AUSTIN ENERGY 2022 BASE RATE REVIEW	**§ § §**	**BEFORE THE CITY OF AUSTIN HEARING EXAMINER**

Direct Testimony and Exhibits

of

BILLIE S. LACONTE

On Behalf of

Texas Industrial Energy Consumers

June 22, 2022

J. POLLOCK
INCORPORATED

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AFFIDAVIT OF BILLIE S. LACONTE

State of Missouri)
) SS
County of St. Louis)

Billie S. LaConte, being first duly sworn, on his oath states:

1. My name is Billie S. LaConte. I am an Associate of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Texas Industrial Energy Consumers to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, Exhibits and Appendices A and B, which have been prepared in written form for introduction into evidence before the Austin City Council Impartial Hearings Examiner; and

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Billie S. LaConte

Subscribed and sworn to before me this 22nd day of June, 2022.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

GLOSSARY OF ACRONYMS

Term	Definition
AE	Austin Energy
DSCR	Debt Service Coverage Ratio
EPE	El Paso Electric Company
ETI	Entergy Texas, Inc.
Fitch	Fitch Ratings
GFT	General Fund Transfer
Moody's	Moody's Investors Service
S&P	Standard & Poor's Global Rating
SPS	Southwestern Public Service Company
SWEPCO	Southwestern Electric Power Company
ROE	Return on Equity
TIEC	Texas Industrial Energy Consumers

EXHIBIT LIST

Exhibit	Description
BSL-1	Corrected Test-Year Debt Service Ratio
BSL-2	Debt Service Coverage Ratio with $110 Million General Fund Transfer
BSL-3	Debt Service Coverage Ratio with 40% Cash for Construction Budget
BSL-4	Debt Service Coverage Ratio with 40% Cash for Construction Budget and $110 Million General Fund Transfer
BSL-5	Debt Service Coverage Ratio with 40% Cash for Construction Budget and $110 Million General Fund Transfer with Non-Electric Revenues and Expenses

DIRECT TESTIMONY OF BILLIE S. LACONTE

Introduction, Qualifications and Summary

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Billie S. LaConte, 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and Associate Consultant at J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University. Since graduating in 1995, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. **Appendix A** to this testimony provides more details regarding my education and experience. **Appendix B** to this testimony contains a list of my appearances.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of Texas Industrial Energy Consumers (TIEC). TIEC's participating member in this case is one of Austin Energy's (AE's) largest electricity consumers. Service is provided under the High Load Factor Primary Voltage (Demand ≥ 20 MW) rate schedule.

Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR DIRECT TESTIMONY?

A I am addressing elements of AE's requested return and its application of the cash flow methodology to derive the return. Specifically, I will address:

- General Fund Transfer (GFT); and
- Internally Generated Funds.

I also demonstrate that my recommendations on the above issues would result in a debt service coverage ratio for Austin Energy that allows it to maintain its AA bond rating.

Q ARE YOU SPONSORING ANY EXHIBITS SUPPORTING YOUR DIRECT TESTIMONY?

A Yes. I am sponsoring **Exhibits BSL-1** through **BSL-5**. These exhibits were either prepared by me or under my direction. Additionally, **Appendix C** contains the discovery responses relied upon and referenced herein.

Q ARE YOU ENDORSING AUSTIN ENERGY'S PROPOSALS ON ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of AE's proposals in this proceeding. In particular, I am not endorsing the cash flow methodology in setting rates for a municipally-owned utility.

<u>Summary</u>

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

<u>General Fund Transfer</u>

- AE's proposed GFT is $121 million, which is 12% of its proposed operating revenue, the highest level allowed under AE's Financial Policies.[1] This is well above AE's historical average GFT ratio, which is 7.8%. It is also $11 million above the historical average GFT, which is $110 million.[2]

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[1] Rate Filing Package, Appendices C at C-69 and B at B-2.

[2] 2020-2021 City of Austin Approved Budget at 407; 2021-2022 City of Austin Approved Budget at 377.

- AE has provided no valid justification for increasing the GFT. AE's test-year GFT should be set no higher than $110 million, which is 10.9% of the proposed operating revenue and above the historical average GFT ratio of 7.8%.

Internally Generated Funds

- AE's proposed return assumes 50% cash funding of construction requirements to preserve a capital structure of 50% debt and 50% equity.[3] This proposal inflates the proposed revenue requirement and is unnecessary to maintain AE's already high credit rating.

- Internal cash funding for construction should be reduced to 40%, allowing AE to take full advantage of low-cost debt while reducing costs to customers. Funding 60% of AE's construction budget with debt falls within the range of debt ratios prescribed in AE's Financial Policies.[4] Furthermore, higher debt funding is preferable because the current cost of debt is low. The increase in costs due to higher debt funding is lower than the cost of using more cash to fund AE's construction projects.

Impacts on Debt Service Coverage Ratio and Credit Rating

- AE's target debt service coverage ratio (DSCR) is 2.0x.[5] My recommendations to establish a GFT based on the average of the three prior years and reducing the amount of construction projects funded by cash to 40% (from 50%) would result in a DSCR of 2.30x, which is well above AE's target.

- The 2.30x DSCR is within the range of DSCRs for public power utilities with AA rated debt, which is AE's current rating. Thus, my recommendations would allow AE to maintain its bond rating.

Q HOW IS YOUR TESTIMONY STRUCTURED?

A I begin my testimony by describing AE's application of the cash flow method to derive its proposed return. I then assess AE's financial risk as reflected by its credit rating and DSCR. Next, I set forth my recommendations that the GFT and amount of internal

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[3] Rate Filing Package, Appendix C at C-72.

[4] Rate Filing Package, Appendix B at B-2.

[5] Rate Filing Package, Appendix B at B-1.

cash funding be reduced, and demonstrate that these recommendations would allow AE to maintain a DSCR above its targeted levels and preserve its credit rating.

Cash Flow Method

Q WHAT IS THE CASH FLOW METHOD?

A The cash flow method is used to develop the return component of AE's total revenue requirement. Unlike an investor-owned utility, AE does not develop its revenue requirement to earn a profit for equity investors. The cash flow method examines the company's cash requirements in excess of its expenses and debt service.

Q HOW DID AUSTIN ENERGY USE THE CASH FLOW METHOD TO DETERMINE THE TEST-YEAR REVENUE REQUIREMENT?

A The derivation of AE's test-year revenue requirement is shown in Table 1, which includes its requested cash flow.

Table 1
Test-Year Revenue Requirement
Excluding Pass-Through Costs
($000)

Component	Amount
O&M Expense	$984,618
Depreciation & Amortization	146,766
Taxes	1,943
Other	6,979
Requested Cash Flow	197,269
Revenue Requirement	1,337,575
Less Pass-Through Costs	488,171
Other Non-rate Revenue	144,435
Base Revenue Requirement	$704,969

Source: Schedule A.

The requested cash flow is a separate component of AE's test-year base revenue requirement. The derivation of AE's requested cash flow is shown in Table 2.

Table 2
Test-Year Requested Cash Flow
($000)

Component	Amount
Return:	
Debt Service	$143,115
Non-Nuclear Decommissioning	8,000
General Fund Transfer	121,000
Internally Generated Funds for Construction	119,818
Sub-Total	$391,933
Less:	
Depreciation & Amortization	$146,766
Interest & Dividend Income	4,270
Contributions in Aid of Construction	43,628
Sub-Total	194,664
Requested Cash Flow	$197,269

Source: Schedule A.

As Table 2 demonstrates, two of the key components of the requested cash flow are the GFT and the amount of cash used to fund construction (*i.e.,* internally generated funds for construction). Both the GFT and internal funds will ultimately affect the DSCR, which, in turn, will affect AE's credit rating.

Q HAS AUSTIN ENERGY ADOPTED FINANCIAL POLICIES THAT GUIDE HOW THE REQUESTED CASH FLOW SHOULD BE DETERMINED?

A Yes. AE's Financial Policies state, among other things:

- The target DSCR is a minimum of 2.0x;
- The GFT shall not exceed 12% of AE's three-year average revenues less power supply costs and on-site energy resource revenue; and

- Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution of ratio between 35% and 60% is desirable (equivalent to a debt funding ratio of between 40% and 65%).[6]

Q DO AUSTIN ENERGY'S FINANCIAL POLICIES MANDATE A SPECIFIED GENERAL FUND TRANSFER AND INTERNALLY GENERATED FUNDS?

A No.

<u>Financial Metrics – Credit Rating and Debt Service Coverage Ratio</u>

Q WHAT IS AE'S CREDIT RATING?

A As noted, AE's credit rating is currently AA per Fitch Ratings, which is the third highest rating available.

Q DO ANY INVESTOR-OWNED VERTICALLY INTEGRATED REGULATED ELECTRIC PUBLIC UTILITIES IN TEXAS HAVE A RATING AS HIGH AS AUSTIN ENERGY?

A No. Southwestern Electric Power Company (SWEPCO) has an A- rating from S&P. Southwestern Public Service Company (SPS) and El Paso Electric Company (EPE) have Baa2 ratings from Moody's. Entergy Texas (ETI) has a Baa2 rating from Moody's.

Q WHAT IS THE RATING SCALE FOR MOODY'S, S&P, AND FITCH?

A Table 3 shows the rating scale for Moody's, S&P and Fitch Ratings.

[6] Rate Filing Package, Appendix B at B-1 and B-2.

Table 3
Credit Rating Scale

Moody's	S&P	Fitch
Aaa	AAA	AAA
Aa1	AA+	AA+
Aa2	AA	AA
Aa3	AA-	AA-
A1	A+	A+
A2	A	A
A3	A-	A-
Baa1	BBB+	BBB+
Baa2	BBB	BBB
Baa3	BBB-	BBB-

Source: https://wolfstreet.com/credit-rating-scales-by-moodys-sp-and-fitch/

Issuances rated below Baa3 and BBB- are considered to be junk bonds. As shown above, AE's credit rating of AA is fully 7 rungs above the lowest rating that is necessary to maintain investment grade status. Additionally, it is significantly higher than the credit ratings for SWEPCO, SPS, EPE, and ETI.

Q IS IT PRUDENT FOR A UTILITY TO PURSUE THE HIGHEST CREDIT RATING POSSIBLE REGARDLESS OF THE COST TO RATEPAYERS?

A No. At some point the benefit to ratepayers in terms of lower debt costs from a higher credit rating is outweighed by the higher revenue requirement needed to obtain that rating. For example, under current conditions, the cost of debt for a Corporate AA rated debt is only 24 basis points lower than that for Corporate A rated debt (4.30%

compared to 4.54%).[7] As a point of reference, AE's current outstanding debt is $2.1 billion.[8] Therefore, assuming that AE was downgraded to an A rating and, hypothetically, immediately refinanced the entirety of its outstanding debt, its annual debt service cost would increase by only $3.6 million per year. To provide context, the impacts of my adjustments to AE's proposed return would reduce the annual revenue requirement by about $20 million per year. It is important to keep this perspective in mind when evaluating claims by utilities that ratepayers always benefit from higher credit ratings. As demonstrated below, however, my recommendations would not affect AE's credit rating.

Q WHAT IS A DEBT SERVICE COVERAGE RATIO?

A The debt service coverage ratio measures a utility's ability to meet its debt service payments. The DSCR is calculated as revenues less operating expense (excluding depreciation and amortization) divided by the annual debt service payments. Table 4 shows how AE derived the DSCR that results from its proposed return.

Table 4
Austin Energy's Derived
Test-Year Debt Service Coverage Ratio
($000)

Component	Amount
Base Revenues	$686,843
Pass-Through Revenues	506,296
Other Revenues (net of bad debt)	172,602
Total	1,365,742
Less Operating Expense	997,736
Funds Available for Debt Service	368,005
Debt Service Payment	$158,458
Debt Service Coverage Ratio	2.32x

Source: Response to TIEC 3-3 which was informally revised in an email dated June 10, 2022.

