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

REDACTED

DIRECT TESTIMONY

AND

WORKPAPERS

OF

CONSTANCE T. CANNADY

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

REVENUE REQUIREMENT ISSUES

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OCTOBER 26, 2022

REDACTED
DIRECT TESTIMONY AND WORKPAPERS OF
CONSTANCE T. CANNADY

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Constance T. Cannady. I am an Executive Consultant under contract with NewGen Strategies & Solutions, LLC. My office is located at 2803 Bowie Street, Amarillo, Texas 79109.

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

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

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. Attachment A provides a description of my qualifications and education, and a list of dockets in which I have provided expert witness testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY AGENCY?

A. Yes, I have. Attachment A includes a list of dockets in which I have provided expert witness testimony before the Public Utility Commission of Texas (the "Commission" or "PUCT") and other regulatory bodies.

II. PURPOSE AND SCOPE

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

A. The purpose of my testimony is to present my analysis, findings, and recommendations with respect to Entergy Texas, Inc.'s ("ETI" or the "Company") request to increase its

Texas Retail base rates. Specifically, I address ETI's proposed treatment of the following expenses:

1. Rate treatment for generating plants scheduled for deactivation between [redacted];
2. Spindletop natural gas storage levels;
3. Capitalized short-term incentive ("STI") compensation for the period 2018-2021;
4. Capitalized non-tax-qualified retirement benefits, (also known as non-qualified deferred compensation ("NQDC");
5. Capitalization of Other Postemployment Benefits ("OPEB");
6. Annual level of overtime compensation;
7. Annual STI compensation;
8. Annual pension and OPEB benefits expenses;
9. Annual property insurance accrual related to storm damages and reserve; and
10. Adjustment to depreciation for requested approval of deactivation dates for certain production plant from [redacted].

Q. IF YOU DO NOT ADDRESS AN ISSUE OR POSITION IN YOUR TESTIMONY, SHOULD THAT BE INTERPRETED AS SUPPORTING THE COMPANY'S POSITION ON THAT ISSUE?

A. No. Any cost or adjustment included in ETI's Rate Filing Package ("RFP") that is not addressed in my testimony does not indicate my acquiescence to ETI's proposed cost or adjustment.

III. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR OVERALL RECOMMENDATIONS THAT IMPACT ETI'S PROPOSED TEXAS REVENUE REQUIREMENTS.

A. Based on the Company's RFP, ETI requests an increase of $131.4 million to its non-fuel retail revenue requirement,[1] resulting in adjusted revenues of $1.296 billion.[2] I am recommending that the Company's proposed rate base of $4.412 billion used in the computation of its requested increase in base rates be reduced by $195.8 million, before accounting for all taxes and other attendant impacts.[3][4] I am also recommending that the operating expenses, including depreciation, be reduced by $110.5 million, before accounting for all taxes and other attendant impacts.[5] As shown on Schedule CTC-1, I recommend that a portion of my recommended adjustments to the computation of base rates be included in a separate Retiring Plant Rate Rider to be used until certain generation plants are no longer providing service to Texas customers.[6] Based on ETI's RFP, the generation plants that I recommend be included in a Retiring Plant Rate Rider [redacted][7] At the time these

[1] ETI Rate Filing Package ("RFP"), Application, at 2.

[2] ETI RFP, Schedule A.

[3] Additional attendant impacts might include adjustments for accumulated deferred income taxes and cash working capital based on recommended adjustments to plant and other rate base balances.

[4] *See Schedule* CTC-1.

[5] *Id.*

[6] *Id.*

[7] ETI RFP, Direct Testimony of Ms. Anastasia R. Meyer, HSPM Exhibit ARM-2.

generation plants cease to provide generation service to Texas customers, the associated plants and operating costs should be removed from the calculation of the Retiring Plant Rate Rider.

More specifically, my recommended adjustments to the computation of base rates include the following adjustments:

- Remove the costs related to the retiring plants from base rates and develop a separate rate rider;
- Adjust the Spindletop facility natural gas inventory to reflect the reasonable level needed for usage at the Sabine generating station;
- Remove the capitalized short-term incentive compensation that was awarded based on financial performance measures;
- Reinstate the treatment of OPEBs in the development of the pension and OPEB reserve account;
- Remove any capitalized non-tax-qualified retirement benefits from the development of the pension and OPEB reserve account;
- Amortize pension settlement costs over a 10-year period;
- Reduce ETI's proposed level of overtime pay to reflect a five-year average;
- Adjust the level of STI compensation to reflect appropriate removal of financially based STI compensation awards;
- Adjust pension and OPEB benefits expenses to remove NQDC benefits expense;
- Adjust pension benefits expense to provide for a longer amortization of settlement costs;
- Reinstate the actuarially determined OPEB net periodic benefits expense in the computation of benefits expense;
- Adjust ETI's proposed annual storm related damages expense to include a longer recovery of the current negative balance in the property reserve account;

- Adjust ETI's proposed base rate depreciation expense to remove depreciation expense related to the plants retiring between [redacted] and reset the Nelson 6 depreciation based on current depreciation rates.

IV. RECOMMENDED ADJUSTMENTS TO RATE BASE

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO ETI'S PROPOSED RATE BASE.

A. As shown on Schedule CTC-1, I am recommending four specific reductions totaling $195,783,157[8] to ETI's proposed rate base of $4,412,141,141[9] that the Company uses to compute base rates. First, I am recommending that net plant in service be reduced by $150,845,002 to consider:[10]

a. My recommendation that recovery for generation plants retiring before the next general rate case decision be included in a separate Retiring Plant Rate Rider;

b. My recommended removal of capitalized STI compensation awarded based on financial performance measures;

c. My recommended removal of any capitalized NQDC benefits; and

d. Removal of the H.E.B generator costs as recommended by Mr. Evan Evans.

Of this amount, I am recommending that $124,557,273 be included as net plant in service in computing a separate Retiring Plant Rate Rider.[11]

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[8] *See* Schedule CTC-1.

[9] RFP, Schedule B.

[10] *See* Schedule CTC-2.

[11] *See* Schedule CTC-1 and Schedule CTC-2B(HSPM).

My second recommended adjustment is to remove $12,542,435 of the Company's requested $17,723,110 coal inventory from base rates and include that inventory in my proposed Retiring Plant Rate Rider for the continued operation of [redacted].[12]

With respect to the natural gas inventory requested by ETI and as stored in the Spindletop facility, I am recommending that the natural gas inventory for both the base rates and my recommended Retired Plant Rate Rider be reflective of actual use of the facility to serve the Sabine generation plants. Based on my analysis, the appropriate level of natural gas inventory stored at the Spindletop facility should be $16,093,096, of which only $4,851,811 should be in base rates with the remaining $11,241,286 included in the Retiring Plant Rate Rider.[13]

Finally, I am recommending that the pension and OPEB over/under reserve account, included as a regulatory asset, be reduced by $6,850,089 reflective of the following adjustments:

a. A reinstatement of the negative over/under balance of OPEB benefits of ($3,103,081) removed by the Company and included as an average balance of ($1,551,541) during the next four-year amortization period;[14]

b. A removal of the $225,334 NQDC over/under balance;[15]

c. A four-year amortization period for non-settlement pension costs and an average balance of $2,625,166 included in rate base;[16] and

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[12] *See* Schedule CTC-3A and Schedule CTC-2B(HSPM).

[13] *See* Schedule CTC-3B (HSPM), Schedule CTC-1, and Schedule CTC-2B(HSPM).

[14] *See* Schedule CTC-4 with average balance determined to be [($3,103,081 ÷ 4 x 2) = ($1,551,541)].

[15] *See* Schedule CTC-4.

[16] *See* Schedule CTC-4 with average balance determined to be [($5,250,332 ÷ 4 x 2) = $2,625,166].

d. A ten-year amortization period for pension settlement costs of $12,240,194 with an average balance of $9,792,155 computed for the first four years.[17]

Q. DO YOUR RECOMMENDED ADJUSTMENTS TO RATE BASE TAKE INTO ACCOUNT ALL ATTENDANT IMPACTS?

A. No. To the extent that the Commission adopts my recommended adjustments, the Company would also need to provide the attendant impacts to the balance of accumulated deferred income taxes, federal income taxes, taxes other than income, and the working capital computation.

A. ADJUSTMENT TO PLANT IN SERVICE

1. Adjustment to Remove Costs Related to Generating Plant Deactivations

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO RATE BASE FOR PLANNED PLANT DEACTIVATIONS.

A. Based on the direct testimony of ETI's witness Ms. Anastasia Meyer, ETI plans to accelerate the deactivation dates for both of the coal generation plants currently providing service to Texas customers.[18] The impact of her recommendations will significantly increase the proposed depreciation rates for these plants to provide for an earlier recovery of the remaining plant balances than originally planned.

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[17] Schedule CTC-4 with average balance determined to be [$12,240,194 – ($12,240,194 ÷ 10 x 2) = $9,792,155].

[18] Direct Testimony of Anastasia R. Meyer at 12.

Q. DO ANY OF THESE ADJUSTED OR CURRENTLY PLANNED DEACTIVATION DATES RESULT IN DEACTIVATIONS DURING THE PERIOD THAT THE BASE RATES FROM THIS PROCEEDING WILL BE IN EFFECT?

A. Yes. Based on Ms. Meyer's HSPM Exhibit ARM-2, [redacted] deactivation date of [redacted] from its previous deactivation date of 2042[19] [redacted][20] With respect to the Sabine generating station, all but [redacted] will likely be deactivated during the period that rates from this proceeding will be in effect.[21]

Q. WHY DO YOU TAKE ISSUE WITH THE COMPANY'S BASE RATE TREATMENT OF GENERATING PLANTS THAT MAY BE DEACTIVATED DURING THE PERIOD THAT RATES FROM THIS PROCEEDING ARE IN EFFECT?

A. 16 Texas Administrative Code ("TAC") § 25.231(c)(2) clearly provides that the plant included in the determination of retail rates must be ". . .used and useful in rendering service to the public."[22] To the extent that a plant is no longer providing service to the public, it is inappropriate to charge ratepayers for the costs related to such plant. In the case of ETI's planned deactivation of [redacted] during the time rates from this proceeding will be in effect, the costs

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[19] See *Application of Entergy Texas, Inc. for Authority to Change Rates*, Docket No. 48371, at Attachment B, Schedule D-6(May 12, 2018).

[20] Direct Testimony of Anastasia R. Meyer, HSPM Exhibit ARM-2.

[21] *Id.*

[22] 16 TAC § 25,231(c)(2).

associated with these plants should not be included in the development of the base rates, but rather should be charged to customers through a separate rate rider until such time that the plant no longer provides service to the public. Therefore, I am recommending that the costs related to each of these plants be removed from base rate treatment and collected from customers via a separate Retiring Plant Rate Rider. As shown on Schedule CTC-2, I have reduced ETI's proposed net plant in service for rate base treatment by $144,905,863[23] to account for these plant balances and included these same net plant costs in my recommended Retiring Plant Rate Rider.[24]

Q. PLEASE EXPLAIN HOW YOU HAVE DETERMINED THAT A DEACTIVATION OF A PLANT IS THE SAME AS A PLANT RETIREMENT.

A. Based on responses to discovery, in which the Company stated the following:

> "A deactivation decision reflects a management decision to remove a unit from service in a certain time frame absent changed circumstances and/or based on assumed resource additions."[25]

When asked if ETI or any of its sister operating companies had ever returned a unit to service subsequent to deactivation, ETI responded that its affiliate Entergy Louisiana had reactivated a unit for one month subsequent to joining the Midcontinent Independent System Operator ("MISO").[26] Given these responses, using a Retiring Plant Rate Rider,

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[23] *See* Schedule CTC-2.

[24] *See* Schedule CTC-2B (HSPM).

[25] *See* Attachment C, ETI Response to Cities RFI No. 5-8.

[26] *See* Attachment D, ETI Response to OPUC RFI No. 3-2.

which can be used during all periods of actual service, is appropriate for retiring or deactivated plant operations.

Q. HOW HAVE YOU DETERMINED THAT THE PROPOSED GENERATING PLANT DEACTIVATIONS WILL LIKELY OCCUR DURING THE TIME THAT RATES FROM THIS PROCEEDING WILL BE IN EFFECT?

A. Based on the general requirement that base rate requests be filed every four years,[27] the next required test year would be December 2025. However, the actual rate case would be filed after that and the litigation will take time beyond the filing. As in this case, the likely resolution will be in 2023 with a 2021 test year. Therefore, it is reasonable for me to conclude that without an earlier filing by the Company, the resolution of the next general base rate case would be as late as 2027. To the extent that any of these plants has already been deactivated at or before that time, customers will be inappropriately paying for services not provided. ETI's proposed base rate treatment of the costs associated with these plants would allow the Company to earn a return on the current balance of the assets and the test year operations and maintenance ("O&M") expenses after these generating plants cease to be used and useful in providing electric service to Texas retail customers. This is clearly a violation of 16 TAC § 25.231(c)(2).

Q. ARE THESE THE ONLY ADJUSTMENTS YOU HAVE MADE TO REMOVE THE COSTS RELATED TO THESE GENERATING PLANTS?

[27] 16 TAC § 25.246.

A. No. I have also removed the O&M expense and depreciation expense identified by the Company as being included for these plant operations in ETI's rate request.[28] However, there may be other attendant impacts that should be quantified by the Company if the Commission agrees with my proposed rate treatment. Other attendant impacts may include adjustments to accumulated deferred income taxes, materials and supplies or other costs directly related to these plants.

Q. ARE YOU RECOMMENDING THAT ANY RECOVERY OF THE COSTS RELATED TO THESE FOUR GENERATING PLANTS BE DENIED BY THE COMMISSION IN THIS PROCEEDING?

A. No. I recommend that rate recovery for the assets and O&M costs associated with these four generating plants be accomplished through a Retiring Plant Rate Rider that allows for charging Texas retail customers the costs to operate these facilities during the period that the generating plants remain used and useful in providing electric service to Texas retail customers.[29]

Q. WHY DO YOU BELIEVE THAT A SEPARATE RETIRING PLANT RATE RIDER PROVIDES EQUITABLE TREATMENT TO BOTH THE COMPANY AND TEXAS RATEPAYERS?

A. The use of a separate rate rider allows ETI to earn a return on the generating plant assets and recover O&M expenses necessary to operate the generating plants, but only for the period that these plants are used and useful in providing electric service to Texas retail

[28] *See* Schedule CTC-5(HSPM) and Attachment E, ETI Response to OPUC RFI No. 3-6

[29] *See* Schedule CTC-2B(HSPM).

customers. The Retiring Plant Rate Rider can be discontinued or adjusted upon the actual deactivation of any of the plants. The only remaining costs for ETI to recover from Texas retail customers would be the net book value of the deactivated assets at the time they are no longer providing service. I recommend that ETI book these remaining costs into a regulatory asset, the recovery of which should be determined in ETI's next general base rate case.

Q. PLEASE EXPLAIN YOUR METHODOLOGY FOR DEVELOPING THE RETIRING PLANT RATE RIDER.

A. As shown on HSPM Schedule CTC-2B and as I have discussed, I recommend that the Retiring Plant Rate Rider include the net plant investment of those generating plants that have deactivation dates on or before [redacted],[30] an appropriate level of fuel inventory[31] and the O&M as identified by the Company.[32] I have computed the return and federal income tax using a pre-tax rate of return that incorporates ETI's proposed capital structure and cost of capital.[33] As shown on HSPM Schedule CTC-2B, the Retiring Plant Rate Rider is estimated to recover approximately [redacted] annually[34] until costs are removed for the deactivation of each plant. I note that my recommended calculation would need to incorporate any changes to the cost components or additional attendant impacts related to these specific generating plants.

[30] *See* Schedule CTC-2B(HSPM).

[31] *Id.*

[32] *See* Attachment E, ETI Response to OPUC RFI No. 3-6.

[33] *See* Schedule CTC-2B(HSPM).

[34] Does not include all attendant impacts.

Q. HOW DOES SUCH A PERIODIC ADJUSTMENT TO THE RETIRING PLANT RATE RIDER PROVIDE COMPLIANCE WITH 16 TAC § 25.231(c)(2)?

A. Because the Retiring Plant Rate Rider would cease to be charged to ratepayers upon deactivation of the generating plants, ratepayers will only provide a return on these assets during the period that the plants are providing electric service. With deactivation, ratepayers would only be responsible for the undepreciated value of the plant assets, without the inclusion of a return component or operating expenses.

Q. HAS THE COMMISSION ADOPTED AN ORDER THAT ESTABLISHES A SEPARATE RATE RIDER FOR THE RECOVERY OF GENERATION PLANT COSTS ONLY DURING THE PERIOD IN WHICH SUCH PLANTS CONTINUE TO PROVIDE ELECTRIC SERVICE TO CUSTOMERS?

A. Yes. The Commission's Order in Docket No. 51415 provided for a separate rate rider for recovery of a coal generating plant that was scheduled to retire within the first year after the test year used by the utility.[35] The finding was as follows:

> 58. It is appropriate to remove all cost recovery for Dolet Hills, the Oxbow investment, and DHLC from base rates and address these issues instead in a Dolet Hills rate rider.
>
> 59. Through the Dolet Hills rate rider, SWEPCO should be permitted, with respect to the period between March 18, 2021 (the date when the rates are effective) and December 31, 2021 (the date of Dolet Hills' retirement) (the operative-plant phase of the Dolet Hills rate rider), to recover the costs ordinarily permitted for an operating generating plant, including a return on

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[35] *Application of Southwestern Electric Power Company for Authority to Change Rates,* Docket No. 51415, Order at Finding of Facts ("FOF") Nos. 58-59 (Jan. 14, 2022).

the plant's net book value (including applicable accumulated deferred federal income taxes and unused materials and supplies), depreciation, and O&M. SWEPCO should similarly be permitted to continue earning a return on the Oxbow investment and the return on equity and associated taxes for DHLC. The charges in the Dolet Hills Rate Rider should be subject to true-up to reflect an updated-net-book value of Dolet Hills after its retirement and again after the plant is closed and final demolition Costs are known.[36]

Q. IS THERE COMMISSION PRECEDENT TO DISALLOW A RETURN ON ELECTRIC PLANT THAT IS NO LONGER PROVIDING SERVICE TO RATEPAYERS, BUT PROVIDE FOR THE RECOVERY OF THE UNDEPRECIATED COSTS OF THE PLANT ASSETS AT RETIREMENT?

A. Yes. In Docket No. 46449, The Commission's decision disallowed any return *on*, but provided for the recovery *of*, the undepreciated costs for Southwestern Electric Power Company's ("SWEPCO") Welsh Unit 2, which had retired by the end of the test year in that proceeding.[37] In the Order on Rehearing, the Commission specifically stated that SWEPCO would not be allowed to earn a return on a plant that was no longer used and useful as follows:

> 69. Allowing SWEPCO a return of, but not on, its remaining investment in Welsh unit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service.[38]

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[36] *Id.*

[37] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 46449, Order on Rehearing at FOF No. 69 (Mar. 19, 2018).

[38] *Id.*

Also, concerning SWEPCO, in Docket No. 51415, the Commission's decision was to provide for the separate rate rider so that a return on the investment would only be available during the period the Dolet Hills generating plant was providing service. Upon retirement, the Commission ruled that the undepreciated remaining book value of Dolet Hills ". . . should be placed in a regulatory asset to be amortized without a return."[39]

Q. ARE YOU RECOMMENDING A SIMILAR BASE RATE TREATMENT FOR THE GENERATING PLANTS THAT ARE CURRENTLY SCHEDULED TO BE DEACTIVATED BEFORE THE NEXT GENERAL RATE CASE?

A. Yes. As with the treatment adopted by the Commission for Welsh Unit 2 and Dolet Hills, I am recommending that ETI be authorized to recover the undepreciated asset balances for each of the generating plants at the time that they no longer provide service to Texas ratepayers. The undepreciated balance should be computed as of the actual deactivation date and evaluated in the next general rate proceeding based on its original retirement dates. The actual undepreciated balances should not include any additional carrying charges.

2. <u>Adjustment to Remove Financially Based Short-Term Incentive Compensation</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO PLANT IN SERVICE RELATED TO CAPITALIZED SHORT-TERM INCENTIVE COMPENSATION.

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[39] *Id.; See also Application of Southwestern Electric Power Company for Authority to Change Rates*, Docket No. 51415, Order at FOF No. 60 (Jan. 14, 2022).

A. As shown on Schedule CTC-2, I am recommending that ETI's proposed net plant in service be reduced by $3,525,289 for capitalized STI compensation that, in my opinion, was awarded based on financial performance measures.[40]

Q. DID ETI PROPOSE AN ADJUSTMENT TO CAPITALIZED STI COMPENSATION FOR THE PURPOSES OF REMOVING AWARDS THAT REFLECTED FINANCIAL PERFORMANCE?

A. Yes. However, for four of the Company's STI compensation plans, there is a financial performance metric that must be met before any STI compensation can be awarded pursuant to these plans.[41] The Company's adjustment does not take this into account.[42] Therefore, my recommended adjustment of $3,525,289 is in addition to the adjustment of $3,809,809 to capitalized STI as removed by the Company.[43] A more detailed discussion of the financial performance metric that "triggers" the payment of STI compensation for three of the STI plans is included later in this testimony.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE ADDITIONAL STI COMPENSATION THAT YOU RECOMMEND BE REMOVED FROM PLANT IN SERVICE.

A. Based on responses to discovery, I calculated a total capitalized STI compensation for each of the years 2018-2021, separated between direct ETI STI compensation and the allocated

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[40] *See* Schedule CTC-2.

[41] Direct Testimony of Jennifer A. Raeder, at 11.

[42] *See* Attachment F, ETI Response to OPUC RFI No. 1-13.

[43] *See* Attachment G, ETI Response to OPUC RFI No. 1-14 (amounts removed from Account 101).

