and billed through service company billings to ETI. These service company billings include both costs incurred by ESL directly on behalf of ETI and an allocation of costs incurred on behalf of all Entergy Operating Companies and allocated to all based on the billing method established in the project code setup.

Q129. ARE ETI'S AFFILIATE CHARGES REASONABLE AND NECESSARY?

A. Yes, the affiliate services provided by ESL are reasonable and necessary costs of the AMS project. These services have been reasonably and necessarily incurred to support the AMS system deployment and operation as I discuss above and as discussed in Mr. Phillips's testimony. As discussed above, these affiliated support services are primarily assigned only to ETI. For the costs allocated among ETI and other Entergy affiliates, the allocation methodology employs an attribution-based allocation factor that ensures that ETI is charged the same unit price for the shared service that is no higher than the price for any other affiliate or third party.

Q130. PLEASE SUMMARIZE YOUR TESTIMONY IN THE AMS RECONCILIATION.

A. My testimony describes and supports ETI's accounting for revenues, costs net of reductions, and investment associated with each Company's respective AMS deployment programs. My testimony also explains variances for certain cost differences between ETI's AMS Surcharge Model and actual AMS costs incurred. Finally, my testimony provides certain accounting assumptions used in the

Company's AMS Surcharge Model. These costs are reasonable and necessary and properly reflect AMS activities.

XI. <u>CONCLUSION</u>

Q131. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT OF DAVID C. BATTEN

THE STATE OF LOUISIANA)
)
ORLEANS PARISH)

This day, David C. Batten 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 David C. Batten. 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.

David C Batten

David C. Batten

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 27th day of June 2022.

Notary Public, State of Louisiana

My Commission expires:
Donald P. DiMaggio
LA Notary Public# 33195
My Commission is for Life

See Native Excel file Batten Direct_Exhibit DCB-1.

See Native Excel file Batten Direct_Exhibit DCB-2.

See Native Excel file Batten Direct_Exhibit DCB-3.

See Native Excel file Batten Direct_WP_DCB-3.

DOCKET NO. 53719

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

REDACTED DIRECT TESTIMONY

OF

ANDREW L. DORNIER

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS INC.
REDACTED DIRECT TESTIMONY OF ANDREW L. DORNIER
2022 RATE CASE

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EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Andrew L. Dornier. 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 the Manager of Fossil Fuel Supply within the System Planning and Operations organization ("SPO"), a department of Entergy Services, LLC ("ESL"). I provide a description of SPO and its responsibilities later in my testimony. ESL is a corporate support services company that provides services to Entergy Texas, Inc. ("ETI" or the "Company") and the other Entergy Operating Companies ("EOCs").[1]

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

A. I am testifying on behalf of ETI.

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[1] The five EOCs are Entergy Arkansas, LLC ("EAL"); Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, LLC ("EML"); Entergy New Orleans, LLC ("ENO"); and ETI. For convenience, I use the term "Entergy" to refer individually and collectively to Entergy Corporation and its affiliates including but not limited to ESL and the EOCs.

A. Qualifications

Q4. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Southeastern Louisiana University with a Bachelor of Science degree in Accounting (2000) and a Master of Business Administration (MBA) (2001). I also earned a Master of Integrated Supply Chain Management (2017) from the University of Wisconsin – Platteville. I am a Certified Public Accountant (CPA) licensed by the Louisiana State Board of CPAs (Lic. #25423) and a Certified Internal Auditor.

Q5. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I began working for ESL as a Lead Internal Auditor in 2008 after approximately seven years of professional auditing experience in both industry and government. In August 2013, I transferred to SPO in The Woodlands to work in the Energy Analysis and Reporting ("EAR") group working on the Intra-System Bill ("ISB"). In July 2015, I was promoted to the Manager of the EAR group with responsibility for producing the ISB as well as a number of other functions. In January 2018, my group was renamed the Settlements, Analysis and Reporting group and restructured to include verification and settlement of Midcontinent Independent System Operator, Inc. ("MISO") market charges and revenues. In that role I was responsible for overseeing reporting and settlements for gas, coal, emissions, fuel oil, and purchased power for all EOCs. In November 2021, I accepted my current position as Manager of Fossil Fuel Supply within SPO. In this role, I am responsible for procuring natural gas, coal, and oil for Entergy's fleet of generating plants across our four-state territory, as well as our two natural gas local distribution companies ("LDCs") in Baton Rouge and New Orleans.

Q6. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE ANY REGULATORY AUTHORITIES?

A. Yes, I have testified several times, including in the following proceedings before the Public Utility Commission of Texas: Docket Nos. 28504, 29408, 30123, 34800, 39896, 41791, 46076, and 52067.

B. <u>Purpose of Testimony</u>

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address the Spindletop salt dome natural gas storage facility ("Spindletop"). Specifically, my testimony: (1) presents the Company's cost-benefit analysis of the continued operation of the Spindletop facility, in accordance with the final order in Docket No. 49916 (ETI's most recent fuel reconciliation); and (2) supports the inventory level for the facility. I also address the Test Year operations and maintenance ("O&M") costs associated with the Southern Gulf Railway ("SGR") and ETI's level of coal inventory. Finally, my testimony describes the Energy and Fuel Management Class of affiliate services and supports the reasonableness of the associated costs billed to ETI during the 12 months ending December 31, 2021 (the "Test Year") by demonstrating:

- the costs included in the Energy and Fuel Management Class of affiliate costs billed to ETI during the Test Year were necessary and reasonable;
- the price charged to ETI for these affiliate services was not higher than the prices charged by ESL for the same item or class of items to other affiliates or non-affiliates; and
- the Test Year costs for the Energy and Fuel Management Class of affiliate services represent the actual cost of these services, and that these services are not duplicated by other entities.

Q8. DO YOU SPONSOR ANY EXHIBITS?

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

Q9. DO YOU SPONSOR ANY SPECIFIC RATE FILING PACKAGE ("RFP") SCHEDULES?

A. Yes. I sponsor or cosponsor the following schedules:

Schedule E-2.1	Inventory Policies
Schedule E-2.2	Inventory Evaluation
Schedule E-2.3	Fuel Inventories
Schedule E-2.4	Inventory Levels
Schedule E-2.5	Inventory Values
Schedule H-12.4a-g	Summary of Purchased Power
Schedule H-12.5b-f	Off-System Sales
Schedule H-12.6a	Monthly Minimum & Peak Dem Load Curve
Schedule H-12.6b	Monthly Load Duration Curve
Schedule H-12.6c	Annual Load Duration Curve
Schedule I-1.2	Monthly Test Year Fuel Burned
Schedule I-2	Fuel & Purchased Power Procurement Practices
Schedule I-3	Fuel & Purchased Power Committees
Schedule I-4	Fuel & Fuel-Related Contracts
Schedule I-7	Natural Gas Storage Description
Schedule I-8	Fuel Properties
Schedule I-9	Employee Organization Charts
Schedule I-10	Employee Ethics
Schedule I-16	Reconcilable Fuel Costs-Monthly

Schedule I-17.1	Coal Cost Breakdown-Monthly
Schedule I-18	Coal & Lignite Supplier Locations
Schedule I-19.2	Unit Trains
Schedule I-19.4	Rail Cars
Schedule I-19.5	Rail Car Leases
Schedule I-19.6	Rail Car Maintenance
Schedule I-19.7	Rail Car Repairs
Schedule I-21	Fuel Management
Schedule O-1.5	System Information
Schedule O-1.6	System Load Factor By Month In Test Year
Schedule Q-8.1	Marginal & Average Cost Schedules
Schedule Q-8.2	Expected Annual Load Duration Curve
Schedule Q-8.3	Representative Marginal/Average Energy Costs
Schedule Q-8.4	Diurnal Load
Schedule Q-8.6	Contract Prices
Schedule Q-8.7	Wholesale Tariffs

II. SPINDLETOP NATURAL GAS STORAGE FACILITY

Q10. PLEASE DESCRIBE SPINDLETOP.

A. Spindletop is a natural gas storage facility owned by ETI. This facility allows ETI to maintain a natural gas inventory used to serve the Sabine Station generating facility.

The storage facility consists of two salt-dome storage caverns, a compression facility used for injecting gas into the caverns, and a pipeline header system that interconnects the storage caverns with the Sabine Station.

Q11. PLEASE DESCRIBE SPINDLETOP'S OPERATIONS.

A. This storage facility provides ETI a means of buying natural gas at one point in time, storing it, and using it at some future point in time. This facility, in many ways, is comparable to the water towers many cities use to provide reliability and flexibility to their water supply systems. With both types of systems, a commodity is injected or pumped (with compressors or water pumps) into a container (a storage cavern or water tower) and is stored for periods when supplies are not available or when the sources of the commodities (gas pipelines or water wells) are unable to provide, or unable to economically provide, the flexibility (or rate of delivery) needed to serve the peak needs of customers.

Q12. DOES SPINDLETOP SERVE TEXAS CUSTOMERS ONLY?

A. Yes. The Spindletop facility only serves ETI's Sabine Station.

Q13. WHAT ARE THE BENEFITS OF ETI OWNING THIS FACILITY?

A. The two primary benefits that Spindletop provides to ETI are: (1) supply reliability; and (2) swing flexibility. Spindletop provides a reliable supply of gas for Sabine Station during gas supply curtailments that can occur as a result of hurricanes, freezes, or other unusual events. If one of these events were to occur, the gas in storage would be available to supplement existing pipeline supplies. For example, ETI withdrew gas from Spindletop during Winter Storm Uri instead of relying on purchases in a market in which supply was severely restricted and potentially unavailable, demand was high, and prices had risen dramatically. The estimated savings of using Spindletop reserves during Winter Storm Uri are discussed further below.

In the event of a total curtailment of supply, the Spindletop storage facility is capable of providing 100 percent of the fuel requirements for all of the units at

Sabine Station for a period of up to 38 days, at a 70 percent capacity factor, which would be important during a major supply disruption, such as a severe weather event. Further, a reliable supply of fuel to the Sabine Station is critical, as it provides 41.6% of the generation capacity ETI relies on to provide reliable service to its customers.

In addition to reliability of supply, the storage facility also provides flexibility of gas supply to the Sabine Station, both on a daily and instantaneous basis. The fluctuation of natural gas demand resulting from changes in instantaneous demand is known as "swing." This flexibility mitigates the Company's dependence on pipelines and/or gas suppliers to provide the needed flexibility. This flexibility is also important given that the Sabine Station units are routinely called upon by MISO to be dispatched to follow load as it varies over time. Spot gas is generally delivered ratably over the contract period such that the contracted volumes are delivered in equal amounts every hour. If ETI wishes to deviate from this ratable flow, the pipeline and/or the supplier will typically charge an additional amount for this "swing" flexibility. Greater swing requirements will, of course, demand a higher fee.

ETI's generating plants must adjust their generation to follow customer load. This means that during high-load situations, such as on-peak, the plants may be at or near their peak generating capacity and must, therefore, have gas available on demand to be able to achieve that peak requirement. During off-peak hours, however, those same plants may be required to turn down their generation to minimum load capacity. As a result, gas supplies delivered into the plant during low-load hours must also be significantly reduced. Generally, this degree of swing flexibility can only be provided under firm contracts, either with the pipeline, the supplier, or both. At the Sabine Station, this swing flexibility is principally managed through Spindletop, which allows ETI to withdraw or inject natural gas to match the varying consumption patterns of the Sabine units, thereby avoiding the incremental cost of firm transportation or supply contracts.

In addition, by being able to withdraw from storage, the Company is able to avoid almost all intraday (or current day) gas purchases for the Sabine Station. In fact, during the 2021 test year, only 2% of the total purchases at the Sabine Station were intraday; approximately 40,000 MMBtus of intraday gas out of approximately 21.5M total MMBtus purchased at the plant.

Q14. DO CHANGES IN THE MARKET PRICE OF NATURAL GAS REDUCE THE NEED FOR SPINDLETOP TO PROVIDE SWING FLEXIBILITY TO THE SABINE STATION?

A. No. Each day, ETI purchases gas according to its anticipated needs for the next day. As I discussed earlier, the delivery of this gas is largely made on a ratable basis with an equal amount delivered in every hour. Because the actual gas requirements will deviate from the ratable delivery throughout the day, ETI uses Spindletop to match the Sabine Station's gas requirements with gas deliveries. When generating requirements dictate the need for more gas than is being delivered, the additional gas requirements will be withdrawn from storage. When generating load drops below the level of gas being delivered, the excess gas will be injected into storage. The market price of natural gas does not reduce the need for this flexibility.

Q15. HAVE COSTS ASSOCIATED WITH THE OPERATION OF SPINDLETOP BEEN CHALLENGED IN THE PAST?