[7] YChart as of June 15, 2022.

[8] AE Response to TIEC 2-1, Attachment TIEC 2-1.

AE's proposed DSCR based on its calculations is 16% higher than its minimum target 2.0x DSCR. However, AE's proposed DSCR includes non-electric revenues and expenses. As I will discuss below, it is inappropriate to include these revenues and expenses in the calculation of its DSCR.

Q WHAT IS AUSTIN ENERGY'S DEBT SERVICE COVERAGE RATIO EXCLUDING THE NON-ELECTRIC REVENUES AND EXPENSES?

A AE's DSCR excluding non-electric revenues and expenses is 2.50x. **Exhibit BSL-1** provides the calculations of my revised DSCR. In AE's response to TIEC 3-3 (which was informally revised in an email dated Jun. 10, 2022), AE provided the components it used to estimate its DSCR for the test year, as shown in Table 4 above. However, AE included non-electric revenues and expenses, which is incorrect. The rates at issue in this proceeding are for AE customers only, not customers for AE's other services, such as district cooling or wholesale transmission costs. AE's electric customers should not be responsible for the costs related to AE's other services. The costs for those services should be determined separately and AE should set the rates for those entities to recover adequate revenues to cover their corresponding costs. Stated differently, AE's retail electric customers should not be responsible for providing AE a return on its cooling and wholesale transmission businesses. Therefore, I excluded the non-electric revenues and expenses when determining AE's actual, proposed DSCR. The resulting corrected 2.50x DSCR is even higher than the minimum 2.0x targeted DSCR.

Q WHAT IS THE RANGE OF DEBT SERVICE COVERAGE RATIOS FOR PUBLIC POWER UTILITIES WITH AA RATED DEBT?

A The DSCR for public power utilities with AA rated debt is 0.90x-3.96x, with a 2.35x average.[9] This is well below the corrected 2.50x DSCR.

Q ARE THERE ANY OTHER INDICATIONS THAT AE'S PROPOSED RETURN IS UNNECESSARILY HIGH?

A Yes. Although AE does not earn a return on its equity (ROE), I have estimated, as a hypothetical, what its ROE equivalent would be using its requested total return, weighted cost of debt and its proposed 50/50 debt-to-equity ratio. AE's requested return is 7.93%[10] including a weighted cost of debt of 3.852%.[11] Using these metrics, AE's ROE is equivalent to 12.0%. This is significantly higher than the national average ROE for regulated electric utilities, which was 9.38% in 2021.[12]

A GIVEN THIS EVIDENCE, IS IT NECESSARY FOR AE TO RECEIVE ITS REQUESTED RETURN TO MAINTAIN ACCESS TO CAPITAL ON REASONABLE TERMS AND MEET ITS FINANCIAL TARGETS?

A No. As discussed in more detail below, AE can reduce its GFT and increase its debt funding, and still have a DSCR that is above its minimum target and within the range of DSCRs for public power utilities with AA rated debt. Thus, AE will be able to

[9] Rate Filing Package, Appendix L at L-17. The range of DSCRs excludes Dover Electric Revenue Fund, which is an outlier with a 17.18x DSCR and an 89% equity ratio.

[10] Rate Filing Package, Schedule B.

[11] AE Response to TIEC 2-1, Attachment TIEC 2-1.

[12] S&P Global, RRA Regulatory Focus, Major Rate Case Decisions, February 10, 2022.

maintain its already high AA credit rating and reduce its rate increase simultaneously if it adjusts these components of its cost of service.

General Fund Transfer

Q WHAT IS AUSTIN ENERGY'S REQUESTED GENERAL FUND TRANSFER FOR THE TEST YEAR?

A As previously stated, AE is requesting $121 million for its GFT in the test year, or 12% of the projected operating revenues, the maximum ratio allowed according to AE's Financial Policies.

Q DO YOU HAVE ANY CONCERNS REGARDING AUSTIN ENERGY'S PROPOSED GENERAL FUND TRANSFER?

A Yes. The ratio of the GFT to operating income is over 50% higher than the average over the past three years. Table 5 provides AE's historical GFT ratio from 2018 through the 2020, as well as the corresponding GFT.

Table 5
Historical and Proposed General Fund Transfer as a % of Operating Revenue
($000)

Year Ending Sept. 30	GFT	GFT as % of Operating Revenue
2018	$109,000	7.8%
2019	110,000	7.6%
2020	111,000	8.1%
Average	110,000	7.8%
Test-Year	121,000	12.0%

Source: 2020-2021 Approved Budget; 2021-2022 Approved Budget

Q SHOULD AUSTIN ENERGY REDUCE ITS PROPOSED GENERAL FUND TRANSFER?

A Yes. AE's requested GFT is too high and unnecessarily inflates its revenue requirement. Reducing AE's GFT to no higher than its historical average GFT of $110 million would be more consistent with its Financial Policies and would mitigate the proposed rate increase.

Q WHAT IS AUSTIN ENERGY'S DEBT SERVICE COVERAGE RATIO USING THE LOWER GFT?

A Reducing the GFT to $110 million would result in a 2.39x DSCR. This is well above AE's targeted 2.0x ratio, and it also falls within the range of DSCRs for public power utilities with AA rated debt discussed above. Table 6 shows the derivation of AE's DSCR using the revised GFT.

Table 6
Austin Energy Test-Year Debt Service Coverage Ratio With $110 Million GFT
($000)

Component	Amount
Base Revenues	$694,951
Pass-Through Revenues	488,171
Other Revenues (net of bad debt)	137,459
Total	1,320,581
Less Operating Expense	978,193
Funds Available for Debt Service	342,387
Debt Service Payment	$143,057
Debt Service Coverage Ratio	2.39x

Source: Exhibit BSL-2.

Exhibit BSL-2 provides the calculations for the revised DSCR.

Q WHAT DO YOU RECOMMEND?

A I recommend reducing AE's GFT by $11 million, to $110 million. The lower GFT reduces AE's DSCR from 2.50x to 2.39x, which is within the range of DSCRs for public power utilities with AA rated debt, as well as above AE's minimum targeted 2.0x DSCR.

<u>Internally Generated Funds</u>

Q WHAT ARE AE'S PROPOSED INTERNALLY GENERATED FUNDS?

A AE's proposed Internally Generated Funds are $119.8 million.[13] This represents the amount of cash used to fund AE's construction budget.

Q IN DETERMINING THE PROPOSED REVENUE REQUIREMENT, WHAT PORTION OF AUSTIN ENERGY'S CONSTRUCTION NEEDS WOULD BE FUNDED INTERNALLY?

A AE is proposing to set rates that will result in funding 50% of its construction needs with cash and 50% with debt.

Q WHAT IS AUSTIN ENERGY'S HISTORICAL DEBT FUNDING RATIO FOR INTERNALLY GENERATED FUNDS?

A AE's historical debt funding ratios in 2019, 2020, and 2021, were 85.1%, 53.2%, and 46.2%, respectively.[14] AE's historical average debt funding ratio is 67.2%.

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[13] Rate Filing Package, Schedule A.

[14] Rate Filing Package, Appendix C at C-71.

Q WHAT ARE AUSTIN ENERGY'S FINANCIAL POLICIES REGARDING ITS DEBT RATIO?

A As previously stated, AE's Financial Policies allow for a debt ratio between 40% and 65%. In other words, Internally Generated Funds can range between 35% and 60% of AE's proposed construction budget.

Q SHOULD AUSTIN ENERGY USE MORE DEBT TO FUND ITS CONSTRUCTION PROJECTS?

A Yes. The amount of Internally Generated Funds should be reduced to reflect 60% debt and 40% cash funding. The higher debt funding would be more consistent with AE's actual, historical debt funding, as well as within the range of its targeted debt ratio. Further, lower cash funding of construction projects is consistent with AE's Financial Policies, and it would not jeopardize its credit rating.

Q WHY SHOULD AUSTIN ENERGY INCREASE THE AMOUNT OF DEBT TO FUND ITS CONSTRUCTION PROJECTS?

A Using more debt funding would reduce AE's revenue requirement and its requested rate increase. Furthermore, the cost of debt is still low; therefore, more debt funding would be more cost efficient for ratepayers. The interest rate for Corporate AA rated debt is currently 4.30%.[15]

Q WHAT IS THE IMPACT OF FUNDING 40% INTERNALLY AND 60% DEBT?

A If AE were to fund an additional 10% of its construction budget with debt, its annual debt payment would increase by $914,000. The amount of cash needed for its

[15] YChart as of June 15, 2022.

construction fund would then be reduced by $15 million. The increased debt cost assumes $15 million is funded by debt with a 4.30% interest rate and repaid over a 30 year term. This is significantly lower than the amount of additional cash needed to fund AE's construction budget with 50% cash. The impact of the higher debt ratio on AE's DSCR is shown in Table 7.

Table 7
Revised Test-Year DSCR with 60% Debt Funding
($000)

Component	
Base Revenues	$692,885
Pass-Through Revenues	488,171
Other Revenues Net of Bad Debt	137,558
Total	1,318,613
Less Operating Expense	978,193
Funds Available for Debt Service	340,420
Debt Service	143,057
Debt Service Coverage Ratio	2.36x

Source: Exhibit BSL-3.

Exhibit BSL-3 provides the derivation of the internally generated funds and debt cost.

Q WOULD THIS HIGHER DEBT FUNDING AFFECT AUSTIN ENERGY'S CREDIT RATING?

A No. As demonstrated above, my recommended higher debt funding would reduce AE's DSCR from 2.50x to 2.36x, which is within the range of DSCRs for public power utilities with AA rated debt and still well above AE's minimum targeted DSCR. Furthermore, the debt ratio for public power utilities with AA rated debt is 0% - 63%.[16] As such, AE can maintain its AA credit rating despite higher debt funding.

[16] Rate Filing Package, Appendix L at L-17.

Q WHAT IS AUSTIN ENERGY'S DEBT SERVICE COVERAGE RATIO IF THE GENERAL FUND TRANSFER IS REDUCED TO $110 MILLION AND 60% OF ITS CONSTRUCTION BUDGET IS FUNDED WITH DEBT?

A Table 8 calculates AE's DSCR using my recommended GFT and debt funding. **Exhibit BSL-4** provides the calculations.

Table 8
Revised Test-Year DSCR
With $110 Million GFT and 60% Debt Funding
($000)

Component	Amount
Base Revenues	$684,657
Pass-Through Revenues	488,171
Other Revenues (net of bad debt)	136,786
Total	1,309,613
Less Operating Expense	978,193
Funds Available for Debt Service	331,420
Debt Service	$143,971
Debt Service Coverage Ratio	2.30x

Source: Exhibit BSL-4.

Q WOULD THE LOWER DEBT SERVICE COVERAGE RATIO AND HIGHER DEBT FUNDING ADVERSELY AFFECT AUSTIN ENERGY'S CREDIT RATING?

A No. The 2.30x DSCR and 60% debt funding are in compliance with AE's targeted credit metrics in its Financial Policies and are within the range of these credit metrics for AA rated public power utilities. Therefore, AE can maintain its AA debt rating while reducing its rate increase.

Q WHAT IS AUSTIN ENERGY'S DEBT SERVICE COVERAGE RATIO IF NON-ELECTRIC REVENUES AND EXPENSES ARE INCLUDED?

A While I believe that the non-electric items should be removed as described above, it is worth noting that, even if they are included, my recommendation results in a DSCR that is above AE's targeted minimum. Table 9 calculates AE's DSCR using my recommended GFT and debt funding but with AE's methodology for calculating the DSCR. **Exhibit BSL-5** provides the calculations.