Entergy Services, Inc. ("ESI") STI compensation.[44] I removed an estimated amount attributable to construction work in progress ("CWIP") each year by using the test year CWIP percentage.[45] In order to estimate the capitalized STI compensation for awards from the three STI plant subject to the financially based performance "trigger," I used the percentage that each of these four STI plans represented of STI compensation awarded during the test year.[46] I determined these percentages separately for the ETI direct STI and the allocated ESI STI. From this result, I estimated that the additional financially based capitalized STI using one-half of the financial performance metric "trigger" that was applicable during the period.[47]

Q. DID YOU ALSO COMPUTE AN ADJUSTMENT TO THE ACCUMULATED RESERVE FOR DEPRECIATION FOR YOUR REMOVAL OF THE CAPITALIZED STI COMPENSATION?

A. Yes. As shown on Schedule CTC-2C, I estimated the impact on the accumulated reserve for depreciation based on the average depreciation rate for the test year. I computed a total depreciation percentage using the half-year convention for the year in which the adjustment was made and assuming a straight-line depreciation through the end of the test year.[48]

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[44] *See* Cannady Workpapers - Incentive (HSPM) and Attachment H, ETI Responses to Cities RFI No. 3-3 and OPUC RFI No. 4-11(HSPM).

[45] RFP WP/Schedule P – Volume 2, AJ18.2.

[46] *See* Cannady Workpapers - Incentive (HSPM).

[47] *Id.*

[48] For example, the adjustment for 2018 would have been depreciated for 3.5 years using the half-year convention. This amount should be removed from the accumulated reserve for depreciation.

3. <u>Adjustment to Remove Costs Related to the HEB Generators</u>

Q. PLEASE EXPLAIN WHY YOU HAVE REMOVED THE NET PLANT IN SERVICE RELATED TO THE H.E.B. GENERATORS.

A. I have include this adjustment based on the recommendations discussed by Mr. Evan Evans in his direct testimony.[49] The adjustment reduces net plant in service by $2,413,851.[50]

B. ADJUSTMENT TO SPINDLETOP NATURAL GAS STORAGE

Q. WHAT IS ETI PROPOSING WITH RESPECT TO THE NATURAL GAS INVENTORY LEVELS AT THE SPINDLETOP FACILITY?

A. As shown on Schedule E-1.1, ETI is proposing to include a 13-month average balance of $30,397,441 for the natural gas inventory maintained at its Spindletop facility.[51] Based on the December 31, 2021, inventory level of 9,819,474 million British thermal units ("MMBtus") with a value of $29,425,564, the price per MMBtu is approximately $2.9966 at test year end.[52]

Q. WHAT LEVEL OF NATURAL GAS INVENTORY ARE YOU RECOMMENDING BE INCLUDED IN BASE RATES?

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[49] Direct Testimony of Evan D. Evans.

[50] *See* Schedule CTC-2.

[51] RFP, Schedule E-1.1, at 1.

[52] RFP, Schedule E-2.4.

A. As shown on Schedule CTC-3B, I recommend that $4,851,811 of the Spindletop natural gas inventory be authorized for base rate treatment. This results in a reduction to the Company's proposed natural gas inventory in base rates of $25,545,630. [53]

Q. DOES YOUR RECOMMENDATION ALSO INCLUDE A LEVEL OF NATURAL GAS INVENTORY TO BE INCLUDED IN THE SEPARATE RETIRING PLANT RATE RIDER?

A. Yes. Also shown on Schedule CTC-3C(HSPM) are my recommended natural gas inventory levels for [redacted], which have deactivation dates between [redacted].[54] I am recommending a total natural gas inventory for these plants of $11,241,286 as shown on Schedule CTC-3B.[55]

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED NATURAL GAS INVENTORY LEVELS?

A. My methodology for determining the appropriate natural gas inventory level to be stored at Spindletop is based on the highest monthly MMBtu burn at each of the Sabine generating plants during the period January 2018 through the test year end.[56] The total of the highest monthly burns for each of the plants was 9,166,224 MMBtus.[57] I added a cushion gas requirement of 5,214,830 MMBtus to the total of the highest monthly MMBtu burns for a

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[53] *See* Schedule CTC-3B.

[54] *See* Schedule CTC-3C (HSPM) and Direct Testimony of Anastasia R. Meyer, Exhibit ARM-2 (HSPM).

[55] *See* Schedule CTC-3B.

[56] *See* Attachment I, ETI Response to OPUC RFI No. 2-3 and RFP, Schedule H-12,3a.

[57] *See* Schedule CTC-3B.

maximum MMBtu requirement of 14,381,053.[58] Using the average cost per MMBtu of $2.9966,[59] I determined that the cost of gas to cover the combined highest monthly burns at the Sabine generating station would be $43,094,265. However, because the Spindletop inventory is not used for all the natural gas requirements at the Sabine generating station, I applied a percentage to the $43.1 million based on actual Spindletop withdrawals as a percentage of the actual monthly burns.[60] Using only the highest three percentages during the test year, I computed an average of 37.34%.[61] Applying this percentage to the $43.1 million resulted in my total recommended natural gas inventory of $16,093,096.[62]

Q. ARE YOU RECOMMENDING THAT ALL OF THIS AMOUNT BE INCLUDED IN BASE RATES?

A. No. Because some of the [redacted] are scheduled for deactivation between [redacted], I am recommending that an inventory of $4,851,811 be included in base rate, and an inventory of $11,241,285 be included in my recommended Retiring Plant Rate Rider.[63]

C. ADJUSTMENT TO PENSION AND OPEB BENEFITS RESERVE

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[58] *Id.*

[59] RFP, Schedule E-2.4.

[60] *See* Attachment J, ETI Response to OPUC 5-6.

[61] *See* Schedule CTC-3B.

[62] *Id.*

[63] *See* Schedule CTC-1.

Q. PLEASE EXPLAIN THE REQUIREMENTS FOR ESTABLISHING A PENSION AND OPEB BENEFITS RESERVE ACCOUNT.

A. Public Utility Regulatory Act ("PURA") § 36.065 specifically provides for an electric utility's ability to establish a pension and OPEB reserve account that reflects the difference between the actual cost of these benefits and the costs included in current rates.[64] The actual cost is to be determined by an actuarial or similar study.[65]

Q. WHAT IS ETI'S RECOMMENDATION WITH RESPECT TO ITS PENSION AND OPEB RESERVE ACCOUNT?

A. ETI is requesting a pension and OPEB reserve account balance for rate base treatment of $17,715,870.[66]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED RESERVE ACCOUNT BALANCE?

A. No. I am recommending several adjustments to the Company's computation of its pension and OPEB reserve account balance. First, I recommend that the balance determined to be appropriately included in base rates reflect the *average balance* during the next four years when the rates from this proceeding will likely be in effect. Second, I recommend that the current negative balance of OPEB continues to be included in the computation of the reserve account because the Company already selected to set up the reserve account with both pension and OPEB costs included. Finally, I recommend that any differences between

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[64] PURA § 36.065(b).

[65] PURA § 36.065(b)(2).

[66] Calculated from the RFP, WP/Schedule P – Volume 2, at 63 [$17,490,526 + $225,334 = $17,715,870].

cost related to non-tax-qualified pension plans be excluded from the computation of the reserve. The total impact of my recommendations is to reduce the Company's requested pension and OPEB reserve account by $6,850,089 as shown on Schedule CTC-4.[67]

Q. PLEASE EXPLAIN YOUR RECOMMENDATION THAT THE RATE BASE REFLECT A BALANCE IN THE PENSION AND OPEB RESERVE ACCOUNT BASED ON AN AVERAGE BALANCE OVER THE NEXT FOUR YEARS.

A. Although rate base components typically reflect a point in time such as the test year end, these balances can be adjusted for known and measurable changes. Because the Company is requesting inclusion of an amortization of the balance in the annual adjusted expense, the balance in the account will continue to decline over the amortization period. Therefore, to avoid having ratepayers provide a return on the reserve account balance as of the test year end, using an average balance ensures that ratepayers will remit a return that is theoretically equal to a return computed each year based on the actual balance at that time. The computation provides for a lower than actual return in the first half of the amortization period and a higher than actual return in the second half of the amortization period.

Q. PLEASE EXPLAIN YOUR REASONING FOR REINSTATING THE OPEB NEGATIVE BALANCE IN THE PENSION AND OPEB RESERVE ACCOUNT.

A. Based on my understanding of ETI's adjustments to OPEB benefits, the Company is removing the cost of any OPEB benefits from rate making treatment. As stated by ETI witness Mr. David C. Batten, ETI proposes to remove the negative OPEB balance from its

[67] *See* Schedule CTC-4.

reserve account as well as to remove the negative actuarially determined test year OPEB benefits expense.[68] Mr. Batten argues that because ETI cannot take the funds from its OPEB trust account to return to ratepayers, the Company would have to provide the refund from its shareholder funds.[69] I do not agree. PURA § 36.065 does not state that the reserve account must reflect positive expense adjustments, but rather both positive and negative adjustments based on having a surplus in the existing reserve or a deficit in the existing reserve.[70] The test year reserve account contains a surplus balance for OPEB expense and should continue to include this balance until it is reconciled going forward.

Q. HOW WAS OPEB EXPENSE TREATED BY ETI IN ITS LAST RATE FILING?

A. In Docket No. 48371, ETI reflected a similar circumstance where the OPEB expense for the test year was negative and the Company's proforma adjustment was a greater negative expense.[71] ETI included the adjusted negative expense in its O&M expense and made no similar request to have the OPEB benefits removed from consideration in rates.[72] The total OPEB expense requested in rates in that proceeding was a negative $2,228,460.[73]

Q. HOW HAS THE ANNUAL OPEB EXPENSE CHANGED SINCE THE 2017 TEST YEAR IN DOCKET NO. 48371?

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[68] Direct Testimony of Mr. David C. Batten, at 8.

[69] *Id.*

[70] PURA § 36.065(c).

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

[72] *See* Attachment K, Rate Filing Package, Docket No. 48371, Bates Stamp 5614.

[73] *See* Attachment K [(($6,204,000) x .5029) + ($13,737,000 x .0649)) = ($2,228,460)].

A. Based on the annual OPEB costs shown in the RFP, Schedule G-2,2, the costs have continued to decline from the costs that were included in the Docket No. 48371 rate filing. ETI witness Ms. Jennifer A. Raeder provided direct testimony concerning the changes made as of January 1, 2021, that have reduced the costs incurred under certain OPEB plan benefits.[74] ETI responded to discovery that these changes in the OPEB plans have resulted in or are expected to result in over $2 million if OPEB cost reductions for each year of the years 2021 through 2026.[75]

Q. IS IT YOUR OPINION THAT ETI'S REQUESTED TREATMENT OF OPEB EXPENSE, BOTH IN ITS RESERVE ACCOUNT AND AS AN O&M EXPENSE DOES NOT COMPLY WITH PURA § 36.065?

A. Yes. Therefore, ETI's proposal to remove the OPEB negative balance of ($3,103,081) from its pension and OPEB reserve account should be disallowed. A discussion of the OPEB expense is included later in my testimony.

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO THE PENSION AND OPEB RESERVE ACCOUNT TO REMOVE THE COSTS RELATED TO ETI'S NON-TAX-QUALIFIED RETIREMENT PLANS?

A. As described by ETI witness Ms. Jennifer A. Raeder, ETI offers non-tax qualified benefit plans that are categorized as supplemental executive benefit plans or restoration benefit plans.[76] Typically, these types of non-tax-qualified retirement benefits plans are

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74 Direct Testimony of Jennifer A. Raeder at 43-44.

75 *See* Attachment L, ETI Response to Cities RFI No. 2-15.

76 Direct Testimony of Jennifer A. Raeder at 44.

established for highly paid management and executives to supplement the already provided pension and retirement benefits afforded to all employees.

Non-tax-qualified retirement benefit plans ("NQDC benefit plans") are established because the Company has a limit as to how much retirement it can provide and deduct for tax purposes under the Employee Retirement Income Security Act ("ERISA").[77] In addition, NQDC benefit plans are not covered by ERISA's requirements that certain funding levels be maintained.

As will be discussed later in my testimony, I am recommending that the cost of ETI's NQDC benefit plans be removed from any base rate consideration in this proceeding.[78] This includes removal of not only the O&M expense, but also amounts recorded in the pension and OPEB reserve account. Therefore, I recommend that the NQDC benefit plan portion of the pension and OPEB reserve account balance as of the test year end be excluded from rate base. My recommendation reduces ETI's proposed pension and OPEB reserve account by $225,344 as shown on Schedule CTC-4.[79]

Q. DOES YOUR RECOMMENDED ADJUSTMENT DOUBLE COUNT THE COMPANY'S ADJUSTMENT TO REMOVE COSTS RELATED TO ITS SUPPLEMENTAL EXECUTIVE RETIREMENT PLANS?

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[77] Internal Revenue Code ("IRC") § 401(a)(17).

[78] *See* Schedule CTC-7.

[79] *See* Schedule CTC-4.

A. No. Because ETI has already removed the costs for its supplemental executive retirement plans, the only NQDC benefit plan costs remaining in the case were for its restoration benefits plan. My adjustment removes the remaining restoration benefits plan costs.

V. RECOMMENDED ADJUSTMENTS TO O&M AND DEPRECIATION EXPENSE

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO ETI'S PROPOSED O&M AND DEPRECIATION EXPENSE.

A. As shown on Schedule CTC-1, I recommend that the Company's O&M expense and payroll taxes be reduced by $33.2 million,[80] before considering all attendant impacts. Of my recommended reduction to O&M expense, I am recommending that $12.6 million be included in the Retiring Plant Rate Rider.[81] With respect to ETI's proposed depreciation expense of $304.3 million,[82] I recommended a reduction to ETI's proposed base rate depreciation expense of $77.3 million.[83] Of this reduction to base rates, I have included $18.9 million of depreciation expense in the calculation of the Retiring Plant Rate Rider.[84] My specific adjustments to O&M expense and depreciation expense include the following:

A. Adjustment to Overtime Expense (including benefits and payroll tax impacts);

B. Adjustment to Short-Term Incentive Expense (including payroll tax impacts);

C. Adjustment to Pension and OPEB Benefits Expense;

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[80] *See Schedule* CTC-1 [($33,056,542) + ($127,902) = ($33,184,444)].

[81] *See* Schedule CTC-1 and Schedule CTC-2B(HSPM).

[82] RFP, Schedule A.

[83] *See* Schedule CTC-1 and Schedule CTC-9 (HSPM).

[84] *Id.*

D. Adjustment to Property Insurance (Storm Reserve) Expense; and

E. Adjustment to Depreciation Expense.

A. ADJUSTMENT TO OVERTIME EXPENSE

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING AN ADJUSTMENT TO ETI'S TEST YEAR OVERTIME EXPENSE.

A. Based on ETI's response to discovery, the test year overtime payroll expense was significantly higher during the 2020 and 2021 periods due to the Montgomery County Power Station beginning commercial operation and owing to Hurricane Laura.[85] Because these events will not be ongoing, it is necessary to normalize the amount of employee overtime that is included in rates.

Q. PLEASE EXPLAIN YOUR CALCULATION TO NORMALIZE THE OVERTIME EXPENSE TO BE INCLUDED IN RATES.

A. As shown on Schedule CTC-6A, I have averaged the direct employee overtime expense for the five-year period 2017-2021. The average overtime for this period is $12,875,237[86] as compared to the test year overtime of $14,673,127;[87] a reduction of $1,797,890. After applying the Company's O&M expense ratio of 49.61%,[88] my recommended adjusted to overtime expense is a reduction of $891,933.[89]

[85] See Attachment M, ETI Response to OPUC RFI No. 1-9.

[86] *See* Schedule CTC-6A.

[87] RFP, Schedule G-1.1.

[88] RFP, WP/ Schedule P – Volume 2, at 93.

[89] *See* Schedule CTC-6A.

Q. DO YOU HAVE ANY RELATED ADJUSTMENTS TO BENEFITS AND PAYROLL TAXES BASED ON YOUR RECOMMENDED ADJUSTMENT TO OVERTIME EXPENSE?

A. Yes. The Company provided the calculations for determining the impacts of its proposed direct employee payroll expense adjustments. I have used these same percentages in determining the impact to the savings plan benefits and payroll taxes for my recommended reduction of $891,933 to direct employee payroll expense. As shown on Schedule CTC-6A, I recommend a reduction to savings plan benefits of $43,705 and a reduction to payroll taxes of $79,917.[90]

B. ADJUSTMENT TO SHORT-TERM INCENTIVE COMPENSATION

Q. HOW HAS ETI CALCULATED THE COMPANY'S PROPOSED LEVEL OF SHORT-TERM INCENTIVE COMPENSATION INCLUDED IN ITS PROPOSED REVENUE REQUIREMENTS?

A. According to the testimony of ETI witness Ms. Jennifer A. Raeder, ETI is only requesting STI compensation expense based on non-financial performance metrics[91] because it has removed $256,998 of STI compensation awarded based on financial performance in its

[90] *Id.*

[91] Direct Testimony of Jennifer A. Raeder at 9.

Executive Annual Incentive Plan.[92] Based on ETI's response to OPUC RFI No. 5-3, ETI has included total STI compensation expense of $8,623,678.[93]

Q. DO YOU AGREE WITH THE ETI'S CALCULATION FOR DETERMINING THE APPROPRIATE LEVEL OF STI COMPENSATION?

A. No. The methodology used by ETI to determine an adjusted test year level of STI compensation is flawed. First, it does not appropriately limit the level of STI compensation based on the STI target percentages by employee. Second, it does not consider that four of its six STI compensation plans require that the calculation of the Entergy company performance multiplier demonstrate a certain threshold performance before any STI compensation will be funded for these four plans and that this performance multiplier includes a financial performance metric.[94]

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO ETI'S PROPOSED LEVEL OF STI COMPENSATION EXPENSE?

A. Yes. As shown on Schedule CTC-6B, I recommend that an additional $3,309,626 be removed from ETI's adjusted level of STI compensation expense.[95]

Q. PLEASE PROVIDE AN OVERVIEW OF THE PURPOSE OF THE STI COMPENSATION PLAN OFFERED TO ETI EMPLOYEES.

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[92] RFP, WP/Schedule P – Volume 2, at 107.

[93] See Attachment N, ETI Response to OPUC RFI No. 5-3 [$4,992,967 + $3,630,711 = $8,623,678].

[94] Direct Testimony of Jennifer A. Raeder, Exhibit JAR-1 (HSPM).

[95] *See* Schedule CTC-6B and Attachment O, ETI Response to Cities RFI No. 3-4.

A. As a component of an employee's total compensation, ETI offers its employees the opportunity to earn incentive compensation based on certain performance metrics. ETI witness Ms. Raeder states that the purposes of the STI incentive plans is to enable ETI to compete with other employers to attract and retain its employees.[96] As with most STI compensation structures, ETI establishes a ***target percentage*** for each employee. Two of the plans award employees based on individual or team performance, with the four largest plans requiring a certain level of overall Entergy performance as a multiplier to the performance of the individual employees[97] The multiplier is referred to as the Entergy Achievement Multiplier ("EAM").[98]

Q. PLEASE EXPLAIN THE MEANING OF "TARGET PERCENTAGE" AS IT RELATES TO STI COMPENSATION.

A. Under the terms of incentive compensation plans, the "target percentage" is the percentage of an employee's base compensation that may be paid as a STI award depending on (1) whether the Company reaches the threshold goals for any required funding trigger, and (2) if the employee meets individual or workgroup performance goals. Target STI compensation percentages are set for each employee, ostensibly based on comparable target percentages for similar jobs in the industry.[99] To the extent that Entergy's EAM meets the goals necessary to trigger the funding of the STI compensation for applicable

[96] Direct Testimony of Jennifer A. Raeder at 8.

[97] Direct Testimony of Jennifer A. Raeder at 13.

[98] Direct Testimony of Jennifer A. Raeder at 12.

[99] *See* Attachment P, ETI Response to OPUC RFI No. 1-10(a-e)(HSPM).

STI plans, the individual employee's "target percentage" will be used to determine the amount paid to that employee.

Q. DID ENTERGY ACHIEVE AN EAM THAT WAS GREATER THAN 100% IN THE 2021 PERFORMANCE YEAR?

A. Yes. Based on ETI Response to OPUC RFI No. 5-4:

> "For Entergy's funded incentive plans (EAIP, SMIP, OSIP, EXIP), the Entergy Achievement Multiplier of 125% was used to determine the 2021 annual incentive compensation funding pool for incentives paid in 2022."[100]

Q. HOW DOES A GREATER THAN 100% EAM AFFECT THE LEVEL OF STI COMPENSATION?

A. A greater than 100% EAM provides for funding the individual employee STI awards at a greater than individual target percentages.

Q. DID ETI EMPLOYEES RECEIVE STI COMPENSATION THAT WAS GREATER THAN THEIR RESPECTIVE TARGET PERCENTAGES?

A. Yes. Based on ETI's responses to OPUC RFI No. 1-10 (HSPM), the total STI compensation awarded to direct ETI employees was approximately [redacted] than STI compensation based on 100% of these employees' respective targets. ESI employees received [redacted] STI awards than these employees' respective targets.[101]

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[100] *See* Attachment Q, ETI Response to OPUC RFI No. 5-4.

[101] *See* Attachment P, ETI Response to OPUC RFI No. 1-10(a-e)(HSPM) and Cannady Workpapers – Incentive (HSPM).

Q. WHY IS IT INAPPROPRIATE TO INCLUDE STI COMPENSATION BASED ON AWARDS THAT ARE GREATER THAN THE TARGET PERCENTAGES FOR EACH EMPLOYEE?