A. Historically, these costs have gone unchallenged. In fact, in ETI's 2018 base-rate case (Docket No. 48371), Office of Public Utility Counsel ("OPUC") witness Constance Cannady recognized the value of the services provided by Spindletop, agreeing that "Spindletop is used and useful in providing service to Texas customers."[2] However, in ETI's 2019 fuel reconciliation proceeding (Docket No. 49916), OPUC witness Scott Norwood recommended a disallowance of 100% of the operating costs related to Spindletop. His recommendation essentially turned on his assertion that ETI failed to demonstrate through cost-benefit analysis, testimony, or discovery that the cost to operate Spindletop was necessary, economically justified, or beneficial to its customers. He argued that the Spindletop operating costs were too high and should, therefore, be disallowed in their entirety.

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[2] *Application of Entergy Texas, Inc. for Authority to Change Rates*, Docket No. 48371, Direct Testimony of Constance T. Cannady at p. 26, ll. 7-8.

Q16. DID THE COMMISSION ADDRESS MR. NORWOOD'S POSITION ON SPINDLETOP IN DOCKET NO. 49916?

A. No. The Commission reconciled ETI's fuel expenses and revenues at issue in Docket No. 49916 in accordance with a settlement that each of the parties to that case either agreed to or did not oppose. The settlement eliminated the need for the Commission to address the merits of Mr. Norwood's argument. However, with regard to Spindletop, the signatories to the settlement[3] agreed to the following:

> ETI will provide a cost-benefit analysis of the continued operation of the Spindletop natural gas storage facility ("Facility") in the application of either its next base rate or fuel reconciliation case, whichever is filed earlier. The cost-benefit analysis is to include, at a minimum, an evaluation of the costs (including carrying costs on stored gas) and benefits to ratepayers of operating the Facility when compared to available alternatives, including immediate retirement of the Facility, acquisition of firm or more flexible gas supply and delivery services, and other feasible supply options, over a range of natural gas and market energy prices, and load forecast scenarios. ETI reserves all rights to interpret the meaning and implications of the results of the aforementioned analysis and also to define the scope of an analysis that is, in ETI's view, a more appropriate measure of the economics and value of the Facility to ETI's customers.[4]

This agreement is reflected in Findings of Fact 55 and 56 in the final order in Docket No. 49916.

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[3] The signatories to the Docket No. 49916 settlement include: ETI, the Public Utility Commission of Texas Staff ("Staff"), OPUC, and Texas Industrial Energy Consumers ("TIEC").

[4] Docket No. 49916, Stipulation and Settlement Agreement at § II.4 (June 11, 2020) (available at Interchange - Documents (texas.gov)).

Q17. HAS ETI PREPARED A COST-BENEFIT ANALYSIS OF THE SPINDLETOP STORAGE FACILITY IN ACCORDANCE WITH THE FINAL ORDER IN DOCKET NO. 49916?

A. Yes. A copy of this analysis is included as highly sensitive Exhibit ALD-1 to this testimony.

Q18. PLEASE DESCRIBE WHAT MUST BE CONSIDERED IN A COST-BENEFIT ANALYSIS OF THE SPINDLETOP STORAGE FACILITY.

A. A cost-benefit analysis of Spindletop must start with an understanding of the value and necessity of the benefits Spindletop provides. These benefits include swing flexibility, reliability of gas supply, not having to sell gas back at a discount when MISO dispatches a unit down or a unit is not able to meet its Day-Ahead Schedule (i.e. Unit Trip), and not having to purchase higher-priced intra-day gas. In the absence of Spindletop, ETI would need to replace those services with market-priced alternatives. Consequently, in a cost-benefit analysis the appropriate comparison is the cost of operating Spindletop versus the cost of obtaining similar services through market purchases. As discussed further below and demonstrated in the attached cost-benefit analysis, Spindletop provides needed services at a cost below that which such services could be obtained at market. Stated differently, replacing Spindletop with market-priced alternatives would increase costs to customers.

Q19. PLEASE DESCRIBE THE TYPES OF SERVICES THAT WOULD HAVE TO BE PROCURED TO REPLACE THE BENEFITS PROVIDED BY THE SPINDLETOP STORAGE FACILITY.

A. The services and, in turn, benefits, Spindletop provides could be replaced by a combination of firm transportation and firm gas supply contracts. Such firm contracts would provide an agreed-upon capacity of gas for the producer or pipeline to supply that could not be curtailed except under certain unforeseen circumstances. Firm service is more expensive than interruptible service. As shown in further detail on HSPM Exhibit ALD-1, Entergy analyzed the cost of replacing Spindletop with a combination of these two services.

A final option for replacing Spindletop would be a year-round, No-Notice Supply agreement for at least 365,000 MMBtu. This option, however, was not analyzed because even if it was available to procure, it would be very expensive and rarely, if ever, used.

Q20. HAVE YOU ANALYZED THE COSTS OF PROCURING SUCH SERVICES?

A. Yes. ETI analyzed the cost of replacing Spindletop with a combination of firm transportation and firm supply. As shown on HSPM Exhibit ALD-1, the estimated annual cost associated with these services are:

Table 1 – Replacement Services Costs

Product/Service	Estimated Annual Cost
• 50 % Firm Transportation	[redacted]
• 50% Firm Supply	[redacted]
Total	[redacted]

Q21. PLEASE DESCRIBE THE PROCESS OF ESTIMATING THE COSTS OF THE SERVICE SHOWN IN TABLE 1 ABOVE?

A. The [redacted] estimated annual costs for Firm Transportation is based on ETI procuring 50% of the Sabine Station capacity at an estimated monthly reservation charge based on the maximum rate for Firm Transportation Service ("FT-1") on Texas Eastern Transmission ("TETCO") for the WLA-WLA path posted on TETCO's currently effective FT-1 rate schedule. The [redacted] estimated annual costs for Firm Supply is based on a Firm Supply proposal ETI received for the Sabine Station in the summer of 2022.

Q22. HOW DO THE COSTS OF THE POTENTIAL REPLACEMENT SERVICES COMPARE WITH THE COSTS ASSOCIATED WITH OPERATING THE SPINDLETOP STORAGE FACILITY OVER THE SAME PERIOD?

A. The cost of the replacement services are significantly more expensive than the cost of operating Spindletop. In 2021, the O&M costs to operate Spindletop that were charged to ETI totaled under [redacted]. As shown in Table 1 above, ETI estimates that the replacement services would cost approximately [redacted].

Q23. IS THE FLEXIBILITY PROVIDED BY SPINDLETOP ASSURED WITH THE POTENTIAL REPLACEMENT SERVICES?

A. No, the flexibility provided by Spindletop is not assured in the potential replacement services in the analysis. As shown in HSPM Exhibit ALD-1, ETI estimates that it saved approximately [redacted] in 2021 by relying on

Spindletop to provide necessary daily swing flexibility. This benefit would no longer be available to ETI customers if the Company was to discontinue use of the Spindletop facility.

Q24. EARLIER YOU MENTIONED THAT SPINDLETOP SERVES TO PROVIDE A RELIABLE SUPPLY OF GAS FOR THE SABINE STATION DURING GAS SUPPLY CURTAILMENTS THAT CAN OCCUR AS A RESULT OF UNUSUAL WEATHER EVENTS AND OFFERED ETI'S EXPERIENCE DURING WINTER STORM URI AS AN EXAMPLE OF THIS BENEFIT. HAVE YOU CALCULATED THE COST SAVINGS ASSOCIATED WITH THE OPERATION OF THE SPINDLETOP STORAGE FACILITY DURING WINTER STORM URI?

A. ETI estimates that its saved approximately $67 million by using Spindletop during Winter Storm Uri versus purchasing gas in the market—assuming such gas was even available.

Q25. PLEASE DESCRIBE ETI'S NATURAL GAS INVENTORY POLICY FOR SPINDLETOP.

A. ETI places emphasis on maintaining a combination of storage inventory or gas supplies to provide a reliable supply of fuel to operate ETI's plants during times of the year when gas industry supply disruptions are more likely to occur. Over and above the inventory requirements needed to address the reliability function, inventory levels must also provide for Spindletop's flexibility function. With respect to the reliability function, historically, major supply disruptions are more likely to occur during the winter and hurricane seasons, which, generally, constitute the ten months of June through March.

Q26. WERE THE GAS INVENTORY LEVELS IN SPINDLETOP DURING THE TEST YEAR TYPICAL OF NORMAL OPERATIONS?

A. Yes. The gas inventory levels in Spindletop during the Test Year were typical of normal operations.

Q27. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE BENEFITS OF SPINDLETOP AND FOUND IT USED AND USEFUL IN PROVIDING SERVICE AND PRUDENT?

A. Yes.[5]

Q28. DOES SPINDLETOP REMAIN USED AND USEFUL?

A. Yes.

Q29. HAS THE ESTIMATED USEFUL LIFE OF THE SPINDLETOP FACILITY CHANGED SINCE ETI'S LAST BASE RATE CASE?

A. Yes. ETI is proposing to extend the useful life of the Spindletop Facility from [redacted] based on the expectation to use the facility to support the proposed

[5] *See, e.g., Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896, Order on Rehearing at 17 (Nov. 1, 2012).

Orange County Advanced Power Station ("OCAPS") to be located at the Sabine Station site. In Docket No. 52487, ETI has applied for an amendment to its certificate of convenience and necessity ("CCN") to construct, own, and operate OCAPS, a new combined-cycle combustion turbine facility. If approved, OCAPS will provide 1,215 MW of modern dispatchable generation in Texas to help meet the resource needs of ETI's customers in a reliable and economic manner, support and promote the Southeast Texas economy, and best position customers for the future. Importantly, OCAPS will be constructed on property owned by ETI in Bridge City, Texas, adjacent to ETI's existing Sabine Station. OCAPS's location at ETI's Sabine Station site will allow it to take advantage of the Company's existing Spindletop gas storage facility, thus supporting the Company's proposed extension of the useful life assumption for the Spindletop Facility. ETI witness Dane Watson incorporates the proposed extended useful in the Depreciation Study presented in his testimony.

III. SOUTHERN GULF RAILWAY

Q30. PLEASE DESCRIBE SOUTHERN GULF RAILWAY.

A. The Southern Gulf Railway ("SGR") is an approximately four-mile rail spur connecting the Nelson 6 coal unit (of which ETI is a co-owner) to a rail line that is served by the BNSF and Union Pacific Railways. The rail spur allows for coal deliveries to the Nelson 6 unit from multiple rail carriers. Before the rail spur was constructed, there was only one rail line that serviced the Nelson 6 unit, limiting transportation service provider options and hindering the ability to receive competitive offers on rail transportation.

Q31. PLEASE BRIEFLY DESCRIBE THE HISTORY OF OWNERSHIP AND OPERATION OF THE SOUTHERN GULF RAILWAY.

A. The SGR was incorporated on February 24, 1993. It was constructed in order to provide Nelson 6 with additional coal transportation providers and facilitate competitive bidding for these services. It has been used as an active railroad intermittently since its construction, depending on the contract in place at the time. When not being used in active service, the SGR can and does act as a storage location for approximately two full train sets.

Q32. WAS THE SGR AN ACTIVE RAILWAY DURING THE TEST YEAR?

A. Yes.

Q33. PLEASE DESCRIBE THE OPERATIONS OF THE SGR.

A. The SGR connects to a BNSF/Union Pacific main line, allowing for coal deliveries directly via BNSF and Union Pacific. Without this railway, Nelson 6 would be dependent exclusively upon Kansas City Southern Railway. During current operations, BNSF delivers loaded coal trains to the SGR. Once delivered, railroad crews from Timber Rock Railroad take control of the train, deliver the train to the plant for unloading, and return the empty train to BNSF on the SGR.

Q34. PLEASE DESCRIBE THE TEST YEAR OPERATION AND MAINTENANCE ("O&M") EXPENSES ASSOCIATED WITH SGR.

A. The Test Year O&M expenses for SGR are $49,280.45.

Q35. DO YOU HAVE AN OPINION REGARDING THE NECESSITY AND REASONABLENESS OF THE TEST YEAR O&M EXPENSES ASSOCIATED WITH SGR?

A. Yes. The Test Year O&M expenses associated with the SGR were reasonable and necessary. As stated above, SGR provides Nelson 6 with additional coal transportation and facilitates competitive bidding for these services. Further, without SGR, Nelson 6 would be dependent on Kansas City Southern Railway.

IV. COAL INVENTORY

Q36. COULD YOU SUMMARIZE THE COAL INVENTORY POLICY APPLICABLE TO NELSON 6?

A. The coal inventory policy applicable to Nelson 6 provides for inventory target levels to help mitigate transportation and unit operating risks. The primary elements of the policy are that it provides for: (1) a base target of 36 days of inventory; (2) an end-of-year 12-month average inventory target of 43 days; and (3) a twice per-year review/analysis to determine if alternative coals will be purchased.

Q37. WHAT IS THE COAL INVENTORY PROCESS FOR BIG CAJUN II, UNIT 3 ("BCII/U3")?

A. Because the Company is not the operator of the BCII/U3 plant, it does not have ultimate control over the coal inventory levels at BCII/U3. Under the Joint Ownership Participation and Operating Agreement for BCII/U3, each year the Company must nominate the level of coal to be delivered for its account at BCII/U3 for the next calendar year. The Company's nomination process is targeted to achieve an end-of-year inventory target of approximately 43 days.