Table 9
Revised Test-Year DSCR
With $110 Million GFT and 60% Debt Funding
Including Non-Electric Revenues and Expenses
($000)

Component	Amount
Base Revenues	$684,657
Pass-Through Revenues	488,171
Other Revenues (net of bad debt)	168,400
Total	1,341,227
Less Operating Expense	997,736
Funds Available for Debt Service	343,491
Debt Service	$159,372
Debt Service Coverage Ratio	2.16x

Source: Exhibit BSL-5.

As shown above, including non-electric revenues and expenses results in a 2.16x DSCR, which is still above AE's targeted minimum 2.0x.

Q **WHAT IS THE IMPACT OF YOUR RECOMMENDED GENERAL FUND TRANSFER AND DEBT FUNDING ON AUSTIN ENERGY'S TEST-YEAR REVENUE REQUIREMENT?**

A The lower GFT and higher debt funding would reduce AE's proposed annual revenue requirement by $20 million or 2.9%, as can be seen on **Exhibit BSL-4**. AE should make every effort to lower its proposed rate increase because customers are already experiencing significant inflationary pressure. Inflation rates are at their highest level since the 1980s. Now is not the time to significantly increase rates when AE has options available at its disposal to reduce its rate increase and provide significant rate relief to its customers.

Q WHAT DO YOU RECOMMEND?

A I recommend that AE reduce its GFT to $110 million and increase debt funding to 60% (40% cash for its construction budget). These adjustments result in a 2.30x DSCR and reduce AE's test-year revenue requirement by $20 million.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

<u>Qualifications of Billie S. LaConte</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Billie S. LaConte. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and am currently employed by J. Pollock, Incorporated as Associate Consultant.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts Degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University.

Upon graduation in May 1995, I joined Drazen Consulting Group, Inc. (DCGI). DCGI was incorporated in 1995 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. I joined J. Pollock in May 2015.

During my tenure at DCGI and J. Pollock my work has focused on revenue requirement issues, cost of capital (return on equity and capital structure), cost allocation, rate design, sales and price forecasts, power cost forecasting, electric restructuring issues, integrated resource plans, formula rate plans, asset management agreements and contract interpretation.

I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This has included advising clients on economic and strategic issues concerning the natural gas pipeline, oil pipeline, electric, wastewater and water utilities. I have prepared cost allocation and rate design studies to provide timely support to clients engaged in settlement negotiations in electric and gas utilities, provided power cost forecasting studies to assist clients in project planning and negotiated contracts with electric utilities for standby services and interruptible rates. I have also prepared studies on electric and gas utilities' performance-based rates (PBR) and benchmarking programs to evaluate their success and to provide recommendations on methods to be used. I worked on contract interpretation to resolve contract disputes for several clients. I have provided financial and cost of service analysis for natural gas pipelines certificate approval from the Federal Energy and Regulatory Commission (FERC) and the Canadian National Energy Board (NEB). Additionally, I completed the Corporate Credit Rating Analysis course presented by Moody's Analytics.

I have worked on various projects located in many states and several Canadian provinces including Alberta, British Columbia, Saskatchewan, Nova Scotia and Quebec. I have testified before the state regulatory commissions of Arkansas, Florida, Georgia, Iowa, Louisiana, Michigan, Minnesota, Missouri, New Mexico, Pennsylvania, Texas and South Carolina, and the provincial regulatory boards of Alberta and Nova Scotia. I similarly have appeared before the St. Louis Metropolitan Sewer District Commission.

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered Class I aggregator in the State of Texas.

Testimony Filed in Regulatory Proceedings
by Billie S. LaConte

UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21148	Rebuttal	MI	Uncollectible Expense; Rate Stability Target	4/29/2022
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21148	Direct	MI	Return on Equity, Capital Structure; Renewable Natural Gas Plant; Incentive Compensation; Transportation Demand Charge; Gas Curtailment and Requirements for Plant Protection; Unauthorized Gas Usage Charge	4/8/2022
SEMCO ENERGY GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-21169	Direct	MI	Facilities Improvement Demand Surcharge	3/18/2022
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/27/2021
EL PASO ELECTRIC COMPANY	Freeport-McMoRan Copper & Gold, Inc.	52195	Direct	TX	Return on Equity; Nuclear Non-Fuel Operation and Maintenance; Rate Case Expense; Retiring Generating Units	10/22/2021
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Projected Year Capital Additions; Projected Year O&M expense	10/5/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Surrebuttal	PA	Return on Equity; Post-Test Year Adjustment	8/5/2021
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	21-044-U	Direct	AR	Formula Rate Plan Extension; Return on Equity; Class Cost-of-Service Study	7/19/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	R-2021-3024601	Direct	PA	Return on Equity; Post-Test Year Adjustment	6/28/2021
FLORIDA LIGHT & POWER COMPANY	Florida Inudstrial Power Users Group	20210015-EI	Direct	FL	Cost of Capital; Early Plant Retirement; Rate Case Expense Amortization; Income Tax Change Mechanism	6/21/2021
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20940	Direct	MI	Return on Equity; Operation and Maintenance Expenses; Incentive Compensation	6/3/2021
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	20-00238-UT	Direct	NM	Rate Design, Retired Plant, Expense Amortization	5/17/2021
PHILADELPHIA WATER DEPARTMENT	Philadelphia Large Users Group	Fiscal Years 2022-2023	Rebuttal	PA	Class Cost-of-Service Study; Stormwater Incentive Program	4/7/2021
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	51415	Direct	TX	Early Plant Retirement; Excess Accumulated Deferred Federal Income Taxes; Self-Insurance Reserve; Imputed Capacity	3/31/2021
SHARYLAND UTILITIES, L.L.C.	Texas Industrial Energy Consumers	51611	Direct	TX	Rate-Case Expenses; Operation and Maintenance Expense; Transmission Cost of Service Refund Rider	3/8/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Surrebuttal	PA	Revenue Allocation; Rate Design	2/9/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Rebuttal	PA	Allocation of Distribution Mains; Revenue Allocation; Rate Design; Universal Service Fund Charge	1/19/2021
PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2020-3018929	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation	12/22/2020

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Surrebuttal (FRP Extension)	AR	FRP Extension; Return on Equity; Capital Structure; Class Cost-of-Service Study; Industrial Rate Design	11/17/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Surrebuttal	PA	Rate Design; Regionalization and Consolidation Surcharge; Return on Equity	10/20/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct (FRP Extension)	AR	FRP Extension; Return on Equity; Capital Structure; Class Cost-of-Service Study; Industrial Rate Design	10/19/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct (2020 Eval. Report)	AR	Historical Year Netting Adjustment; :Long-Term Debt Costs	10/5/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Rebuttal	PA	Rate Design	9/29/2020
PENNSYLVANIA-AMERICAN WATER COMPANY	Pennsylvania-American Large Water Users Group	2020-3019369 2020-3019371	Direct	PA	Regionalization and Consolidation Surcharges; Commercial Rate Design	9/8/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Rebuttal	MI	Financial Compensation Mechanism; Deferred Capital Spending Recovery Mechanism; Karn 1 & 2 Retention and Separation costs, return on equity, storm restoration deferral; PowerMIFleet Pilot Foundational Infrastructure Program; Conservation Voltage Reduction	7/14/2020
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Projected Year Capital Expenditures; Capitalization Policy; Projected Year Adjustments	7/2/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20697	Direct	MI	Return on Equity; Capital Structure; Debt Cost; Additional Surcharges and Deferred Regulatory Accounts	6/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Rebuttal	MI	Return on Equity; Statistical Analysis of Distribution Mains Allocation	5/5/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20650	Direct	MI	Return on Equity; Capital Structure; Long-Term Debt Cost	4/14/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Rebuttal	MI	Return on Equity	4/14/2020
DTE GAS COMPANY	Association of Businesses Advocating Tariff Equity	U-20642	Direct	MI	Return on Equity; Operation and Maintenance Expenses	3/24/2020
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20618	Direct	MI	Certificate of Convenience and Necessity	1/17/2020
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/30/2019
GEORGIA POWER COMPANY	Georgia Association of Manufacturers and Georgia Industrial Group	42516	Direct	GA	Alternate Rate Plan; Coal Combustion Residual Cost Recovery; Amortization of Retired Plant	10/17/2019
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Tax Cuts and Jobs Act Impact; Projected Year Revenues; Projected Year BRORB; Grid Modernization; Advanced Metering Infrastructure Expense	10/4/2019
SOUTHWESTERN ELECTRIC POWER COMPANY	Western Arkansas Large Energy Consumers	19-008-U	Surrebuttal	AR	SWEPCO's Formula Rate Review; Energy Cost Recovery Rider; Distribution Reliability Rider	9/24/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Settlement Support	AR	Support of Settlement	7/31/2019

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
SOUTHWESTERN ELECTRIC POWER COMPANY	Western Arkansas Large Energy Consumers	19-008-U	Direct	AR	SWEPCO's Formula Rate Review; Capital Structure; Distribution Reliability Rider; Arkansas Formula Rate Plans	7/16/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Formula Rate Plan, Capital Additions, Operation and Maintenance Expenses	7/2/2019
ENTERGY LOUISIANA, LLC	Occidential Chemical Corporation	U-35130	Cross-Answering	LA	Fuel Tracking Mechanism	7/1/2019
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	49421	Direct	TX	Unprotected Excess Deferred Income Tax Rider; Incentive Compensation	6/6/2019
ENTERGY LOUISIANA, LLC	Occidential Chemical Corporation	U-35130	Direct	LA	Fuel Tracking Mechanism	5/10/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Rebuttal	MI	Return on Equity	4/29/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Supplemental Surrebuttal	AR	Gas Distribution Uprstream Services Contracting Process	4/23/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Surrebuttal	AR	Gas Distribution Uprstream Services Contracting Process	4/12/2019
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20322	Direct	MI	Return on Equity; Capital Structure; Project vs. Historical Test Year; Earnings Sharing Mechanism	4/5/2019
DUKE ENERGY PROGRESS, LLC	Nucor Steel - South Carolina	2018-318-E	Direct	SC	Excess Deferred Income Tax Rider; Post-Test Year Adjustments; Coal Ash Pond Closure Expense; End-of-Life Nuclear Costs; Regulatory Assets; Return on Equity and Equity Ratio	3/4/2019
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	18-057	Direct	AR	Gas Distribution Uprstream Services Contracting Process	2/12/2019
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/30/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Formula Rate Plan Tariff; Long-Term Debt Cost and Preferred Equity; Projeced Year Capital Additions; Historical Year Capital Additions	10/4/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Rebuttal	MI	Return on Equity	10/1/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-20134	Direct	MI	Return on Equity, Capital Structure and Long-Term Debt Cost, Investment Recovery Mechanism Excess Sharing Mechanism	9/10/2018
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Opposition	AR	Opposition to Settlement Agreement	8/3/2018
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Impact of Tax Cuts and Jobs Act of 2017; Forecast Revenues; Uncollectible Expense; Pipeline Integrity Assessment and Remediation Expense	7/2/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	17-052	Surrebuttal	AR	Utility Restructuring Costs and Tax Effects	5/31/2018

