always has made safety its top priority, in 2018 the Company implemented additional safety standards for its line workers, which impact the duration of some outages. ETI's implementation of these more rigorous safety practices is designed to further protect workers from high-risk work on energized conductor. Most notably, ETI increased the usage of more de-energized work zones. These required de-energized clearance zones necessitate additional steps to ensure the lines are de-energized. This additional outage time, although necessary for the protection of our employees and contractors, negatively impacts SAIDI as it increases the duration of outages.

Q29. HOW DO YOU MONITOR FEEDER PERFORMANCE?

A. ETI tracks individual feeder reliability performance using SAIFI and SAIDI.

Q30. ARE THERE ANY OTHER FEEDER-SPECIFIC PERFORMANCE MEASURES UNDER THE COMMISSION'S RULES?

A. Yes. ETI also evaluates its performance under the Commission's 300% feeder measure in 16 TAC § 25.52(f)(2). This measure determines if a feeder exceeds four times the system average of SAIDI and SAIFI for two consecutive years. In

2021, out of 413 feeders, ETI had one feeder in violation for the SAIFI category, 99.76% compliance, and two feeders in violation for the SAIDI category, which is 99.52% compliance. Since 2009 (the past 13 years), ETI has had 11 years with zero SAIFI feeders, and only two SAIFI feeders for the other two years. ETI had five years with zero SAIDI feeders, and only one feeder that violated SAIDI two years in a row.

B. Reliability Performance Efforts

Q31. HOW IS THE COMPANY WORKING TO IMPROVE THE DELIVERY OF SERVICE TO ITS CUSTOMERS?

A. Several years ago, ETI began a multi-faceted strategic approach to distribution reliability improvement that largely targeted specific, under-performing devices and segments of feeders that would have a significant impact on customer interruptions while implementing preventive and remedial measures as well. While that approach has been successful at addressing outages on those specific devices and line segments, the Company recently began taking steps to implement a longer-term strategy to achieve sustained reliability through more wholistic, data-driven, proactive investments at the whole-feeder level that will replace aging infrastructure and take advantage of technological advancements. ETI is also investigating potential resiliency enhancements to help minimize outage durations through mechanical coordination and to increase reliability during unfavorable weather. ETI is still in the development stage of these modifications but has already completed extensive pole structural analysis training with distribution designers to account for higher wind loadings in designs.

Q32. PLEASE EXPLAIN.

A. ETI, for several years, has expanded its strategic business initiatives and investments to further improve reliability performance and better meet customers' expectations through the utilization of advanced technologies. This is sometimes referred to in the industry as "grid modernization." The Commission's approval of ETI's Advanced Metering System ("AMS") is an example of grid modernization, and AMS established a foundation for a wholistic distribution reliability strategy that incorporates the emerging technologies and establishes a more advanced way of maintaining and operating the distribution grid. Company witness William Phillips, Jr. addresses the AMS deployment in more detail. In conjunction with and building upon the AMS data and communications network, ETI's distribution reliability strategy has evolved through the deployment of additional advanced technologies, e.g., Distribution Management System ("DMS"), Outage Management System ("OMS"), EAM, and Distribution Automation ("DA"), which together facilitate preventive, data-driven approaches to maintenance. Through these enhancements, for example, ETI distribution operators now have real-time visibility into what is happening on individual devices, including AMS meters, in the field via the communications network and DMS, and new communicating devices can be controlled remotely via DA investments. Adding EAM facilitates a more data-driven, proactive approach to making reliability improvements by, for example, identifying devices for replacement before they fail. These changes were enabled by the maturation and investment in new technologies and implemented in response to both increasing customer expectations and increasing frequency and severity of extreme weather events, both of which necessitate continued implementation of a more modern, responsive, and resilient grid to, among other things, minimize the frequency and duration of outages.

Continuing with the evolution in technology and its implementation, ETI's long-term reliability strategy is being enhanced to include more proactive and long-lasting reliability improvements in order to improve the service quality to customers and enhance the resiliency of the distribution grid to extreme weather. The enhanced strategy, which incorporates the use of new, advanced technologies described above, involves a wholistic, coordinated effort to undertake proactive replacement and hardening of distribution infrastructure and accelerated deployment of communicating devices that enable additional functionalities. For example, the FOCUS program has produced significant reliability improvements on the lower-performing devices and line segments that are identified and addressed through that program. FOCUS will continue to provide benefits going forward as devices and line segments degrade over time, and the load profile on feeders will change as customers and customer types on the feeder change over time. On the other hand, a new feeder-level investment program ("FLIP") is designed to identify investments in infrastructure and technology along entire feeders that are intended to produce sustainable, whole feeder reliability performance improvements and support future capabilities and functionalities.