Q38. DO YOU HAVE AN OPINION REGARDING THE TEST-YEAR INVENTORY LEVELS FOR NELSON 6 AND BCII/U3?

A. Yes. The Test-Year solid fuel inventory levels for the Nelson 6 and BCII/U3 were reasonable and necessary as are the costs incurred to maintain those levels.

V. THE ENERGY AND FUEL MANAGEMENT CLASS OF COSTS

Q39. PLEASE IDENTIFY THE ORGANIZATIONS THAT COMPRISE THE ENERGY AND FUEL MANAGEMENT CLASS OF AFFILIATE SERVICES THAT YOU SPONSOR.

A. The Test-Year expenses relating to the Energy and Fuel Management Class of affiliate services relate to tasks performed by SPO and the Enterprise Planning Group ("EPG"). SPO and EPG are the only organizations within ESL or Entergy that perform the services included in this class.

A. Energy and Fuel Management Class Organizations During the Test Year

Q40. PLEASE PROVIDE AN OVERVIEW OF THE PURPOSE AND ORGANIZATIONS INCLUDED WITHIN THE ENERGY AND FUEL MANAGEMENT CLASS DURING THE TEST YEAR.

A. EPG[6] provides integrated strategic resource planning, analysis for the EOCs, including ETI. EPG's work includes, but is not limited to, the evaluation of generation resources and supply-side alternatives to meet ETI's electric utility needs. EPG's work is future focused, spanning 1 year to 30 years into the future. SPO, by contrast, manages the near-term duties (current to 18 months out) required to participate in MISO and Regional Transmission Organization ("RTO") markets for capacity, energy, and ancillary services. In order to perform this function, SPO is structured in two primary "offices"—front and back—and provides a general support function. The front and back offices engage in discrete aspects of planning, operations, and settlements.

B. Necessity of Services

1. EPG

Q41. WHAT ACTIVITIES DOES EPG PERFORM?

A. EPG supports the long-term integrated strategic resource planning for ETI and the other EOCs. Specifically, EPG conducts scenario planning across market,

[6] EPG was formed in mid-2020 as a new department, which combined existing functions across several departments to form an integrated resource planning group. The Planning Analysis Group and its associated responsibilities, previously housed in SPO, moved into EPG in June 2020.

commodity, growth, technology, and resource assumptions. EPG is responsible for the development of long-term commodity assumptions, the development of a strategy to satisfy MISO's resource adequacy requirements, and the evaluation of customer value delivered by potential resources[7] within a broad portfolio. Ultimately, EPG's scenario planning supports the ETI resource planning strategy and annual resource plans, which must meet customers' needs, balance core planning objectives (affordability, reliability, and sustainability), and also satisfy MISO and retail jurisdiction requirements.

ETI relies on EPG's analytics to meet MISO's annual resource adequacy requirements and evaluate adequate reserve margin over the planning horizon. As part of annual business planning activities, EPG determines the near-term capacity short position and, if applicable, evaluates the potential products to responsibly manage that position (e.g., purchase of capacity credits, tolling agreements, and power purchase agreements). SPO's Energy Management Organization ("EMO") determines any annual purchase of products within MISO's annual Planned Resource Auction ("PRA").

Q42. ARE THE SERVICES EPG PROVIDES NECESSARY?

A. Yes. It is common practice for utilities in an RTO to employ these types of planning and analysis functions and to procure limited- and long-term fuel and

[7] Pursuant to the identification of resources identified through the formal Requests for Proposals process, EPG is responsible for the analysis supporting procurement of limited- and long-term fuel and generation resources to meet the electric utility needs of ETI.

generation resources to meet the electric utility needs of their customers and to achieve the goal of meeting the RTO's resource adequacy requirements.

2. SPO

Q43. EARLIER YOU TESTIFIED THAT SPO IS STRUCTURED IN TWO PRIMARY OFFICES WITH AN ADDITIONAL GENERAL SUPPORT FUNCTION. CAN YOU PROVIDE A GENERAL MAPPING AS TO HOW THE EXISTING SPO GROUP FUNCTIONS FIT INTO THIS TWO-OFFICE AND GENERAL SUPPORT STRUCTURE?

A. Yes, see Table 1:

Table 1: Mapping of SPO Functions

	Front-Office	Back-Office	SPO Support
Energy Management Organization ("EMO")	✓		
Local Balancing Authority ("LBA") Services	✓		
Commercial Operations, Back-Office and Support Services	✓	✓	
Regulatory and Strategic Initiatives ("RSI")	✓		✓

3. Front-Office

Q44. WHAT IS THE FUNCTION OF THE FRONT-OFFICE?

A. SPO's Front-Office manages all of the market-facing activities in the MISO market. Those activities include bids and offers of load and generation, fossil fuel procurement activities, and load forecasting. They also include other operations activities performed by the EMO, long-term resource planning activities and the acquisition of long-term resources performed by the Planning Analysis group, and finally, the Local Balancing Authority ("LBA"), Meter Data Management Agents

("MDMA") and Meter Data Quality ("MDQ") functionality in the LBA Services group.

a. EMO

Q45. WHAT FUNCTIONS DOES THE EMO PERFORM?

A. In the MISO RTO, the EMO retains responsibility for the actual commitment and dispatch of ETI's resources based on dispatch instructions provided by MISO. Accordingly, EMO continues to maintain a dispatch center that operates around the clock for monitoring real-time conditions, evaluating and responding to dispatch instructions from MISO, and substituting generating units for those previously offered to MISO when appropriate. The EMO also maintains a gas and oil supply function in order to plan for and procure natural gas for ETI's gas-fired generation and to ensure administration of gas transportation agreements in an effective and efficient manner. The EMO is also responsible for the planning, procurement, and transportation of coal for the Nelson 6 coal-fired power plant, administering coal supply contracts, and managing maintenance of the rail car fleet.

Further, the EMO is responsible for preparing load forecasts for ETI to submit as a demand bid to MISO in the day-ahead market and to formulate resource offers for generation into the MISO market. Additionally, the EMO submits "financial schedules" to MISO for a large group of third-party transactions to facilitate settlement associated with these transactions.[8] Finally, the EMO participates in MISO's annual PRA at the direction of ETI to ensure resource adequacy is met in an economic manner.

Q46. ARE THE SERVICES EMO PROVIDES NECESSARY?

A. Yes. Further, it is common practice for utilities operating in an RTO to:

- employ a short-term planning function, a dispatch function, and various RTO market functions such as preparing demand bids, resource offers, and financial schedules;
- have gas and oil supply functions in order to meet their projected gas and oil demand and to ensure effective and efficient administration of the utility's gas and fuel oil supply and transportation agreements; and
- have a coal supply function in order to meet its projected coal demand and to ensure effective and efficient administration of its coal supply, railcar maintenance, and coal transportation agreements.

b. Commercial Operations

Q47. WHAT ACTIVITIES DOES THE COMMERCIAL OPERATIONS GROUP PERFORM?

A. Commercial Operations is responsible for: (1) the acquisition of long-term resources through the creation and posting of RFPs as well as any contract negotiation and execution resulting from RFPs or unsolicited offers; and

[8] Financial schedules are used in MISO to transfer the generation credits from one Market Participant to another, typically in the case of a bilateral capacity/energy purchase between Market Participants or in the case of a co-owned generating unit.

(2) outreach to counterparties and managing the terms of the executed contracts for ETI.

Q48. ARE THE SERVICES THE COMMERCIAL OPERATIONS GROUP PROVIDES NECESSARY?

A. Yes. It is common practice for utilities to employ a commercial group that is responsible for creating and posting RFPs as well as the drafting, execution, and management of resulting contracts.

4. <u>LBA Services</u>

Q49. WHAT FUNCTIONS DOES THE LBA SERVICES GROUP PERFORM?

A. This group is responsible for carrying out ESL's function as an LBA within MISO and, in that capacity, maintaining responsibility for reliability within the LBA area. The LBA Services group is also responsible for carrying out MDMA and MDQ functions.

Q50. ARE THESE LBA SERVICES NECESSARY?

A. Yes. The NERC-required functions associated with being a Balancing Authority are split between MISO and ESL, and the LBA Services Group is responsible for performing those functions assigned to ESL. ESL, as the LBA, is responsible for, among other things, monitoring the transmission metering, generation metering, and actual net interchange in real time, providing updated load forecasts to MISO, verifying whether resources are following MISO dispatch instructions, and performing emergency operations, if needed, to ensure system reliability. The MDMA/MDQ functionality is required to perform the acquisition, aggregation, quality assurance, and reporting of the detailed hourly nodal data required in the MISO settlement process.

5. <u>Back-Office</u>

Q51. WHAT IS THE FUNCTION OF THE BACK-OFFICE?

A. The Back-Office is responsible for performing the accounting, billing and settlements, and some administrative functions for SPO, which include the responsibility for:

- performing settlement responsibilities associated with natural gas, fuel oil, coal, purchased power, and the MISO Market;
- performing energy accounting responsibilities, such as the allocation and categorization of MISO Market transactions;
- performing various analytical and reporting responsibilities; and
- reviewing and submitting settlement disputes to MISO.

Q52. WHAT DOES SPO'S BACK-OFFICE GROUP DO?

A. The Back-Office group is responsible for providing business and compliance support services to SPO, and, in turn, for ETI. These services include bulk power energy accounting and administration, accounting related to bilateral wholesale power and fuel invoices, and shadow settlements (i.e., an audit of the daily MISO settlement statement).

The Back-Office group also develops and manages SPO's budget (including the monitoring of related activities and costs) and identifies and implements cost control initiatives. Lastly, the Back-Office group monitors compliance with the electric reliability standards for SPO and ensures that SPO's activities are compliant with the Sarbanes-Oxley Act.

Q53. ARE THE SERVICES THE BACK-OFFICE GROUP PROVIDES NECESSARY?

A. Yes. It is common practice for utilities operating power plants and operating in an RTO to maintain an organization to provide: (1) bulk power accounting; (2) administration of billing associated with the combined system; (3) administration and accounting related to bilateral wholesale power and fuel invoices to enhance the efficiency and effectiveness of the other fuel, energy, and dispatch related functions; (4) shadow settlements and settlements with MISO; and (5) compliance with the electric reliability standards.

As part of the overall management of SPO's fuel and energy management activities, the budgeting and cost control measures provided by the SPO Back-Office group help ensure the reasonableness and necessity of the costs incurred and that such expenditures are managed within the approved budget.

6. SPO General Support Activities

Q54. PLEASE DESCRIBE THE GROUP THAT, IN ADDITION TO THE FRONT- AND BACK-OFFICE FUNCTIONS, PROVIDES CORE SUPPORT FUNCTIONS TO SPO.

A. There are certain types of activities that are common across each of the two primary offices and provided through a core support group. These activities include executive management (i.e., the Vice President of System Planning and Operations) and Regulatory and Strategic Initiatives ("RSI").

Q55. WHAT DOES THE REGULATORY AND STRATEGIC INITIATIVES GROUP DO?

A. This group focuses on and supports several key initiatives facing ETI, primarily the activities (i.e., working groups, proposed market changes, and annual meetings) related to ETI's membership in MISO. It includes three sub-groups each with its own particular focus. The Regulatory section supports the filing requirements of this Commission and federal regulators. The Strategic Initiatives section is responsible for congestion management analysis, including development of ETI's strategy for the nomination, acquisition, and management of Auction Revenue Rights ("ARRs") and Financial Transmission Rights ("FTRs"). The Project and Performance Management section provides both Front-Office and Back-Office support. This section is responsible for the formal Requests for Proposals process by which ETI solicits proposals for purchased power agreements or acquires new or existing power plants. In addition, this section is responsible for coordination of the development of SPO's key performance measures and oversight of the internal approval processes for major SPO projects. In addition, this section manages the compilation and submission of the MISO Commercial Model that outlines the generation and load asset registration in the MISO market.

Q56. ARE THESE SERVICES NECESSARY?

A. Yes. The decision to join an RTO—specifically, MISO—has far-reaching implications for how ETI plans and operates its generation system. The Regulatory and Strategic Initiatives group is responsible for evaluating issues and situations that will affect future operations. This group plays a key role in ensuring ETI's future operations are consistent with reliable and economic service. Participation in the MISO RTO requires that utilities have the ability to study and manage ARRs and FTRs in order to effectively hedge congestion costs. Also, it is common practice for utilities to maintain organizational groups to provide various aspects of regulatory support. Lastly, it is common practice for utilities to utilize a competitive solicitation process when procuring purchased power or acquiring new or existing power plants to facilitate the utility's procurement of the resource at a reasonable price. The efficient and cost effective performance of the necessary SPO activities enumerated earlier in my testimony requires attention to the performance measures provided by the SPO Project and Performance Management group.

Q57. DO ANY OTHER ENTITIES DUPLICATE THE ENERGY AND FUEL MANAGEMENT CLASS OF SERVICES?