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
PUBLIC SERVICE COMPANY OF NEW MEXICO	City of Farmington, New Mexico; Board of County Commissioners for San Juan County	17-00174	Direct	NM	Integrated Resource Plan; Future of San Juan Generation Station	5/4/2018
ENTERGY ARKANSAS, INC. and CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Electric Energy Consumers, Inc. and Arkansas Gas Consumers, Inc.	18-006	Direct	AR	Effect on Revenue Requirement due to 2017 Tax Cuts and Jobs Act	3/29/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U18424	Rebuttal	MI	Rate of Return	3/21/2018
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	18-014-TF	Direct	AR	Impact of Tax Cuts and Jobs Act of 2017 and Tax Adjustment Rider	3/19/2018
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18424	Direct	MI	Rate of Return, Capital Structure	2/28/2018
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	17-050-U	Surrebuttal	AR	Asset Management Agreement Proposal	1/12/2018
CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	17-050-U	Direct	AR	Asset Management Agreement Proposal	12/8/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/31/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Forecast Revenues, Cost of Debt, Revenue Requirement and Capital Additions	10/4/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Rebuttal	MI	Return on Equity	9/7/2017
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-18322	Direct	MI	Return on Equity, Capital Structure	8/10/2017
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Settlement Support	AR	Support of Settlement	7/31/2017
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Gas Consumers, Inc.	17-010-FR	Direct	AR	Rate of Return, Capital Structure, Labor Expense	7/3/2017
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Settlement Support	AR	Support of Settlement	10/24/2016
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	16-036-FR	Direct	AR	Rate of Return, Forecast Revenue, Capitalization	9/30/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349, 2016-2537352, 2016-2537359	Surrebuttal	PA	Return on Equity	8/31/2016
METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349, 2016-2537352, 2016-2537359	Direct	PA	Return on Equity	7/22/2016
NORTHERN STATES POWER	Xcel Large Industrials	15-826	Direct	MN	Return on Equity, Multi-Year Rate Plan	6/14/2016
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Electric Energy Consumers, Inc.	15-098-U	Surrebuttal	AR	Return on Equity, Formula Rate Plan, Capital Structure	6/7/2016
CENTERPOINT ENERGY RESOURCES CORP	Arkansas Electric Energy Consumers, Inc.	15-098-U	Direct	AR	Return on Equity, Captial Structure	4/14/2016

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
MISSOURI-AMERICAN WATER COMPANY	BJC Healthcare	WR-2011-0337	Rebuttal	MO	Return on Equity	1/19/2012
MISSOURI-AMERICAN WATER COMPANY	BJC Healthcare	WR-2011-0337	Direct	MO	Return on Equity	11/17/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Supplemental	MO	Rate Model	9/16/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Surrebuttal	MO	Rate Increase, CIRP, Consent Decree	8/19/2011
METROPOLITAN ST. LOUIS SEWER DISTRICT	Barnes-Jewish Hospital	N/A	Rebuttal	MO	Rate Increase, CIRP, Consent Decree	7/18/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Surrebuttal	MO	Return on Equity, Energy Efficiency Cost Recovery	4/15/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Rebuttal	MO	Return on Equity, Energy Efficiency Cost Recovery	3/25/2011
AMEREN UE	Missouri Energy Group	ER-2011-0028	Direct	MO	Return on Equity	2/8/2011
AMEREN UE	Missouri Energy Group	EO-2010-0255	Direct	MO	Prudence Audit of FAC Periods 1 and 2	11/22/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Direct - In Support	AR	Supporting the Proposed Settlement Agreement	5/11/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Surrebuttal	AR	Return on Equity	4/14/2010
ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	09-084-U	Direct	AR	Return on Equity	2/26/2010
AMEREN UE	Missouri Energy Group	ER-2010-0036	Direct	MO	Energy Efficiency Costs	12/18/2009
AMEREN UE	Missouri Energy Group	ER-2008-0318	Surrebuttal	MO	Return on Equity	11/5/2008
AMEREN UE	Missouri Energy Group	ER-2008-0318	Direct	MO	Return on Equity, Off-System Sales	8/28/2008
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Rebuttal	MO	Long-Term Financial Plan, Capital Financing	5/2/2007
AMEREN UE	Missouri Energy Group	ER-2007-0002	Surrebuttal	MO	Return on Equity, Interruptible Demand, Response Pilot	2/27/2007
AMEREN UE	Missouri Energy Group	ER-2007-0002	Direct	MO	Interruptible Rate	12/29/2006
AMEREN UE	Missouri Energy Group	ER-2007-0002	Direct	MO	Return on Equity, Off-System Sales, Sharing Mechanism, 10% Cap on Residentials	12/15/2006
AMEREN UE	Missouri Energy Group	EA-2005-0180	Rebuttal	MO	Economic Analysis	1/31/2005
NOVA SCOTIA POWER INC.	Avon Valley Greenhouses	NSUARB-P-881	Direct	NS	Cost of Capital	10/12/2004
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Surrebuttal	MO	Working Capital, Return on Equity, Cost Allocation	12/5/2003

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UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Rebuttal	MO	Rate Design	11/10/2003
MISSOURI-AMERICAN WATER COMPANY	Missouri Energy Group	WR-2003-0500	Direct	MO	Return on Equity, Acquisition Adjustment, Cash Working Capital	10/3/2003
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Direct	MO	Revenue Requirement, Financial Planning	4/22/2003
INTERSTATE POWER AND LIGHT COMPANY	Lee County Energy Users Group- Direct	RPU-02-3	Surrebuttal	IA	Revenue Requirement, Return on Equity	9/19/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Surrebuttal	MO	Revenue Requirement, Capital Financing	8/13/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Surrebuttal	MO	Revenue Requirement, Captial Financiaing, Cost Allocation	7/28/2002
INTERSTATE POWER AND LIGHT COMPANY	Lee County Energy Users Group- Direct	RPU-02-3	Direct	IA	Revenue Requirement, Return on Equity	7/26/2002
METROPOLITAN ST. LOUIS SEWER DISTRICT	Missouri Energy Group	N/A	Rebuttal	MO	Revenue Requirement, Capital Financing	7/10/2002

APPENDIX C

Discovery Responses Relied Upon in Direct Testimony

Discovery Response	Reference Location in Testimony	Begins on Page No.
AE Response to TIEC 2-1	Footnotes 8 and 11	28
AE Response to TIEC 3-3 – as filed	N/A	30
Informal Correction of AE Response to TIEC 3-3 via email	Table 4	31

TIEC 2-1: Please provide a schedule (in Excel format with all formulas and links intact) listing Austin Energy's outstanding long-term debt issuances, as well as any future debt issuances, that calculates Austin Energy's weighted average long-term debt cost for the test year. If the company is not able to provide a schedule listing all debt issuances, please provide the weighted average long-term debt cost for the test year.

ANSWER: Austin Energy does not include future debt issuances.

See Attachment TIEC 2-1.

Prepared by: MG

Sponsored by: Monica Gonzalez

Company Name: Austin Energy
Reporting Period: FYE September 30, 2021
Summary of Long-Term Financial Obligations

Line	Issuer/ Note Number/ Description	Issuance Date	Term (Years)	Interest Rate	Fixed or Variable Rate	Original Principal Amount	Cumulative Principal Repayments	Current Net Obligation	% of Total Long-Term Debt	Cost of Debt	Weighted Average Cost
1	Subordinate Lien Revenue Refunding Bonds, Series 1998	11/12/1998	30	5.230%	Fixed	$103,952,013	$53,702,167	$50,249,846	2.441%	5.230%	0.128%
2	Separate Lien Bond, Series 2008	3/1/2008	25	5.820%	Fixed	$50,000,000	$16,655,000	$33,345,000	1.620%	5.820%	0.094%
3	Separate Lien Bond, Series 2010B	6/1/2010	30	5.500%	Fixed	$100,990,000	$6,395,000	$94,595,000	4.596%	5.500%	0.253%
4	Separate Lien Bond, Series 2012A	12/1/2012	25	4.580%	Fixed	$267,770,000	$38,045,000	$229,725,000	11.161%	4.580%	0.511%
5	Separate Lien Bond, Series 2012B	12/1/2012	25	2.350%	Fixed	$107,715,000	$29,935,000	$77,780,000	3.779%	2.350%	0.089%
6	Separate Lien Bond, Series 2015A	5/1/2015	30	5.000%	Fixed	$327,845,000	$0	$327,845,000	15.929%	5.000%	0.796%
7	Separate Lien Bond, Series 2015B	5/1/2015	25	2.930%	Fixed	$81,045,000	$44,225,000	$36,820,000	1.789%	2.930%	0.052%
8	Separate Lien Bond, Series 2017A	1/1/2017	30	4.580%	Fixed	$101,570,000	$4,720,000	$96,850,000	4.706%	4.580%	0.216%
9	Separate Lien Bond, Series 2019A	5/22/2019	13	2.730%	Fixed	$464,540,000	$62,480,000	$402,060,000	19.534%	2.730%	0.533%
10	Separate Lien Bond, Series 2019B	7/30/2019	30	5.000%	Fixed	$169,850,000	$0	$169,850,000	8.252%	5.000%	0.413%
11	Separate Lien Bond, Series 2019C	7/30/2019	30	3.000%	Fixed	$104,775,000	$655,000	$104,120,000	5.059%	3.000%	0.152%
12	Separate Lien Bond, Series 2020A	10/27/2020	30	5.000%	Fixed	$227,495,000	$0	$227,495,000	11.053%	5.000%	0.553%
13	Separate Lien Bond, Series 2020B	10/27/2020	30	2.580%	Fixed	$49,870,000	$0	$49,870,000	2.423%	2.580%	0.063%
14	Premiums, Discounts, and Issuance Costs - Unamortized							$ 157,621,039	7.658%	0.000%	0.000%
15											
16	Total							$2,058,225,885	100%		3.852%
17											
18	Total Short-Term Debt							$ 76,600,000			0.066%

TIEC 3-3: Confirm that Austin Energy would achieve a 2.7 times Debt Service Coverage ratio under the proposed rates. If not confirmed, quantify the Debt Service Coverage ratio under the proposed rates.

ANSWER: Not confirmed. Austin Energy estimates the debt service coverage resulting from the proposed base rates will be approximately 2.35 times (as approximated in the table below) based on the information contained in the Base Rate Filing Package.

Note: There can be nuanced differences in the components used in the calculation of debt service coverage depending on who is performing the calculation (e.g., credit rating agencies, Austin Energy, etc.) and the intended purpose of the calculation (e.g., GAAP financials, debt covenant or financial policy compliance, etc.).

Base Revenues (proposed base rates)	$ 691,986,641
Pass-Through Revenues	506,296,114
Other (net of bad debt)	172,601,937
Total	$ 1,370,884,691
Operating Expenses (excluding depreciation)	$ 997,736,055
Funds Available for Debt Service	$ 373,148,637
Debt Service	$ 158,458,228
Debt Service Coverage Ratio	**2.35**

Prepared by: GR

Sponsored by: Grant Rabon

From: Taylor Denison <tdenison@lglawfirm.com>
Sent: Friday, June 10, 2022 2:36 PM
To: Hubbard, John R. <jhubbard@omm.com>
Cc: Thomas Brocato <tbrocato@lglawfirm.com>; Hallmark, Ben <bhallmark@omm.com>; Coleman, Katie <kcoleman@omm.com>
Subject: RE: TIEC's 3rd RFI Follow-Up and Other Items

[EXTERNAL MESSAGE]

John and Ben,

Attached is an explanation for TIEC 3-3. We are still working on 3-6. Thanks!

TIEC 3-3
Our question asked to quantity the Debt Service Coverage Ratio under the proposed rates, but the calculation in the response does not appear to use the same numbers as in Schedule A of the rate filing package. For example, (i) the Base Revenues in Schedule A is $686,843,493, but the number in the response to 3-3 was $691,986,641; (ii) the Operating Expenses from Schedule A were $984,617,801 (Line 5, column J), but the number used in 3-3 was $997,736,055; (iii) the debt service quantity from Schedule A is $143,115, 070 (Line 16, column J), but the number in the RFI calculation is $158,458,228; and (iv) it is unclear how bad debt was subtracted out of “Other (net bad debt)” from the calculation because the other revenue from Schedule A ($144,435,404) was less than the amount used in the calculation ($172,601,937). Please provide a calculation using the figures that go into the proposed rates or an explanation reconciling the difference between Schedule A and this discovery response.

Response:
Austin Energy did reference an erroneous base revenue amount in the debt service coverage calculation. Thus, the corrected calculation is shown in the table below.