Q33. WHAT ARE THE COMPANY'S MAJOR RELIABILITY AND INFRASTRUCTURE IMPROVEMENT PROGRAMS?

A. ETI's major reliability-focused efforts are: FOCUS Program, Backbone Program,[4] Internal projects, Pole Program, Equipment Inspection and Maintenance Program, Underground Cable Program, Sectionalization projects, and FLIP. ETI also maintains a robust vegetation management program, which I describe in the next section. Some of these efforts are reactive, meaning that the actions taken are in response to devices that have failed and/or outages that have occurred, while others are proactive, meaning that the actions are taken to prevent devices from failing and/or outages from occurring. Thus, while some of the specific remedies and mitigation measures may be similar among the programs, the process for identifying issues is purposely varied to maximize the customer benefits of these investments.

Q34. PLEASE DESCRIBE THE FOCUS PROGRAM.

A. The FOCUS Program is a reactive program that uses historical outage data over the prior two-year period and an algorithm to identify devices (e.g., breakers, reclosers, line fuses, and sectionalizers) where reliability has been adversely affected. The FOCUS Program then creates a list of devices, which is prioritized by customer interruptions and reviewed and updated on a quarterly basis. Using the algorithm rank along with local knowledge, areas behind the devices are then

[4] During 2020 the Backbone reliability program began being phased out and incorporated into other reliability programs.

selected based on historical customer interruptions and frequency of outages to have work performed during the calendar year. The intent of the FOCUS Program is to improve the reliability performance of the selected FOCUS-identified devices. These investments have resulted in improved reliability. For example, devices addressed through FOCUS have seen an average 61% improvement in customer interruptions in the three years following the completed in-service-date.

The FOCUS Program addresses the reliability needs of each device through a Reliability Inspection process (i.e., point by point) to identify repairs and improvements that have the potential of improving a line segment's performance and developing a remediation plan, which may include the following:

- installation of animal guards and/or protective covers to mitigate animal outages;
- replacement of cross-arms, insulators, conductors, arresters, switches, and other equipment;
- vegetation mitigation impacting the segment performance;
- shielding, installation, or relocation of lightning arresters, removing grounds from metal brackets in the primary zone, and/or the installation of Hendrix ground wire and ground rods to improve system Base Insulation Level ("BIL");
- review of protective device coordination; and
- replacing fuses with multi-shot devices such as cutout mounted reclosers (e.g., Trip Saver II's) to prevent momentary interruptions from becoming sustained interruptions.

The following pictures illustrate a few of the components that are inspected in the FOCUS program, from left to right: (1) lightning arrester; (2) cross-arm (including primary wires, secondary wires, a disconnect switch, and insulators); and (3) insulator close-up.

Figure 8 illustrates the overall FOCUS process.