A. No. As mentioned above, SPO and EPG are the only groups within Entergy that provide the Energy and Fuel Management Class of services. The responsibilities between SPO and EPG are clearly delineated between near-term (current to 18 months) and longer-term (1 year to 30 years) horizons. ETI does not duplicate these services.

C. <u>Overview of Costs</u>

Q58. WHAT ARE THE TOTAL ETI ADJUSTED TEST-YEAR CHARGES FOR THE ENERGY AND FUEL MANAGEMENT CLASS THAT YOU SPONSOR?

A. As shown in Table 2 below, the total affiliate charges for the Energy and Fuel Management Class that I sponsor are $4,297,959.

Table 2: Total ETI Affiliate Charges for the Energy and Fuel Management Class for January 1, 2021 – December 31, 2021[9]

		Total ETI Adjusted		
Class	**Total Billings**	**Amount**	**% Direct Billed**	**% Allocated**
Energy and Fuel Management Class	$27,050,575	$4,297,959	30%	70%

[9] **Total Billings** is ESL's total billings to all Entergy companies for the Test Year, plus all other affiliate charges that originated from any Entergy company. This is the amount from Column C of Exhibits ALD-A, ALD-B, and ALD-C. **Total ETI Adjusted Amount** is ETI's cost of service amount after pro forma adjustments and exclusions. **% Direct Billed** is the percentage of the Total ETI Adjusted Amount that was billed directly to ETI for the Test Year. **% Allocated** is the percentage of the Total ETI Adjusted Amount that was allocated to ETI for the Test Year.

Q59. PLEASE DESCRIBE THE ALPHA EXHIBITS SUPPORTING THE INFORMATION INCLUDED IN TABLE 2.

A. Attached to my direct testimony are exhibits showing the calculation of the Total ETI Adjusted amount for the Energy and Fuel Management Class. Exhibit ALD-A shows the information broken down by the departments comprising the class; Exhibit ALD-B shows the same information broken down by project code and by the billing method assigned to each project code; and Exhibit ALD-C shows the information by class, department, billing method, and project code. ETI witness Ryan Dumas discusses these affiliate exhibits in detail in his direct testimony.

Q60. ARE THERE ANY KNOWN AND MEASURABLE ADJUSTMENTS APPLICABLE TO THIS AFFILIATE CLASS?

A. Yes. Exhibit ALD-D shows the Pro Forma Adjustments and their sponsoring witnesses.

Q61. WHAT ARE THE MAJOR COST COMPONENTS OF THE CHARGES FOR THE ENERGY AND FUEL MANAGEMENT CLASS?

A. Table 3 below shows the major cost components.

Table 3: Major Components of ETI Affiliate Charges for the Energy and Fuel Management Class for January 1, 2021 – December 31, 2021

Cost Component	Total ETI Adjusted	% of Total*
Payroll and Employee Costs	$3,144,813	73%
Outside Services	$445,124	10%
Office & Employee Expenses	$79,572	2%
Service Company Recipient	$499,881	12%
Other	$128,570	3%
Total	**$4,297,959**	**100%**

* Percent may not add to 100 due to rounding.

Q62. WHAT IS THE PURPOSE OF THIS TABLE AND ITS COST CATEGORIES?

A. I directly sponsor the costs shown in this table because they comprise the Total ETI Adjusted amount for the Energy and Fuel Management Class for the Test Year. This breakout of costs provides an additional "view" of the components of this class. In addition, I identify other witnesses in this case who also support these costs because they address the corporate structures and practices that underlie these costs.

For example, the table demonstrates that 73% of the costs in the Energy and Fuel Management Class are labor-related costs ("Payroll and Employee Costs"). Jennifer Raeder discusses ESL's overall compensation-related structure and practices. "Outside Services" reflect the services provided by non-Entergy employees and firms, such as the independent monitors overseeing resource procurement processes. "Office and Employee Expenses" covers the costs of maintaining workspaces, office supplies, and employee travel related expenses. ETI witnesses Dawn Renton and Bobby Sperandeo provide secondary support for this category of costs. Workspaces and office supplies are primarily addressed by

Ms. Renton. Mr. Sperandeo supports the employee business travel and expense processes. Finally, the costs for "Service Company Recipient," which are services that ESL provides to itself, are in turn spread to all affiliates that receive ESL services. Mr. Dumas explains this process. Other miscellaneous costs and credits are included in the "Other" cost components. My testimony addresses the necessity and reasonableness of the amounts for these costs.

D. Reasonableness of Costs

Q63. PLEASE DESCRIBE ANY BENCHMARKING THAT SUPPORTS THE REASONABLENESS OF THESE COSTS.

A. As discussed by Mr. Sperandeo, the Company has provided benchmarking analysis of total Company non-production O&M costs, including administrative and general ("A&G") costs, which include costs associated with the Energy and Fuel Management Class. Mr. Dumas also addresses benchmarking that applies at the service company (ESL) level. These analyses further support the reasonableness of costs in the Energy and Fuel Management Class.

Q64. WHAT WERE THE ACTUAL COST TRENDS FOR THE ENERGY AND FUEL MANAGEMENT CLASS FOR THE LAST THREE YEARS AS COMPARED TO THE TEST YEAR?

A. Table 4 below presents the total affiliate O&M costs allocated to ETI for the class as a whole for the last three years and the Test Year. These charges have been adjusted to remove Corporate Aviation costs and Nuclear and Gas department costs.

Table 4: Energy and Fuel Management Cost Trends[10]

2018	2019	2020	Test Year
$3,354,768	$3,759,486	$4,260,811	$4,297,959

Q65. WHAT DO THESE COST TRENDS REFLECT?

A. The cost trends reflect slight increases from 2018 to 2019 and 2019 to 2020. However, the Energy and Fuel Management Class costs have remained relatively flat over the last two years—2020 and the Test Year. The increase from 2018 to 2019 was primarily attributable to facilitating the 2019 ETI Solar Request for Proposals ("RFP"), preparing and filing the 2019 ETI Fuel Reconciliation, and developing and implementing the Power Through project. The increase from 2019 to 2020 was primarily attributable to facilitating the 2020 combined-cycle gas turbine ("CCGT") RFP, planning related to the Hardin County Peaking Facility and Montgomery County Power Station transactions, and the creation of EPG (as discussed in previous questions). While the costs for specific RFPs or projects may change, the Company expects that these types of costs will continue for the foreseeable future.

[10] Excludes pro forma adjustments except as described above.

Q66. DOES EPG AND SPO HAVE IN PLACE A BUDGETING PROCESS TO CONTROL COSTS?

A. Yes. Both SPO and EPG undergo an extensive annual budget preparation and review process. Within this process, both groups finalize a proposed budget for the following year. As an input to the budget, both groups are allocated a certain percentage increase in wages for the organization's employees. This allows for the flexibility to reward individual performance in any given year, but also ensures that total labor costs continue to track labor market conditions. Further, non-labor costs are reviewed for necessity and cost effectiveness. Each group prepares annual budgets within the organization, and executive management, corporate management, and, ultimately, the board of directors of Entergy approve the budgets.

Q67. IS COMPLIANCE WITH THE BUDGET MONITORED?

A. Yes. Executive management continually monitors incurred expenses against budget and frequently subjects expenses to a pre-approval requirement before those expenses may be incurred. For example, management generally pre-approves employee training (e.g., seminars and travel) before an employee's registration for such training. Likewise, management discusses and approves most employee business travel before the employee incurs travel costs. Additionally, on a monthly basis, executive management reviews expenditures to ensure they are on track with the annual budget. To the extent that there are deviations within the budget year, there may be advancements or postponements of discretionary projects, with the approval of the executive management, to ensure that the expenditures are reasonable.

Q68. ARE EMPLOYEES HELD ACCOUNTABLE FOR DEVIATIONS FROM BUDGET?

A. Most employee expenses are pre-approved at the appropriate level of management. The Vice President, System Planning & Operations, and Vice President, Enterprise Planning, must pre-approve any significant unbudgeted cost. Adherence to budget is a priority for all EPG and SPO staff. The performance goals of the employees also include compliance with approved budgets.

Q69. HOW ARE COSTS WITHIN THE ENERGY AND FUEL MANAGEMENT CLASS BILLED TO ETI?

A. Please refer to Exhibits ALD-B and ALD-C. These exhibits show all the costs included in the Energy and Fuel Management Class by project code and reflect the ESL billing method assigned to each project code. Mr. Dumas explains the affiliate billing process.

Where appropriate, costs are billed directly to ETI and other affiliates. Costs that are billed directly to ETI reflect the fact that certain Energy and Fuel Management Class activities are for the specific benefit of ETI. Only when incurred costs benefit more than one of the EOCs, and thus direct billing is not reasonably practicable, are such costs billed through a reasonable allocation method.

Q70. ON WHAT BASIS ARE COSTS OF THESE ENERGY AND FUEL MANAGEMENT SERVICES BILLED?

A. Each ESL affiliate class of service, including the Energy and Fuel Management Class, uses one or more project codes. As Mr. Dumas explains, only one billing method is assigned to each project code. Several organizations may bill to a single project code. However, the billing method for each project code remains the same, regardless of which organization charges to that project code. A billing method is selected based on cost causation. This procedure ensures that the price charged to ETI for the services is no higher than the price charged to other affiliates for the same or similar services, and represents the actual cost of the services.

Q71. PLEASE FURTHER EXPLAIN WHAT YOU MEAN BY COSTS BEING "BILLED DIRECTLY" OR "ALLOCATED"?

A. Affiliate charges are incurred by ETI when ESL employees or employees of other affiliate companies provide services to ETI. Affiliate costs are charged to ETI through one of two methods. The costs are either billed directly to ETI or the costs are allocated to ETI based on the primary cost driver of the activity or project. Both the EPG and SPO functions have consolidated, across the Utility organization, those activities that are common to all EOCs for which scale and scope efficiencies can be realized. I will use the example of RSI Group in SPO to explain whether an ESL charge will be billed directly to ETI or allocated to ETI. If an RSI employee is working on a specific ETI project, such as a Texas rate case, then ETI is the only EOC that benefits from this regulatory activity and all of the resulting costs will be billed directly to ETI. Conversely, if the same employee was working on a specific project for all the EOCs, the resulting costs would be allocated based on the primary cost driver—in this case, the load responsibility ratio. These rules apply to all of the work performed by employees providing services within the Energy and Fuel Management Class.

Q72. HOW DID EPG AND SPO DETERMINE WHICH ENTITY SHOULD BE BILLED?

A. As a necessary part of accurately apportioning costs to the various Entergy affiliates, a billing method is assigned to each project code that first identifies the entities to which the cost is to be apportioned. When a project code is established, EPG and SPO select a billing method based on the factors driving EPG and SPO to incur the expense—i.e., "cost drivers." A staff member initially assigns a billing method, and management and the Affiliate Accounting and Allocations group (headed by Mr. Dumas) reviews the billing method for appropriateness. In addition, management and budget coordinators also review billing methods assigned to project codes periodically. Each project code has only one billing method assigned to it and the billing method is selected to ensure that every affiliate receiving service receives the appropriate allocation. Therefore, the costs of all services performed under a project code are direct billed or allocated among the EOCs using the same criteria, at cost without profit or markup. The use of a single billing method for each project code ensures that all EOCs causing costs to be incurred and benefiting from the service pay an appropriate share of the costs. It also ensures that the EOCs are, in total, charged no more and no less than 100% of the costs for services provided under the project code. Finally, the use of a single billing method, which is assigned based on cost causation principles, ensures that each EOC is paying the same price for the same service, and that the prices ESL charges to ETI are no higher than the prices ESL charges to the other EOCs for similar services.

Q73. PLEASE DESCRIBE THE PREDOMINANT BILLING METHODS EMPLOYED FOR THE ALLOCATED COSTS OF THE ENERGY AND FUEL MANAGEMENT CLASS OF SERVICES.

A. The predominant billing methods for the Energy and Fuel Management Class allocated costs are PKLOADAL and PKLDEXAM, which together make up 67% of the billings to ETI for this class of services. PKLOADAL costs, representing 55% of the billings to ETI for this class, are allocated among all of the EOCs on a peak load ratio. PKLDEXAM costs, representing 12% of ETI billings for this class, are allocated on a peak load ratio of the EOCs, excluding Entergy Arkansas, LLC and Entergy Mississippi, LLC. Direct costs are billed under DIRECTTX and make up 30% of the billings to ETI for this class. I describe these billing methods in Exhibit ALD-3.

Q74. HOW ARE THE REMAINING COSTS BILLED?

A. The remaining billing methods, which account for approximately 3% of the costs billed to ETI, are billed through a number of other project codes and billing methods. Given the relative dollar amounts, I have not gone into detail in this discussion in an effort to keep the discussion at a manageable length. However, the project codes and billing methods used to bill the remaining costs in this class are provided in my Exhibits ALD-B and ALD-C. A reader may reference these exhibits and then refer to the specific project code summary contained in exhibits to the testimony of Mr. Dumas for a discussion of the particular billing method used and the cost drivers for the activities captured in the particular project code.