A. One of the arguments offered by the Company in support of including STI compensation in rates is that STI incentive plans provide Entergy with the ability to attract and retain employees, which ETI argues will benefit customers.[102] However, STI percentages are not set per employee based on actual competing company STI compensation, but rather based on comparing the STI target percentages included in compensation studies, which include competing company information. Employees know what their respective STI target percentage is, but not what will actually occur in any given year. Therefore the level of STI compensation necessary to attract and retain employees should be limited to 100% of employee STI target percentages. The target percentage amount is known to the employee, whereas the actual STI awards are not known until the end of the STI plan period.

Q. HAVE OTHER TEXAS ELECTRIC UTILITIES FILED REVENUE REQUIREMENTS WITH LIMITS ON THE UTILITY'S STI COMPENSATION BASED ON 100% OF TARGET PERCENTAGE?

[102] Direct Testimony of Jennifer A. Raeder at 11.

A. Yes. In Docket No. 51415, SWEPCO made an adjustment to limit its STI compensation to 100% of employee targets.[103] Southwestern Public Service Company made a similar adjustment in Docket No. 51802.[104]

Q. HOW MANY OF THE DIRECT ETI EMPLOYEES WERE AWARDED STI COMPENSATION THAT WAS GREATER THAN 100% OF THE 2021 PERFORMANCE YEAR?

A. Based on ETI Response to OPUC RFI No. 1-10 (HSPM), [redacted] of direct ETI employees received STI compensation that was greater than 100% of their respective targets. [105] The total STI compensation awarded as a percentage of the total STI compensation at targets for all direct ETI employees was [redacted].[106]

Q. WHAT WAS THE AVERAGE PERCENTAGE OF TARGET THAT WAS AWARDED TO ESI EMPLOYEES FOR THE 2021 PERFORMANCE YEAR?

A. Again, based on ETI Response to OPUC RFI No. 1-10 (HSPM), [redacted] of ESI employees received STI compensation that was greater than 100% of their respective targets.[107] The total STI compensation awarded as a percentage of the total STI compensation at targets for all ESI employees was [redacted].

[103] *Application of Southwestern Electric Power Company for Authority to Change Rates,* Docket No. 51415, Direct Testimony of Brian J. Frantz at 12.. (Oct. 14, 2020).

[104] *Application of Southwestern Public Power Company for Authority to Change Rates,* Docket No. 51802, Direct Testimony of Stephanie N. Niemi at 52 (Feb. 8, 2021).

[105] Cannady Workpapers – Incentive (HSPM).

[106] *Id.*

[107] *Id.*

Q. WHAT IS THE IMPACT OF FIRST ADJUSTING THE INDIVIDUAL EMPLOYEE STI COMPENSATION TO TARGET FOR EMPLOYEES WHO RECEIVED AWARDS THAT WERE GREATER THAN TARGET?

A. As shown on Confidential Schedule CTC-7A, setting the level of STI compensation to the target percentages reduces the test year STI compensation by $1,630,576.[108]

Q. EXPLAIN THE IMPORTANCE OF THE EAM WHEN DETERMINING THE AMOUNT OF STI COMPENSATION THAT IS REASONABLY INCLUDED IN RATES.

A. The EAM is considered the "trigger" for payment of the STI compensation for four of the six STI plans[109] The funding level for each of the three plans is premised on Entergy's performance pursuant to the performance metrics of the EAM. Without meeting such performance metrics, the funding level could be reduced or eliminated.[110]

Q. DOES THE EAM INCLUDE PERFORMANCE MEASURES THAT ARE FINANCIALLY BASED?

A. Yes. In the 2021 STI plan year, the EAM was comprised of 60% of earning-per-share performance and 40% of other operational performance measures, including safety, diversity, environmental steward and customer service issues.[111] For the years 2018, 2019 and 2020, the EAM was based 100% on financial performance measures with an equal

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[108] *See* Schedule CTC-6B [$7,292,688 - $8,923,264 = ($1,630,576)].

[109] Direct Testimony of Jennifer A. Raeder, Exhibit JAR-1 (HSPM).

[110] *Id.*

[111] *See* Attachment R, Notice of 2022 Annual Meeting of Shareholders and Proxy Statement, at 6, 2021 Proxy Statement, at 7, and 2020 Proxy Statement, at 42, 2019 Proxy Statement, at 8.

weighting for earning-per-share and adjusted operating cash flow performance.[112] The EAM calculation was changed for the 2021 performance year.[113]

Q. WHY IS IT IMPORTANT THAT THE COMPANY DEMONSTRATE THAT THE STI COMPENSATION INCLUDED IN RATES BE BASED ENTIRELY ON OPERATIONAL PERFORMANCE MEASURES AND NOT ON FINANCIALLY BASED PERFORMANCE METRICS?

A. As demonstrated by the PUCT cases cited below, the PUCT has consistently found that incentive compensation awarded based on operational performance measures is recoverable in rates, while incentive compensation awarded based on financial performance measures cannot be included in rates. The findings generally state that financially based incentive compensation should be the responsibility of a company's shareholders, not the ratepayers. Specifically, the PUCT has provided the following rulings with respect to financially based incentive compensation:

1. SPS – Docket No. 43695

> "It is well-established that a utility may not include in its rates the costs of incentives that are tied to financial-performance measures. The Commission agrees with the SOAH ALJs' characterization of the annual incentive plan as 'complicated' and notes that when a utility elects to adopt a compensation plan that involves both financially-based and performance-based metrics, the utility still must show it has removed all aspects of the financially-based goals from its requested expense."[114]

2. Entergy Texas, Inc. – Docket No. 40295

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[112] *Id.*

[113] *Id.*

[114] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at 5 (Feb. 23, 2016).

"The Commission has ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services."[115]

3. SWEPCO – Docket No. 40443

"215. The PUC permits a utility to recover in its base rate incentives that are designed to achieve 'operational measures' and that are necessary and reasonable to provide utility services, but not incentive programs that are designed to achieve 'financial measures.'

216. Operational measures are those designed to encourage a utility's employees to meet goals and standards relating to the efficient operation of the utility, a benefit to shareholders and ratepayers alike.

217. Financial measures are those designed to encourage employees to achieve financial targets, a benefit primarily to shareholders."[116]

4. AEP Texas, Central Company - Docket No. 33309

"82. TCC's inclusion of annual and long-term incentive compensation related to financial incentives in cost of service is unreasonable because it is not necessary for the provision of T&D utility services."[117]

As provided in the Proposal for Decision with respect to incentive compensation as adopted by the Commission in Docket No. 40443:

[115] *Application of Entergy Texas, Inc. for Rate Case Expenses Pertaining to PUC Docket No. 39896*, Docket No. 40295, Order at 2 (May 21, 2013).

[116] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing at FOF Nos. 215-217 (Mar. 6, 2014).

[117] *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 33309, Order on Rehearing at FOF No. 82 (Mar. 4, 2008).

> "If an amount is identified as part of an incentive compensation program, then it will be subject to the Commission's tests to determine whether the incentives will be included in rate base."[118]

Based on this strong Commission precedent, an electric utility must definitively show that any incentive compensation included in rates was awarded based on operational performance measures and that any incentive compensation awarded based on financial performance measures has been excluded from rates.

Q. DOES ETI'S PROPOSED ADJUSTMENT EFFECTIVELY REMOVE ALL OF THE STI COMPENSATION THAT WAS AWARDED ON THE BASIS OF FINANCIAL PERFORMANCE?

A. No.

Q. WHAT HAS BEEN THE COMMISSION PRECEDENT FOR DETERMINING THE LEVEL OF STI COMPENSATION THAT WAS FUNDED BY MEANS OF A "TRIGGER" THAT CONTAINED FINANCIAL PERFORMANCE METRICS?

A. To the extent that the utility has not been able to specifically identify the amount of the STI compensation that was funded by means of the financial performance metrics included within a funding "trigger," the Commission has adopted a calculation of financially based STI by using one-half of the percentage that the financial based metric is of the total "trigger."[119]

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[118] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Proposal for Decision at 80 (May 20, 2013).

[119] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at 5-6 (Feb. 23, 2016) and *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Direct Testimony of Donna Ramas at 25 (Dec. 8, 2014).

Q. BASED ON THE 2021 EAM WITH 60% BASED ON FINANCIAL PERFORMANCE, ARE YOU RECOMMENDING THAT 30% OF THE STI FOR THOSE PLANS THAT REQUIRE THE USE OF THE EAM BE REMOVED FROM RATE CONSIDERATION?

A. Yes. As shown on Schedule CTC-6B, I have computed a reduction to ETI's STI compensation expense to reflect the 30% of the STI plans that are subject to the EAM as a "trigger" for funding.[120] Adjusting the applicable STI plans for the financial performance metric of the EAM "trigger" results in an additional reduction of $1,678,687 to the Company proposed STI expense.[121]

As discussed earlier in my testimony, a corresponding adjustment was made to remove the STI compensation capitalized during the test year. As shown on Schedule CTC-2C, the EAM in the years 2018 through 2020 was based on Entergy's EAM that was 100% based on financial performance. Therefore, the adjustment to capitalized STI compensation for the "trigger" in these years was at 50%; or one-half of 100%.[122]

C. ADJUSTMENT TO PENSION AND OPEB EXPENSE

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST WITH RESPECT TO PENSION AND OPEB BENEFITS EXPENSE.

A. The Company is requesting an adjusted pensions and OPEB benefits expense of

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[120] *See* Schedule CTC-6B.

[121] *Id.* [($3.309,262)(total adjustment) – ($1,630,576)(target adjustment) = ($1,678,687)(adjustment for "trigger")].

[122] *See* Schedule CTC-2C.

$9,827,958.[123] In addition, ETI is requesting a three-year amortization of the deferred pension and OPEB benefits reserve account with results in an annual amortization of $5,905,290.[124] The request includes employee benefits expense for both qualified and non-qualified pension plans, but completely removes all costs related to OPEB expense, which, in the test year, was a negative $5,674,398.[125]

Q. DO YOU AGREE WITH THE LEVEL OF EMPLOYEE BENEFITS EXPENSE REQUESTED BY THE COMPANY?

A. No. As shown on Schedule CTC-7, I recommend the follow adjustments to ETI's proposed pension and OPEB expense.

- Remove expenses related to the restoration benefits retirement plans;
- Reinstate the test year OPEB expense;
- Amortize the pension and OPEB reserve account for a 4-year period for those deferrals related to the annual net periodic benefit expense; and
- Amortize pension settlement costs over a 10-year period.

My total recommended adjustment to the Company's proposed pension and OPEB benefits expense is a reduction of $12,552,823 for a total recommended pension and OPEB expense of $3,180,425.[126]

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO EXCLUDE THE COMPANY'S RESTORATION BENEFIT RETIREMENT PLANS.

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[123] *See* Attachment S, ETI Response to Cities RFI No. 2-18.

[124] RFP, WP/Schedule P – Volume 2, at 63.

[125] RFP, WP/P AJ 17.1.

[126] *See* Schedule CTC-7.

A. Based on the direct testimony of ETI witness Ms. Raeder, the Company offers three restoration benefit retirement plans that are classified as NQDC and are for highly paid employees and executives.[127] In response to OPUC RFI No. 1-18, ETI has included $525,920 in direct ETI restoration benefits expense and $803,501 in ESI allocated restoration benefits expense.[128] I am recommending that the entire expense of $1,329,421 be disallowed.[129] As I have discussed earlier in my testimony, I am also recommending that the pension and OPEB reserve account exclude any NQDC benefits and, therefore, recommend that any amortization of these balances also be disallowed. My total recommended reduction to pension and OPEB expense for removal of NQDC benefits is $1,404,536.[130]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. As I have testified, ETI's restoration benefit retirement plans are NQDC non-funded pension benefit for certain executives and highly paid management employees.[131] The Company does not have a separate fund for its restoration benefits retirement plans and makes no regular contributions to such a plan.[132]

Q. WHY IS THE FACT THAT THESE RESTORATION BENEFIT RETIREMENT PLANS ARE NQDC NON-FUNDED BENEFIT PLANS IMPORTANT WHEN

[127] Direct Testimony of Jennifer A. Raeder at 44.

[128] *See* Attachment T, ETI Response to OPUC RFI No. 1-18.

[129] *See Schedule* CTC-7.

[130] *Id.*

[131] *See* Attachment T, ETI Response to OPUC RFI No. 1-18.

[132] *See* Attachment U, ETI Response to OPUC RFI No. 1-16 (Confidential).

DETERMINING THE REASONABLENESS OF PASSING ON SUCH BENEFITS EXPENSES TO RATEPAYERS?

A Unlike Entergy's tax-qualified pension plans, which are available to all qualified ETI and ESI employees and are managed via separate pension funds, the Company does not [redacted][133] The restoration benefits are paid on an as needed basis with the Company's available cash. In addition, there are no guarantees that the restoration benefits will be paid to the participants. Any funding that would be provided by ratepayers would not specifically be used to pay restoration benefits but would be used as the Company's general funds. In essence, any payment by ratepayers for the restoration benefits plans is cost-free capital to the Company, without any requirement that it be used to pay for restoration benefits. To appropriately include this type of benefits expense, there should be a deduction to rate base for the accumulated amount of restoration benefits expense paid for by ratepayers. The Company has not proposed such an adjustment to rate base. Therefore, NQDC is not reasonable or necessary to provide electric utility service to Texas ratepayers.

Q. HAS THE COMMISSION TAKEN A POSITION WITH RESPECT TO NQDC BENEFIT PLANS?

[133] *Id.* at 3.

A Yes. In recent decisions, the Commission has consistently disallowed the costs related to NQDC benefit plans for inclusion in rates. The following decisions provide some examples:

1. SWEPCO – Docket No. 46449

"227. SWEPCO's non-qualified executive retirement benefits in the amount of $191,007 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in SWEPCO's cost of service."[134]

2. Entergy Texas, Inc. – Docket No. 39896

"142. ETI's non-qualified executive retirement benefits in the amount of $2,114,931 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in ETI' s cost of service."[135]

Q. DID THE COMPANY REMOVE THE EXPENSE RELATED TO THE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP") AS IT DID IN DETERMINING THE PENSION AND OPEB RESERVE ACCOUNT BALANCE?

A Yes. The Company has removed $89,351 in SERP benefits from its pension and benefits expense.[136] My recommended reduction is in addition to this amount and does not double-count ETI's adjustment.

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT FOR THE REINSTATEMENT OF OPEB EXPENSE?

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[134] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 46449, Order on Rehearing at FOF No. 227 (Mar. 19, 2018).

[135] *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Cost, and Obtain Deferred Accounting Treatments*, Docket No. 39896, Order on Rehearing at FOF No. 142 (Nov. 2, 2012).

[136] RFP, WP/Schedule P – Volume 2, at 20.

A As shown on Schedule CTC-7, I am recommending a reinstatement of the test year negative OPEB expense of $5,674,698 for ETI direct employees. This amount, added to the Company's proposed ESI allocated OPEB expense of $558,166,[137] results in my recommended negative OPEB expense of $5,116,232. With respect to the amortization of the pension and OPEB reserve balance, I recommend an additional reduction of $775,770,[138] which provides for a four-year amortization of the reinstated negative reserve balance of $3,103,081.[139]

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO ETI'S PROPOSED REMOVAL OF COSTS RELATED TO OPEBS?

A As I have testified, PURA § 36.065 provides for the recovery of pension and OPEB expense based on the most recent actuarially determined costs. PURA § 36.065 does not provide for differing treatments of these types of expenses just because the result is a negative expense. In essence, ETI's proposed removal of all OPEB expense from its request is inconsistent with its previous treatment of these results, even when the results were negative in the past.[140] In addition, Mr. Batten's argument that in order to reduce rates due to a negative OPEB expense, the Company would have to use its own funds to pay ratepayers is disingenuous. There is no specific tracking of any of the monies received from ratepayers through rates for pension and OPEB benefits to determine if ratepayers

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[137] *See* Attachment T, ETI Response to Cities RFI No. 2-18.

[138] *See* Schedule CTC-7.

[139] RFP, WP/Schedule P – Volume2, at 63.

[140] *See* Attachment K, Rate Filing Package, Docket No. 48371, Bates Stamp 5614.

have paid more or less than what ETI has deposited into its separate pension and OPEB funds.[141]

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO ETI'S REQUESTED AMORTIZATION PERIOD FOR THE PENSION PORTION OF ITS RESERVE ACCOUNT.

A First, I am recommending that those components appropriately included in the pension portion of the reserve account should be amortized no sooner than during the four years before the next general rate case is required to be filed.[142] I have adjusted the deferrals for the net periodic pension expense based on this four-year amortization. This recommendation reduces the pension expense by $1,457,561.[143] Second, I am recommending that the settlement costs included as a deferral for pension expense be amortized over a ten-year period. This recommendation reduces ETI proposed amortization expense by an additional $1,836,022, for a total reduction of $3,293,583, as shown on Schedule CTC-7.[144]

Q. WHY ARE YOU RECOMMENDING A TEN-YEAR AMORTIZATION PERIOD FOR THE PENSION SETTLEMENT COSTS?

A As I understand the testimony of Mr. David Batten, the settlement pension costs are due to an immediate recognition of pension lump sum payments that exceed the net periodic

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[141] Pension and OPEB funding are determined by the actuarial studies and not based on that portion of the rates that was specifically related to approved pension and OPEB expenses.

[142] 16 TAC § 25.246.

[143] Cannady Non-Confidential Workpapers.

[144] *See Schedule* CTC-7.

pension benefits cost actuarially determined. [145] ETI began to experience settlement cost in 2020[146] after amending certain of its qualified pension plans to allow employees to receive lump-sum distributions of their pension benefits.[147] ETI witness Ms. Jennifer Raeder provided the following statement:

> "By allowing participants to receive lump-sum distributions, ETI is able to reduce the size and rate of growth of the pension liability, which in turn reduces ETI's and customers' exposure to changing market conditions. . . It also reduces the payment of premiums to the Pension Benefit Guaranty Corporations and administrative expense from pension trust assets. However, in the near term, the additional of the limp-sum feature has resulted in increased volatility in the accounting recognition for pension costs through settlement accounting. Entergy expects that this increased volatility in pension costs relating to the lump sum distributions from the plans will continue in the near term. . ."[148]

In its proposal, ETI has included a three-year amortization of the total deferred settlement costs but has made no attempt to estimate the potential cost reduction on pension expense that is expected to occur during the time rates from this proceeding will be in effect. With an expected reduction pension expense, requesting that all the settlement costs be collected from customers without any consideration for the expected pension expense reduction is inappropriate.

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[145] Direct Testimony of David C. Batten at 6.

[146] *See* Attachment V, ETI Response to OPUC RFI No. 1-15.

[147] Direct Testimony of Jennifer A. Raeder at 68.

[148] *Id.* at 68-69.

Q. HOW HAVE YOU DETERMINED THAT NET PERIODIC PENSION EXPENSE WILL BE LESS THAN THE AMOUNT FROM THE 2021 ACTUARIAL STUDY?

A In response to OPUC RFI No. 8-20 (HSPM), ETI shows that net period pension expense is estimated [redacted][149] Therefore, I am recommending a longer amortization period for the settlement costs that not only provides for collection of the settlement costs, but also allows for the opportunity to incorporate the lower pension expense before settlement costs are fully recovered. With a ten-year amortization, a review of the lower pension expense can be determined in the next general rate case.

D. ADJUSTMENT TO PROPERTY INSURANCE RESERVE ACCRUAL

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST WITH RESPECT ITS ANNUAL ACCRUAL FOR ITS PROPERTY INSURANCE RESERVE.

A. ETI witness Mr. Gregory S. Wilson recommends including an annual property insurance accrual of $14,555,000.[150] Mr. Wilson's recommendation is based on a Monte Carlo Simulation model, that, based on his assumptions, results in an annual storm expense of $6,315,000 and an additional accrual of $8,240,000 to achieve a property insurance reserve balance of $15,244,000 over a four-year period.[151] Mr. Wilson's analysis excludes projected storms with non-capital costs in excess of $26.32 million under the assumption

[149] *See* Attachment W, ETI Response to OPUC RFI No. 8-20 (HSPM).

[150] Direct Testimony of Gregory S. Wilson, at 4.

[151] *Id.* at 5.

that ETI will propose to securitize these storm related costs.[152]

Q. DO YOU AGREE WITH MR. WILSON'S ANALYSIS?

A. Not entirely. Based on the catastrophic non-capital related storm expenses incurred by ETI as trended to current costs, the Company has not experienced a single storm of $26.32 million (that has not been securitized) since 2007.[153] Therefore, I recommend that the Monte Carlo simulation provide for limited single storm costs using the 2020 single largest trended storm expense of $16,194,787.[154] In addition, based on the total trended storm expense for 2020 of $21,279,726,[155] I recommend that any series of storms in any given year be limited to $22.0 million. Making these changes to the Monte Carlo simulation model results in an average annual storm expense of $6,185,000.[156]

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE PROPERTY INSURANCE RESERVE TARGET?

A. Based on my recommended changes to the Monte Carlo simulation model, I am recommending a target balance for the property insurance reserve of $14,778,000.[157] This compares to the $15,244,000 proposed by Mr. Wilson.[158] As shown on Schedule CTC-8, the additional accrual to achieve the target balance over the next four year is $3,695,000

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[152] *Id.* at 9.

[153] *Id.*. WP/GSW Testimony.

[154] *Id.* WP/GSW Testimony.

[155] *Id.* Exhibit GSW-3.

[156] *See* Schedule CTC-8.

[157] Cannady Workpapers, Storm Expense.