	Test Year
Base Revenues (proposed base rates)	$ 686,843,493
Pass-Through Revenues	506,296,114
Other (net of bad debt)	172,601,937
Total	$ 1,365,741,544
Cash Operating Expenses	$ 997,736,055
Funds Available for Debt Service	$ 368,005,489
Electric Utility Bonds	$ 158,458,228
Debt Service Coverage Ratio on Electric Utility Bonds	**2.32**

The other amounts questioned, are accurate based on the following explanation.

To arrive at the indicated amount for other revenue, starting with the $144,435,404 shown in Excel cell M41 of Schedule A, one must:

- Add the $29,890,394 in non-electric revenue (Excel cell E41 on Schedule A)
- Subtract the test year bad debt expense of $5,994,177 (Excel cell N126 on Schedule G-1)
- Add the test year interest income of $4,270,316 (Excel cell N184 on Schedule G-1)

To arrive at the indicated amount for cash operating expenses, starting with the $984,617,801 shown in Excel cell M11 of Schedule A, one must:

- Add the $19,542,660 in non-electric expenses ($829,067 in O&M from Excel cell F157 on Schedule G-1 plus $18,713,593 in other expenses from Excel cell F167 on Schedule G-1)
- Subtract the test year bad debt expense of $5,994,177 (Excel cell N126 on Schedule G-1)
- Subtract the test year economic development expense of $9,353,024 (Excel cell F48 on Schedule G-6)
- Add other expenses, such as taxes other than income taxes, of $8,922,794 (Excel cell N171 on Schedule G-1)

To arrive at the indicated amount for bond debt service, starting with the $143,115,070 shown in Excel cell M23 of Schedule A, one must:

- Add the $15,400,861 in FY 2022 non-electric debt service (Excel cell G15 on WP C-3.1.1)
- Subtract the $57,703 in test year commercial paper (Excel cell O10 on WP C-3.1)

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AUSTIN ENERGY
Corrected Test-Year Debt Service Ratio

Line		Amount
1	Base Revenues	$686,843
2	Pass-Through Revenues	506,296
3	Other Revenues	144,435
4	Bad Debt	(5,994)
5	Interest Income	4,270
6	Sub-total Other Revenues	142,712
7	Total	$1,335,851
8	O&M	$984,618
9	Bad Debt	(5,994)
10	Economic Development	(9,353)
11	Other Expense	8,923
12	Total Expense	$978,193
13	Funds Available for Debt Service	$357,658
14	Debt Service	$143,057
15	DSCR	2.50

Austin Energy
Debt Service Coverage Ratio with $110 Million General Fund Transfer

Line		Austin Energy	TIEC	Difference Amount	Difference Percent
		(1)	(2)	(3)	(4)
1	Base Revenues	$704,969	$694,951	($10,018)	-1.4%
2	Pass-Through Revenues	488,171	488,171		
3	Other Revenues	144,435	143,454		
4	Bad Debt	(5,994)	(5,994)		
5	Interest Income	4,270	4,270		
6	Sub-total Other Revenues	142,711	137,459		
5	Total	$1,335,851	$1,320,581		
8	O&M	$984,618	$984,618		
9	Bad Debt	(5,994)	(5,994)		
10	Economic Development	(9,353)	(9,353)		
11	Other Expense	8,923	8,923		
12	Total Expense	$978,193	$978,193		
13	Funds Available for Debt Service	$357,658	$342,387		
13	Debt Service	$143,057	$143,057		
14	DSCR	2.50	2.39		

Note: Service Area Lighting revenues moved to Base Revenues.

AUSTIN ENERGY
Debt Service Coverage Ratio with 40% Cash for Construction Budget

Line		Austin Energy	TIEC	Difference Amount	Difference Percent
1	Base Revenues	$704,969	$692,885	($12,084)	-1.7%
2	Pass-Through Revenues	488,171	488,171		
3	Other Revenues	144,435	139,282		
4	Bad Debt	(5,994)	(5,994)		
5	Interest Income	4,270	4,270		
6	Sub-total Other Revenues	142,711	137,558		
7	Total	$1,335,851	$1,318,613		
8	O&M	$984,618	$984,618		
9	Bad Debt	(5,994)	(5,994)		
10	Economic Development	(9,353)	(9,353)		
11	Other Expense	8,923	8,923		
12	Total Expense	$978,193	$978,193		
13	Funds Available for Debt Service	357,658	$340,420		
14	Debt Service	$143,057	$143,057		
15	Additional Debt Service		$914		
16	Total Debt Service		$143,971		
17	DSCR	2.50	2.36		

Note: Service Area Lighting revenues moved to base revenues.

AUSTIN ENERGY
Debt Service Coverage Ratio with 40% Cash for Construction Budget and $110 Million General Fund Transfer

Line		Austin Energy	TIEC	Difference Amount	Difference Percent
1	Base Revenues	$704,969	$684,657	($20,312)	-2.9%
2	Pass-Through Revenues	488,171	488,171		
3	Other Revenues	144,435	138,510		
4	Bad Debt	(5,994)	(5,994)		
5	Interest Income	4,270	4,270		
6	Sub-total Other Revenues	142,711	136,786		
5	Total	$1,335,851	$1,309,613		
8	O&M	$984,618	$984,618		
9	Bad Debt	(5,994)	(5,994)		
10	Economic Development	(9,353)	(9,353)		
11	Other Expense	8,923	8,923		
12	Total	$978,193	$978,193		
13	Funds Available for Debt Service	$357,657	$331,420		
13	Debt Service	$143,057	$143,057		
15	Additional Debt Service		$914		
16	Total Debt Service		$143,971		
17	DSCR	2.50	2.30		

Note. Service Area Lighting revenues moved to base rate revenues.

AUSTIN ENERGY

Debt Service Coverage Ratio with 40% Cash for Construction Budget and
$110 Million General Fund Transfer Including Non-Electric Revenues and Expenses

Line		Austin Energy	TIEC	Difference Amount	Difference Percent
1	Base Revenues	$704,969	$684,657	($20,312)	-2.9%
2	Pass-Through Revenues	488,171	488,171		
3	Other Revenues	174,326	170,124		
4	Bad Debt	(5,994)	(5,994)		
5	Interest Income	4,270	4,270		
6	Sub-total Other Revenues	172,602	168,400		
5	Total	$1,365,742	$1,341,227		
8	O&M	1,004,160	$1,004,160		
9	Bad Debt	(5,994)	(5,994)		
10	Economic Development	(9,353)	(9,353)		
11	Other Expense	8,923	8,923		
12	Total	$997,736	$997,736		
13	Funds Available for Debt Service	$368,006	$343,491		
13	Debt Service	$158,458	$158,458		
15	Additional Debt Service		$914		
16	Total Debt Service		$159,372		
17	DSCR	2.32	2.16		

Note. Service Area Lighting revenues moved to base rate revenues.

AUSTIN ENERGY 2022 BASE RATE REVIEW	§ § §	BEFORE THE CITY OF AUSTIN HEARING EXAMINER

Workpapers to the

Direct Testimony and Exhibits

of

BILLIE S. LACONTE

On Behalf of

Texas Industrial Energy Consumers

June 22, 2022

J. POLLOCK
INCORPORATED

Work Paper C-3.2.1
General Fund Transfer K&M Adjustment
Test Year 2021

WP C-3.2.1

No.	Description	TY2021	Approved FY2022 Budget	Test Year	K&M Adj
1	General Fund Transfer	$ 114,000,000	$ 114,000,000	$ 121,000,000	$ 7,000,000
2					
3	**Test Year Revenue**				
4	Other Revenue (includes T-COS Revenues)			$ 144,435,404	
5	Base Rate Revenue Requirement			686,843,493	
6	Non-PSA Pass-Throughs (CBC + Regulatory)			178,117,592	
7	Non-PSA Revenue (at full cost recovery)			$ 1,009,396,489	
8					
9	GFT % of Revenue			12.0%	
10					
11	Calculated GFT			$ 121,127,579	
12	Calculated GFT (rounded)			$ 121,000,000	

The General Fund transfer shall not exceed 12% of Austin Energy three-year average revenues less power supply costs, calculated using the current year estimate and the previous two years' actual revenues less power supply costs from the City's Comprehensive Annual Financial Report.

10. Austin Energy shall maintain a minimum quick ratio of 1.50 (current assets less inventory divided by current liabilities). The source of this information should be the Comprehensive Annual Financial Report.

11. Austin Energy shall maintain a minimum operating cash equivalent (also known as Working Capital) of 60 days of budgeted operations and maintenance expense, less power supply costs, plus the amount of additional monies required to bring the sum of all Austin Energy's reserves to no less than 150 days of operating and maintenance expense.

12. Net revenue generated by Austin Energy shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other Austin Energy requirements. Once these obligations have been met, any remaining net revenues will be deposited in the following order into Austin Energy's reserve funds until each reserve reaches its minimum funding level: Working Capital, Contingency Reserve, Power Supply Stabilization Reserve, and then Capital Reserve. The sum of the four reserves shall be the cash equivalent of no less than 150 days of operating and maintenance expense.

13. The General Fund transfer shall not exceed 12% of Austin Energy three-year average revenues less power supply costs and on-site energy resource revenue, calculated using the current year estimate and the previous two years' actual revenues less power supply costs and on-site energy resource revenue from the City's Comprehensive Annual Financial Report.

14. Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable.

15. The Capital Reserve shall be created and established for providing extensions, additions, replacements, and improvements to the electric system. The Capital Reserve shall maintain a minimum cash equivalent of 50% of the previous year's electric utility depreciation expense.

16. The Contingency Reserve shall be created and established for unanticipated or unforeseen events that reduce revenue or increase obligations, such as costs related to a natural disaster, extended unplanned plant outages, insurance deductibles, or unexpected costs created by Federal or State legislation. The Contingency Reserve may be used to fund unanticipated power supply expenses only after the Power Supply Stabilization Reserve has been fully depleted. The Contingency Reserve shall maintain an operating cash equivalent of 60 days of budgeted operations and maintenance expense, less power supply costs. In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted funding level within two fiscal years.

17. Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support (1) the full cost (direct and indirect) of operations including depreciation, (2) debt service, (3) General Fund transfer, (4) equity funding of capital investments, (5) requisite deposits of all reserve accounts, (6) sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements, if applicable, and (7) any other current obligations. In addition, Austin Energy may recommend to Council in the budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies and other Austin Energy requirements such as working capital.

    In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds.

    A rate adequacy review shall be completed every five years, at a minimum, through performing a cost of service study.