Q75. HAVE YOU DETERMINED THAT THE COSTS REFLECTED IN THE REMAINING COSTS ASSOCIATED WITH THIS CLASS HAVE BEEN BILLED APPROPRIATELY?

A. Yes, I have reviewed each of the project codes and the associated billing methods used to bill the remaining costs of this class. The cost drivers reflected in the billing method used to bill the costs of each project code are consistent with and reflect the cost drivers of the services captured in each respective project code.

Q76. HAVE YOU REACHED A CONCLUSION ABOUT THE MANNER ESL BILLS ETI FOR THIS CLASS OF AFFILIATE SERVICES?

A. Yes. The unit cost to ETI as a result of the application of these billing methods is no higher than the unit cost to other affiliates for the same or similar service and represents the actual cost of the services.

VI. CONCLUSION

Q77. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF ANDREW L. DORNIER

THE STATE OF TEXAS)
)
COUNTY OF MONTGOMERY)

This day, 6/23/2022 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 Andrew L. Dornier. I am of legal age and a resident of the State of Texas. 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.

Andrew L. Dornier

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 23 day of June 2022.

Carol Tompkins
Notary Public, State of Texas

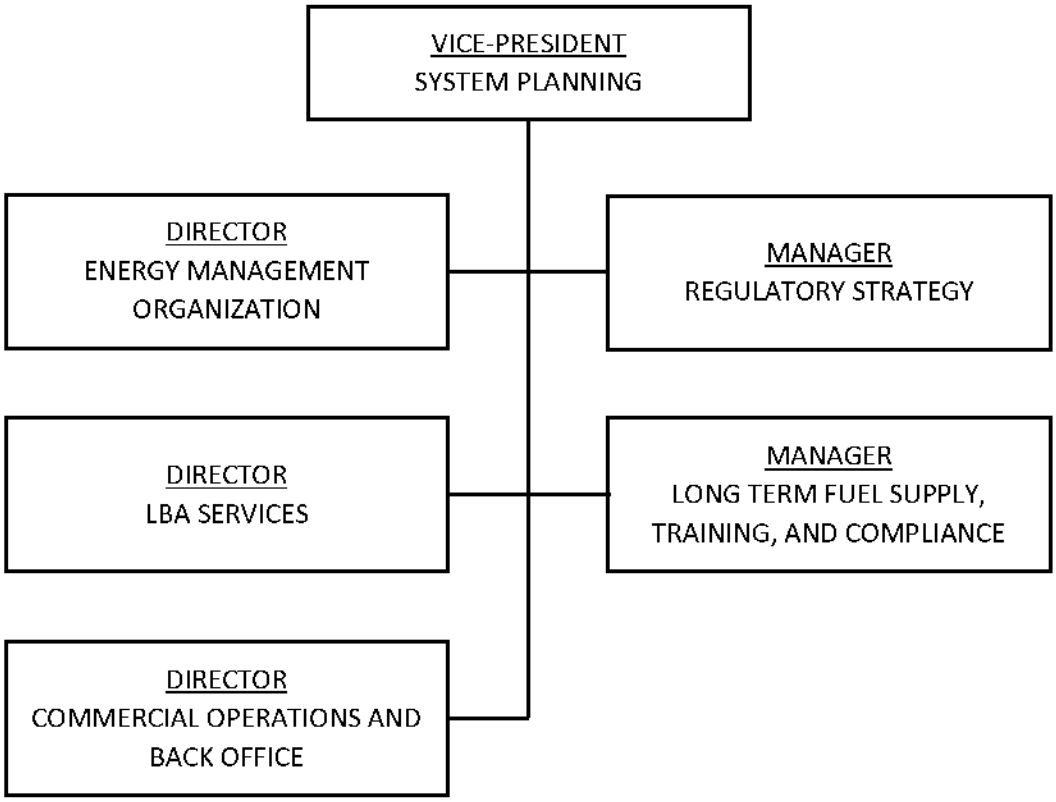
My Commission expires:
February 01, 2025

CAROL TOMPKINS
My Notary ID # 130989368
Expires February 1, 2025

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

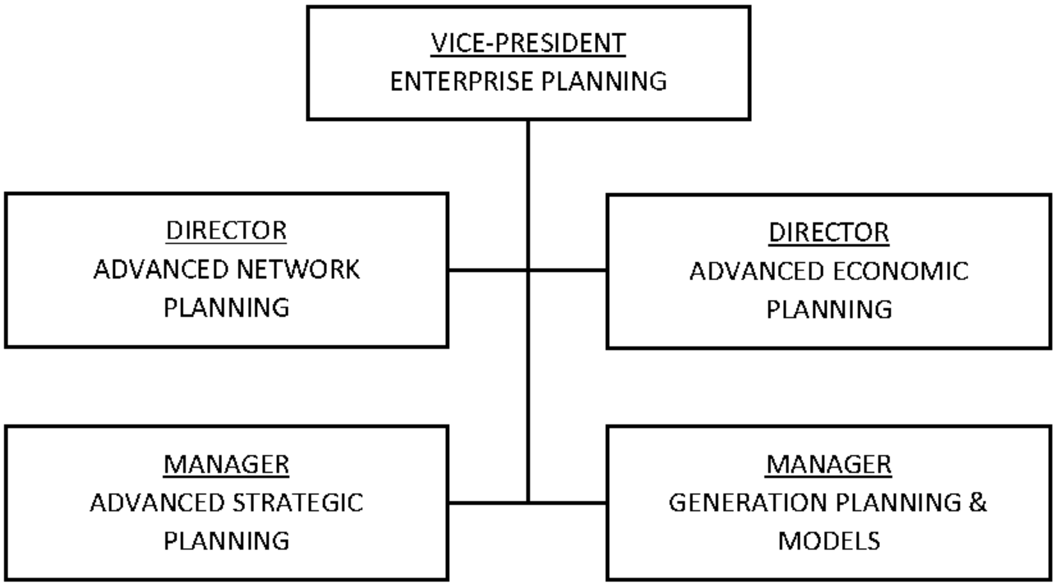
SYSTEM PLANNING AND OPERATIONS ORGANIZATION CHART

AS OF DECEMBER 31, 2021



ENTERPRISE PLANNING GROUP ORGANIZATION CHART

AS OF DECEMBER 31, 2021



Predominant Affiliate Billing Methods for Energy and Fuel Management

Billing Allocation Methodology	Basis for Selection of Billing Allocation Methodology
PKLOADAL	The majority of SPO and EPG services relate to the procurement, planning, commitment, settlement, and dispatch of the EOCs' generating resources and its wholesale power transactions. Accordingly, for the majority of SPO and EPG's services, it is appropriate to apportion the corresponding cost in a manner that relates to the need of the EOC for resources and the need of the EOCs as a whole. PKLOADAL, which is based upon a ratio of each EOC's peak load at the time of all the EOCs' peak load (calculated using a 12-month rolling average of the coincident peaks), accomplishes this. For instance, Project Code F3PCCSPUTI captures costs associated with planning and analytical activities performed for the EOCs. Peak load ratio drives the associated costs for each of the EOCs. Accordingly, PKLOADAL, which apportions cost based on peak load ratio, is an appropriate billing method for this type of project.
PKLDEXAM	ETI, ELL, and ENO (along with other non-affiliate entities) are operated as a single LBA within MISO. Accordingly, it is appropriate to apportion the corresponding cost in a manner that relates to the needs of each of the participating EOCs. PKLDEXAM, which is based upon a ratio of each of the participating EOC's peak load at the time of their coincident peak load (calculated using a 12-month rolling average of the coincident peaks), accomplishes this.
DIRECTTX	Billing Method DIRECTTX represents ESL costs that are directly applicable to ETI only. The billing method directly bills ETI 100% of the charges. Projects using this billing method represent costs appropriately charged solely to ETI.

See Native Excel file Dornier Direct_Exhibits A through D.

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

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DOCKET NO. 53719

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

REDACTED DIRECT TESTIMONY

OF

ANASTASIA R. MEYER

ON BEHALF OF

ENTERGY TEXAS, INC.

JULY 2022

ENTERGY TEXAS INC.
REDACTED DIRECT TESTIMONY OF ANASTASIA R. MEYER
2022 RATE CASE

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND PURPOSE

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

A. My name is Anastasia R. Meyer. My business address is 2107 Research Forest Drive, The Woodlands, TX 77380. I am employed by Entergy Texas, Inc. ("ETI" or the "Company") as Manager of Resource Planning.

Q2. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony to the Public Utility Commission of Texas ("Commission") on behalf of ETI. ETI is an integrated utility company that provides bundled generation, transmission, distribution, and customer services to approximately 486,000 retail customers in Southeast Texas. ETI is a subsidiary of Entergy Corporation, which also owns, among other subsidiaries, Entergy Louisiana, LLC ("ELL"), Entergy New Orleans, LLC, Entergy Arkansas, LLC, and Entergy Mississippi, LLC (collectively, along with ETI, the "Entergy Operating Companies").

Q3. PLEASE BRIEFLY DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

A. I am responsible for the management and administration of ETI's resource planning activities. My duties include coordinating the generation resource planning activities for ETI and implementing the Company's supply plan for meeting the load and energy requirements of ETI's retail customers.

Q4. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Applied Mathematical Sciences from Texas A&M University in 2008. In May 2008, I joined Entergy Services, LLC ("ESL")[1] as an Analyst in the System Planning and Operations ("SPO") organization, where my duties focused on resource planning and production cost modeling. Over the course of roughly six years, I held positions of increasing levels of responsibility over development and analysis of long-term generation plans and multiple requests for proposals that led to transactions on long-term resources. In October 2014, I was promoted to the position of Project Manager for Regulatory and Strategic Initiatives within SPO. In that position, I was responsible for, among other things, developing and enhancing processes for participation in the markets operated by the Midcontinent Independent System Operator, Inc. ("MISO") Regional Transmission Organization. I accepted my current position as Manager of Resource Planning with ETI in February 2016.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I sponsor the Company's Power Purchase Agreements' ("PPA") capacity costs for the 12 months ending December 31, 2021 (the "Test Year"). Second, I describe the Company's deactivation date assumptions supporting the useful lives in the depreciation study, including recent changes for the Roy S. Nelson Generating Station Unit 6 ("Nelson 6"), Big Cajun 2 Unit 3, and Sabine 1.

[1] ESL, formerly Entergy Services, Inc., is the service company for the five Entergy Operating Companies.

Q6. WHAT EXHIBITS DO YOU SPONSOR IN YOUR TESTIMONY?

A. I sponsor the exhibits listed after the Table of Contents at the beginning of my testimony.

Q7. DO YOU SPONSOR ANY SCHEDULES IN ETI'S RATE FILING PACKAGE?

A. Yes. I co-sponsor schedules H-12.4a-g and I-4.

II. PPA CAPACITY COSTS

Q8. WHERE ARE THE TEST YEAR PPA CAPACITY COSTS IDENTIFIED IN THE COMPANY'S RATE FILING PACKAGE?

A. The total Test Year purchased power costs for the Company are provided in Schedule H-12.4a-g. The capacity costs are identified as "other" in that schedule. These costs in the amount of approximately $191.2 million consist of third-party PPA capacity payments, affiliated PPA capacity payments, MISO Planning Resource Auction ("PRA") purchases, and renewable energy credits ("RECs").

Q9. IN WHAT SCHEDULE ARE THE PPAS ASSOCIATED WITH THESE COSTS IDENTIFIED?

A. All of the Company's PPAs that were in effect during the Test Year have been provided with Schedule I-4.

A. Third-Party PPAs

Q10. HAS THE COMMISSION PREVIOUSLY REVIEWED THE PPAS REFLECTED IN SCHEDULE I-4 THAT HAVE ASSOCIATED CAPACITY COSTS IDENTIFIED IN SCHEDULE H-12.4A-G?

A. All but one of the PPAs provided with Schedule I-4 that have associated capacity costs during the Test Year have been submitted to the Commission for review in prior base rate proceedings. The single PPA containing capacity payments that has not been previously reviewed by the Commission is an extension of a PPA with East Texas Electric Cooperative, Inc. ("ETEC") for the purchase of capacity and energy from ETEC's San Jacinto Peaking Power generating facility. The original ETEC San Jacinto PPA was executed in 2008 with a start date of June 1, 2009, for 150 megawatts ("MW") from Units 1 and 2 at the facility. A subsequent extension was executed in 2014 for a five-year term, for 75 MW from Unit 2. Both the original ETEC San Jacinto PPA and the 2014 extension were submitted to the Commission for review in prior base rate proceedings. In Docket No. 48371, the Commission deemed the 2014 extension to be reasonable and necessary and entered into prudently.[2] In May 2019, the ETEC San Jacinto PPA was again extended, this time for a term of the earlier of three years or closing of the acquisition of the Hardin County Peaking Facility ("Hardin Facility") and transfer to ETEC of a partial interest in the Montgomery County Power Station ("MCPS") (together, "the Transactions"). This extension (the "2019 Extension")

[2] *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates*, Docket No. 48371, Order at Finding of Fact No. 60 (Dec. 20, 2018).

was for the same 75 MW and included the same capacity price agreed to in the 2014 extension. The 2019 Extension terminated at the closing of the Transactions, which occurred on June 4, 2021.