[158] Direct Testimony of Gregory S. Wilson, at 5.

per year.[159]

Q. ARE YOU RECOMMENDING ANOTHER ADJUSTMENT TO ETI'S PROPOSED PROPERTY INSURANCE ACCRUAL?

A. Yes. Mr. Wilson also proposes to replace the test year end negative property insurance reserve balance of $17.73 million over the next four years; or an annual accrual of $4,429,000. I disagree. The vast majority of the negative balance is due to the additional expense of $15.8 million incurred for Hurricane Laura restoration activities that was not included in ETI's securitization of Hurricane Laura costs. When asked to explain the reasoning for including hurricane costs related to single storm costs that have been securitized separately, ETI provided the following:

> "The $15.8 million referenced in OPUC 1-3 are the expenses associated with the Company's storm restoration activities for Hurricane Laura that were not included in the amount authorized for securitization in Docket No. 51997 either as a result of the settlement agreement in Docket No. 51997 or because the final invoices were processed subsequent to the amounts included for approval in Docket No. 51997."[160]

Given that Hurricane Laura costs comprise approximately 90% of the test year negative balance in the property insurance reserve account,[161] I am recommending that this negative balance be reinstated over the next 20-year period for an annual recovery of $887,000.[162]

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[159] *See* Schedule CTC-8.

[160] *See* Attachment X, ETI Response to OPUC RFI No. 4-6.

[161] $15.8(Hurricane Laura) ÷ $17.73 (negative balance) = 89.1%.

[162] *See* Schedule CTC-8.

Q. PLEASE EXPLAIN.

A. Based on the Company's ability to securitize catastrophic storm expenses, ETI should not be allowed to recover any expenses related to such storms in a manner that is significantly faster than through the securitization mechanism; e.g. securitization bonds. In Docket No. 51997, the parties did agree that the Company could pursue recovery of any additional costs related to Hurricane Laura in a future filing, but also provided that the ". . . other parties retain the right to take whatever positions they wish with respect to the reasonableness or prudence of such costs."[163] Given that the financial instruments used to securitize these types of storm costs typically have amortization periods significantly greater than four years, my recommendation of 20 years provides for the recovery over a period that more reasonably balances the benefits to both shareholders and ratepayers.

Q. HAS THE COMPANY REQUESTED A 20-YEAR PERIOD TO RECOVER A NEGATIVE PROPERTY INSURANCE BALANCE IN THE PAST?

A. Yes. In Docket No. 41791, ETI's witness Mr. Gregory Wilson proposed a 20-year accrual to the property insurance reserve to recover the then negative balance of $55.9 million.[164]

E. ADJUSTMENT TO DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S PROPOSED DEPRECIATION EXPENSE FOR PRODUCTION PLANT.

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[163] *Application of Entergy Texas, Inc. for Determination of System Restoration Costs,* Docket No. 51997, Unopposed Settlement Agreement at 3. (Sept 28, 2021).

[164] *See* Attachment Y, ETI Response to Commission Staff RFI No. 4-2.

A. I am recommending three distinct adjustments to the Company's proposed depreciation expense for production plant. First, I recommend that ETI's proposed depreciation expense related to plants for which ETI estimates deactivation dates between [redacted] be removed from rate base and an annual depreciation expense based on current rates be included in my recommended Retiring Plant Rate Rider. As shown on Schedule CTC-9 (HSPM), I have removed [redacted][165] from base rates based on ETI's proposed annual depreciation expense related to these plants. Second, I am also recommending that the depreciation rates for the Nelson Unit 6 and Nelson Common assets continue to be depreciated at the current rates and not accelerated to match a deactivation date that is [redacted] than the original retirement date for this generating station.[166] This adjustment reduces ETI's proposed depreciation expense by [redacted].[167] Finally, based on the recommendation of Mr. Evan Evans, I have removed the $126,869 of depreciation expense for the H.E.B generators as proposed by the Company.[168] My total recommended adjustment to base rate depreciation expense is a reduction of $77,295,218.[169]

Q. ARE YOU RECOMMENDING THAT A PORTION OF THIS REDUCTION TO BASE RATE DEPRECIATION EXPENSE BE INCLUDED IN THE RETIRING PLANT RATE RIDER?

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[165] *See* Schedule CTC-9(HSPM).

[166] RFP, Direct Testimony of Anastasia R. Meyer, Exhibit ARM-2(HSPM) and Attachment B, Rate Filing Package, Docket No. 48371, 2018, Schedule D-6.

[167] *See* Schedule CTC-9(HSPM).

[168] RFP, WP/Schedule P-Volume, WP/PAJ 12.6.

[169] *See* Schedule CTC-1 and Schedule CTC-9 (HSPM).

A. Yes. As shown on Schedule CTC-1, I have computed the depreciation expense for the Retiring Plant Rate Rider. I have computed the depreciation for the Retiring Plant Rate Rider based on the current depreciation rates for those plants. As shown on Schedule CTC-1, with the detailed calculation included on Schedule CTC-9 (HSPM), I recommend that the Retiring Plant Rate Rider include annual depreciation expense of $18,902,444.[170] To the extent that the Commission adopts depreciation rates for these generation plant assets that are different from the current rates, the depreciation expense included in the Retiring Plant Rate Rider should be adjusted accordingly.

Q. WHY ARE YOU RECOMMENDING THAT THE NELSON UNIT 6 AND NELSON COMMON ASSETS BE DEPRECIATED AT CURRENT RATES?

A. In prior cases, this Commission has determined that early retirement of a plant should not result in an accelerated recovery of production plant assets to match any planned early retirement. Specifically, in Docket No. 46449, SWEPCO requested approval of the early retirement of Welsh Unit 2. In that proceeding, the Commission allowed SWEPCO to recover the undepreciated balance as of the early retirement but based on the original retirement date resulting in a recovery period of 24 years.[171] Also concerning SWEPCO, the Commission found that the requested early retirement of Dolet Hills should have a undepreciated balance recovery period based on its original retirement date.[172] Therefore,

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[170] *Id.*

[171] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 46449, Order on Rehearing at FOF No. 70 (Mar. 19, 2018).

[172] *See* Docket No. 51415, Order at FOF No. 61 (Jan. 14, 2022).

I am recommending that the depreciation rates for Nelson Unit 6 and Nelson Common continue to reflect the original retirement date for this proceeding. When the plant is ultimately deactivated, the remaining balance at that time should be amortized over the plant's original life without any return included in rates.

VI. TESTIMONY SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission:

1. Remove all revenue requirement components related to the continued operations of those plants for which ETI plans to deactivate between [redacted] and recover such costs via a Retiring Plant Rate Rider. The portion of the rider that is related to each plant would only remain in effect during the time the plant is used and useful in providing electric service to Texas retail customers.

2. Adjust the fuel inventory to remove the fuel requirement to be included in the Retiring Plant Rate Rider and reduce the natural gas inventory at Spindletop to reflect the actual use of the inventory for meeting Sabine burn requirements.

3. Adjust the pension and OPEB reserve account to:

    a. Reinstate the negative OPEB reserve balance;

    b. Remove the NQDC portion of the reserve balance; and

    c. Reflect an average balance of the reserve account to reflect the annual amortization included in expense.

4. Normalize the level of overtime pay to reflect a five-year average.

5. Require ETI to re-compute the Company's STI compensation adjustment to address the following:

    a. Adjust the STI compensation by employee to reflect 100% of target payment; and

    b. Remove one-half of the amount of STI compensation awarded via STI Plans that would not be funded without the financial based trigger.

6. Adjust the pension and OPEB expense to address the following:
    a. Reinstate the negative OPEB expense for the test year;
    b. Remove all expenses related to NQDC plans;
    c. Change the amortization rate of the pension and OPEB reserve balance to 4 years except for the pension settlement costs; and
    d. Amortize the pension settlement costs over a ten-year period.
7. Adjust the property insurance reserve accrual as follows:
    a. Establish an annual accrual for storm expense and target reserve that is based on a Monte Carlo Simulation calculation that limits the highest single storm to one experienced by ETI in 2020 and limit the annual storm expense to the 2020 total storm expense; and
    b. Amortize the negative property insurance reserve over a 20-year period similar to that recommended by ETI in Docket No. 41791.
8. Adjust depreciation expense as follows:
    a. Remove ETI's proposed depreciation expense for those plants that may be deactivated between [redacted];
    b. Include depreciation expense in the Retiring Plant Rate Rider based on current depreciation rates;
    c. Adjust the proposed depreciation expense for Nelson Unit 6 and Nelson Common to reflect current depreciation rates: and
    d. Remove the depreciation expense for the H.E.B. generator as recommended by Mr. Evan Evans.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to amend and supplement my testimony based on the receipt of ETI's pending responses to OPUC's 12th request for information filed October 17, 2022, and any outstanding supplemental responses by ETI to OPUC's requests for information.

SCHEDULES

PROVIDED ELECTRONICALLY

(Public and Highly Sensitive)

ATTACHMENTS

Connie Cannady

With over thirty-five years of financial and managerial consulting experience, Connie Cannady is an expert in the areas of utility regulation and franchising of utility services, both at the local and state level. She was employed at NewGen Strategies and Solutions, LLC (NewGen) from 2012-2021 and at J. Stowe & Co. from 2008 to 2012 with the formation of NewGen. Prior to joining J. Stowe & Co., Ms. Cannady was the Founder and President of C2 Consulting Services, Inc., a woman-owned business enterprise. Ms. Cannady's previous experience also includes serving as a Manager at Reed-Stowe & Co. Inc.; Manager of Accounting and Control for the Information Services Division of Blue Cross of California; Senior Consultant for Touché Ross & Co. (now Deloitte); and Management Auditor for the U.S. General Accounting Office.

EDUCATION

- Master of Public Affairs, University of Texas
- Bachelor of Arts in Political Science, Vanderbilt University

KEY EXPERTISE

- Expert Witness and Litigation Support
- Regulatory Proceedings
- Utility ROW Franchising and Compensation
- Cost Allocation Models

RELEVANT EXPERIENCE

Expert Witness and Litigation Support

Ms. Cannady served as project manager and lead analyst for numerous regulatory proceedings for rates, assisting clients by providing expert testimony and litigation support regarding utility rate and regulatory issues before state and local regulatory bodies and courts. She frequently works with coalitions of cities served by investor-owned utilities and provides analyses and expert witness support related to the utilities' requests for rate increases. Ms. Cannady also provided support services to the U.S. Army Corp of Engineers concerning rate proceedings impacting utility rates at U.S. Army installations.

Her direct experience includes conducting analyses with respect to the reasonableness of various rate base issues, including the prudency of costs. Areas of analysis and provided testimony include:

- Reasonableness of certain rate based costs related to benefits and other operating reserves
- Calculation of Accumulated deferred income taxes
- Reasonableness of operations and maintenance expenses related to labor expense, benefits expense, including health and welfare, pension, deferred compensation, ESOPs and other savings plans, corporate overhead cost allocation methodologies, call center operations, bonuses and other long and short-term incentive pay programs, taxes other than income and federal income taxes.
- Reasonableness of affiliated transaction expenses
- Computation of fuel factors and purchase power factors to be used in the collection of power costs
- Reasonableness of certain advanced meter investments
- Reasonableness of requested inclusion of certain regulatory assets
- Analysis of the "used and useful" nature of requested plant additions
- Analysis of customer class cost allocation methodologies

Ms. Cannady's expert witness and litigation support clients include:

Maryland Public Service Commission

- U.S. Army Installations Served by Baltimore Gas & Electric; Case Nos. 9355 and 9406

New York Public Service Commission

- U.S. Army Installations Served by Orange & Rockland Utilities; Case Nos. 14-E-0493 and 14-G-0494

Public Utility Commission of Texas

- Cities Served by CenterPoint Energy Houston Electric; Dockets Nos. 48266, 45747and 12065
- Cities Served by Southwestern Electric Power Company (SWEPCO), Texas; Docket Nos. 37364, 39708, 40443, 40446
- Cities Served by AEP Texas Central Company, Texas; Docket No. 33309
- Cities Served by AEP Texas North Company, Texas; Docket Nos. 33310, 4202 and 4716
- Cities Served by Sharyland Utilities, Texas; State Office of Administrative Hearings (SOAH); Docket No. 473-99-2566, and Docket No.51611
- Cities Served by Texas-New Mexico Power Company, Texas; Docket Nos. 15560, 12900, 10200, 22636, 36025, 22745
- Cities served by Oncor Electric Delivery Company, Texas; Docket Nos. 48325, 48231, 5640
- Cities served by Entergy Texas; Docket No. 51381, 51381, 48371 and 4510
- Cities Served by General Telephone Company of the Southwest (Verizon); Docket Nos. 4300 and 5011
- Project No. 14400 - Integrated Resource Planning
- Office of Public Utility Counsel – AEP Texas, Inc. Docket No. 49494
- Office of Public Utility Counsel – SPS Docket No. 49831 and Docket No. 51802
- Office of Public Utility Counsel – SWEPCO Docket No. 51415
- Office of Public Utility Counsel – Entergy Texas, Inc. Docket No. 48371
- Office of Public Utility Counsel – Sharyland Utilities, LLC Docket No. 51611

North Carolina Utilities Commission

- Duke Energy Progress – Docket No. E-2 SUB 1142

Oklahoma Corporation Commission

- Arkansas Oklahoma Gas Corporation; Cause No. PUD 001346

Railroad Commission of Texas

- CenterPoint Energy Entex; Docket GUD Nos. 9654, 9902, 10038, 10182, 10432, 10567, and 10920
- Atmos Energy; Docket GUD Nos. 9670, 10000, 10170, 10174, 10359, 10580, and 10900
- Texas Gas Services, Docket GUD Nos. 10488, 10526, 10766 and 10928
- TXU Gas; Docket No. GUD 9400
- TXU Gas Transmission; Docket No. GUD 8935
- Lone Star Gas Company Gate Rate; Docket No. GUD 8664
- Lone Star Gas Company Gate Rate; Docket No. GUD 3543

Arizona Corporation Commission

- Arizona Public Service Company, Arizona; Docket No. U-1345-82-266.

New Mexico State Corporation Commission

- Continental Telephone Company of the West; Docket No. 942
- General Telephone Company of the Southwest; Docket No. 990

Colorado Public Utilities Commission

- Southern Colorado Power - Cost Allocation Study

Alabama Public Service Commission

- Alabama Power Company - Fuel Procurement Review

Indiana Regulatory Commission

- Northern Indiana Public Service Company – Cause No. 44733-TDSIC-2

- Office of Public Utility Counsel – El Paso Electric Docket No. 52195

FERC

- NESCOE, Docket No. ER18-1639 regarding Constellation Mystic Power, LLC
- Northern Indiana Public Service Company-Cause No. 44733-TDSIC-3
- Northern Indiana Public Service Company Cause No. 45159
- Indiana Michigan Power Company Cause Nos. 45325 and 45576

Cost Allocation Modeling

Ms. Cannady has conducted cost allocation modeling for municipal utility clients. She has developed a cost allocation model (CAM) for allocating all utility overhead as well as the city's general fund overhead to the functions of production, distribution and transmission. The objectives of these studies were to more accurately reflect the fully loaded transmission costs to be separated from distribution costs in deregulated utility markets. The CAM models also include functionalizing the aggregated capitalized interest so that the value of the utility assets can be more accurately reported. Ms. Cannady has also assisted municipal clients in developing a cost allocation model to be used by the city to allocate general fund costs to each of its enterprise operations, including the electric utility, water and wastewater, and solid waste. Finally, Ms. Cannady has reviewed the appropriateness of cost allocation methodologies used by utility operations when developing rates. Her cost allocation projects include:

- Develop CAM model for Garland Power & Light, Garland, Texas
- Develop CAM model for Water and Wastewater Operations - City of Garland, Texas
- Review of Overhead Cost Allocations – Lower Colorado River Authority
- Review of Cost Allocation for Maintenance Activities – San Jacinto River Authority
- Develop Indirect Cost Allocation Model – City of Greenville, Texas
- Develop Indirect Cost Allocation Model – City of Denton Texas
- Develop Indirect Cost Allocation Model – City of Terrell, Texas
- Develop Indirect Cost Allocation Model – City of Brenham, Texas

Franchising of Utility Service in Municipal Right-of-Way

Ms. Cannady has assisted numerous municipalities/counties in negotiating franchises that allow utility service providers to construct in the municipalities' rights-of-way. In addition, Ms. Cannady has assisted in reviewing the actual payments made by the utilities to determine the accuracy of such payments in accordance with franchise terms or state and federal laws. She has assisted municipalities/counties in Texas, California, Washington, New York, Missouri, Illinois, Massachusetts, Maine and Kentucky. The majority of the projects concern the payment of cable services, but many of the projects have also involved review of franchising terms and payments from natural gas utility operations, electric service operations and telecommunications services.

Right-of-Way Costs

Ms. Cannady has conducted analysis of the costs incurred by municipalities in allowing utilities to have ubiquitous access to the Right-of-Way. Her clients include:

- City of Durham, North Carolina
- City of Atlanta, Georgia
- City of Cheyenne, Wyoming
- City of Tucson, Arizona
- Texas Municipal League, Texas

WORKSHOPS AND PRESENTATIONS

Ms. Cannady is an instructor on behalf of Electric Utility Consultants, Inc. (EUCI), co-authoring and presenting witness preparation materials at multiple conferences and speaking on related topics at industry forums. Her experience includes:

NARUC Staff Subcommittee on Accounting & Finance

- *Expert Witness Techniques*

Electric Utility Consultants, Inc. (EUCI)

- *EUCI Witness Preparation Training Conferences* (six conferences in 2013, 2014, 2016, 2017 2018, and 2019

Government Finance Officers Association of Texas

- *Franchise Fees – Accuracy and Compliance*
- *Franchise Fees, Identifying the Issues*

Texas Association of Telecommunications Officers and Advisors

- *Effective Competition: A Case Study - The City of Denton*
- *Customer Service Issues*
- *Issues Regarding Cable Television Franchise Payments*

National Association of Telecommunications Officers and Advisors

- *Hooray for Competition*
- *Prime Real Estate: Managing the Public Rights-of-Way*

The ABC's of Energy Conference

- *Rate Making Issues*

Oklahoma Municipal League

- *Cable Rights*

Federal Bar Association

- *Basics of Cable Television Regulation*

Record of Testimony Submitted by Connie Cannady

Utility	Proceeding	Subject of Testimony	Before	Client	Date
1. Texas-New Mexico Power Company	Docket No. 53436	Treatment of Corporate Overhead and Depreciation including in Distribution Cost Recovery Factor.	Public Utility Commission of Texas	Alliance of Texas-New Mexico Municipalities	2022
2. El Paso Electric Company	Docket No. 52195	Cost recovery for retiring plants, payroll, incentive compensation, and benefits expenses	Public Utility Commission of Texas	Office of Public Utility Counsel	2021
3. Indiana Michigan Power Company	Cause No. 45576	Treatment of Requested Deferred Tax Asset and EDIT Refund, AMI Deployment Cost Recovery	Indiana Utility Regulatory Commission	Cities of Marion, Fort Wayne, and South Bend, Indiana	2021
4. Southwestern Public Service Company – Xcel Energy	Docket No. 51802	Cost recovery of production related assets for coal and wind facilities and incentive compensation for direct and service company employees	Public Utility Commission of Texas	Office of Public Utility Counsel	2021
5. SWEPCO	Docket No. 51415	Rate Base and Operating Income Issues	Public Utility Commission of Texas	Office of Public Utility Counsel	2021
6. Sharyland Utilities, LLC	Docket No. 51611	Revenue Requirements for Transmission Cost of Service	Public Utility Commission of Texas	Office of Public Utility Counsel	2021
7. Entergy Texas, Inc.	Docket No. 51381	Cost Components of New Generation Facility	Public Utility Commission of Texas	Office of Public Utility Counsel	2020
8. Time Warner Cable Texas et.al	Case No. 6:19-cv-345-ADA-JCM	Audit of Franchise Fees and PEG Fees (expert report filed)	US District Court – Western District of Texas	Cities Served by Time Warner Cable and Charter Communications d/b/a Spectrum	2020
9. Comcast Cable	Civil Action No. 4:19-CV-00458	Audit of Franchise Fees and PEG Fees (expert report and deposition)	US District Court - Southern District of Texas	Cities Served by Comcast Cable	2020
10. Texas Gas Services	GUD No. 10928	Revenue Requirements, labor and labor related expenses, storm reserve, impacts of TCJA	Railroad Commission of Texas	Cities Served by Texas Gas Utilities	2020
11. Southwestern Public Service Company – Xcel Energy	Docket No. 49831	Cost recovery of production related assets for coal and wind facilities and incentive compensation for direct and service company employees	Public Utility Commission of Texas	Office of Public Utility Counsel	2020

Record of Testimony Submitted by Connie Cannady

Utility	Proceeding	Subject of Testimony	Before	Client	Date
12. CenterPoint Energy Entex Beaumont/East Texas Division	GUD No. 10920	Treatment of labor related incentive compensation, pension and OPEB benefits, amortization of regulatory assets, and treatment of non-qualified pension benefits	Railroad Commission of Texas	East Texas Coalition of Cities	2020
13. Atmos West Texas Triangle Pipeline	GUD No. 10900	Treatment of labor related incentive compensation and excess deferred taxes from passage of TCJA	Railroad Commission of Texas	West Texas Cities	2019
14. Indiana Michigan Power Company	Cause No. 45235	Treatment of Tax Rate Change and EDIT Refund, Nuclear Decommissioning Fund, Recovery of Plant Investment, AMI Deployment	Indiana Utility Regulatory Commission	Cities of Marion and Fort Wayne, Indiana	2019
15. AEP Texas, Inc	Docket No. 49494	Revenue Requirements, labor and labor related expenses, storm reserve, impacts of TCJA	Public Utility Commission of Texas	Office of Public Utility Counsel	2019
16. Northern Indiana Public Service Company	Cause No. 45159	Treatment of Corporate Tax Rate Change and EDIT and Depreciation on Early Plant Retirement	Indiana Utility Regulatory Commission	U.S. Steel Corporation	2019
17. Constellation Mystic Power, LLC	Docket No. ER18-1639	Cash Working Capital, Overtime Expense, Incentive Pay, TCJA Impacts and True-Up Protocols	Federal Energy Regulatory Commission	New England States Committee on Electricity	2018
18. Entergy Texas, Inc.	Docket No. 48371	Post Test Year Adjustment, Storm Regulatory Assets, Retired Plant, Employee Benefits, Treatment of Excess Deferred Income Taxes	Public Utility Commission of Texas	Office of Public Utility Counsel	2018
19. Oncor Electric Service Company	Docket No. 48325	Proposed amortization of excess deferred income taxes, refund of income tax overcharges since January 1, 2018 and appropriate carrying charges	Public Utility Commission of Texas	Alliance of Oncor Cities	2018
20. Oncor Electric Service Company	Docket No. 48231	Proposed CIS Depreciation Rate and treatment of Corporate Tax Rate	Public Utility Commission of Texas	Alliance of Oncor Cities	2018