Austin Energy Fund

	2017-18 Actual	2018-19 Actual	2019-20 Estimated	2019-20 Amended	2020-21 Approved
Beginning Balance	**370,751,398**	**431,443,231**	**413,409,738**	**364,417,031**	**394,198,544**
Revenue					
Base Revenue	629,312,889	628,594,026	628,486,091	630,361,573	630,532,538
Power Supply Revenue	455,306,962	494,847,147	426,505,530	421,981,148	419,011,440
Community Benefit Revenue	53,901,735	50,117,379	61,674,235	61,284,808	56,477,345
Regulatory Revenue	131,450,234	123,695,001	138,055,199	138,012,724	140,841,730
Transmission Revenue	78,616,166	81,733,749	84,317,165	84,317,165	86,229,397
Other Revenue	57,500,126	73,716,611	64,644,138	64,644,138	73,720,823
Interest Income	11,474,358	17,094,843	14,084,678	14,084,678	9,205,964
Total Revenue	**1,417,562,470**	**1,469,798,754**	**1,417,767,037**	**1,414,686,235**	**1,416,019,238**
Total Available Funds	**1,417,562,470**	**1,469,798,754**	**1,417,767,037**	**1,414,686,235**	**1,416,019,238**
Program Requirements					
Power Supply	457,116,477	469,295,206	366,640,629	362,116,248	359,440,629
Recoverable Expenses	144,359,078	146,165,785	153,012,724	153,012,724	161,340,559
Non-Fuel Operations and Maintenance	293,563,941	321,490,629	350,219,955	352,038,076	390,254,854
Conservation	13,418,349	14,836,839	15,630,336	15,638,163	15,583,565
Conservation Rebates	23,453,368	20,222,818	23,123,501	23,123,501	22,426,910
Nuclear and Coal Plants Operating	89,071,962	93,350,694	96,427,220	96,442,360	85,435,229
Other Operating Expenses	5,797,162	5,419,851	5,444,301	5,444,301	9,536,377
Total Program Requirements	**1,026,780,337**	**1,070,781,822**	**1,010,498,666**	**1,007,815,373**	**1,044,018,123**
Other Requirements					
Accrued Payroll	529,847	1,377,289	573,267	573,267	642,116
Total Other Requirements	**529,847**	**1,377,289**	**573,267**	**573,267**	**642,116**
Debt Service Requirements					
General Obligation Debt Service	19,824	11,060	876	1,152	3,990
Capital Lease	131,106	65,777	125,209	125,209	125,209
Debt Service (Principal and Interest)	90,992,083	131,637,674	151,091,594	153,921,915	157,967,358
Total Debt Service Requirements	**91,143,013**	**131,714,511**	**151,217,679**	**154,048,276**	**158,096,557**
Transfers Out					
Electric Capital Improvement Program	58,667,247	66,629,448	102,249,936	80,495,689	39,902,889
General Fund	109,000,000	110,000,000	111,000,000	111,000,000	114,000,000
Contingency Reserve Fund	0	0	0	0	0
Capital Reserve	25,939,482	29,385,258	0	0	5,000,000
Power Supply Stabilization Reserve	5,000,000	10,000,000	0	0	0
Voluntary Utility Assistance Fund	1,435,625	600,000	5,600,000	5,600,000	600,000
Trunked Radio	547,625	836,653	892,059	892,059	954,138
Workers' Compensation	1,842,174	1,676,513	1,514,778	1,514,778	1,415,955
Administrative Support	26,025,231	28,929,319	29,544,635	29,544,635	31,303,352
CTM Support	8,663,171	10,038,245	11,224,739	11,224,739	13,185,223
Economic Development Fund	6,872,809	8,535,853	9,069,619	9,069,619	8,367,233
All Other Transfers	5,920,424	3,294,155	3,592,853	3,592,853	3,589,487
Total Transfers Out	**249,913,788**	**269,925,444**	**274,688,619**	**252,934,372**	**218,318,277**
Total Requirements	**1,368,366,982**	**1,473,799,065**	**1,436,978,231**	**1,415,371,288**	**1,421,075,073**
Excess (Deficiency) of Total Available Funds Over Total Requirements	49,195,488	(4,000,311)	(19,211,194)	(685,053)	(5,055,835)
Adjustment to GAAP	11,496,345	(14,033,182)	0	0	0
Ending Balance	**431,443,231**	**413,409,738**	**394,198,544**	**363,731,978**	**389,142,709**

Note: Numbers may not add due to rounding.

Austin Energy Fund

	2018-19 Actual	2019-20 Actual	2020-21 Estimated	2020-21 Amended	2021-22 Approved
Beginning Balance	**431,443,231**	**413,409,743**	**387,799,388**	**394,198,544**	**261,018,082**
Revenue					
Base Revenue	628,594,026	617,506,790	614,673,183	630,532,538	629,480,229
Power Supply Revenue	494,847,147	420,065,608	418,063,424	419,011,440	482,458,483
Community Benefit Revenue	50,117,379	54,577,926	57,419,906	56,477,345	58,171,775
Regulatory Revenue	123,695,001	129,555,994	139,037,533	140,841,730	145,929,842
Transmission Revenue	81,733,749	83,791,065	84,229,796	86,229,397	91,546,021
Other Revenue	73,716,611	73,786,144	73,720,823	73,720,823	78,707,707
Interest Income	17,094,843	10,577,499	9,205,964	9,205,964	3,964,439
Total Revenue	**1,469,798,754**	**1,389,861,025**	**1,396,350,629**	**1,416,019,238**	**1,490,258,496**
Total Available Funds	**1,469,798,754**	**1,389,861,025**	**1,396,350,629**	**1,416,019,238**	**1,490,258,496**
Program Requirements					
Power Supply	469,295,206	367,919,379	358,502,008	359,440,629	422,253,118
Recoverable Expenses	146,165,785	153,368,687	159,145,980	161,340,559	167,675,750
Non-Fuel Operations and Maintenance	321,490,629	353,396,097	388,930,250	390,254,854	413,159,374
Conservation	14,836,839	14,569,938	15,709,765	15,587,615	16,946,139
Conservation Rebates	20,222,818	20,370,692	22,426,910	23,588,747	22,551,910
Nuclear and Coal Plants Operating	93,350,694	98,983,652	85,435,229	85,435,229	87,833,737
Other Operating Expenses	5,419,851	5,755,057	9,536,377	9,536,377	6,104,680
Total Program Requirements	**1,070,781,822**	**1,014,363,502**	**1,039,686,519**	**1,045,184,010**	**1,136,524,708**
Other Requirements					
Accrued Payroll	1,377,289	573,267	642,116	642,116	1,035,461
Total Other Requirements	**1,377,289**	**573,267**	**642,116**	**642,116**	**1,035,461**
Debt Service Requirements					
General Obligation Debt Service	11,060	876	3,988	3,990	0
Capital Lease	65,777	136,194	125,209	125,209	125,209
Debt Service (Principal and Interest)	131,637,674	151,953,395	161,175,750	157,967,358	161,784,550
Total Debt Service Requirements	**131,714,511**	**152,090,465**	**161,304,947**	**158,096,557**	**161,909,759**
Transfers Out					
Electric Capital Improvement Program	66,629,448	80,495,689	143,082,965	39,902,889	40,245,149
General Fund	110,000,000	111,000,000	114,000,000	114,000,000	114,000,000
Capital Reserve	29,385,258	(381,411)	0	5,000,000	0
Power Supply Stabilization Reserve	10,000,000	0	0	0	0
Voluntary Utility Assistance Fund	600,000	5,600,000	5,600,000	5,600,000	600,000
Trunked Radio	836,653	767,329	712,490	712,490	932,282
Workers' Compensation	1,676,513	1,514,778	1,415,955	1,415,955	1,480,188
Administrative Support	28,929,319	29,544,635	31,303,352	31,303,352	28,465,411
CTM Support	10,038,245	11,224,739	13,185,223	13,185,223	11,520,911
Economic Development Fund	8,535,853	9,069,619	8,367,233	8,367,233	9,353,024
All Other Transfers	3,294,155	3,468,199	3,831,135	3,831,135	3,547,303
Total Transfers Out	**269,925,444**	**252,303,577**	**321,498,353**	**223,318,277**	**210,144,268**
Total Requirements	**1,473,799,065**	**1,419,330,812**	**1,523,131,935**	**1,427,240,960**	**1,509,614,196**
Excess (Deficiency) of Total Available Funds Over Total Requirements	(4,000,311)	(29,469,787)	(126,781,306)	(11,221,722)	(19,355,700)
Adjustment to GAAP	(14,033,177)	3,859,432	0	0	0
Ending Balance	**413,409,743**	**387,799,388**	**261,018,082**	**382,976,822**	**241,662,382**

Note: Numbers may not add due to rounding.

Austin Energy
Electric Cost of Service and Rate Design

Work Paper C-3.3.1 **WP C-3.3.1**
Historical Capital Spending

No.	Fund Acct	Description	Reference	Actual FY 2019	Actual FY 2020	Actual FY 2021	Three-Year Average	Adjustments	Test Year
				(A)	(B)	(C)	(D)	(E)	(F)
51		**Cash Funding of Capital Costs (Includes CIAC after percent funded assumption)**							
52	Fund 3060	NEPA	WP C-3.3	$ 15,865,384	$ 21,995,288	$ 12,258,563	$ 16,706,412		$ 16,706,412
53	Fund 3070	South Texas Project (STP)	WP C-3.3	3,295,089	4,952,306	3,187,547	3,811,648		3,811,648
54	Fund 3080	Fayette Power Plant (FPP)	WP C-3.3	300,761	2,127,940	381,550	936,750		936,750
55	Fund 3120	Alternate Energy	WP C-3.3	328,976	1,641,737	21,418	664,044		664,044
56	Fund 3220	Power Production	WP C-3.3	5,113,972	1,768,689	1,484,839	2,789,167		2,789,167
57	Fund 3230	Transmission	WP C-3.3	18,481,030	21,804,311	19,446,763	19,910,701		19,910,701
58	Fund 3240	Distribution Substation	WP C-3.3	5,663,327	6,225,983	10,760,494	7,549,935		7,549,935
59	Fund 3250	Distribution	WP C-3.3	72,117,715	66,887,691	63,048,292	67,351,233		67,351,233
60	Fund 3260	Customer Services Billing & Meter	WP C-3.3	19,416	29,523	182,737	77,225		77,225
61	Fund 3290	Support Services	WP C-3.3	9,489,590	19,009,788	84,223,041	37,574,140		13,820,215
62	Fund 3300	Capital Outlay (vehicles)	WP C-3.3	1,809,459	3,071,946	3,646,813	2,842,739		2,842,739
63	Fund 3310	Support Services	WP C-3.3	190,784	(32,262)	33,438	63,987		63,987
64	Fund 3330	Nacogdoches Generating Facility	WP C-3.3	197,302,617	100,463	17,550	65,806,877		-
65									
66		Total Cash to Fund Capital Spending		**$ 329,978,118**	**$ 149,583,404**	**$ 198,693,044**	**$ 226,084,855**		**$ 136,524,054**
67									
68		**Known & Measurable Calculation**							
69		Cash funding assumption	**50%**						
70						FY 2021			TY 2021
71						Cash Funding of			Cash Funding of
72		Adjustment to funds based on TY 2021				Capital Costs		Adjustment	Capital Costs
73		NEPA (removed)							
74		Power Production	Lines 53 thru 56			5,092,904		3,108,704	8,201,608
75		Transmission	Line 57			19,446,763		463,939	19,910,701
76		Distribution Substation	Line 58			10,760,494		(3,210,559)	7,549,935
77		Distribution	Line 59			63,048,292		4,302,941	67,351,233
78		Customer Services Billing & Meter	Line 60			182,737		(105,512)	77,225
79		Support Services	Line 61			84,223,041		(70,402,827)	13,820,215
80		Capital Outlay (vehicles)	Line 62			3,646,813		(804,073)	2,842,739
81		Support Services	Line 63			33,438		30,549	63,987
82		Nacogdoches Generating Facility (removed)							
83						$ 186,434,481		**$ (66,616,839)**	$ 119,817,642
84									
85									
86							**Total Adjustment to Electric**	**$ (66,616,839)**	
87								**WP C-3.3**	

Appendix B: Austin Energy Financial Policies

1. The term of debt generally shall not exceed the useful life of the asset, and in no case shall the term exceed 30 years.

2. Capitalized interest shall only be considered during the construction phase of a new facility if the construction period exceeds seven years. The time frame for capitalizing interest may be three years but not more than five years. Council approval shall be obtained before proceeding with financing that includes capitalized interest.

   Note: Austin Energy does not use capitalized interest.

3. Principal repayment delays shall be one to three years, but shall not exceed five years.

4. Austin Energy shall maintain either bond insurance policies or surety bonds issued by highly rated (AAA) bond insurance companies, a funded debt service reserve, or a combination of both for its existing revenue bond issues, in accordance with the Combined Utility Systems Revenue Bond Covenant.

5. A debt service reserve fund shall not be required to be established or maintained for the Parity Electric System Obligations so long as the "Pledged Net Revenues" of the System remaining after deducting the amounts expended for the Annual Debt Service Requirements for Prior First Lien and Prior Subordinate Lien Obligations is equal to or exceeds 150% of the Annual Debt Service Requirements of the Parity Electric Utility Obligations. If the "Pledged Net Revenues" do not equal or exceed 150% of the Annual Debt Service Requirements of the Parity Electric Utility Obligations, then a debt service reserve fund shall be established and maintained in accordance with the Supplemental Ordinance for such Parity Electric System Obligations.