Q11. PLEASE DISCUSS GENERALLY THE DECISION TO EXTEND THE ETEC SAN JACINTO PPA IN 2019.

A. The 2019 Extension was the result of a desire by both ETI and ETEC to resolve certain issues between them while also supporting the addition of new, efficient generation for the benefit of their respective customers in East Texas. It was an essential part of ETI's and ETEC's agreement, and facilitated the Transactions by which ETI would acquire Hardin from ETEC for the net book value of the asset and ETI would transfer a partial interest in MCPS to ETEC. ETI and ETEC entered into the settlement agreement (the "Settlement Agreement") on June 14, 2017.

At the May 23, 2019 ETI Operating Committee meeting, the ETI Operating Committee members concurred and the ETI President and Chief Executive Officer ("CEO") approved the 2019 Extension. The minutes from this ETI Operating Committee are contained in my highly sensitive Exhibit ARM-1.

In Docket No. 50790, the Commission found that ETEC's transfer of the Hardin Facility to ETI was in the public interest and that removing a partial interest in MCPS from ETI's certificate of convenience and necessity was in the "public convenience and necessity" because the transactions were mutually dependent.[3] These Transactions were also mutually dependent on the 2019 Extension.

Q12. DOES THE ETEC SAN JACINTO PPA HELP SATISFY IDENTIFIED RELIABILITY NEEDS OF ETI?

A. Yes. ETI must maintain a portfolio of resources to provide reliable service to customers, and the ETEC San Jacinto PPA was a part of that portfolio. In addition, ETI relied on that purchased capacity to satisfy its annual resource adequacy requirements in MISO.

Q13. HOW DOES THE ETEC SAN JACINTO PPA TAKE INTO CONSIDERATION ENVIRONMENTAL INTEGRITY?

A. The PPA includes an operating restriction that places a limit on emissions.

Q14. DOES THE ETEC SAN JACINTO PPA IMPROVE SERVICE OR LOWER COSTS TO CUSTOMERS?

A. Yes. The PPA helps meet the Company's planning objectives, including reliably meeting customer power needs at a reasonable cost, while also considering planning and operational risks. As noted above, ETI relies on the capacity to satisfy its resource adequacy requirements in MISO, and the energy margins from

[3] *Joint Report and Application of Entergy Texas, Inc. and East Texas Electric Cooperative, Inc. for Regulatory Approvals Related to Transfers of the Hardin County Peaking Facility and a Partial Interest in Montgomery County Power Station*, Docket No. 50790, Order at Finding of Fact Nos. 64, 77 (Apr. 7, 2021).

the resource serve to reduce customers' costs.

B. Affiliate PPAs

Q15. DID ETI INCUR ANY CAPACITY COSTS DURING THE TEST YEAR AS A RESULT OF A PPA WITH AN AFFILIATE?

A. Yes. ETI is party to life-of-unit PPAs for two generation facilities owned by ELL: the River Bend nuclear plant and the natural gas-fired Perryville plant. ETI makes monthly payments to ELL for its share of capacity (29.75% of River Bend and 31.88% of Perryville) and associated energy pursuant to a cost-based formula rate.

Since their inception in January 2008, ETI's payments associated with the River Bend and Perryville PPAs were made pursuant to Service Schedule MSS-4 of the Entergy System Agreement. With the termination of the Entergy System Agreement on August 31, 2016, a Federal Energy Regulatory Commission ("FERC")-approved replacement rate schedule was implemented to replicate the cost-based formula rate found in Service Schedule MSS-4.[4] That replacement tariff is currently utilized for ETI's payments associated with the River Bend and Perryville PPAs. The energy costs associated with these PPAs are treated as eligible fuel expense recovered through ETI's Fixed Fuel Factor rate. The capacity costs are treated as non-fuel costs.

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[4] FERC approved the replacement tariff in Entergy Services, Inc. Docket Nos. ER13-1508, et al. Under this tariff, the cost structure for the underlying resource is unique to the respective plant, but the formula rate charged is the same as is used for other transactions governing the purchase and sale of capacity and energy between Entergy Operating Companies.

III. DEACTIVATION DATE ASSUMPTIONS

Q16. WHAT ARE THE DEACTIVATION DATE ASSUMPTIONS SUPPORTING THE USEFUL LIVES USED IN THE DEPRECIATION STUDY?

A. See highly sensitive Exhibit ARM-2 for the deactivation date assumptions for ETI's owned generating units, which support the useful lives used in the depreciation study for this base rate case proceeding. These deactivation date assumptions are used in ETI's long-term resource planning process and were approved by the ETI Operating Committee as a part of the Business Plan 2022 ("BP22") planning process. They represent a reasonable expectation of the useful lives of these resources. Deactivation assumptions are necessary reference points used to assess current and future capacity needs, and to appropriately budget and prioritize maintenance dollars among ETI's fleet of resources.

Q17. WHAT ARE THE DEACTIVATION DATE ASSUMPTIONS FOR THE NEW GENERATING UNITS INCLUDED IN THIS BASE RATE CASE?

A. There are several resources included in this base rate case filing that were not included in the depreciation study included in Docket No. 48371. These include the Hardin Facility, MCPS, and two utility-owned backup generators at H-E-B stores across ETI's service territory. The useful life used in the depreciation study for the Hardin Facility is 2041, which reflects the date agreed to in the approved Settlement Agreement in Docket No. 50790.[5] In 2041, the Hardin Facility will be

[5] Docket No. 50790, Order at Finding of Fact Nos. 50-51 and Ordering Paragraph No. 4.

40 years old. The deactivation date for MCPS is based on the [redacted]-year useful life for new combined cycle gas turbines. Finally, the Company assigned a [redacted]-year useful life for the backup generators based on the manufactures' stated design life for these resources.

Q18. PLEASE DESCRIBE HOW UNIT DEACTIVATION ASSUMPTIONS ARE DEVELOPED FOR USE IN RESOURCE PLANNING.

A. As part of the annual supply planning process, ETI along with ESL's Enterprise Planning Group ("EPG") and Power Generation organization monitor a host of factors, including market and unit conditions, to determine reasonable deactivation dates for ETI's generation fleet. Power Generation monitors, ascertains the condition of, and budgets for the Entergy Operating Companies' existing generation fleet. Power Generation has a number of processes in place to assess unit conditions, on both an immediate and long-term basis. In addition, Power Generation occasionally engages third-party consultants to assist with unit condition assessments. Power Generation evaluates continued investments as resources near the end of their useful lives, as there is a higher risk of major component or unit failure and lower certainty that the benefits obtained with sustaining unit availability will outweigh the costs of those investments.

Based on these ongoing assessments, deactivation assumptions for ETI's generation fleet are developed based on a number of factors, including unit age, criticality, reliability, expected useful life, estimates of the cost to maintain each unit, cost of compliance with environmental regulations, and evaluation of current and projected unit conditions. Additionally, with co-owned generating units, co-owner considerations may also influence the deactivation assumptions, particularly when that co-owner is the operator of the unit.

Q19. ARE THERE ADDITIONAL PROCESSES THAT SUPPORT MAKING CHANGES TO DEACTIVATION DATE ASSUMPTIONS?

A. Yes. As ETI works through the formal process to make a deactivation date decision, those assessments may help inform changes to deactivation date assumptions based on unit and market conditions. ETI's process to make a deactivation decision starts with ETI providing direction to EPG to prepare a detailed deactivation analysis to support a formal decision to change the status of a unit. Reasons that may warrant such an analysis include:

- an approaching deactivation date assumption for a particular unit;
- a change in estimated costs and spending commitments required to keep a particular unit compliant with reliability and environmental standards;
- a component failure, weather event, or other occurrence at a unit that would require a significant incremental investment to enable the unit to continue operating;
- an opportunity to obtain more economic capacity arises (e.g., through a Request for Proposals, an unsolicited offer, or developments in the capacity market); or
- a change in the criticality of a unit to the reliable operation of the transmission system.

As necessary, Power Generation will develop an estimated projected spend for unit-specific projects necessary to safely, reliably, and economically sustain or extend the useful life of a given unit. The projected spend reflects the operating history and characteristics of the unit, maintenance intervals, and condition of unit components, all of which are based on first-hand observation of unit operations by operators and other subject matter experts. EPG may also request that the Transmission Planning organization analyze what, if any, transmission upgrades or other mitigation measures are expected to be necessary if the unit is deactivated. EPG will, as appropriate, use the information provided by Power Generation and Transmission Planning to conduct a cost/benefit analysis of keeping the unit operational compared to deactivation and reliance on alternative resources. The cost/benefit analysis includes, but is not limited to, those items described above, along with the impact to other forecasted fixed and variable supply costs, and risks to reliability and economics. When the analysis suggests that the resource no longer meets planning objectives and is in favor of deactivation, the cost/benefit analysis will be presented for a formal decision on whether to deactivate. ETI's Operating Committee will review the analysis prepared by EPG and make a recommendation to the ETI President and CEO, who will make the ultimate decision whether to deactivate a unit. As discussed above, this type of analysis can also be used to determine if a change to a deactivation date assumption is warranted given various market and unit conditions.

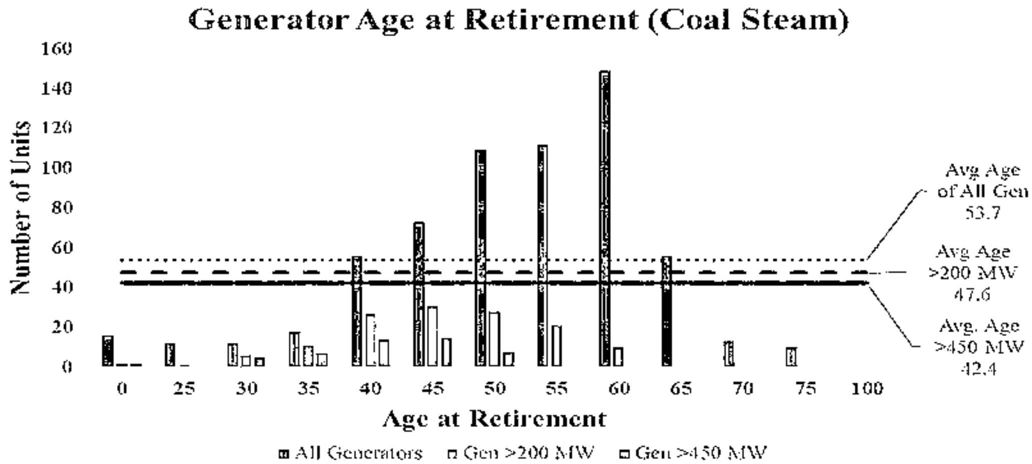
Q20. HAS ETI RECENTLY MADE A DECISION TO CHANGE THE DEACTIVATION DATES FOR CERTAIN GENERATING UNITS?

A. Yes. As discussed in more detail below, the deactivation date assumption for Nelson 6 has changed from [redacted], and Big Cajun 2 Unit 3 has changed from [redacted]. ETI also recently made a deactivation decision for Sabine 1 to extend the deactivation date from 2022 to May 31, 2023, to align with the transfer of the existing transmission rights at the site to the new proposed Orange County Advanced Power Station ("OCAPS"), as discussed in more detail below.

Q21. HOW WILL THE AGE OF NELSON 6 AND BIG CAJUN 2 UNIT 3 AT THEIR PROPOSED DEACTIVATION DATES COMPARE TO THE INDUSTRY AVERAGE?

A. As shown in Exhibit ARM-2, these units will be over 40 years old by their assumed deactivation dates. Figure 1 below shows an average retirement age of 42.4 years for coal-fired generating capacity greater than 400 MW. Nelson 6's age at deactivation of [redacted] years exceeds the average, while Big Cajun 2 Unit 3's age of [redacted].

Figure 1: Generator Age at Retirement[6]



Thus, the changes to the deactivation dates for Nelson 6 and Big Cajun 2 Unit 3 represent a reasonable expected useful life for these resources.

A. Nelson 6

Q22. PLEASE DESCRIBE NELSON 6.

A. Nelson 6 is Unit 6 of the Roy S. Nelson Generating Plant. Nelson 6 is a 521.4 MW[7] coal-fired power station in Westlake, Louisiana located within the West of the Atchafalaya Basin ("WOTAB") load pocket. Nelson 6 is jointly owned by ETI (29.8%), ELL (40.25%), EAM Nelson Holding, LLC. (10.9%), Sam Rayburn G&T, Inc. (10%) and ETEC (9.1%). Nelson 6 went into service in 1982 and is currently 40 years old. It is my understanding that since Cleco Power and Southwestern Electric Power Company ("SWEPCO") shut down the Dolet Hills

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[6] This figure is from my workpapers.