Record of Testimony Submitted by Connie Cannady

Utility	Proceeding	Subject of Testimony	Before	Client	Date
		Change in Distribution Cost Recovery Tracker Rate			
21. CenterPoint Energy Houston Electric	Docket No. 48226	Treatment of Corporate Tax Rate Change in Distribution Cost Recovery Tracker Rate	Public Utility Commission of Texas	Texas Coast Utilities Coalition	2018
22. CenterPoint Energy Entex South Division	GUD No. 10669	Rate Base and Operating Income Issues, Affiliated Charges, Treatment of Excess Deferred Income Taxes (Settled)	Railroad Commission of Texas	Alliance of CenterPoint Municipalities	2018
23. Northern Indiana Public Service Company	Cause No. 44733-TDSIC-3	Treatment of Corporate Tax Rate Change and EDIT	Indiana Utility Regulatory Commission	U.S. Steel Corporation	2018
24. Duke Energy Progress	Docket No. E-2 SUB 1142	Cancelled Plant Prudency, Deferred Asset Treatment, Benefits	North Carolina Utilities Commission	U.S. Dept. of Defense and Other Federal Agencies	2017
25. Northern Indiana Public Service Company	Cause No. 44733-TDSIC-2	Tax Gross-Up Treatment in Investment Tracker	Indiana Utility Regulatory Commission	U.S. Steel Corporation	2017
26. Atmos Pipeline Texas	GUD No. 10580	Rate Base and Operating Income Issues, ADIT NOL	Railroad Commission of Texas	Atmos Cities Steering Committee	2017
27. CenterPoint Energy Entex Texas Gulf Division	GUD No. 10567	Rate Base and Operating Income Issues, Affiliated Charges	Railroad Commission of Texas	Gulf Coast Coalition of Cities	2017
28. CenterPoint Energy Houston Electric	Docket No. 45747	Allocation of Certain Corporate Costs included in DCRF rate adder	Public Utility Commission of Texas	Texas Coast Utilities Coalition	2016
29. CenterPoint Energy Entex	GUD No. 10432	Rate Base and Operating Income Issues, Affiliated Charges	Railroad Commission of Texas	Texas Coast Utilities Coalition	2015
30. Baltimore Gas and Electric	Case No. 9355	Rate Base and Operating Income Issues, Cost Allocation Issues	Maryland Public Service Commission	U.S. Dept. of Defense and Other Federal Agencies	2014
31. Atmos Energy	Docket No. 10359	Rate Base and Operating Income Issues	Railroad Commission of Texas	Atmos Cities Steering Committee	2014
32. SWEPCO	Docket No. 40443	Rate Base and Operating Income Issues	Public Utility Commission of Texas	Cities Served by SWEPCO	2012
33. CenterPoint Energy Entex	GUD No. 10182	Rate Base and Operating Income Issues	Railroad Commission of Texas Case Settled Before Hearing	East Texas Cities	2012

Record of Testimony Submitted by Connie Cannady

Utility	Proceeding	Subject of Testimony	Before	Client	Date
34. Atmos Energy	GUD No. 10174	Rate Base and Operating Income Issues	Railroad Commission of Texas	West Texas Cities Steering Committee	2012
35. Atmos Energy	GUD No. 10170	Rate Base and Operating Income Issues	Railroad Commission of Texas	Atmos Cities Steering Committee	2012
36. CenterPoint Energy Entex	GUD No. 10038	Rate Base and Operating Income Issues	Railroad Commission of Texas	Steering Committee of Cities Served by CenterPoint South Texas Division	2011
37. Atmos Energy	GUD No. 10000	Rate Base and Operating Income Issues	Railroad Commission of Texas	Atmos Cities Steering Committee	2010
38. Texas-New Mexico Power Company	Docket No. 38480	Rate Base and Operating Income Issues	Public Utility Commission of Texas	Cities Served by TNMP	2010
39. CenterPoint Energy Entex	GUD No. 9902	Labor Costs, Group Benefits, and Valorem Taxes	Railroad Commission of Texas	Gulf Coast Coalition of Cities Served by CenterPoint Houston Division	2009
40. AEP – Texas Central Company	Docket No. 33309	Labor Costs, Group Benefits, and Energy Efficiency Program Costs	Public Utility Commission of Texas	Cities Served by AEP Texas Central Company	2007
41. AEP – Texas North Company	Docket No. 33310	Labor Costs, Group Benefits, and Energy Efficiency Program Costs	Public Utility Commission of Texas	Cities Served by AEP Texas North Company	2007
42. Atmos Energy	Docket No. GUD 9670	Operations and Maintenance Expenses and Summary Schedules	Railroad Commission of Texas	Atmos Cities Steering Committee	2006
43. TXU Gas	Docket No. GUD 9400	Rate Base and Present Revenue Computation	Railroad Commission of Texas	Allied Coalition of Cities	2003
44. Texas-New Mexico Power Company	Docket No. 22745	Fuel Costs and Recovery	Public Utility Commission of Texas	Cities Served by TNMP	2001
45. Lone Star Gas Company	Docket No. GUD 8935	Purchased Gas Adjustment Clause	Railroad Commission of Texas Case Settled Before Hearing	Allied Coalition of Cities	1999
46. Garland Independent School District v. Lone Star Gas Company	Cause No. 97-00070-A	Natural Gas Billings based on Contractual Rates	Texas State District Court	Garland Independent School District	1997

Record of Testimony Submitted by Connie Cannady

Utility	Proceeding	Subject of Testimony	Before	Client	Date
47. Houston Lighting & Power Company	Docket No. 12065	Appropriate Rate Treatment of Fuel Inventories and Fuel Expense	Public Utility Commission of Texas	Gulf Coast Coalition of Cities	1994
48. Texas Electric Utilities Company	Docket No. 5640	Appropriate Rate Base to be Included in Rates	Public Utility Commission of Texas	Cities Steering Committee	1985

SCHEDULE D-6
2018 TX RATE CASE
PAGE 1 OF 1

Entergy Texas, Inc.
Cost of Service
Schedule D-6 Retirement Data for All Generating Units
Electric
For the Test Year Ended December 31, 2017

Unit Name	Net Dependable Capacity (MW)	In-Service Date	Service Life	Depreciation Retirement Date	Planning Retirement Date
Lewis Creek Station					
Unit 1	250	1970	64 Years	2034	Note 1
Unit 2	250	1971	63 Years	2034	Note 1
Sabine Station					
Unit 1	212	1962	60 Years	2022	Note 1
Unit 2	0	1962	54 Years	2016	Note 2
Unit 3	387	1966	60 Years	2026	Note 1
Unit 4	459	1974	52 Years	2026	Note 1
Unit 5	449	1979	60 Years	2039	Note 1
Big Cajun 2					
Unit 3	101	1983	60 Years	2043	Note 1
Roy S. Nelson Station					
Unit 6	164	1982	60 Years	2042	Note 1

Notes:
[1] The resource plan for Entergy Texas, Inc. does not contain retirement dates for specific generating units
[2] This unit was retired in 2016.

Sponsored by Gerard L. Fontenot
Amounts may not add or tie to other schedules due to rounding.

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

Response of: Entergy Texas, Inc. to the Fifth Set of Data Requests	Prepared By: Anastasia R. Meyer
	Sponsoring Witnesses: Anastasia R. Meyer, Andrew L. Dornier
of Requesting Party: CITIES	Beginning Sequence No. LC428
	Ending Sequence No. LC432

Question No.: CITIES 5-8 Part No.: Addendum:

Question:

In reference to the direct testimony of Ms. Gale at page 7, line 7, through page 8, line 13, for each power plant and the Spindletop Storage facility listed provide the current expected or planned retirement/deactivation date.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

There are currently no scheduled retirement dates for Entergy Texas, Inc. ("ETI") owned power plants. The Company maintains deactivation planning assumptions for all units, which do not represent a decision to deactivate or retire units on a particular schedule. For certain units, ETI's President and CEO has approved deactivation decisions based on the best information currently available. A deactivation decision reflects a management decision to remove a unit from service in a certain time frame absent changed circumstances and/or based on assumed resource additions. These decisions can be adjusted as warranted by new information.

The public and highly sensitive workpaper with the deactivation schedule, which is attached as Exhibit ARM-2 to the Direct Testimony of Anastasia R. Meyer, was filed with ETI's Application. The public and highly sensitive workpaper with the deactivation schedule, which is attached as Exhibit ARM-2 to the Direct Testimony of Anastasia R. Meyer, was filed with ETI's Application. Ms. Meyer's public workpapers are included in ETI's "Voluminous Exhibits and Workpapers_Public.zip" file, which is available for download via the Commission's Interchange at the following link: https://interchange.puc.texas.gov/search/documents/?controlNumber=53719&itemNumber=3

ETI is proposing to extend the useful life of the Spindletop Natural Gas Storage Facility from [redacted]. Please refer to the Direct Testimony of Andrew L. Dornier, pages 15-16 (Q27 through Q29) for justification and support.

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

Response of: Entergy Texas, Inc. to the Third Set of Data Requests	Prepared By: Clint Aymond, Ryan Gay Sponsoring Witnesses: Khamsune Vongkhamchanh, Andrew Dornier
of Requesting Party: Office of Public Utility Counsel	Beginning Sequence No. PI1173 Ending Sequence No. PI1175

Question No.: OPUC 3-2 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Mr. Khamsune Vongkhamchanh, page 10. As a member of MISO since 2013, has Entergy Texas, Inc. or any of its sister operating companies had to reactivate generation that had been deactivated or retired. If yes, provide the following information with respect to the generation facility that was reactivated due to MISO membership:

a. Plant station and unit number;

b. Current status of plant unit;

c. Date of reactivation;

d. Length of reactivation;

e. MW placed on the MISO transmission grid; and

f. Revenue received by ETI or sister company for such reactivation.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

Yes, Entergy Louisiana, LLC has reactivated one generation unit since (but not due to) joining the Midcontinent Independent System Operator (MISO).

a. Waterford 1
b. Suspended
c. February 15, 2021
d. February 15, 2021 – March 4, 2021
e. 125-300 MW

Question No.: OPUC 3-2

f. See the highly sensitive attachment (TP-53719-00OPC003-X002_HSPM) for the MISO revenues received during the period of reactivation. Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

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

Response of: Entergy Texas, Inc.	Prepared By: Brad Fleming, Joshua Paternostro, Tuyen Dang, Justina Holmes
to the Third Set of Data Requests	Sponsoring Witnesses: Beverley Gale, Allison P. Lofton
of Requesting Party: Office of Public Utility Counsel	Beginning Sequence No. PI1171 Ending Sequence No. PI1172

Question No.: OPUC 3-6 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Ms. Beverley Gale, pp. 7-8. For each of the plant units Nelson Unit 6, Sabine Unit 1, Sabine Unit 3, Sabine Unit 4, and Big Cajun Unit 3, please provide the following information by plant that is included in ETI' s requested cost of service:

a. Gross plant balances at test year end by FERC account;

b. Per Books accumulated depreciation at test year end by FERC account;

c. Adjusted accumulated depreciation by FERC account;

d. Per Books O&M expense at test year end by FERC account;

e. Adjusted O&M expense by FERC account;

f. Per Book depreciation expense prior to proposed adjustments by FERC account;

g. Adjusted depreciation expense after proposed adjustments by FERC account;

h. Thirteen-month average value of fuel inventories by fuel type at test year end;

i. Non-reconcilable fuel costs at test year end;

j. Per Books A&G expense by FERC account at test year end;

k. Adjusted A&G expense by FERC account;and

l. Other per plant expenses included in the requested cost of service with a detailed description.

Question No.: OPUC 3-6

Response:

a.	Please see attachment (TP-53719-00OPC003-X006).
b. through k.	See response to subpart a.
l.	No other plant expenses are included in the requested cost of service.

TP-53719-00OPC003-X006

Entergy Texas, Inc.
Docket No. 53719
OPUC 3-6 parts a, f & g

Plant Unit	Plant Account	Plant Account Description	Plant Balance December 31, 2021	AJ23 - Remove Securitized Storm Costs	Adjusted Plant Balance December 31, 2021	Per Book Depreceiation Expense	Proposed Depreciati on Rate	AJ12 Adjusted Depreciation Expense	Proforma Amount	Notes
Sabine Unit 1	311	Structures & Improvements	1,991,549	-	1,991,549	116,067	35.881%	714,583	598,516	
Sabine Unit 1	312	Boiler Plant Equipment	16,152,112	(157,676)	15,994,436	840,921	25.727%	4,114,864	3,273,943	
Sabine Unit 1	314	Turbogenerator Units	31,882,830	-	31,882,830	3,445,762	26.693%	8,510,406	5,064,645	
Sabine Unit 1	315	Accessory Electric Equip	7,753,103	-	7,753,103	236,224	25.276%	1,959,704	1,723,480	
Sabine Unit 1	316	Misc Power Plant Equip	91,345	-	91,345	6,038	25.765%	23,535	17,497	
			57,870,939	(157,676)	57,713,263	4,645,012		15,323,092	10,678,080	
Sabine Unit 3	311	Structures & Improvements	2,249,488	(657,696)	1,591,792	53,319	14.155%	225,321	172,002	
Sabine Unit 3	312	Boiler Plant Equipment	33,672,419	-	33,672,419	1,311,966	11.795%	3,971,805	2,659,839	
Sabine Unit 3	314	Turbogenerator Units	34,386,761	-	34,386,761	2,269,107	12.513%	4,302,983	2,033,877	
Sabine Unit 3	315	Accessory Electric Equip	10,284,187	-	10,284,187	574,858	12.787%	1,315,041	740,183	
			80,592,855	(657,696)	79,935,159	4,209,250		9,815,150	5,605,900	
Sabine Unit 4	311	Structures & Improvements	7,634,446	(359,774)	7,274,671	278,055	11.286%	821,054	542,999	
Sabine Unit 4	312	Boiler Plant Equipment	57,394,994	-	57,394,994	2,723,777	12.434%	7,136,339	4,412,561	
Sabine Unit 4	314	Turbogenerator Units	64,438,454	-	64,438,454	2,746,376	14.194%	9,146,089	6,399,713	
Sabine Unit 4	315	Accessory Electric Equip	9,297,318	-	9,297,318	348,349	11.535%	1,072,488	724,139	
Sabine Unit 4	316	Misc Power Plant Equip	101,334	-	101,334	5,144	16.192%	16,408	11,264	
			138,866,546	(359,774)	138,506,772	6,101,702		18,192,379	12,090,677	
Nelson 6	310.1	Land	1,269	-	1,269		N/A		-	
Nelson 6	311	Structures & Improvements	29,599,787	(409,533)	29,190,253	480,425	8.301%	2,423,091	1,942,666	
Nelson 6	312	Boiler Plant Equipment	121,588,007	-	121,588,007	2,694,255	9.005%	10,948,495	8,254,240	
Nelson 6	312.1	Boiler Plant Railcars	1,061,827	-	1,061,827	-	0.000%	-	-	(1)
Nelson 6	314	Turbogenerator Units	29,880,365	(903,973)	28,976,392	725,107	9.436%	2,734,075	2,008,969	
Nelson 6	315	Accessory Electric Equip	20,861,464	-	20,861,464	415,131	8.172%	1,704,770	1,289,640	
Nelson 6	316	Misc Power Plant Equip	1,658,801	-	1,658,801	34,572	8.986%	149,061	114,488	
			204,651,519	(1,313,507)	203,338,012	4,349,489		17,959,492	13,610,003	
Big Cajun Unit 3	310.1	Land	85,639	-	85,639		N/A		-	
Big Cajun Unit 3	311	Structures & Improvements	19,684,801	-	19,684,801	346,343	16.580%	3,263,706	2,917,364	
Big Cajun Unit 3	312	Boiler Plant Equipment	60,534,154	-	60,534,154	1,359,273	17.566%	10,633,379	9,274,106	
Big Cajun Unit 3	314	Turbogenerator Units	18,427,011	-	18,427,011	324,868	16.735%	3,083,774	2,758,906	
Big Cajun Unit 3	315	Accessory Electric Equip	12,166,066	-	12,166,066	238,678	16.943%	2,061,308	1,822,631	
Big Cajun Unit 3	316	Misc Power Plant Equip	829,561	-	829,561	23,916	17.906%	148,545	124,629	
			111,727,233	-	111,727,233	2,293,078		19,190,713	16,897,635	

Note:
(1) Annualized depreciation expense is recorded in fuel inventory. [$1,061,827 X 11.609% = $123,267]

Entergy Texas, Inc.
Docket No. 53719
OPUC 3-6 parts b & c

Plant Unit	Plant Account	Plant Account Description	Accumulated Depreciation December 31, 2021	AJ23 - Remove Securitized Storm Costs	Adjusted Accumulated Depreciation Balance December 31, 2021
Sabine Unit 1	311	Structures & Improvements	(1,791,811)	-	(1,791,811)
Sabine Unit 1	312	Boiler Plant Equipment	(14,798,694)	(7,994)	(14,806,687)
Sabine Unit 1	314	Turbogenerator Units	(21,171,101)	-	(21,171,101)
Sabine Unit 1	315	Accessory Electric Equip	(7,727,331)	-	(7,727,331)
Sabine Unit 1	316	Misc Power Plant Equip	(91,366)	-	(91,366)
			(45,580,302)	(7,994)	(45,588,296)
Sabine Unit 3	311	Structures & Improvements	(1,284,317)	(58,655)	(1,342,973)
Sabine Unit 3	312	Boiler Plant Equipment	(26,211,198)	-	(26,211,198)
Sabine Unit 3	314	Turbogenerator Units	(20,088,273)	-	(20,088,273)
Sabine Unit 3	315	Accessory Electric Equip	(6,809,447)	-	(6,809,447)
			(54,393,236)	(58,655)	(54,451,892)
Sabine Unit 4	311	Structures & Improvements	(5,461,862)	(39,853)	(5,501,714)
Sabine Unit 4	312	Boiler Plant Equipment	(24,618,567)	-	(24,618,567)
Sabine Unit 4	314	Turbogenerator Units	(21,680,005)	-	(21,680,005)
Sabine Unit 4	315	Accessory Electric Equip	(7,075,025)	-	(7,075,025)
Sabine Unit 4	316	Misc Power Plant Equip	(19,593)	-	(19,593)
			(58,855,051)	(39,853)	(58,894,904)
Nelson 6	311	Structures & Improvements	(22,548,155)	(66,969)	(22,615,124)
Nelson 6	312	Boiler Plant Equipment	(69,495,595)	-	(69,495,595)
Nelson 6	312.1	Boiler Plant Railcars	(132,829)	-	(132,829)
Nelson 6	314	Turbogenerator Units	(10,664,867)	(57,285)	(10,722,152)
Nelson 6	315	Accessory Electric Equip	(15,638,433)	-	(15,638,433)
Nelson 6	316	Misc Power Plant Equip	(1,091,284)	-	(1,091,284)
			(119,571,162)	(124,254)	(119,695,416)
Big Cajun Unit 3	311	Structures & Improvements	(16,772,401)	-	(16,772,401)
Big Cajun Unit 3	312	Boiler Plant Equipment	(41,303,525)	-	(41,303,525)
Big Cajun Unit 3	314	Turbogenerator Units	(14,842,882)	-	(14,842,882)
Big Cajun Unit 3	315	Accessory Electric Equip	(9,757,632)	-	(9,757,632)
Big Cajun Unit 3	316	Misc Power Plant Equip	(554,043)	-	(554,043)
			(83,230,483)	-	(83,230,483)