6. Debt service coverage of a minimum of 2.0x shall be targeted for the Electric Utility Bonds. All short-term debt, including commercial paper, and non-revenue obligations will be included at 1.0x.

   Note: Debt service coverage for the FY 2017-18 Budget is 4.1x.

7. Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and materials inventories. The term of short-term debt will not exceed five years. Both tax-exempt and taxable commercial paper may be issued in order to comply with the Internal Revenue Service rules and regulations applicable to Austin Energy. Total short-term debt shall generally not exceed 20% of outstanding long-term debt.

8. Commercial paper may be used to finance capital improvements required for normal business operation for electric system additions, extensions, and improvements or improvements to comply with local, State and Federal mandates or regulations. However, this shall not apply to new nuclear generation units or conventional coal generation units.

   Commercial paper will be converted to refunding bonds when dictated by economic and business conditions. Both tax-exempt and taxable refunding bonds may be issued in order to comply with the Internal Revenue Service rules and regulations applicable to Austin Energy.

   Commercial paper may be used to finance voter approved revenue bond projects before the commercial paper is converted to refunding bonds.

9. Ongoing routine, preventive maintenance should be funded on a pay-as-you-go basis.

Search

US Corporate A Effective Yield

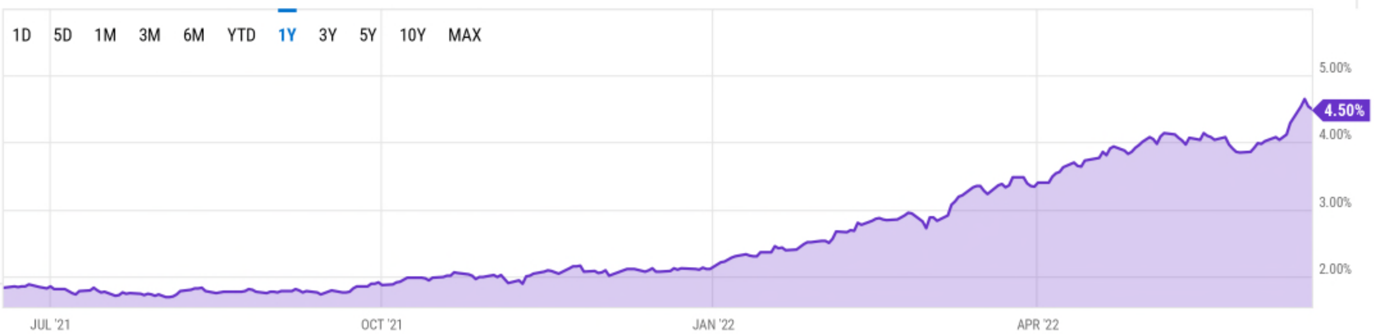
4.50% for Jun 16 2022

\+ WATCHLIST

Overview Interactive Chart

Level Chart

VIEW FULL CHART



Basic Info

US Corporate A Effective Yield is at 4.50%, compared to 4.54% the previous market day and 1.88% last year. This is higher than the long term average of 4.48%.

Report	Bank of America Merrill Lynch	Region	United States
Category	Interest Rates	Source	Bank of America Merrill Lynch

Stats

Last Value	4.50%
Latest Period	Jun 16 2022
Last Updated	Jun 21 2022, 09:03 EDT
Next Release	Jun 22 2022, 09:00 EDT
Long Term Average	4.48%
Average Growth Rate	0.10%

Value from The Previous Market Day	4.54%
Change from The Previous Market Day	-0.88%
Value from 1 Year Ago	1.88%
Change from 1 Year Ago	139.4%
Frequency	Market Daily
Unit	Percent

Adjustment	N/A
Notes	Bank of America Merrill Lynch U.S. Corporate A Effective Yield

Historical Data

View and export this data back to 1996. Upgrade now.

Date	Value	Date	Value
June 16, 2022	4.50%	May 12, 2022	3.97%
June 15, 2022	4.54%	May 11, 2022	4.03%
June 14, 2022	4.65%	May 10, 2022	4.07%
June 13, 2022	4.54%	May 09, 2022	4.12%
June 10, 2022	4.29%	May 06, 2022	4.14%
June 09, 2022	4.12%	May 05, 2022	4.09%
June 08, 2022	4.08%	May 04, 2022	3.98%
June 07, 2022	4.04%	May 03, 2022	4.05%
June 06, 2022	4.08%	May 02, 2022	4.08%
June 03, 2022	4.02%	April 30, 2022	4.01%
June 02, 2022	3.98%	April 29, 2022	3.96%
June 01, 2022	3.99%	April 28, 2022	3.92%
May 31, 2022	3.92%	April 27, 2022	3.86%
May 30, 2022	3.86%	April 26, 2022	3.83%
May 27, 2022	3.85%	April 25, 2022	3.88%
May 26, 2022	3.86%	April 22, 2022	3.94%
May 25, 2022	3.91%	April 21, 2022	3.91%
May 24, 2022	3.97%	April 20, 2022	3.81%
May 23, 2022	4.08%	April 19, 2022	3.86%
May 20, 2022	4.04%	April 18, 2022	3.77%
May 19, 2022	4.08%	April 14, 2022	3.73%
May 18, 2022	4.10%	April 13, 2022	3.64%
May 17, 2022	4.14%	April 12, 2022	3.65%
May 16, 2022	4.04%	April 11, 2022	3.70%
May 13, 2022	4.07%	April 08, 2022	3.63%

Related Indicators

Corporate Bond Rates

Moody's Seasoned Aaa Corporate Bond Yield	4.41%
Moody's Seasoned Baa Corporate Bond Yield	5.41%
US Corporate AA Effective Yield	4.25%
US Corporate AAA Effective Yield	4.05%
US Corporate BBB Effective Yield	5.19%

Search

US Corporate AA Effective Yield

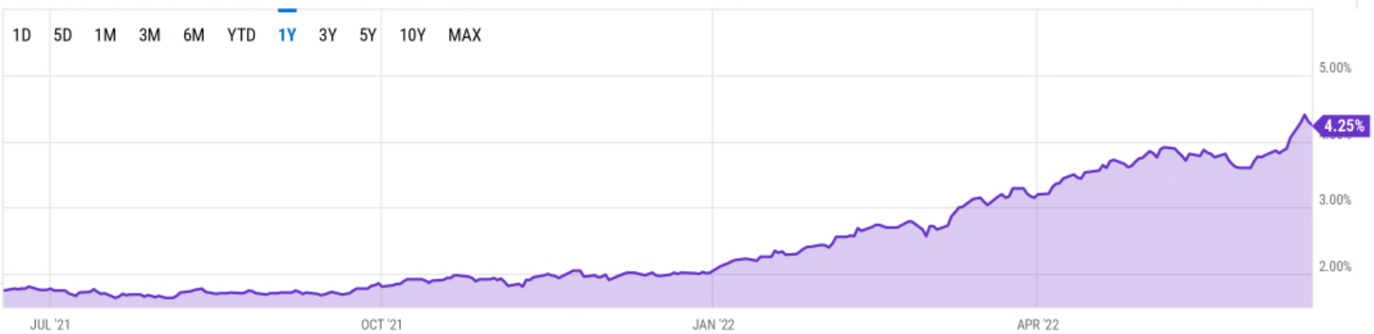
4.25% for Jun 16 2022

+ WATCHLIST

Overview Interactive Chart

Level Chart

VIEW FULL CHART



Basic Info

US Corporate AA Effective Yield is at 4.25%, compared to 4.30% the previous market day and 1.81% last year. This is higher than the long term average of 4.06%.

Report	Bank of America Merrill Lynch	Region	United States
Category	Interest Rates	Source	Bank of America Merrill Lynch

Stats

Last Value	4.25%	Value from The Previous Market Day	4.30%
Latest Period	Jun 16 2022	Change from The Previous Market Day	-1.16%
Last Updated	Jun 21 2022, 09:03 EDT	Value from 1 Year Ago	1.81%
Next Release	Jun 22 2022, 09:00 EDT	Change from 1 Year Ago	134.8%
Long Term Average	4.06%	Frequency	Market Daily
Average Growth Rate	0.40%	Unit	Percent

011

Adjustment	N/A
Notes	Bank of America Merrill Lynch U.S. Corporate AA Effective Yield

Historical Data

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Date	Value	Date	Value
June 16, 2022	4.25%	May 12, 2022	3.71%
June 15, 2022	4.30%	May 11, 2022	3.78%
June 14, 2022	4.40%	May 10, 2022	3.83%
June 13, 2022	4.29%	May 09, 2022	3.89%
June 10, 2022	4.05%	May 06, 2022	3.91%
June 09, 2022	3.89%	May 05, 2022	3.88%
June 08, 2022	3.86%	May 04, 2022	3.76%
June 07, 2022	3.82%	May 03, 2022	3.82%
June 06, 2022	3.86%	May 02, 2022	3.85%
June 03, 2022	3.79%	April 30, 2022	3.75%
June 02, 2022	3.76%	April 29, 2022	3.74%
June 01, 2022	3.77%	April 28, 2022	3.69%
May 31, 2022	3.70%	April 27, 2022	3.63%
May 30, 2022	3.60%	April 26, 2022	3.61%
May 27, 2022	3.60%	April 25, 2022	3.66%
May 26, 2022	3.61%	April 22, 2022	3.72%
May 25, 2022	3.65%	April 21, 2022	3.70%
May 24, 2022	3.71%	April 20, 2022	3.60%
May 23, 2022	3.81%	April 19, 2022	3.64%
May 20, 2022	3.76%	April 18, 2022	3.56%
May 19, 2022	3.81%	April 14, 2022	3.53%
May 18, 2022	3.83%	April 13, 2022	3.44%
May 17, 2022	3.87%	April 12, 2022	3.45%
May 16, 2022	3.78%	April 11, 2022	3.50%
May 13, 2022	3.81%	April 08, 2022	3.44%

Related Indicators

Corporate Bond Rates

Moody's Seasoned Aaa Corporate Bond Yield	4.41%	US Corporate AAA Effective Yield	4.05%
Moody's Seasoned Baa Corporate Bond Yield	5.41%	US Corporate BBB Effective Yield	5.19%
US Corporate A Effective Yield	4.50%		

TIEC 2-1: Please provide a schedule (in Excel format with all formulas and links intact) listing Austin Energy's outstanding long-term debt issuances, as well as any future debt issuances, that calculates Austin Energy's weighted average long-term debt cost for the test year. If the company is not able to provide a schedule listing all debt issuances, please provide the weighted average long-term debt cost for the test year.

ANSWER: Austin Energy does not include future debt issuances.

See Attachment TIEC 2-1.