[7] Unit capacity based on Generation Verification Test Capacity for MISO Planning Year 2022-2023 (June 1, 2022 through May 31, 2023).

Power Station east of Mansfield at the end of 2021 at 36 years of operation, Nelson 6 and Big Cajun 2 are the only two coal power plants left in Louisiana.[8]

Q23. PLEASE PROVIDE THE ENVIRONMENTAL COMPLIANCE COSTS ASSOCIATED WITH CONTINUING TO OPERATE NELSON 6.

A. Based on an assessment of the EPA's Regional Haze Program, the Company expects that it would be required to invest in sulfur dioxide ("SO_2") emission reduction technology ranging from approximately $108.8 million to $473.8 million (in 2019 dollars) in capital costs alone if the facility operated into the 2030s.[9] The Company estimates capital costs ranging from approximately $12.2 million to $172.3 million (in 2019 dollars) for nitrogen oxides ("NO_X") emission reduction options.[10] Significant investment in the aging facility, such as repowering it to gas, is not expected to be prudent and would likely increase the costs to customers. Due to the age of the unit, the year over year capital and operations & maintenance ("O&M") expenses to maintain Nelson 6, and the heightened scrutiny of coal-generating units by regulatory agencies (and the increased costs associated with additional regulations and compliance), the Company conducted an economic analysis to determine whether it would be more

[8] Kristen Mosbrucker, *One of the Last Coal-Fired Power Plants in Louisiana to Close, Laying off Dozens*, The Advocate, Oct. 28, 2021, available at: https://www.theadvocate.com/baton_rouge/news/business/article_190562bc-3824-11ec-bcfa-239aa1f91d40.html.

[9] *See* Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, Entergy Services LLC on behalf of Entergy Louisiana LLC, Roy S. Nelson Electric Generating Plant at Table 2-3 (July 30, 2020) available at https://edms.deq.louisiana.gov/app/doc/view?doc=12280842 (providing the estimated costs for SO_2 emissions reduction options).

[10] *Id.* at Table 3-3.

cost-effective to deactivate the unit earlier than 2030.

Q24. PLEASE DESCRIBE THE ECONOMIC ANALYSIS AND THE RESULT.

A. EPG examined whether it would be more economic to build a new 372 MW generic combustion turbine ("CT") with hydrogen capabilities than to continue to infuse capital into an aging coal-fired generating unit subject to increased environmental compliance costs. Because ETI is currently short generation capacity, a CT replacement was conservatively used to assess whether it was economic to deactivate Nelson 6 earlier than 2030. EPG determined it would be more economic to retire Nelson 6 as early as [redacted]. However, because ETI continues to be short generation capacity even with its plan to add OCAPS by 2026,[11] ETI plans to continue operating Nelson 6 through [redacted] to provide it with an adequate opportunity to procure replacement capacity as it works to modernize its generation fleet. ETI changed Nelson 6's deactivation date assumption from [redacted]. The presentations summarizing the results of the analysis are provided in highly sensitive Exhibits ARM-3 and ARM-4.

B. Big Cajun 2 Unit 3

Q25. PLEASE DESCRIBE BIG CAJUN 2 UNIT 3.

A. Big Cajun 2 was Louisiana's first coal-fired station and is located near the Mississippi River in New Roads, Louisiana. Unit 3 is a coal-fired unit that

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[11] *Application of Entergy Texas, Inc. to Amend its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station*, Docket No. 52487 (pending).

generates 554.5 MW[12] and is jointly owned by Louisiana Generation, LLC (58%), ELL (24.15%), and ETI (17.85%). It is operated by Cleco Cajun LLC. Unit 3 went into service in 1983 and is currently 39 years old. As a minority owner, ETI has limited control over the ongoing operations and retirement of Unit 3.

Q26. HAS CLECO PUBLICLY COMMITTED TO DEACTIVATING BIG CAJUN 2 UNIT 3?

A. Yes. In response to a March 18, 2020 Regional Haze Four-Factor Analysis Information Collection from the Louisiana Department of Environmental Quality, Trinity Consultants prepared and submitted a report on behalf of Cleco Power, Cleco Cajun LLC, and Louisiana Generating, LLC (together, "Cleco").[13] In that report, dated July 24, 2020, Cleco committed to "retir[ing] Units 2 and 3 no later than December 31, 2032."[14]

Q27. COULD CLECO DEACTIVATE BIG CAJUN 2 UNIT 3 SOONER THAN 2032?

A. Yes. The report provides the estimated costs of implementing SO_2 and NO_x emission reduction technologies and the timing of such implementation. It estimates $94.8 million in annual costs for Big Cajun 2 Unit 3 for SO_2 and NO_x

[12] Unit capacity based on Generation Verification Test Capacity for MISO Planning Year 2022-2023 (June 1, 2022 through May 31, 2023).

[13] Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, July 24, 2020, available at https://edms.deq.louisiana.gov/app/doc/view?doc=12280837.

[14] *Id.* at 1-1.

emission reductions beginning in 2028, when there is only four years left of the unit's remaining useful life.[15] The tables below are reproduced from the report:

Table 2-4. Estimated Costs of SO_2 Emissions Reduction Options

Unit	SO_2 Reduction Option	Total Capital Cost ($MM)	Annualized Capital Costs ($MM/year)	Annual O&M Costs ($MM/year)	Total Annual Costs ($MM/year)	Cost Effectiveness ($/ton)
3	WFGD	335.5	99.1	26.2	125.3	16,209
	DFGD	263.7	77.9	25.3	103.2	13,809
	DSI	25.5	7.5	14.2	21.7	5,250

Table 3-4. Estimated Costs of NO_X Emissions Reduction Options

Unit	NO_X Reduction Option	Total Capital Cost ($MM)	Annualized Capital Costs ($MM/year)	Annual O&M Costs ($MM/year)	Total Annual Costs ($MM/year)	Cost Effectiveness ($/ton)
1 (nat. gas only)	SCR	48.2	4.6	3.7	8.2	22,482
2	SCR	53.4	15.8	3.8	19.6	47,568
3	SCR	204.6	60.4	12.7	73.1	68,986

Cleco could decide to deactivate Big Cajun 2 Unit 3 before 2028 to avoid these substantial additional costs. For instance, Cleco and SWEPCO agreed to shut down their Dolet Hills plant at the end of 2021 in an effort to reduce costs,[16] five years earlier than the 2026 date SWEPCO committed to as part of a settlement in a contested proceeding before the Arkansas Public Service Commission.[17]

As a regulated utility, ETI must engage in resource planning to ensure it

[15] *See id.* at 2-3, 3-3 (Tables 2-4 and 3-4).

[16] *See id.* at 1-2 ("Cleco will be ceasing operations at Dolet Hills by the end of 2021."); Elena Vasilyeva *Cleco, SWEPCO to close Louisiana Coal Plant Early*, Argus Media, Nov. 1, 2021, available at https://www.argusmedia.com/en/news/2269477-cleco-swepco-to-close-louisiana-coal-plant-early.

[17] *In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs*, Arkansas Public Service Commission Docket No. 19-008-U, Unanimous Settlement Agreement at 11 (Oct. 15, 2019); *see* Docket No. 19-008-U, Notice Pursuant to Unanimous Modified Settlement Agreement (Nov. 25, 2020) ("This Notice is intended to notify the parties herein that the decision has been made by SWEPCO and Cleco management to retire the Dolet Hills Power Station after completion of the seasonal operation period of 2021, but no later than December 31, 2021, rather than December 31, 2026.").

has sufficient capacity to meet its load-serving obligations. Given the environmental compliance factors discussed above, it is reasonable and prudent for the Company to plan for the possibility of an early deactivation and to assign a deactivation date to Big Cajun 2 Unit 3 that is earlier than 2032.

Q28. DID THE COMPANY ALSO CONDUCT AN ECONOMIC ANALYSIS WITH RESPECT TO BIG CAJUN 2 UNIT 3?

A. Yes. EPG evaluated the ongoing capital and O&M expenses associated with Big Cajun 2 Unit 3 assuming a [redacted] deactivation against replacement capacity purchases based on a levelized CT and from the MISO PRA. [redacted] Because the Cleco 2021 budget was low compared to the Company's historical experience as a co-owner of the plant, EPG also ran sensitivities based on the Cleco 2020 budget. EPG also conducted the analysis based on the Nelson 6-contracted price of coal to view sensitivities associated with Energy Ventures Analysis, Inc. ("EVA") coal price fluctuations.

EPG determined that the [redacted] deactivation scenario was more economically favorable for ETI, as the replacement capacity purchases in that timeframe would be less costly than the ongoing capital and O&M spend for Big

Cajun 2 Unit 3.[18] In [redacted], it would cost [redacted] (NPV 2021$) more to operate the unit than to obtain replacement capacity from the PRA when considering all planned resources.[19] Based on Cleco's public commitment to retire the unit by 2032, the cost projections for emission reduction technologies beginning in 2028, [redacted], and the Company's internal economic evaluation, ETI determined it was reasonable and prudent to change its deactivation date assumption for Big Cajun 2 Unit 3 from [redacted].

Q29. ARE THERE ANY OTHER CONSIDERATIONS THAT SUPPORT THE CHANGES TO THE UNIT DEACTIVATION DATE ASSUMPTIONS FOR NELSON 6 AND BIG CAJUN 2 UNIT 3?

A. Yes. It is my understanding from Entergy's environmental team that there is a new proposed U.S. Environmental Protection Agency ("EPA") rule[20] that was published after the economic analyses that resulted in the change to the deactivation date assumptions for Nelson 6 and Big Cajun 2 Unit 3 were conducted, which provides additional support for these assumptions. The proposed rule establishes more stringent NOx emissions allowance budgets for fossil fuel-fired power plants in 25 states, including Louisiana and Texas, that

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[18] *See* highly sensitive Exhibit ARM-4 at 18.

[19] *Id.*

[20] Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20036 (proposed Apr. 6, 2022) (to be codified at 40 C.F.R. pts. 52, 75, 78 and 97).

would be expected to affect Nelson 6 and Big Cajun 2 Unit 3 operations.[21] In order to operate these units beyond 2026 and comply with these new proposed rule requirements, the co-owners would have to install selective catalytic reduction ("SCR") systems totaling approximately $230 million for Nelson 6 and $214 million for Big Cajun 2 Unit 3.[22] Based on ETI's ownership percentages, this would result in an incremental $107 million in costs for ETI customers. The exact impact of this new rule on these plants is still under evaluation by Entergy, but this is just one example of the environmental risks associated with continuing to operate the plants.

C. <u>Sabine 1</u>

Q30. PLEASE DESCRIBE SABINE 1.

A. Sabine 1 is a 201.8 MW[23] steam gas generator in Bridge City, Texas located within the WOTAB load pocket. Sabine 1 was placed into service in 1962 and is currently 60 years old. It has operated well beyond the average life of similarly sized resources and will be 61 years of age when it is expected to be deactivated

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[21] United States Environmental Protection Agency, *Proposed State Budgets under the CSAPR for the 2015 Ozone NAAQS*, https://www.epa.gov/csapr/proposed-state-budgets-under-csapr-2015-ozone-naaqs.

[22] These SCR costs are based on the EPA's estimates as part of the proposed rule. See the EPA-HQ-OAR-2021-0668-0113_content.xlsx file located on EPA's website at https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0113 at tab "SCR_horz" column BY. Nelson 6 is listed in this EPA file as FACILITY_NAME (column B) "R S Nelson" and UNITID (column H) "6." Big Cajun 2 Unit 3 is FACILITY_NAME (column B) "Big Cajun 2" and UNITID (column H) "2B3."

[23] Unit capacity based on Generation Verification Test Capacity for MISO Planning Year 2022-2023 (June 1, 2022 through May 31, 2023).

and placed into suspension in 2023, which is dependent on the timing of the in-service date for OCAPS.

Q31. DID THE COMPANY CHANGE THE DEACTIVATION YEAR FOR SABINE 1 FROM THE ONE PRESENTED IN ITS PRIOR RATE CASE?

A. Yes. ETI is planning to use the existing transmission infrastructure and MISO network transmission service at the Sabine plant for its new proposed OCAPS unit in order to reduce the overall costs to customers. However, to transfer the network transmission service currently assigned to Sabine 1, 3, and 4 to OCAPS, ETI must follow the MISO rules that place a 3-year limit on the amount of time the deactivating units (Sabine 1, 3 and 4) are out of service prior to being replaced. Thus, ETI extended the deactivation date for Sabine 1 from 2022 to 2023 to meet the 3-year requirement. From 2023 until it is replaced by OCAPS in 2026, Sabine 1 is expected to be in a state of suspension, and ETI will still be required to offer the resource into the MISO PRA each year of suspension at its avoided cost. See highly sensitive Exhibit ARM-5 for the ETI Operating Committee decision to deactivate Sabine 1 on May 31, 2023, contingent on OCAPS being placed into service.

Q32. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT OF ANASTASIA R. MEYER

THE STATE OF TEXAS)
)
COUNTY OF MONTGOMERY)

This day, June 17, 2022, 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 Anastasia R. Meyer. I am of legal age and a resident of the State of Texas. 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.