TP-53719-00OPC003-X006

Entergy Texas, Inc.
Docket No. 53719
OPUC 3-6 parts d, e, j and k

Plant Unit	Account	Account Description	Total Activity	Adjusted Amount	Notes
Big Cajun 2 Unit #3	500000	Oper Supervision & Engineerin	141,573	141,573	O&M
Big Cajun 2 Unit #3	501000	Fuel	(501,205)	(581,757)	O&M
Big Cajun 2 Unit #3	501203	Fuel-Natural Gas	960,636	(2,787,268)	O&M
Big Cajun 2 Unit #3	501301	Fuel - Coal	10,165,105	(52,918,434)	O&M
Big Cajun 2 Unit #3	502000	Steam Expenses	358,725	358,725	O&M
Big Cajun 2 Unit #3	505000	Electric Expenses	243,893	243,893	O&M
Big Cajun 2 Unit #3	506000	Misc Steam Power Expenses	283,122	283,122	O&M
Big Cajun 2 Unit #3	509101	NOX Seasonal Allowances Exp	14	(2,149)	O&M
Big Cajun 2 Unit #3	509103	NOX Conversion Allowance Exp	143	(338)	O&M
Big Cajun 2 Unit #3	510000	Maintenance Supr & Engineerin	275,168	275,168	O&M
Big Cajun 2 Unit #3	511000	Maintenance Of Structures	271,495	271,495	O&M
Big Cajun 2 Unit #3	512000	Maintenance Of Boiler Plant	2,003,063	2,003,063	O&M
Big Cajun 2 Unit #3	513000	Maintenance Of Electric Plant	518,547	518,547	O&M
Big Cajun 2 Unit #3	514000	Maintenance Of Misc Steam Plt	97,869	97,869	O&M
Big Cajun 2 Unit #3	562000	Station Expenses	19	19	O&M
Big Cajun 2 Unit #3	570000	Maint. Of Station Equipment	22,238	22,238	O&M
Big Cajun 2 Unit #3	920000	Adm & General Salaries	5,745	5,642	A&G
Big Cajun 2 Unit #3	924000	Property Insurance Expense	237,214	237,214	A&G
Big Cajun 2 Unit #3	925000	Injuries & Damages Expense	13,292	13,292	A&G
Big Cajun 2 Unit #3	926000	Employee Pension & Benefits	1,360	1,186	A&G
Big Cajun 2 Unit #3	930200	Miscellaneous General Expense	318,751	318,751	A&G
			15,416,769	**(51,498,147)**	
Nelson Unit #6	500000	Oper Supervision & Engineerin	261,112	260,388	O&M
Nelson Unit #6	501000	Fuel	(143,258)	(143,258)	O&M
Nelson Unit #6	501100	Fuel - Oil	289,023	(2,429,901)	O&M
Nelson Unit #6	501301	Fuel - Coal	11,153,380	(88,587,751)	O&M
Nelson Unit #6	502000	Steam Expenses	199,364	199,320	O&M
Nelson Unit #6	502100	Chemicals-MATS Compliance	554,171	(4,908,255)	O&M
Nelson Unit #6	505000	Electric Expenses	377,279	377,214	O&M
Nelson Unit #6	506000	Misc Steam Power Expenses	678,293	676,543	O&M
Nelson Unit #6	509101	NOX Seasonal Allowances Exp	7	(4,395)	O&M
Nelson Unit #6	509103	NOX Conversion Allowance Exp	262	(787)	O&M
Nelson Unit #6	510000	Maintenance Supr & Engineerin	18,030	17,977	O&M
Nelson Unit #6	511000	Maintenance Of Structures	303,293	303,313	O&M
Nelson Unit #6	512000	Maintenance Of Boiler Plant	3,809,313	3,809,449	O&M
Nelson Unit #6	513000	Maintenance Of Electric Plant	393,712	393,744	O&M
Nelson Unit #6	514000	Maintenance Of Misc Steam Plt	222,198	222,198	O&M
Nelson Unit #6	570000	Maint. Of Station Equipment	2,571	2,571	O&M
Nelson Unit #6	924000	Property Insurance Expense	19,849	19,849	A&G
Nelson Unit #6	925000	Injuries & Damages Expense	57,991	57,991	A&G
Nelson Unit #6	926000	Employee Pension & Benefits	164,459	164,447	A&G
Nelson Unit #6	930200	Miscellaneous General Expense	1,859,912	1,859,912	A&G
			20,220,960	**(87,709,432)**	
Sabine Unit #1	500000	Oper Supervision & Engineerin	26,225	(128,548)	O&M
Sabine Unit #1	502000	Steam Expenses	31,367	31,367	O&M
Sabine Unit #1	505000	Electric Expenses	7,366	7,366	O&M
Sabine Unit #1	506000	Misc Steam Power Expenses	11,448	10,428	O&M
Sabine Unit #1	509101	NOX Seasonal Allowances Exp	22	(6,486)	O&M
Sabine Unit #1	510000	Maintenance Supr & Engineerin	5,606	5,581	O&M
Sabine Unit #1	511000	Maintenance Of Structures	31,185	31,055	O&M
Sabine Unit #1	512000	Maintenance Of Boiler Plant	1,005,289	1,005,289	O&M

Sabine Unit #1	513000	Maintenance Of Electric Plant	848,339	848,339	O&M
Sabine Unit #1	514000	Maintenance Of Misc Steam Plt	81,105	81,105	O&M
Sabine Unit #1	570000	Maint. Of Station Equipment	1,402	1,371	O&M
Sabine Unit #1	926000	Employee Pension & Benefits	95,918	93,386	A&G
			2,145,272	**1,980,254**	
Sabine Unit #3	500000	Oper Supervision & Engineerin	23,817	(131,497)	O&M
Sabine Unit #3	502000	Steam Expenses	3,405	3,405	O&M
Sabine Unit #3	505000	Electric Expenses	18,046	18,046	O&M
Sabine Unit #3	506000	Misc Steam Power Expenses	4,210	4,210	O&M
Sabine Unit #3	509101	NOX Seasonal Allowances Exp	26	(3,517)	O&M
Sabine Unit #3	510000	Maintenance Supr & Engineerin	2,655	2,648	O&M
Sabine Unit #3	512000	Maintenance Of Boiler Plant	1,057,118	1,057,118	O&M
Sabine Unit #3	513000	Maintenance Of Electric Plant	470,743	470,743	O&M
Sabine Unit #3	514000	Maintenance Of Misc Steam Plt	49,043	49,043	O&M
Sabine Unit #3	570000	Maint. Of Station Equipment	3,188	3,188	O&M
Sabine Unit #3	926000	Employee Pension & Benefits	86,443	82,028	A&G
			1,718,696	**1,555,417**	
Sabine Unit #4	500000	Oper Supervision & Engineerin	50,930	(108,156)	O&M
Sabine Unit #4	505000	Electric Expenses	11,175	11,175	O&M
Sabine Unit #4	506000	Misc Steam Power Expenses	6,007	5,885	O&M
Sabine Unit #4	509101	NOX Seasonal Allowances Exp	96	(23,003)	O&M
Sabine Unit #4	510000	Maintenance Supr & Engineerin	34,498	34,498	O&M
Sabine Unit #4	511000	Maintenance Of Structures	1,882	1,882	O&M
Sabine Unit #4	512000	Maintenance Of Boiler Plant	1,548,413	1,548,413	O&M
Sabine Unit #4	513000	Maintenance Of Electric Plant	2,050,191	2,050,191	O&M
Sabine Unit #4	514000	Maintenance Of Misc Steam Plt	107,062	107,062	O&M
Sabine Unit #4	570000	Maint. Of Station Equipment	2,374	2,374	O&M
Sabine Unit #4	926000	Employee Pension & Benefits	109,502	104,879	A&G
			3,922,130	**3,735,199**	

Entergy Texas, Inc.
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Plant/Description	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	13 Month Average
OIL														
SABINE	8,646	8,484	8,269	8,056	8,056	8,056	7,841	7,841	7,841	7,519	7,197	6,875	6,767	7,804
NELSON	110,820	110,820	137,648	172,975	167,608	167,608	337,210	277,629	274,014	270,399	305,528	264,797	371,740	228,369
TOTAL OIL	119,466	119,304	145,917	181,032	175,664	175,664	345,050	285,469	281,855	277,918	312,725	271,672	378,507	236,173
COAL														
BC2U3	16,281,523	15,859,524	14,916,171	14,981,092	14,669,399	14,310,004	13,660,543	12,558,361	11,267,132	9,939,361	9,294,064	7,989,125	7,325,349	12,542,435
NELSON	3,834,021	4,600,553	4,292,856	4,760,190	4,131,018	5,376,056	6,612,091	7,287,182	6,247,677	5,202,369	4,768,651	4,744,224	5,491,889	5,180,675
TOTAL COAL	20,115,544	20,460,077	19,209,028	19,741,282	18,800,417	19,686,059	20,272,634	19,845,543	17,514,810	15,141,731	14,062,715	12,733,349	12,817,238	17,723,110

Entergy Texas, Inc.
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PLANT/DESCRIPTION	JANUARY 2021	FEBRUARY 2021	MARCH 2021	APRIL 2021	MAY 2021	JUNE 2021	JULY 2021	AUGUST 2021	SEPTEMBER 2021	OCTOBER 2021	NOVEMBER 2021	DECEMBER 2021	TOTALS 2021
SABINE OIL	0	0	0	207,006	252,072	8,233	(1,597)	28,280	48	0	0	0	494,042
NEL.COAL AD VALOREM TAXES	0	416	229	1,680	0	0	230	986	702	419	217	40	4,918
NEL. COAL CAR MAINT.	0	54,281	37,220	72,111	0	0	17,670	84,965	66,465	44,276	25,927	4,011	406,925
NEL. COAL COAL CAR LEASES	0	11,330	6,728	11,763	0	0	2,159	10,077	7,973	5,376	3,186	484	59,077
NEL. COAL ASH PROCEEDS	0	0	(28,099)	0	(3,802)	(27,000)	0	(41,954)	(6,774)	(3,647)	(31,981)	0	(143,258)
NEL. COAL HANDLING	89,457	87,616	89,920	74,952	62,972	104,193	52,705	137,691	180,170	86,365	121,301	141,511	1,228,853
BC II U3 RAIL CAR LEASE COST	17,077	(50)				14,982							32,009
BC II U3 ASH PROCEEDS	(1,630)	(10,947)	(11,500)	(5,960)	(5,216)	(37,015)	(49,777)	(66,149)	(75,809)	(70,129)	(76,221)	(90,851)	(501,205)
BC II U3 HANDLING	98,381	56,735	57,314	50,742	252,813	(29,499)	47,396	73,928	64,928	128,514	93,698	100,883	995,832
TOTAL INELIGIBLE COSTS	203,286	199,382	151,812	412,294	558,839	33,893	68,786	227,822	237,703	191,173	136,126	156,078	2,577,194

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

Response of: Entergy Texas, Inc. to the First Set of Data Requests	Prepared By: Jessica B. Little Sponsoring Witnesses: Allison P. Lofton, Jennifer A. Raeder
of Requesting Party: Office of Public Utility Counsel	Beginning Sequence No. LR229 Ending Sequence No. LR229

Question No.: OPUC 1-13 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Ms. Lofton, pages 22-23. Please confirm or deny that Ms. Lofton took into consideration the performance metrics required to fund the annual incentive compensation plans when developing her recommended adjustment to remove financially based incentive compensation costs. If deny, please provide a detailed explanation of why such consideration was not given to the performance metrics required for funding any annual incentive compensation plan. If confirm, please provide the detailed computations that demonstrate removal of such financially based incentive compensation awards.

Response:

Deny. See the Direct Testimony of Jennifer A. Raeder page 14 (Q24), and pages 31-34 (Q47-Q50), for a discussion of the Company's position on the disallowance of annual incentive compensation expense based on the incorporation of a financially based funding metric in the formula used to determine the annual incentive compensation pool.

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

Response of: Entergy Texas, Inc. to the First Set of Data Requests of Requesting Party: Office of Public Utility Counsel	Prepared By: Brad Fleming Sponsoring Witness: Allison P. Lofton Beginning Sequence No. LR230 Ending Sequence No. LR230

Question No.: OPUC 1-14 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Ms. Lofton, pages 22-23. Please provide a schedule that shows the adjustment to plant in service to remove all financially based incentive compensation by year for each of the years since Docket No. 39896. Please provide this information by FERC account. Also, please provide all underlying workpapers which show the calculation of the adjustment by year.

Response:

Entergy Texas, Inc. ("ETI") has filed an objection to this request.

However, subject to and without waiving its objection, please see attachment (TP-53719-00OPC001-X014) which provides the requested information for the period January 1, 2018 through December 31, 2021. The portion of incentive compensation that is deemed financially based is removed from plant in service and is reflected in the plant in service balance as of December 31, 2021 in Schedule P.

Entergy Texas, Inc.
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Year	General Ledger Account[1]	Financially based Incentive Compensation removed from ETI's books
2018	253101	(1,005,875)
2018	253106	(677,746)
2019	1010AM	(1,123,262)
2019	106000	(582,946)
2020	1010AM	(830,752)
2020	106ECC	(111)
2021	1010AM	(849,793)
2021	1010CC	(124)
2021	106000	(142,584)
2021	106ECC	(81)

[1]Prior to 2019, the disallowed portion of financially-based incentive compensation in plant in service was rececorded to contra accounts 253101, 253106. Beginning in 2019, the disallowed portion in plant in service is recorded to a specific resource code within the 101 and 106 plant in service accounts.

Entergy Texas, Inc.
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OPUC 1-14

Disallowed Incentive Calculation 2018-2021

Period	ESL Total Incentive Compensation Amount	ESL Financially Based Incentive Amount	ESL Percentage Disallowed (Financially Based/Total)
1/2018-4/2018	58,480,870.81	6,241,855.62	10.67%
5/2018-3/2019	68,840,363.36	5,130,202.00	7.45%
4/2019-3/2020	70,462,858.76	3,299,154.00	4.68%
4/2020-3/2021	89,531,656.86	3,928,981.00	4.39%
4/1/2021-12/2021	86,334,463.31	6,327,594.00	7.33%

Note:
ESL Incentive Compensation is calculated on ESL payroll and billed to affiliates based on the billing method on the project code associated with the payroll transactions. The portion that is billed to ETI is then adjusted based on the calculated percentage disallowed. The result of that calculation is is the portion that is removed from ETI's plant in service amount.

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

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

of Requesting Party: CITIES

Prepared By: Lauren Hayes
Sponsoring Witnesses: Allison P. Lofton, Jennifer A. Raeder
Beginning Sequence No. EV1442
Ending Sequence No. EV1442

Question No.: CITIES 3-3 Part No.: Addendum:

Question:

Incentive compensation:

For each incentive plan (including all short-term, long- term and stock-based plans) please provide the amounts of awards for the test year and each of the three years prior to the test year.

Response:

Please see table below for short-term incentive ("STI") and long-term incentive ("LTI") awards for 2018 – 2021 for Energy Services, LLC and Entergy Texas, Inc. Please refer to the Direct Testimony of Jennifer A. Raeder, Q17, pg. 7 for a description of Entergy's incentive plans.

Note: The OSIP was not established until the 2020 Plan Year.

Incentive Plan	**2018**	**2019**	**2020**	**2021**
EAIP	$10,417,799	$15,668,390	$15,057,322	$17,549,217
SMIP	$48,382,374	$61,895,964	$57,445,220	$64,841,375
OSIP	n/a	n/a	$523,064	$1,718,922
EXIP	$13,718,397	$16,713,588	$16,262,669	$15,583,165
TSPB	$603,970	$663,857	$659,081	$660,902
TSIP	$1,007,557	$1,247,232	$1,332,834	$1,217,014
Total STI	**$74,130,097**	**$96,189,031**	**$91,280,190**	**$101,570,595**
Restricted Stock	$22,896,810	$29,528,743	$29,199,150	$28,528,579
Stock Options	$5,260,931	$6,306,100	$6,129,608	$6,715,870
PUP	$15,765,782	$19,199,370	$18,388,824	$20,147,610
Total LTI[1]	**$43,923,523**	**$55,034,213**	**$53,717,582**	**$55,392,059**

[1]Award values for LTI are illustrative only and were calculated using Stock Option, Restricted Stock, and Performance Unit values provided by Pay Governance Compensation Model data. The actual values will vary depending on the terms and conditions of the applicable plans and programs, including eligibility and vesting requirements.

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

Response of: Entergy Texas, Inc. to the Fourth Set of Data Requests	Prepared By: Lauren Hayes, Jo Ann Sivori Sponsoring Witnesses: Jennifer A. Raeder, Ryan Dumas
of Requesting Party: Office of Public Utility Counsel	Beginning Sequence No. LS7 Ending Sequence No. LS8

Question No.: OPUC 4-11 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Ms. Raeder, HSPM Exhibit JAR-2. Please provide the information contained in this exhibit for the Annual Incentive Payout for the 2018 performance, the 2019 performance, and the 2020 performance. Please also include the percentage of each of the ESI plans that were allocated to ETI.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

Please see the highly sensitive attachments (TP-53719-00OPC004-X011-001_HSPM through TP-53719-00OPC004-X011-003_HSPM) for the short-term incentive allocations for the 2018, 2019, and 2020 Plan Years. See also the highly sensitive attachment (TP-53719-00OPC004-X011-004_HSPM) for approximation of percentages of Entergy Services, LLC plans that were allocated to Entergy Texas, Inc. Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

This page contains

Highly Sensitive Material

Native Files (Highly Sensitive)

provided on CD

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

Response of: Entergy Texas, Inc. to the Second Set of Data Requests	Prepared By: Ryan Gay, Chad Pulcher Sponsoring Witnesses: Andrew Dornier, Beverley Gale
of Requesting Party: Office of Public Utility Counsel	Beginning Sequence No. PI48 Ending Sequence No. PI48

Question No.: OPUC 2-3 Part No.: Addendum:

Question:

Please refer to Schedule H-12.3a, sponsored by Ms. Gale. Please provide the information contained in this schedule for each generating plant by month for the period January 2018 through December 2020.

Response:

See the attachment (TP-53719-00OPC002-X003). Please note that the Montgomery County Power Station was not in service until January 2021 and the Hardin County Peaking Facility was not acquired until June 2021.

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

LEWIS CREEK 1 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	NET HEAT RATE (Btu/kWh)
Jan-18	100,205	0	100,205	99.66	0	0	52.82	32%	0	0	744	N/A	N/A	N/A	1,053.60	10,514
Feb-18	53,934	0	53,934	73.65	0	23.28	31.47	43%	1	0	428.9	N/A	N/A	N/A	579.67	10,748
Mar-18	110,907	0	110,907	100	0	0	58.54	82%	0	0	743	N/A	N/A	N/A	1,230.27	11,093
Apr-18	128,040	0	128,040	100	0	0	69.74	70%	0	0	720	N/A	N/A	N/A	1,336.60	10,439
May-18	120,563	0	120,563	99	1	0	63.55	98%	0	1	736.53	N/A	N/A	N/A	1,277.38	10,595
Jun-18	114,324	0	114,324	99.38	0	0	62.27	74%	0	0	720	N/A	N/A	N/A	1,253.72	10,966
Jul-18	115,153	0	115,153	96.64	3.36	0	60.69	94%	0	0	719.02	N/A	N/A	N/A	1,271.87	11,045
Aug-18	46,660	2	46,658	38.91	60.13	0	24.59	99%	1	0	296.6	N/A	N/A	N/A	495.15	10,612
Sep-18	121,744	0	121,744	100	0	0	66.31	100%	0	0	720	N/A	N/A	N/A	1,345.64	11,053
Oct-18	51,844	1	51,843	48.51	0	51.49	27.33	59%	0	0	360.9	N/A	N/A	N/A	543.48	10,483
Nov-18	2,459	0	2,459	23.52	0	76.48	1.34	81%	2	0	38.83	N/A	N/A	N/A	29.30	11,915
Dec-18	48,359	0	48,359	90.86	9.91	0	25.49	35%	1	3	538.37	N/A	N/A	N/A	586.61	12,130
Jan-19	68,656	1	68,655	80.85	0	19.15	36.19	0%	0	0	601.5	N/A	N/A	N/A	772.34	11,250
Feb-19	3,509	0	3,509	4.69	78.09	78.57	2.05	0%	1	0	31.55	N/A	N/A	N/A	32.00	9,118
Mar-19	99,009	0	99,009	99.68	0	0	52.26	0%	0	0	743	N/A	N/A	N/A	1,092.50	11,034
Apr-19	138,255	0	138,255	100	0	0	75.3	99%	0	0	720	N/A	N/A	N/A	1,522.17	11,010
May-19	132,787	0	132,787	100	0	0	70.82	98%	0	0	744	N/A	N/A	N/A	1,407.48	10,600
Jun-19	117,331	0	117,331	94.19	5.81	0	64.67	90%	0	2	678.2	N/A	N/A	N/A	1,274.30	10,861
Jul-19	138,608	0	138,608	100	0	0	73.93	100%	0	0	744	N/A	N/A	N/A	1,486.46	10,724
Aug-19	138,207	0	138,207	99.79	0	0	73.72	100%	0	0	744	N/A	N/A	N/A	1,471.56	10,647
Sep-19	106,644	0	106,644	96.97	3.01	0	58.78	96%	0	1	698.3	N/A	N/A	N/A	1,153.93	10,820
Oct-19	70,551	0	70,551	58.3	0	41.7	37.63	56%	0	0	433.77	N/A	N/A	N/A	755.42	10,707
Nov-19	0	1	(1)	0	0	100	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Dec-19	35,920	0	35,920	28.8	0	41.93	19.16	47%	1	0	357.32	N/A	N/A	N/A	374.37	10,422
Jan-20	119,537	0	119,537	94.14	0	3.9	63.76	90%	0	1	676.77	N/A	N/A	N/A	1,273.06	10,650
Feb-20	125,591	0	125,591	90.33	0	3.44	71.61	96%	0	0	672.03	N/A	N/A	N/A	1,387.65	11,049
Mar-20	108,447	0	108,447	77.39	0	22.61	57.92	75%	1	0	562.65	N/A	N/A	N/A	1,143.33	10,543
Apr-20	131,953	0	131,953	94.54	0	0	72.72	100%	0	0	720	N/A	N/A	N/A	1,421.63	10,774
May-20	3,761	1	3,760	5	0	95	2.03	5%	0	0	37.23	N/A	N/A	N/A	42.51	11,306
Jun-20	90,460	0	90,460	61.82	0	38.18	50.46	58%	1	0	445.08	N/A	N/A	N/A	961.81	10,632
Jul-20	144,739	0	144,739	100	0	0	78.13	99%	0	0	744	N/A	N/A	N/A	1,555.29	10,745
Aug-20	124,005	0	124,005	99.95	0	0	66.94	89%	0	0	744	N/A	N/A	N/A	1,298.68	10,473
Sep-20	125,292	0	125,292	100	0	0	69.89	91%	0	0	720	N/A	N/A	N/A	1,189.27	9,492
Oct-20	95,159	0	95,159	84.38	4.06	6.39	50.16	87%	0	1	668.17	N/A	N/A	N/A	1,184.03	12,443
Nov-20	59,422	0	59,422	71.6	0	26.77	32.32	57%	2	0	424.5	N/A	N/A	N/A	606.43	10,205
Dec-20	88,183	0	88,183	78.06	0	0	46.48	99%	0	0	744	N/A	N/A	N/A	1,104.40	12,524