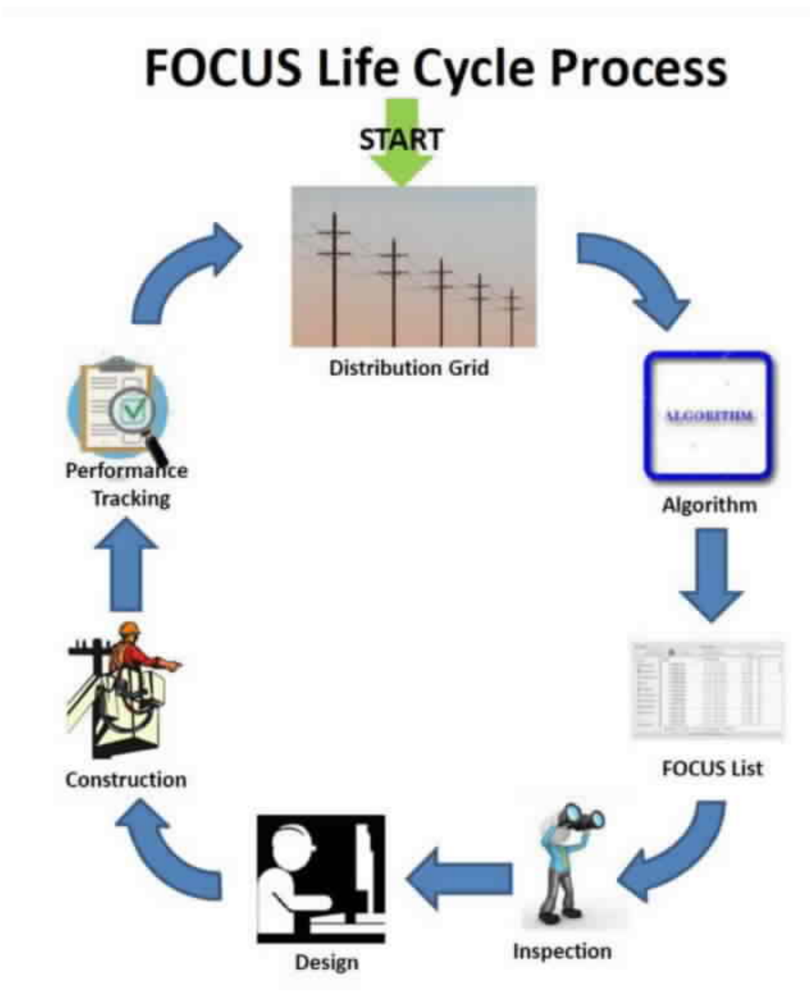

Figure 8

The actual spending for the FOCUS Program for 2017 through 2021 (capital and Operations and Maintenance ("O&M")) is shown in Exhibit MLT-2. The Company significantly increased spending on the FOCUS Program since 2017 in an effort to maintain and improve the reliability of the distribution grid.

Q35. PLEASE DESCRIBE THE BACKBONE PROGRAM.

A. The Backbone Program was a proactive (i.e., not based on historical outages) infrastructure program designed to inspect and address the portion of selected circuits that have the largest potential for customer impact, which is the portion of the line from the substation breaker up to and including the first protective device that has the responsibility of isolating the remainder of the circuit. If the first protective device falls within the first 15 spans of the circuit, inspection would continue past that point to the next protective device or to the end of the feeder, whichever is first. The intent of the Backbone Program was to proactively identify potential problems before they result in an outage. Figure 9 illustrates the line segment inspected in the Backbone Program.

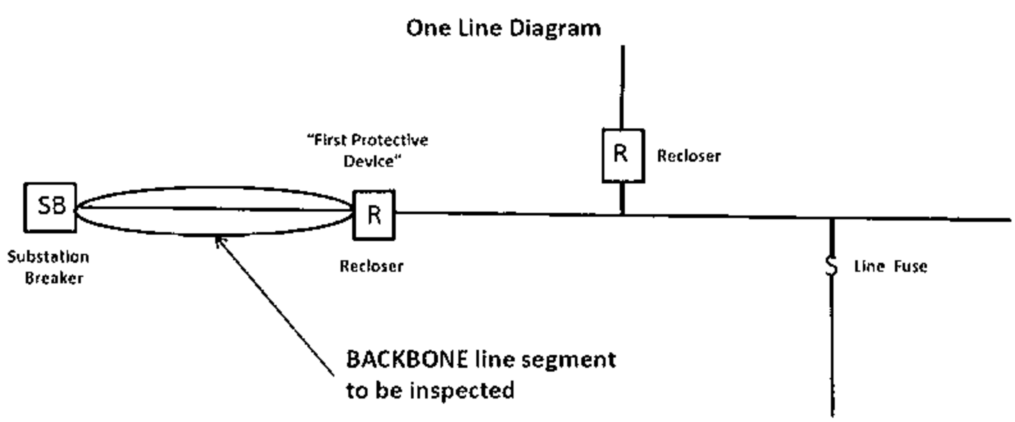

Figure 9

The actual spending for the Backbone Program for 2017 through 2021 (capital and O&M) is shown in Exhibit MLT-2. As noted above, in 2020 the Backbone program began being phased out and incorporated into other reliability programs.

Q36. PLEASE DESCRIBE THE INTERNAL PROJECTS CATEGORY.