Anastasia R. Meyer

SUBSCRIBED AND SWORN TO BEFORE ME, notary public, on this the 17th day of June 2022.

NOTARY PUBLIC STATE OF TEXAS
NANCY MAXWELL
Notary ID #129702124
My Commission Expires
January 12, 2026

Nancy Maxwell
Notary Public, State of Texas

My Commission expires:
1-12-2026

HIGHLY SENSITIVE PROTECTED MATERIALS
FINAL

ENTERGY TEXAS, INC.
OPERATING COMMITTEE
MINUTES OF THE MAY 23, 2019 MEETING

Members:
[redacted]

Advisory Members:
[redacted]

Other participants:
[redacted]

A safety briefing was provided by [redacted] at the outset of the meeting.

Nine items were discussed:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]
6. [redacted]
7. ETEC San Jacinto Tolling Agreement Extension (Decision)
8. [redacted]
9. [redacted]

1. [redacted]

[redacted]

[redacted]

2. [redacted]

[redacted]

HIGHLY SENSITIVE PROTECTED MATERIALS
FINAL

[redacted]

3. [redacted]

4. [redacted]

5. [redacted]

6. [redacted]

7. ETEC San Jacinto Tolling Agreement Extension (Decision)

HIGHLY SENSITIVE PROTECTED MATERIALS
FINAL

[redacted] presented an overview of the negotiated terms of the San Jacinto Tolling Agreement extension. After responding to questions from the Committee, [redacted] requested ETI Operating Committee concurrence and ETI CEO approval to execute the contract extension with ETEC for 75 MW from San Jacinto Unit 2.
(Attachment G)

The ETI Operating Committee concurred with the recommendation and ETI's President & CEO Sallie Rainer approved.

[redacted]

8. [redacted]

9. [redacted]

ATTACHMENT G

Utility Reimagined

ETEC San Jacinto 2 Toll Extension

ETI Operating Committee • May 23, 2019
Decision

Entergy | WE POWER LIFE™

Purpose

- Request ETI Operating Committee concurrence and ETI CEO approval to execute the San Jacinto 2 Toll Extension as outlined in this presentation

San Jacinto 2 Toll Extension

- Settlement Agreement
  - The Settlement Agreement executed in 2017 included an extension of the San Jacinto 2 Tolling agreement
- Commercial Terms
  - Delivery Term
    - The earlier of (a) the first day after the Hardin Plant Closing, (b) the termination of the Hardin Plant Purchase, (c) the termination of the San Jac 2 Extension, (d) May 31, 2022.
  - Pricing Terms
    - Capacity - [redacted]
    - Variable - [redacted]
    - Start-up - [redacted]

Approval Request

- **ETI Operating Committee Concurrence:**
  - Request ETI Operating Committee concurrence to execute the San Jacinto 2 Toll Extension as outlined in this presentation

- **ETI CEO Approval:**
  - Request ETI CEO approval to execute the San Jacinto 2 Toll Extension as outlined in this presentation

Overview of ETI's Current Generation Portfolio

Generating Assets Owned or Controlled by ETI in 2021									
Plant	**Unit**	**Megawatt Capability***	**Technology Type**	**Fuel**	**COD Month/Year**	**Deactivation Date Assumption****	**Region**	**Age of Unit in 2022*****	**Age of Unit at assumed deactivation *****
Big Cajun 2	3	103	Coal	Coal	1/1983	[redacted]	Central	39	[redacted]
Hardin	1 & 2	146	CT	Gas	1/2010	[redacted]	WOTAB	12	[redacted]
HEB Backup Generator (#594)		1	Other Gas	Gas	10/2019	[redacted]	Western	3	[redacted]
HEB Backup Generator (#48)		1	Other Gas	Gas	9/2021	[redacted]	WOTAB	1	[redacted]
Lewis Creek	1	249	Other Gas	Gas	12/1970	[redacted]	Western	52	[redacted]
Lewis Creek	2	254	Other Gas	Gas	5/1971	[redacted]	Western	51	[redacted]
Montgomery County Power Station		853	CCCT	Gas	1/2021	[redacted]	Western	1	[redacted]
Perryville	1	168	CCCT	Gas	7/2002	[redacted]	Central	20	[redacted]
Perryville	2	49	CT	Gas	7/2001	[redacted]	Central	21	[redacted]
River Bend	1	288	Nuclear	Nuclear	1/1986	[redacted]	Central	36	[redacted]
Roy Nelson	6	156	Coal	Coal	5/1982	[redacted]	WOTAB	40	[redacted]
Sabine	1	212	Other Gas	Gas	3/1962	[redacted]	WOTAB	60	[redacted]
Sabine	3	359	Other Gas	Gas	12/1966	[redacted]	WOTAB	56	[redacted]
Sabine	4	513	Other Gas	Gas	8/1974	[redacted]	WOTAB	48	[redacted]
Sabine	5	447	Other Gas	Gas	12/1979	[redacted]	WOTAB	43	[redacted]
Total Owned + Affiliated PPAs		**3,799**							
Unaffiliated PPAs		**439**							
Total Capacity		**4,237**							

*Megawatt capability based on Installed Capacity ("ICAP").

Exhibit ARM-2
2022 Rate Case
Page 1 of 1
(Public Version)

This workpaper contains information that is Highly Sensitive and will be provided under the terms of the Protective Order (Confidentiality Disclosure Agreement) entered in this case.

FINAL

HIGHLY SENSITIVE PROTECTED MATERIALS

ENTERGY TEXAS, INC.
OPERATING COMMITTEE
MINUTES OF THE DECEMBER 15, 2021 MEETING

Members:
Eli Viamontes, [redacted]

Advisory Members:
[redacted]

Other participants:
[redacted]

[redacted] started the meeting by communicating to those on the call that there were Market Function Employees ("MFEs") on the meeting and to not discuss any non-public transmission function information on the call until the MFEs had left the meeting. [redacted] then provided the safety briefing and diversity message.

Seven items were discussed:

1. Supply Plan – Business Plan 2022 (BP22) (Decision)[redacted]

1. **Supply Plan – Business Plan 2022 (BP22) (Decision)**

[redacted] provided an overview of the changes to the supply plan for BP22 including incorporating the solar capacity credit stepdown approved at the October 20, 2021, ETI Operating Committee meeting. Liberty County Solar Facility was removed from the BP22 Supply Plan given the Public Utility Commission of Texas denied ETI's certificate of convenience and necessity application. [redacted] also discussed several key ongoing analyses that could affect the supply plan in the future. After responding to several questions from the Committee, [redacted] requested Committee concurrence and CEO approval of the BP22 Supply Plan as outlined in the presentation (Attachment A).

The ETI Operating Committee concurred with the recommendation and ETI President & CEO Eli Viamontes approved.

FINAL

HIGHLY SENSITIVE PROTECTED MATERIALS

[redacted]

2. [redacted]

[redacted]

3. [redacted]

[redacted]

4. [redacted]

[redacted]

5. [redacted]

[redacted]

6. [redacted]

[redacted]

7. [redacted]

[redacted]

FINAL

HIGHLY SENSITIVE PROTECTED MATERIALS

[redacted]

ATTACHMENT A

Business Plan 2022 (BP22)

Entergy Texas: Long-Term Supply Plan

Entergy | WE POWER LIFE℠

Creating sustainable value for all

ETI Operating Committee Presentation Objective

The objectives of this presentation are:

- to provide an overview of the assumption changes for BP22 that affect the surplus and deficit positions for ETI
- to discuss key market considerations and analyses which have been considered in the adjustment of the supply plans
- to review BP22 ETI Supply Plan

*This presentation seeks a **concurrence** by the ETI Operating Committee and **approval** by the ETI CEO*

ETI Business Plan 2022 Changes

The ETI Supply Plan for BP22 will incorporate the following methodology updates:

- MTEP21 Solar Capacity Credit Stepdown as approved at the September 30, 2021, ETI Operating Committee meeting
- Battery-to-Solar ratio and battery capacity credit methodology
- Given magnitude of potential industrial load projects, capacity needs are reflected as a range for BP22

The following key input assumptions have been updated for BP22:

- ✓ Near-Term Planning Reserve Margin (Adopted a 9.38% PRM for 2021-2024 to align with results from MISO's 21/22 LOLE Study)
- ✓ GVTC Ratings (2021-2022 PY)
- ✓ Transmission Losses of 1.8%
- ✓ BP21 Peak Load Forecast as approved at the August 18, 2021, ETI Operating Committee meeting
- ✓ 2021 LMR Ratings

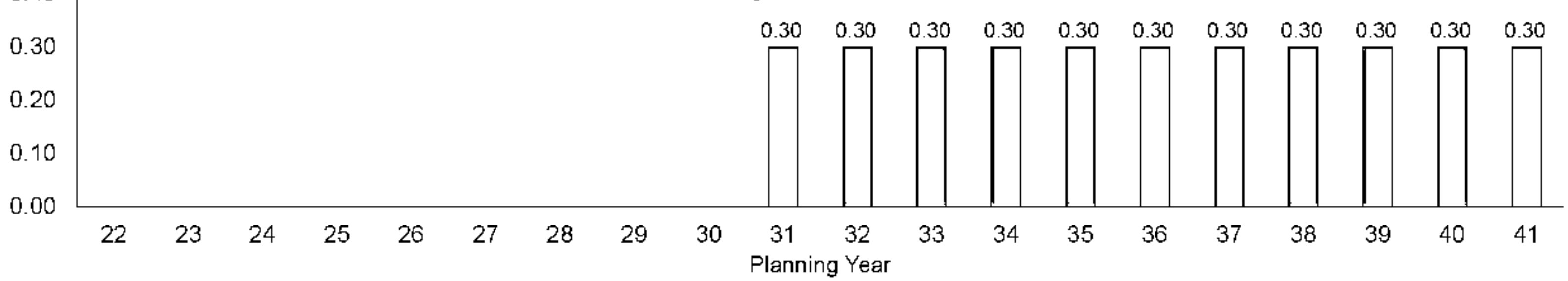
Key resource changes for BP22 include:

1. Increase of 2025 ETI Solar from 200 MW to 400 MW based on approval granted at the April 26, 2021, ETI Operating Committee meeting
2. Perryville 1 & 2 operational lives were extended to [redacted], respectively from [redacted]
3. Hardin 1 & 2 operational lives were extended to [redacted]
4. Nelson 6 deactivation moved to [redacted]
5. Big Cajun 2 Unit 3 deactivation moved to [redacted]
6. Addition of [redacted] to LMRs
7. Removal of [redacted] from LMRs
8. Addition of HEB #048 and Lone Star College distributed generators
9. Updated the 2026 ETI 2x1 to align with OCAPS assumptions given selection from the 2020 ETI Request for Proposals
10. Changes to planned resources to meet remaining capacity needs as outlined in the presentation

Battery Storage Recommendations for BP22

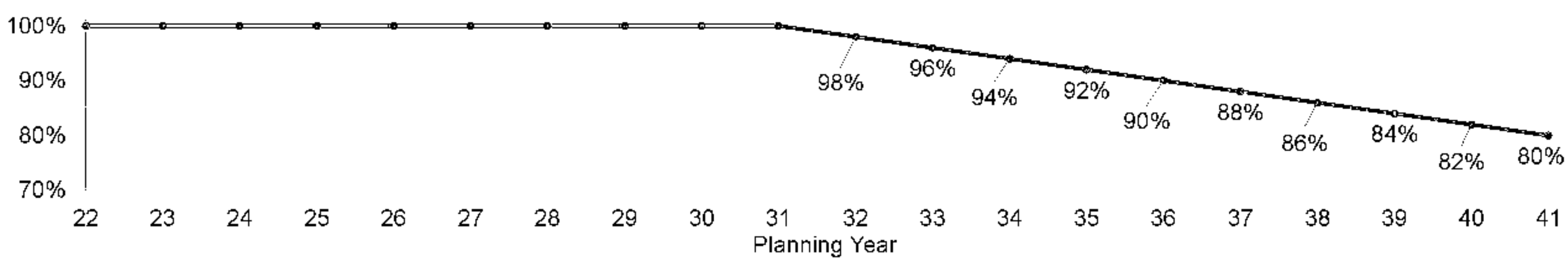
- Establish a battery to solar ratio that will apply to all solar resources built in a given future year. An internal flexibility study found that at higher solar penetrations, the cumulative battery to solar ratio should be ~15 MW to 100 MW to meet system flexibility needs. By building a battery to solar ratio of 0.3 beginning in 2031, it is projected that the cumulative battery to solar ratio will be at least 0.15 by 2041.

Battery to Solar Ratio



- Implement a battery capacity credit step down assumption that aligns with the Effective Load Carrying Capability (ELCC) findings from the recent Entergy flexibility study.[1]

Battery Capacity Credit



[1] *The battery capacity credit assumption and battery to solar ratio calculations are based on the low carbon portfolios used in the 2021 summer portfolio analyses.*