Note:
If start-up begins for a super-critical unit within 24 hours of unit coming off line, the start-up is considered to be a hot start. If start-up begins for a drum unit within 72 hours of the unit coming off line, the start-up is considered to be a hot start. Outside of these time frames, the start-up is considered to be a cold start-up. Simple cycle CTs (Hardin 1 and 2) are always hot starts. For Montgomery country, the 72 rule still applies

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

LEWIS CREEK 2 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	NET HEAT RATE (Btu/kWh)
Jan-18	101,361	0	101,361	99.66	0	0	53.22	100%	0	0	744	N/A	N/A	N/A	1,065.75	10,514
Feb-18	62,897	127	62,770	66.95	0	17.75	36.49	82%	0	0	552.75	N/A	N/A	N/A	676.00	10,769
Mar-18	0	262	(262)	1.51	0	98.49	-0.14	0%	0	0	0	N/A	N/A	N/A	0.00	0
Apr-18	12,912	852	12,060	24.6	37.11	39.39	6.54	14%	1	0	166.28	N/A	N/A	N/A	134.79	11,176
May-18	119,733	24	119,709	100	0	0	62.85	98%	1	0	738.37	N/A	N/A	N/A	1,268.58	10,597
Jun-18	106,387	0	106,387	100	0	0	57.72	99%	0	0	720	N/A	N/A	N/A	1,166.68	10,966
Jul-18	113,656	0	113,656	100	0	0	59.66	96%	0	0	744	N/A	N/A	N/A	1,255.34	11,045
Aug-18	112,276	0	112,276	100	0	0	58.95	100%	0	0	744	N/A	N/A	N/A	1,191.46	10,612
Sep-18	100,368	242	100,126	89.1	0	10.9	54.32	88%	1	0	641.5	N/A	N/A	N/A	1,109.38	11,080
Oct-18	96,777	0	96,777	100	0	0	50.81	98%	0	0	744	N/A	N/A	N/A	1,014.51	10,483
Nov-18	92,598	0	92,598	98.73	0	0	50.17	99%	0	0	721	N/A	N/A	N/A	1,103.31	11,915
Dec-18	64,696	0	64,696	99.33	0	0	33.97	100%	0	0	744	N/A	N/A	N/A	784.77	12,130
Jan-19	81,131	0	81,131	100	0	0	42.59	100%	0	0	744	N/A	N/A	N/A	912.68	11,249
Feb-19	100,650	0	100,650	100	0	0	58.51	100%	0	0	672	N/A	N/A	N/A	917.77	9,118
Mar-19	59,237	227	59,010	71.03	0	28.97	31.02	70%	0	0	527.77	N/A	N/A	N/A	653.64	11,077
Apr-19	0	189	(189)	0	0	100	-0.1	0%	0	0	0	N/A	N/A	N/A	0.00	0
May-19	36,523	456	36,067	31.98	0	68.02	19.16	28%	1	0	237.9	N/A	N/A	N/A	387.12	10,734
Jun-19	125,918	0	125,918	99.91	0	0	69.12	99%	0	0	720	N/A	N/A	N/A	1,367.56	10,861
Jul-19	139,793	0	139,793	100	0	0	74.27	100%	0	0	744	N/A	N/A	N/A	1,499.17	10,724
Aug-19	140,062	0	140,062	100	0	0	74.41	100%	0	0	744	N/A	N/A	N/A	1,491.31	10,647
Sep-19	111,658	0	111,658	99.66	0	0	61.3	99%	0	0	720	N/A	N/A	N/A	1,208.18	10,820
Oct-19	127,246	0	127,246	100	0	0	67.07	100%	0	0	744	N/A	N/A	N/A	1,362.48	10,707

Nov-19	107,292	0	107,292	100	0	0	58.36	100%	0	0	721	N/A	N/A	N/A	1,199.26	11,177
Dec-19	114,051	0	114,051	100	0	0	60.12	99%	0	0	744	N/A	N/A	N/A	1,188.69	10,422
Jan-20	138,289	0	138,289	100	0	0	72.89	100%	0	0	744	N/A	N/A	N/A	1,472.77	10,650
Feb-20	78,314	572	77,742	75.62	30.15	0	43.8	56%	1	0	393.03	N/A	N/A	N/A	865.29	11,130
Mar-20	79,542	658	78,884	58.02	34.51	12.81	41.64	53%	1	2	411.38	N/A	N/A	N/A	838.59	10,631
Apr-20	0	93	(93)	0	0	100	-0.05	0%	0	0	0	N/A	N/A	N/A	0.00	0
May-20	36,492	151	36,341	27.56	0	69.73	19.23	28%	1	0	225.23	N/A	N/A	N/A	412.47	11,350
Jun-20	121,927	0	121,927	78.74	0	0	66.67	100%	0	0	720	N/A	N/A	N/A	1,296.39	10,632
Jul-20	89,853	400	89,453	64.05	0	32.73	47.34	60%	1	0	480.72	N/A	N/A	N/A	965.51	10,794
Aug-20	122,447	0	122,447	100	0	0	64.8	89%	0	0	744	N/A	N/A	N/A	1,282.36	10,473
Sep-20	124,138	0	124,138	100	0	0	67.88	91%	0	0	720	N/A	N/A	N/A	1,178.32	9,492
Oct-20	106,300	0	106,300	100	0	0	56.03	100%	0	0	744	N/A	N/A	N/A	1,322.65	12,443
Nov-20	100,015	0	100,015	98.98	0	0	54.4	99%	0	0	721	N/A	N/A	N/A	1,020.69	10,205
Dec-20	85,577	0	85,577	78.01	0	0	45.11	99%	0	0	744	N/A	N/A	N/A	1,071.75	12,524

Note:
If start-up begins for a super-critical unit within 24 hours of unit coming off line, the start-up is considered to be a hot start. If start-up begins for a drum unit within 72 hours of the unit coming off line, the start-up is considered to be a hot start. Outside of these time frames, the start-up is considered to be a cold start-up. Simple cycle CTs (Hardin 1 and 2) are always hot starts. For Montgomery country, the 72 rule still applies

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

NELSON 6 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				NET HEAT RATE (Btu/kWh)
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	
Jan-18	103,903	225	103,678	86.17	0	12.13	85.16	5%	1	0	653.78	N/A	N/A	N/A	1,112.62	10,732
Feb-18	49,624	549	49,075	45.8	2.23	42.42	44.63	3%	1	1	378.3	N/A	N/A	N/A	549.75	11,202
Mar-18	8,528	427	8,101	6.99	0	90.04	6.66	0%	0	0	74	N/A	N/A	N/A	89.14	11,004
Apr-18	7,090	356	6,734	6.84	0	88.61	5.71	0%	1	0	81.98	N/A	N/A	N/A	87.62	13,011
May-18	80,781	694	80,087	63.91	22.5	0	65.73	6%	1	2	576.57	N/A	N/A	N/A	883.54	11,032
Jun-18	102,862	238	102,623	89.57	6.13	0	87.03	6%	0	1	675.83	N/A	N/A	N/A	1,148.97	11,196
Jul-18	116,639	0	116,639	99.15	0	0	95.72	6%	0	0	744	N/A	N/A	N/A	1,336.79	11,461
Aug-18	115,964	0	115,964	97.69	0	0	95.17	6%	0	0	744	N/A	N/A	N/A	1,346.56	11,612
Sep-18	70,167	420	69,747	75.34	15.47	0	59.14	22%	1	0	608.58	N/A	N/A	N/A	832.61	11,938
Oct-18	56,366	557	55,809	66.84	29.89	0	45.81	33%	1	0	521.62	N/A	N/A	N/A	692.97	12,417
Nov-18	72,279	0	72,279	99.71	0	0	61.18	75%	0	0	721	N/A	N/A	N/A	876.15	12,122
Dec-18	55,622	0	55,622	81.11	0	0	45.6	83%	0	0	744	N/A	N/A	N/A	690.22	12,409
Jan-19	41,394	187	41,207	79.09	5.1	0	33.77	78%	0	1	706.07	N/A	N/A	N/A	546.19	13,255
Feb-19	83,566	0	83,566	89.7	0	0	75.91	51%	0	0	672	N/A	N/A	N/A	977.81	11,701
Mar-19	29,239	540	28,699	25.72	0	73.87	23.65	7%	0	0	194.15	N/A	N/A	N/A	322.69	11,244
Apr-19	12,044	477	11,567	15.09	0	84.71	9.87	11%	1	0	110.1	N/A	N/A	N/A	143.69	12,422
May-19	54,566	1,175	53,391	59.5	36.76	0	43.83	33%	2	0	470.53	N/A	N/A	N/A	614.04	11,501
Jun-19	68,733	0	68,733	95.96	0	0	58.25	78%	0	0	720	N/A	N/A	N/A	858.88	12,496
Jul-19	80,238	0	80,238	95.97	0	0	65.82	66%	0	0	744	N/A	N/A	N/A	991.25	12,354
Aug-19	55,275	581	54,694	75.94	17.94	0	44.87	52%	1	2	610.55	N/A	N/A	N/A	651.15	11,905
Sep-19	67,588	0	67,588	87.57	0	0	57.28	58%	0	0	720	N/A	N/A	N/A	821.98	12,162
Oct-19	26,443	511	25,932	39.97	0	58.06	21.33	35%	0	0	312.02	N/A	N/A	N/A	316.90	12,220
Nov-19	2,186	573	1,613	3.74	0	95.77	1.46	3%	1	0	30.48	N/A	N/A	N/A	29.82	18,492
Dec-19	16,788	1,494	15,295	20.66	70.21	0	12.6	13%	2	0	221.65	N/A	N/A	N/A	237.56	15,532
Jan-20	3,508	1,483	2,025	82.2	30.1	15.45	1.75	1%	1	0	37.15	N/A	N/A	N/A	29.79	14,711
Feb-20	0	601	(601)	32.38	0	67.62	-0.46	0%	0	0	0	N/A	N/A	N/A	0.00	0
Mar-20	0	239	(239)	0	0	100	-0.19	0%	0	0	0	N/A	N/A	N/A	0.00	0
Apr-20	0	409	(409)	0	0	100	-0.35	0%	0	0	0	N/A	N/A	N/A	0.00	0
May-20	22,667	849	21,817	31.46	9	35.44	18.77	13%	1	0	437.08	N/A	N/A	N/A	334.57	15,335
Jun-20	47,185	547	46,638	85.33	0	12.05	41.65	36%	1	0	516.3	N/A	N/A	N/A	540.90	11,598
Jul-20	49,241	528	48,713	52.08	2	36.62	42.11	15%	0	0	447.22	N/A	N/A	N/A	533.00	10,942
Aug-20	77,128	494	76,635	80.67	21	0	65.98	12%	1	0	525.12	N/A	N/A	N/A	870.45	11,358
Sep-20	0	252	(252)	0	100	0	-0.18	0%	0	0	0	N/A	N/A	N/A	0.00	0
Oct-20	0	526	(526)	0	100	0	-0.41	0%	0	0	0	N/A	N/A	N/A	0.00	0
Nov-20	0	1,020	(1,020)	0	100	0	-0.85	0%	0	0	0	N/A	N/A	N/A	0.00	0
Dec-20	78,689	224	78,465	88.88	7.86	0	67.42	70%	1	0	685.53	N/A	N/A	N/A	898.97	11,457

Note:
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Nelson 6 - All generation and fuel consumption data based on ETI's 29.75% share. All other data based on 100% of unit.

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

SABINE 1 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				NET HEAT RATE (Btu/kWh)
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	
Jan-18	17,987	1,675	16,312	91.67	26.27	0	10.44	7%	3	0	138.65	N/A	N/A	N/A	239.44	14,679

Feb-18	2,647	1,388	1,259	82.15	0	17.85	1.04	6%	0	0	38.33	N/A	N/A	N/A	38.78	30,815
Mar-18	0	991	(991)	49.71	0	50.29	-0.48	0%	0	0	0	N/A	N/A	N/A	0.00	0
Apr-18	5,210	1,665	3,546	100	0	0	2.46	5%	1	0	41.82	N/A	N/A	N/A	64.29	18,133
May-18	59,998	202	59,796	92.35	6.88	0	37.55	79%	1	1	663.2	N/A	N/A	N/A	731.63	12,235
Jun-18	30,745	864	29,881	46.22	24.99	7.96	19.43	50%	3	2	409.33	N/A	N/A	N/A	355.56	11,899
Jul-18	62,438	475	61,963	88.92	10.45	0	38.97	72%	2	0	577.22	N/A	N/A	N/A	750.22	12,108
Aug-18	74,705	0	74,705	100	0	0	46.93	98%	0	0	744	N/A	N/A	N/A	886.81	11,871
Sep-18	15,863	1,458	14,405	100	0	0	9.52	15%	1	0	148.68	N/A	N/A	N/A	184.62	12,816
Oct-18	9,662	1,595	8,068	82.93	53.41	0	5.24	14%	1	0	110.77	N/A	N/A	N/A	117.88	14,611
Nov-18	10,134	1,619	8,515	97.15	15.09	0	5.71	15%	2	0	115.73	N/A	N/A	N/A	125.00	14,680
Dec-18	0	1,816	(1,816)	100	0	0	-0.94	0%	0	0	0	N/A	N/A	N/A	0.00	0
Jan-19	3,867	1,725	2,142	100	0	0	1.54	9%	1	0	68.98	N/A	N/A	N/A	47.30	22,081
Feb-19	23,738	589	23,148	80.67	0	0	16.09	61%	0	0	408.45	N/A	N/A	N/A	289.09	12,488
Mar-19	20,668	1,393	19,276	99.29	0	0	12.27	30%	3	0	240.12	N/A	N/A	N/A	276.93	14,367
Apr-19	5,188	1,149	4,039	10.63	93.34	0	2.84	4%	1	1	45.78	N/A	N/A	N/A	65.56	16,230
May-19	0	391	(391)	0	100	77.43	-0.01	0%	0	0	0	N/A	N/A	N/A	0.00	0
Jun-19	24,856	667	24,189	34.62	63.76	0	15.9	31%	1	0	252.48	N/A	N/A	N/A	307.51	12,713
Jul-19	40,976	1,069	39,907	94.62	10.82	0	25.31	33%	1	0	329.58	N/A	N/A	N/A	464.68	11,644
Aug-19	72,287	588	71,699	91.42	10.61	0	45.35	45%	2	0	537.62	N/A	N/A	N/A	845.37	11,790
Sep-19	48,177	411	47,766	74.97	26.32	0	31.21	62%	0	1	503.23	N/A	N/A	N/A	583.25	12,211
Oct-19	0	1,355	(1,355)	42.5	100	0	-0.68	0%	0	0	0	N/A	N/A	N/A	0.00	0
Nov-19	32,642	970	31,672	83.47	23.83	0	20.64	42%	2	0	330.33	N/A	N/A	N/A	474.25	14,974
Dec-19	24,362	1,118	23,243	95.44	11.47	0	14.72	32%	2	1	262.17	N/A	N/A	N/A	292.47	12,583
Jan-20	2,350	1,578	771	91.97	52.99	5.25	0.67	2%	1	0	18.33	N/A	N/A	N/A	28.76	37,288
Feb-20	14,458	1,378	13,080	100	0	0	8.93	18%	1	0	139.97	N/A	N/A	N/A	181.30	13,861
Mar-20	45,871	503	45,368	52.11	9.07	40.1	28.66	34%	0	0	344.07	N/A	N/A	N/A	564.62	12,445
Apr-20	89,840	5	89,835	100	0	0	58.34	88%	1	0	718.58	N/A	N/A	N/A	1,015.98	11,309
May-20	92,407	0	92,407	100	0	0	58.34	81%	0	0	744	N/A	N/A	N/A	1,078.65	11,673
Jun-20	100,843	38	100,805	98.68	1.32	0	65.83	69%	0	1	710.52	N/A	N/A	N/A	1,084.50	10,758
Jul-20	79,033	202	78,830	89.86	0	10.14	49.78	67%	1	0	647.57	N/A	N/A	N/A	900.31	11,421
Aug-20	66,809	223	66,585	87.25	12.75	0	42.04	73%	1	0	649.12	N/A	N/A	N/A	864.94	12,990
Sep-20	72,076	112	71,964	99.13	0	0	46.96	81%	0	0	671.13	N/A	N/A	N/A	902.94	12,547
Oct-20	57,503	383	57,120	90.57	0	5.71	35.95	66%	1	0	540.38	N/A	N/A	N/A	806.00	14,111
Nov-20	23,399	1,348	22,051	97.12	7.99	0	14.45	30%	2	1	230.27	N/A	N/A	N/A	292.07	13,245
Dec-20	25,407	1,118	24,290	77.1	11.36	0	15.34	25%	1	2	282.73	N/A	N/A	N/A	306.53	12,620

Note:
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ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

SABINE 3 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				NET HEAT RATE (Btu/kWh)
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	
Jan-18	100,546	765	99,781	95.84	4.94	0	33.45	76%	1	0	594.43	N/A	N/A	N/A	1,338.48	13,414
Feb-18	29,342	1,692	27,650	40.44	74.17	0	10.31	20%	1	0	139.35	N/A	N/A	N/A	429.94	15,550
Mar-18	57,356	1,720	55,636	83.03	30.88	0	18.71	34%	1	0	282.2	N/A	N/A	N/A	663.21	11,920
Apr-18	93,492	1,018	92,474	86.6	18.77	0	32.07	51%	1	0	417.4	N/A	N/A	N/A	1,153.60	12,475
May-18	161,578	0	161,578	99.88	0	0	52.72	93%	0	0	744	N/A	N/A	N/A	1,970.32	12,194
Jun-18	58,169	1,473	56,697	41.1	59.77	0	19.19	37%	1	0	281.52	N/A	N/A	N/A	672.70	11,865
Jul-18	148,757	147	148,610	91.46	2.28	0	48.48	92%	0	2	721.32	N/A	N/A	N/A	1,787.37	12,027
Aug-18	153,099	0	153,099	100	0	0	49.96	99%	0	0	744	N/A	N/A	N/A	1,817.41	11,871
Sep-18	153,401	0	153,401	76.2	0	0	51.72	98%	0	0	720	N/A	N/A	N/A	1,785.28	11,638
Oct-18	115,038	322	114,716	92.81	7.19	0	37.06	91%	0	0	690.48	N/A	N/A	N/A	1,403.44	12,234
Nov-18	64,240	1,023	63,217	66.88	4.41	19.9	21.09	63%	1	1	462.98	N/A	N/A	N/A	792.33	12,534
Dec-18	0	3,108	(3,108)	74.22	100	21.33	-0.86	0%	0	0	0	N/A	N/A	N/A	0.00	0
Jan-19	8,792	3,205	5,587	95.05	34.06	0	1.94	9%	1	0	71.33	N/A	N/A	N/A	107.54	19,248
Feb-19	96,302	305	95,997	78.94	0	16.53	34.34	83%	0	0	560.93	N/A	N/A	N/A	1,172.80	12,217
Mar-19	44,565	2,307	42,258	71.66	31.75	13.14	13.75	29%	1	1	232.72	N/A	N/A	N/A	597.10	14,130
Apr-19	71,255	2,116	69,139	34.57	62.5	0	23.17	32%	1	0	269.98	N/A	N/A	N/A	900.36	13,023
May-19	173,884	0	173,884	90.44	0	0	56.74	84%	0	0	744	N/A	N/A	N/A	1,918.12	11,031
Jun-19	162,050	0	162,050	84.47	0	0	54.63	89%	0	0	720	N/A	N/A	N/A	2,004.85	12,372
Jul-19	57,106	1,486	55,620	27.02	71	0	18.21	19%	0	0	215.77	N/A	N/A	N/A	647.60	11,643
Aug-19	57,457	1,066	56,391	32.3	66.13	0	18.46	26%	1	0	251.97	N/A	N/A	N/A	671.94	11,916
Sep-19	31,436	538	30,898	19.29	0	79.78	10.5	17%	0	0	145.58	N/A	N/A	N/A	380.58	12,317
Oct-19	0	487	(487)	0	0	100	-0.06	0%	0	0	0	N/A	N/A	N/A	0.00	0
Nov-19	0	3,005	(3,005)	0	100	4.94	-0.91	0%	0	0	0	N/A	N/A	N/A	0.00	0
Dec-19	0	2,554	(2,554)	0	100	0	-0.72	0%	0	0	0	N/A	N/A	N/A	0.00	0
Jan-20	10,209	2,768	7,440	22.44	45.45	56.41	2.47	0%	2	1	129.98	N/A	N/A	N/A	124.97	16,796
Feb-20	101,772	775	100,997	65.17	0	20.64	34.91	35%	0	2	485.38	N/A	N/A	N/A	1,276.21	12,636
Mar-20	0	1,716	(1,716)	0	0	100	-0.49	0%	0	0	0	N/A	N/A	N/A	0.00	0
Apr-20	65,810	1,994	63,816	47.43	25.37	21.44	21.37	40%	1	1	325.92	N/A	N/A	N/A	744.23	11,662
May-20	111,245	840	110,405	64.12	12.14	0	37.31	58%	2	0	569.92	N/A	N/A	N/A	1,298.54	11,762
Jun-20	100,992	1,028	99,964	51.12	15.62	16.14	34.92	49%	2	0	464.22	N/A	N/A	N/A	1,086.10	10,865
Jul-20	130,009	205	129,805	53.14	0	6.23	43.82	90%	0	0	697.62	N/A	N/A	N/A	1,481.03	11,410
Aug-20	98,633	589	98,044	56.6	8.77	5.58	33.11	75%	1	1	617.17	N/A	N/A	N/A	1,276.95	13,024

	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	NET HEAT RATE (Btu/kWh)
Sep-20	124,921	0	124,921	52.9	0	0	43.58	69%	0	0	720	N/A	N/A	N/A	1,564.98	12,528
Oct-20	54,680	291	54,388	19.7	0	61.07	17.62	22%	0	0	289.67	N/A	N/A	N/A	766.42	14,092
Nov-20	8,365	1,060	7,305	18.43	82.21	56.73	2.51	4%	1	0	38.75	N/A	N/A	N/A	104.41	14,294
Dec-20	58,248	1,438	56,810	70.88	6.85	0	18.38	46%	0	0	433.75	N/A	N/A	N/A	702.76	12,370