A. The purpose of the activities in the Internal Projects category is to address National Electric Safety Code ("NESC") compliance, Entergy Service Standards compliance, and other emergent critical infrastructure needs that arise and cannot be timely addressed in any other reliability program. Examples of compliance projects include adjusting the height of existing service and/or secondary cable over a roadway or existing communications cable to maintain prescribed clearance. An example of an Entergy Service Standards compliance project is replacing bare wire leads on a recloser with insulated wire leads to help mitigate animal interference. An example of an emergent critical infrastructure need is when heavy rainstorms erode a ditch, and an adjacent pole then becomes in danger of collapse. Internal Projects can be initiated by Company personnel at any time during the year.

The actual spending for the Internal Projects category for 2017 through 2021 (capital and O&M) is shown in Exhibit MLT-2.

Q37. PLEASE DESCRIBE THE POLE PROGRAM.

A. The Pole Program is a cyclical proactive inspection and preventive maintenance program. The program consists of a visual inspection of the pole and full excavation where possible or sounding and selective boring when full excavation is not possible. The recommended actions depend on the results of the inspection. Poles judged to be sound receive no further action. Those identified as needing additional attention are either treated in the field or reinforced, depending on the condition of the pole. Those that are deemed beyond treatment or reinforcement are prioritized for replacement.

ETI's engineering designers are now evaluating new and replacement poles with an extreme wind criteria utilizing structural analysis software. Based on the poles analyzed, the software has indicated the need to install some Class 1 poles (as opposed to Class 3 poles) based on the horizontal loading and the extreme wind analysis. ETI will attempt to install Class 1 poles where the software recommends such poles. However, there are instances in which existing equipment of other non-electric utilities, such as gas and water, in the ground obstructs the space needed to install a Class 1 pole. ETI will work to identify all foreign utilities in the ground where a Class 1 pole is recommended to be installed, but notes that a Class 3 pole may have to be installed due to construction constraints.

ETI's Pole Program is strategically focused on addressing poles identified in pole inspections as needing repair or replacement and on addressing joint use transfers. Joint use transfers are projects to provide additional clearances between the Company's facilities and joint use facilities, increase structure height or strength of poles containing joint use facilities, or transfer, purchase, or sell joint use facilities.

The following pictures illustrate excavating and treating a pole:

The actual spending for the Pole Program for 2017 through 2021 (capital and O&M) is shown in Exhibit MLT-2. The Company has significantly increased spending on the Pole Program since 2017 in an effort to maintain and improve the reliability of the distribution grid.

Q38. PLEASE DESCRIBE THE EQUIPMENT INSPECTION AND MAINTENANCE CATEGORY.

A. This category includes a program in which ETI performs an annual inspection of all reclosers greater than 100 amps, line capacitors, and voltage regulators on the distribution line system. Equipment problems identified during those inspections are also addressed. The actual spending for the Equipment Inspection Program for 2017 through 2021 (capital and O&M) is shown in Exhibit MLT-2.

Q39. PLEASE DESCRIBE THE UNDERGROUND CABLE CATEGORY.

A. ETI increased investment in underground cable replacements largely due to aging infrastructure in the underground Networks, and in particular The Woodlands Network. The activities performed in this category include the replacement of end-of-life underground conductor with new cable in a conduit, which facilitates faster restoration in the event of an outage. With ETI focusing efforts to improve its SAIDI performance, these improvements should help drive a reduction in outage duration. The actual and budgeted spending for the Underground Cable category for 2017 through 2021 (capital and O&M) is shown in Exhibit MLT-2. The Company has significantly increased spending on Underground Cable program since 2017 in an effort to maintain and improve the reliability of the distribution grid.

Q40. PLEASE DESCRIBE THE SECTIONALIZATION CATEGORY.

A. The Company funds an annual sectionalization program that identifies opportunities to reduce customer exposure through the addition of automatic isolating devices (i.e., an automated load transfer scheme ("ALT")), pole top switches, and reclosers. An ALT is a group of multiple reclosers that communicate with each other to minimize the outage to as small of an area as possible, thus quickly restoring service to as many customers as possible.

Potential projects are planned, prioritized, and implemented based on their projected impact on reliability, and projects are based on analyzing the data returned from new reporting and analytics from a combination of DA, which I