Note:
If start-up begins for a super-critical unit within 24 hours of unit coming off line, the start-up is considered to be a hot start. If start-up begins for a drum unit within 72 hours of the unit coming off line, the start-up is considered to be a hot start. Outside of these time frames, the start-up is considered to be a cold start-up. Simple cycle CTs (Hardin 1 and 2) are always hot starts. For Montgomery country, the 72 rule still applies

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

SABINE 4 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	NET HEAT RATE (Btu/kWh)
Jan-18	108,493	2,373	106,121	68.51	37.1	0	26.66	48%	1	0	397.18	N/A	N/A	N/A	1,444.27	13,610
Feb-18	42,645	2,059	40,586	85.78	41.06	0	11.39	16%	2	0	137.12	N/A	N/A	N/A	624.86	15,396
Mar-18	225,541	559	224,982	74.16	0	25.84	56.58	68%	0	0	514.47	N/A	N/A	N/A	2,607.94	11,592
Apr-18	0	1,588	(1,588)	58.17	0	41.83	-0.3	0%	0	0	0	N/A	N/A	N/A	0.00	0
May-18	211,582	727	210,855	81.95	4.93	0	52.9	68%	1	2	679.38	N/A	N/A	N/A	2,580.09	12,236
Jun-18	201,532	882	200,650	79.83	11.01	0	52.04	83%	1	0	610.55	N/A	N/A	N/A	2,330.64	11,615
Jul-18	167,464	1,064	166,400	68.68	30.78	0	41.79	62%	1	0	483.15	N/A	N/A	N/A	2,012.14	12,092
Aug-18	170,995	724	170,270	73.96	18.05	0	42.73	68%	0	1	543.25	N/A	N/A	N/A	2,029.85	11,921
Sep-18	0	2,133	(2,133)	64.16	100	0	-0.41	0%	0	0	0	N/A	N/A	N/A	0.00	0
Oct-18	196,087	302	195,786	100	0	0	49.02	90%	1	0	688.8	N/A	N/A	N/A	2,392.22	12,219
Nov-18	229,263	0	229,263	100	0	0	59.24	100%	0	0	721	N/A	N/A	N/A	2,827.73	12,334
Dec-18	205,549	0	205,549	100	0	0	51.46	99%	0	0	744	N/A	N/A	N/A	2,361.55	11,489
Jan-19	207,472	0	207,472	100	0	0	51.94	100%	0	0	744	N/A	N/A	N/A	2,537.59	12,231
Feb-19	40,924	1,862	39,063	22.76	0	77.24	10.88	17%	1	0	120.7	N/A	N/A	N/A	498.39	12,759
Mar-19	120,329	1,234	119,095	67.12	0	32.88	29.88	57%	1	0	426.55	N/A	N/A	N/A	1,612.24	13,537
Apr-19	3,960	2,844	1,117	6.09	97.92	0	0.39	1%	1	0	14.37	N/A	N/A	N/A	50.04	44,805
May-19	121,061	1,276	119,785	43.48	8.51	50.15	30.24	42%	1	0	339.3	N/A	N/A	N/A	1,335.43	11,149
Jun-19	33,839	2,088	31,751	12.77	57.94	64.94	8.34	4%	2	0	106.17	N/A	N/A	N/A	418.65	13,185
Jul-19	197,853	1,359	196,494	69.77	28.63	0	49.51	65%	2	0	531.02	N/A	N/A	N/A	2,243.73	11,419
Aug-19	201,864	845	201,019	66.75	27.09	0	50.65	70%	1	0	542.42	N/A	N/A	N/A	2,360.73	11,744
Sep-19	243,068	0	243,068	97.75	0	0	63.25	100%	0	0	720	N/A	N/A	N/A	2,942.67	12,108
Oct-19	230,126	361	229,765	83.4	10.91	0	57.54	83%	0	0	662.82	N/A	N/A	N/A	2,816.52	12,258
Nov-19	42,988	3,885	39,104	28.61	74.43	0	10.18	20%	1	0	165.58	N/A	N/A	N/A	624.57	15,972
Dec-19	185,670	811	184,859	66.34	11.55	0	46.29	84%	1	0	632.65	N/A	N/A	N/A	2,229.05	12,058
Jan-20	184,719	1,155	183,565	57.21	0	15.19	45.98	67%	0	0	600.6	N/A	N/A	N/A	2,261.15	12,318
Feb-20	3,212	1,328	1,884	18.28	0	81.72	0.56	0%	1	0	20.1	N/A	N/A	N/A	40.28	21,383
Mar-20	0	193	(193)	0	0	100	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Apr-20	78,660	575	78,084	32.44	0	65.78	20.24	27%	1	1	246.37	N/A	N/A	N/A	889.54	11,392
May-20	201,688	1,152	200,535	82.26	0	14.6	50.52	76%	1	0	578.65	N/A	N/A	N/A	2,354.26	11,740
Jun-20	241,268	0	241,268	91.57	0	0	62.77	99%	0	0	720	N/A	N/A	N/A	2,594.67	10,754
Jul-20	255,760	0	255,760	83.27	0	0	64.41	100%	0	0	744	N/A	N/A	N/A	2,913.54	11,392
Aug-20	103,237	1,640	101,597	39.86	44.77	17.82	25.64	36%	2	0	323.78	N/A	N/A	N/A	1,336.56	13,156
Sep-20	127,037	2,237	124,800	81.82	17.41	0	32.53	52%	0	0	374.82	N/A	N/A	N/A	1,591.49	12,752
Oct-20	52	2,604	(2,552)	17.39	99.14	0	-0.53	0%	1	0	5.22	N/A	N/A	N/A	0.73	0
Nov-20	83,939	1,165	82,773	27.21	65.95	0	21.46	32%	1	0	245.47	N/A	N/A	N/A	1,047.70	12,657
Dec-20	218,125	0	218,125	79.29	0	0	54.6	99%	0	0	744	N/A	N/A	N/A	2,631.64	12,065

Note:
If start-up begins for a super-critical unit within 24 hours of unit coming off line, the start-up is considered to be a hot start. If start-up begins for a drum unit within 72 hours of the unit coming off line, the start-up is considered to be a hot start. Outside of these time frames, the start-up is considered to be a cold start-up. Simple cycle CTs (Hardin 1 and 2) are always hot starts. For Montgomery country, the 72 rule still applies

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

SABINE 5 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	NET HEAT RATE (Btu/kWh)
Jan-18	40,132	2,234	37,897	50.72	38.72	20.25	10.66	32%	1	0	269.75	N/A	N/A	N/A	534.23	14,097
Feb-18	51,701	1,972	49,729	43.28	15.74	38.64	15.48	43%	1	0	300.97	N/A	N/A	N/A	757.56	15,234
Mar-18	69,651	894	68,757	87.77	7.39	0	19.26	82%	1	0	611.92	N/A	N/A	N/A	805.38	11,713
Apr-18	114,110	1,545	112,565	75.58	21.15	0	32.61	70%	0	0	504.25	N/A	N/A	N/A	1,408.01	12,508
May-18	144,916	38	144,878	94.94	0	0	40.98	98%	1	0	742.07	N/A	N/A	N/A	1,767.14	12,197
Jun-18	80,052	1,524	78,528	53.06	0	21.56	22.97	74%	0	1	534.87	N/A	N/A	N/A	925.77	11,789
Jul-18	144,473	325	144,148	90.44	0	1.09	40.79	94%	1	0	710.93	N/A	N/A	N/A	1,735.89	12,042
Aug-18	130,909	26	130,883	88.25	0.26	0	37.01	99%	0	1	742.05	N/A	N/A	N/A	1,554.00	11,873
Sep-18	141,186	0	141,186	88.61	0	0	41.27	100%	0	0	720	N/A	N/A	N/A	1,643.12	11,638
Oct-18	58,351	2,810	55,541	69.23	27.23	0	15.58	59%	1	0	448.85	N/A	N/A	N/A	711.87	12,817
Nov-18	65,026	1,171	63,854	92.43	1.92	0	18.42	81%	1	0	595.92	N/A	N/A	N/A	802.02	12,560
Dec-18	20,583	3,173	17,410	93.95	0	0	4.95	35%	1	0	264.52	N/A	N/A	N/A	236.48	13,583

Jan-19	0	799	(799)	12.12	0	87.1	-0.12	0%	0	0	0	N/A	N/A	N/A	0.00	0
Feb-19	0	222	(222)	0	0	100	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Mar-19	0	320	(320)	0	0	100	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Apr-19	0	682	(682)	0	0	100	-0.06	0%	0	0	0	N/A	N/A	N/A	0.00	0
May-19	0	757	(757)	0	0	100	-0.06	0%	0	0	0	N/A	N/A	N/A	0.00	0
Jun-19	15,737	1,373	14,365	6.86	0	87.96	4.6	8%	1	0	86.7	N/A	N/A	N/A	194.70	13,554
Jul-19	179,567	39	179,528	99	0.46	0	53.76	98%	0	1	740.55	N/A	N/A	N/A	2,036.35	11,343
Aug-19	180,119	0	180,119	91.15	0	0	53.93	99%	0	0	744	N/A	N/A	N/A	2,106.43	11,695
Sep-19	71,097	2,658	68,439	78.74	28.74	0	21.22	52%	1	0	379.57	N/A	N/A	N/A	860.73	12,577
Oct-19	130,505	0	130,505	95.99	0	0	36.52	95%	0	0	744	N/A	N/A	N/A	1,597.25	12,239
Nov-19	90,761	817	89,944	90	10.12	0	25.97	88%	0	1	640.77	N/A	N/A	N/A	1,318.66	14,661
Dec-19	11,181	5,802	5,379	82.95	30.52	0	1.56	5%	1	0	120.48	N/A	N/A	N/A	134.23	24,956
Jan-20	58,642	4,366	54,276	93.49	0	2.9	15.25	32%	1	0	266.27	N/A	N/A	N/A	717.84	13,226
Feb-20	182,817	0	182,817	98.58	0	0	54.74	98%	0	0	698	N/A	N/A	N/A	2,292.50	12,540
Mar-20	224,509	0	224,509	98.73	0	0	62.98	100%	0	0	743	N/A	N/A	N/A	2,763.47	12,309
Apr-20	189,794	0	189,794	100	0	0	54.93	99%	0	0	720	N/A	N/A	N/A	2,146.33	11,309
May-20	82,442	2,308	80,133	61.86	0	38.14	22.72	48%	1	0	361.55	N/A	N/A	N/A	962.33	12,009
Jun-20	211,530	0	211,530	99.07	0	0	61.88	99%	0	0	720	N/A	N/A	N/A	2,274.86	10,754
Jul-20	190,252	0	190,252	90.02	0	0	53.85	100%	0	0	744	N/A	N/A	N/A	2,167.29	11,392
Aug-20	142,751	490	142,260	89.9	8.16	0	40.27	85%	0	1	683.3	N/A	N/A	N/A	1,848.13	12,991
Sep-20	159,834	39	159,795	99.49	0.51	0	46.73	94%	0	2	716.32	N/A	N/A	N/A	2,002.36	12,531
Oct-20	160,217	0	160,217	100	0	0	44.87	97%	0	0	744	N/A	N/A	N/A	2,245.68	14,017
Nov-20	128,899	596	128,303	86.79	0	13.21	37.08	87%	0	0	625.75	N/A	N/A	N/A	1,608.89	12,540
Dec-20	7,907	3,755	4,153	45.15	0	47.11	1.26	6%	1	1	50.98	N/A	N/A	N/A	95.40	22,972

Note:
If start-up begins for a super-critical unit within 24 hours of unit coming off line, the start-up is considered to be a hot start. If start-up begins for a drum unit within 72 hours of the unit coming off line, the start-up is considered to be a hot start. Outside of these time frames, the start-up is considered to be a cold start-up. Simple cycle CTs (Hardin 1 and 2) are always hot starts. For Montgomery country, the 72 rule still applies

ENTERGY TEXAS, INC.
GENERATING UNIT DATA
JANUARY 1, 2018 - DECEMBER 31, 2020

BIG CAJUN II, UNIT 3 GENERATING UNIT DATA

	PRODUCTION MWh			OPERATING STATISTICS (%)								FUEL CONSUMPTION BILLION Btu				NET HEAT RATE (Btu/kWh)
	Gross Unit Output	Station Service	Net Unit Output	Equivalent Availability Factor	Forced Outage Rate	Scheduled Outage Factor	Net Capacity Factor	% Time on AGC	# Of Cold Starts*	# of Hot Starts*	Hours Connected to Load	Cold Start	Hot Start	Operations	Total	
Jan-18	41,443	0	41,443	64.52	25.63	0	55.62	0%	2	0	541.4	N/A	N/A	N/A	449.48	10,846
Feb-18	28,366	0	28,366	77.64	19.8	0	40.76	5%	1	2	411.88	N/A	N/A	N/A	308.68	10,882
Mar-18	57,613	0	57,613	94.05	0	0	74.78	27%	0	0	738.72	N/A	N/A	N/A	630.96	10,952
Apr-18	0	0	0	2.01	0	97.22	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
May-18	31,676	0	31,676	51.65	3.45	44.02	41.12	17%	1	1	402.12	N/A	N/A	N/A	337.82	10,665
Jun-18	52,691	0	52,691	89.81	9.61	0	70.69	29%	0	2	641.55	N/A	N/A	N/A	550.13	10,441
Jul-18	65,855	0	65,855	99.14	0	0	85.5	41%	0	0	744	N/A	N/A	N/A	697.91	10,598
Aug-18	52,324	0	52,324	86.27	13.34	0	67.93	24%	1	1	616.65	N/A	N/A	N/A	566.15	10,820
Sep-18	39,380	0	39,380	69.1	26.28	4.81	52.83	26%	1	2	495.07	N/A	N/A	N/A	432.14	10,974
Oct-18	23,474	0	23,474	39.66	61.56	0	30.48	11%	2	0	278.38	N/A	N/A	N/A	250.32	10,664
Nov-18	58,438	0	58,438	88.17	10.77	0	78.41	9%	1	1	643.35	N/A	N/A	N/A	633.72	10,844
Dec-18	54,303	0	54,303	79.5	16.07	0	75.99	6%	1	1	613.03	N/A	N/A	N/A	595.00	10,957
Jan-19	44,751	0	44,751	76.65	19.93	0	58.17	44%	2	0	565.08	N/A	N/A	N/A	504.48	11,273
Feb-19	37,209	0	37,209	94.01	0.43	5.06	53.49	68%	0	2	600.68	N/A	N/A	N/A	426.86	11,472
Mar-19	60,780	0	60,780	98.32	0	0	78.93	81%	0	0	743	N/A	N/A	N/A	651.41	10,717
Apr-19	20,053	0	20,053	35.47	0	58.96	26.9	20%	1	0	295.47	N/A	N/A	N/A	212.70	10,607
May-19	35,258	0	35,258	92.07	0	5.37	45.77	88%	0	1	699.33	N/A	N/A	N/A	375.22	10,642
Jun-19	4,719	0	4,719	89.58	29.11	2.31	6.33	15%	2	0	142.2	N/A	N/A	N/A	51.40	10,891
Jul-19	1,548	0	1,548	97.44	0	2.56	2.01	4%	1	0	41.23	N/A	N/A	N/A	16.87	10,903
Aug-19	2,946	0	2,946	100	0	0	3.82	8%	1	0	70.03	N/A	N/A	N/A	31.89	10,826
Sep-19	13,381	0	13,381	77.32	12.6	0	17.95	32%	2	1	428.17	N/A	N/A	N/A	142.40	10,642
Oct-19	27,268	0	27,268	93.68	0	0	35.4	93%	0	1	699.18	N/A	N/A	N/A	297.54	10,912
Nov-19	25,008	0	25,008	84.73	11.78	0	33.55	84%	1	1	628.23	N/A	N/A	N/A	263.90	10,553
Dec-19	17,885	0	17,885	98.28	0	0	23.18	58%	0	0	457.3	N/A	N/A	N/A	191.59	10,712
Jan-20	0	0	0	79.28	0	19.33	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Feb-20	0	0	0	98.28	0	0	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Mar-20	11,285	0	11,285	98.28	0	0	14.67	39%	1	0	321.13	N/A	N/A	N/A	119.25	10,568
Apr-20	1,804	0	1,804	98.28	0	0	2.42	5%	1	0	57.12	N/A	N/A	N/A	19.37	10,738
May-20	4,180	0	4,180	98.28	0	0	5.43	14%	1	0	118.9	N/A	N/A	N/A	44.74	10,703
Jun-20	2,670	0	2,670	99.91	0	0	3.71	3%	1	0	44.47	N/A	N/A	N/A	27.93	10,464
Jul-20	1,148	0	1,148	96.43	0	0	1.54	3%	0	0	26.47	N/A	N/A	N/A	12.28	10,692
Aug-20	7,015	0	7,015	96.43	0	0	9.43	17%	1	0	143.9	N/A	N/A	N/A	73.86	10,528
Sep-20	2,499	0	2,499	92.96	31.06	0	3.47	7%	1	0	57.4	N/A	N/A	N/A	26.36	10,548
Oct-20	0	0	0	6.22	0	93.55	0	0%	0	0	0	N/A	N/A	N/A	0.00	0
Nov-20	1,474	0	1,474	72.31	47.62	22.41	2.13	3%	2	0	41.83	N/A	N/A	N/A	0.00	0
Dec-20	7,829	0	7,829	67.7	29.41	24.01	10.44	17%	1	0	147.95	N/A	N/A	N/A	85.10	10,870

Note:
If start-up begins for a super-critical unit within 24 hours of unit coming off line, the start-up is considered to be a hot start. If start-up begins for a drum unit within 72 hours of the unit coming off line, the start-up is considered to be a hot start. Outside of these time frames, the start-up is considered to be a cold start-up. Simple cycle CTs (Hardin 1 and 2) are always hot starts. For Montgomery country, the 72 rule still applies
Big Cajun II, Unit 3 - All generation and fuel consumption data based on ETI's 17.85% share. All other data is based on 100% of unit. Big Cajun II, Unit 3 data shown as in ESL's systems.

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

Response of: Entergy Texas, Inc.	Prepared By: Joseph R. Gay
to the Fifth Set of Data Requests	Sponsoring Witness: Andrew Dornier
of Requesting Party: Office of Public Utility	Beginning Sequence No. LC419
Counsel	Ending Sequence No. LC420

Question No.: OPUC 5-6 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Mr. Dornier, Exhibit ALD-1, WP/ALD Testimony 2 HSPM. Please provide the monthly injections, measured in MMBTUs, and the monthly withdrawals, measured in MMBTUs, at Spindletop for the period January 2018 through December 2020.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

Please see the highly sensitive attachment (TP-53719-00OPC005-X006_HSPM). Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

Native Files (Highly Sensitive)

provided on CD

Entergy Texas, Inc.
Cost of Service
AJ19 ASC 715-60 Defined Benefit Plans—Other Postretirement
Electric
For the Test Year Ended December 31, 2017

This adjustment is to reflect estimated change in ASC 715-60 Defined Benefit Plans-Other Postretirement expense (formally FAS 106) for total ETI.

Line No.	Description	Amount
1	Total Test Year ASC 715-60 Costs-ETI	(1,751,004)
2	Estimated Annual ASC 715-60 Costs-ETI	(6,204,000)
3	Estimated Change in ASC 715-60 Costs-ETI (1)	(4,452,996)
4	O&M Expense Allocation	50.29%
5	ETI Direct O&M ASC 715-60 Expenses Estimated Increase/(Decrease) (2)	(2,239,412)
6		
7	Total Test Year ASC 715-60 Costs-ESI	14,905,980
8	Estimated Annual ASC 715-60 Costs-ESI	13,737,000
9	Estimated Change in ASC 715-60 Costs-ESI (3)	(1,168,980)
10	ETI Allocated O&M Expense Allocation	6.49%
11	Affiliate Billed to ETI Estimated Change in ASC 715-60 Expenses (4)	(75,867)
12		
13	**Total ETI ASC 715-60 Adjustment (5)**	**(2,315,278)**

Notes:
(1) Line 2 - Line 1
(2) Line 3 * Line 4
(3) Line 8 - Line 7
(4) Line 9 * Line 10
(5) Line 5 + Line 11

Amounts may not add or tie to other schedules due to rounding.

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

Response of: Entergy Texas, Inc.	Prepared By: Noel Christmann, Terri Rivera, Soraya Woods
to the Second Set of Data Requests	Sponsoring Witnesses: Jennifer A. Raeder, Allison P. Lofton, David C. Batten
of Requesting Party: CITIES	Beginning Sequence No. EV1433 Ending Sequence No. EV1434

Question No.: CITIES 2-15 Part No.: Addendum:

Question:

Retirement plans: Please quantify the savings which have been achieved or that are expected to be achieved from changes to Company's retirement plans or post-retirement benefits.

Response:

1. Postretirement Health Plan

The adoption of the Medicare Exchange for non-bargaining and certain bargaining Medicare-eligible participants resulted in a plan amendment that is amortized annually into expense over approximately 6 years. The resulting change in annual expense/(income), including amounts billed from Entergy Services, LLC, was:

	ETI
FY-2021:	$ (2,152,000)
FY-2022:	$ (2,764,000)

2. Qualified Pension Plans

a. The merger of the Non-Bargaining Cash Balance Plan into Plan NBI on January 1, 2022 resulted in a decrease in the annual amortization of unrecognized (gain)/loss. The resulting change in annual expense/(income), including amounts billed from Entergy Services, LLC was:

	ETI
FY-2021:	n/a
FY-2022:	$ (1,154,000)