Prepared by: MG

Sponsored by: Monica Gonzalez

Company Name: Austin Energy
Reporting Period: FYE September 30, 2021
Summary of Long-Term Financial Obligations

Line	Issuer/ Note Number/ Description	Issuance Date	Term (Years)	Interest Rate	Fixed or Variable Rate	Original Principal Amount	Cumulative Principal Repayments	Current Net Obligation	% of Total Long-Term Debt	Cost of Debt	Weighted Average Cost
1	Subordinate Lien Revenue Refunding Bonds, Series 1998	11/12/1998	30	5.230%	Fixed	$103,952,013	$53,702,167	$50,249,846	2.441%	5.230%	0.128%
2	Separate Lien Bond, Series 2008	3/1/2008	25	5.820%	Fixed	$50,000,000	$16,655,000	$33,345,000	1.620%	5.820%	0.094%
3	Separate Lien Bond, Series 2010B	6/1/2010	30	5.500%	Fixed	$100,990,000	$6,395,000	$94,595,000	4.596%	5.500%	0.253%
4	Separate Lien Bond, Series 2012A	12/1/2012	25	4.580%	Fixed	$267,770,000	$38,045,000	$229,725,000	11.161%	4.580%	0.511%
5	Separate Lien Bond, Series 2012B	12/1/2012	25	2.350%	Fixed	$107,715,000	$29,935,000	$77,780,000	3.779%	2.350%	0.089%
6	Separate Lien Bond, Series 2015A	5/1/2015	30	5.000%	Fixed	$327,845,000	$0	$327,845,000	15.929%	5.000%	0.796%
7	Separate Lien Bond, Series 2015B	5/1/2015	25	2.930%	Fixed	$81,045,000	$44,225,000	$36,820,000	1.789%	2.930%	0.052%
8	Separate Lien Bond, Series 2017A	1/1/2017	30	4.580%	Fixed	$101,570,000	$4,720,000	$96,850,000	4.706%	4.580%	0.216%
9	Separate Lien Bond, Series 2019A	5/22/2019	13	2.730%	Fixed	$464,540,000	$62,480,000	$402,060,000	19.534%	2.730%	0.533%
10	Separate Lien Bond, Series 2019B	7/30/2019	30	5.000%	Fixed	$169,850,000	$0	$169,850,000	8.252%	5.000%	0.413%
11	Separate Lien Bond, Series 2019C	7/30/2019	30	3.000%	Fixed	$104,775,000	$655,000	$104,120,000	5.059%	3.000%	0.152%
12	Separate Lien Bond, Series 2020A	10/27/2020	30	5.000%	Fixed	$227,495,000	$0	$227,495,000	11.053%	5.000%	0.553%
13	Separate Lien Bond, Series 2020B	10/27/2020	30	2.580%	Fixed	$49,870,000	$0	$49,870,000	2.423%	2.580%	0.063%
14	Premiums, Discounts, and Issuance Costs - Unamortized							$ 157,621,039	7.658%	0.000%	0.000%
15											
16	Total							$2,058,225,885	100%		3.852%
17											
18	Total Short-Term Debt							$ 76,600,000			0.066%

Retail Systems

Obligor	Rating	Outlook/ Watch	Region	Total Operating Revenue ($000)	Coverage of Full Obligations (x)	Debt Service Coverage (x)	Net Adjusted Debt/Adjusted FADS (x)	Equity/ Capitalization (%)	Days Cash on Hand	Liquidity Cushion (Days)	Transfers/ Operating Revenue (%)	Capex/ D&A (%)
AA+ Rated Credits												
Chattanooga Electric Power Board — Electric System, TN	AA+	Stable	SERC	561,855	1.10	1.72	7.26	52	56	82	3.34	153
Concord Utility Funds, NC	AA+	Stable	SERC	130,405	3.08	6.24	(0.93)	91	857	857	0.52	119
Nashville Electric Service, TN	AA+	Stable	SERC	1,278,700	1.26	2.36	5.65	55	129	138	2.49	266
Chelan CO Public Utility District No. 1 — Consolidated, WA	AA+	Stable	WECC	353,522	2.49	2.87	1.97	69	693	693	2.84	250
AA+ Rated Median				**457,689**	**1.88**	**2.62**	**3.81**	**62**	**411**	**415**	**2.67**	**202**
AA Rated Credits												
Austin Electric, TX	AA	RWN	ERCOT	1,373,556	0.93	0.90	8.52	48	222	222	8.74	93
New Braunfels Utilities, TX	AA	RWN	ERCOT	181,185	1.79	3.53	5.52	67	171	171	4.49	448
JEA – Electric System and Bulk Power Supply System, FL	AA	Stable	FRCC	1,241,789	1.99	2.14	3.77	43	207	207	7.56	103
Kissimmee Utility Authority, FL	AA	Stable	FRCC	175,897	1.49	3.04	3.50	89	240	240	10.21	287
Lakeland Energy System, FL	AA	Stable	FRCC	298,645	2.48	2.87	4.03	47	243	243	13.25	154
New Smyrna Beach Utilities Commission, FL	AA	Stable	FRCC	59,458	1.12	1.24	8.27	72	90	90	6.29	167
Orlando Utilities Commission, FL	AA	Stable	FRCC	866,463	1.75	1.84	4.77	50	270	270	14.07	127
Tallahassee Electric Fund, FL	AA	Stable	FRCC	298,201	1.03	1.03	8.03	45	356	356	16.52	49
Jacksonville Beach Combined Utility Funds, FL	AA	Stable	FRCC	95,003	1.66	3.96	2.22	99	287	287	4.24	323
Rochester Public Utilities, MN	AA	Stable	MRO	169,193	1.73	3.05	4.47	53	275	275	4.95	102
Dover Electric Revenue Fund, DE	AA	Stable	RFC	81,405	2.41	17.18	0.66	89	699	699	13.79	24
Fayetteville Public Works Commission, NC	AA	Stable	SERC	339,147	1.66	2.71	4.19	76	238	238	4.38	277
Lincoln Electric System, NE	AA	Stable	SPP	311,213	1.53	1.74	6.41	37	232	484	6.71	173
Springfield Public Utility, MO	AA	Stable	SPP	429,829	1.84	2.42	3.95	69	331	331	3.46	162
Clark County Public Utility District — Elec. and Generation, WA	AA	Stable	WECC	460,044	1.23	1.37	3.78	54	303	324	5.48	120
Colorado Springs Utilities, CO	AA	Stable	WECC	884,352	1.77	1.90	6.47	46	217	273	4.05	93
Grant County Public Utility District No. 2, WA	AA	Stable	WECC	321,174	2.35	2.35	4.39	49	621	621	5.57	147
Idaho Falls Power, ID	AA	Stable	WECC	57,411	2.75	—	0.76	100	506	506	8.86	145
Pasadena Water & Power, CA	AA	Stable	WECC	217,873	1.70	2.53	2.23	72	760	760	7.95	73
Roseville Electric Fund, CA	AA	Positive	WECC	171,973	2.56	3.94	2.57	65	620	620	4.19	79
Sacramento Municipal Utility District, CA	AA	Stable	WECC	1,587,905	1.79	2.16	5.03	43	278	278	—	155
AA Rated Median				**298,645**	**1.75**	**2.39**	**4.19**	**54**	**275**	**278**	**6.50**	**145**

Schedule B
Summary of Rate Base by Function

Schedule B

No.	Description	Reference	Total Company	Non-Electric Adjustment/Transfer	Total Electric	Known & Measurable	Adjusted Total Electric to Texas	Normalized Allocation to: Production	Transmission	Distribution	Customer
			(A)	(B)	(C)	(I)	(J)	(K)	(L)	(M)	(N)
1	Net Plant in Service	Schedules B-1, B-2, B-3, B-5	$ 2,690,835,416	$ (167,842,225)	$ 2,522,993,191	$ (139,839,016)	$ 2,383,154,175	$ 760,216,204	$ 420,785,935	$ 1,080,553,025	$ 121,599,010
2								-	-	-	-
3	Construction Work in Progress	Schedule B-4	282,652,064	(84,310,430)	198,341,634	-	198,341,634	20,873,302	47,293,428	120,837,770	9,337,134
4	Plant Held for Future Use	Schedule B-6	23,115,022	-	23,115,022	-	23,115,022	19,375,316	3,739,706	-	-
5	Materials and Supplies	Schedule B-8	88,940,516	-	88,940,516	-	88,940,516	66,597,166	2,796,445	19,546,905	-
6	Cash Working Capital	Schedule B-9	62,522,666	(24,364)	62,498,303	(7,182,540)	55,315,763	19,560,354	3,920,763	16,544,293	15,290,353
7	Prepayments	Schedule B-10	21,574,954	(44,120)	21,530,834	-	21,530,834	21,404,619	20,538	103,335	2,341
8	Nuclear Fuel in Process	Schedule B-11	50,662,905	-	50,662,905	-	50,662,905	50,662,905	-	-	-
9	Advances to FPP	Schedule B-11	2,686,518	-	2,686,518	-	2,686,518	2,686,518	-	-	-
10	Less: Customer Deposits	Schedule B-11	(19,574,083)	-	(19,574,083)	-	(19,574,083)	(7,240,266)	-	(8,878,725)	(3,455,093)
11	Less: Contributions in Aid of Construction	Schedule B-11	(316,042,514)	-	(316,042,514)	-	(316,042,514)	-	(3,589,765)	(312,452,749)	-
12	Sub-Total		$ 196,538,047	$ (84,378,914)	$ 112,159,134	$ (7,182,540)	$ 104,976,594	$ 193,919,913	$ 54,181,115	$ (164,299,170)	$ 21,174,736
13											
14	Total Rate Base	Line 1 + 12	$ 2,887,373,464	$ (252,221,139)	$ 2,635,152,325	$ (147,021,556)	$ 2,488,130,769	$ 954,136,117	$ 474,967,051	$ 916,253,855	$ 142,773,746
15											
16	Total Revenue (Current Rates and Test Year Pass-Throughs)										
17	Base Revenue	WP G-10.1.1	$ 635,932,232	$ -	$ 635,932,232	$ 2,691,512	$ 638,623,744				
18	Recoverable Fuel		280,064,066	-	280,064,066	48,114,456	328,178,522				
19	Green Choice		27,806,016	-	27,806,016	(27,806,016)	-				
20	Other Pass-Throughs (CBC + Regulatory)		181,836,571	-	181,836,571	(3,718,979)	178,117,592				
21	Other Revenue	Schedule E-5	171,511,285	(29,890,394)	141,620,891	2,814,513	144,435,404				
22	Total Revenue		$ 1,297,150,170	$ (29,890,394)	$ 1,267,259,776	$ 22,095,486	$ 1,289,355,262				
23											
24	Total Operating Costs [1]	Schedule G-1	$ (1,341,924,158)	$ 29,504,031	$ (1,312,420,127)	$ 172,113,832	$ (1,140,306,295)				
25											
26	Return [2]	Line 22 + 24	$ (44,773,988)	$ (386,363)	$ (45,160,351)	$ 194,209,318	$ 149,048,967				
27											
28	**Rate of Return (Implied Under Current Rates) [3]**	Line 26 / 14	**-1.6%**		**-1.7%**		**6.0%**				
29											
30	Rate Revenue (Cost of Service)	Schedule G-1					$ 1,193,139,607				
31	Other Revenue	Schedule G-1					144,435,404				
32	Total Operating Costs [1]	Schedule G-1					(1,140,306,295)				
33	Return [2]						$ 197,268,716				
34											
35	**Rate of Return (Implied Under Cost of Service) [3]**	Line 33 / 14					**7.9%**				
36											
37	Rate Revenue (Proposed Rates) [4]	Schedule H-5					$ 1,193,135,986				
38	Other Revenue	Schedule G-1					144,435,404				
39	Total Operating Costs [1]	Schedule G-1					(1,140,306,295)				
40	Return [2]						$ 197,265,095				
41											
42	**Rate of Return (Implied Under Proposed Rates) [3]**	Line 40 / 14					**7.9%**				
43											
44											

45 Note:
46 [1] Total Operating Costs does not include the General Fund Transfer (GFT) to the City of Austin, but it does include transfers for shared services (e.g.,
47 [2] For the return to be sufficient, the return plus depreciation, interest income and CIAC should recover the cost of: 1) debt service, 2) GFT, 3) cash funding for
48 [3] The return is reflective of the entire electric utility and includes the portion of the utility regulated by the PUCT (i.e., Transmission)
49 [4] Revenue projected under the proposed rates and test year pass-throughs, but excludes CAP fee revenue as this benefit goes to Customer Assistance Program

RRA Regulatory Focus
Major Rate Case Decisions
February 10, 2022

Major Energy Rate Case Decisions – January – December 2021

Quarterly update on decided rate cases

Lisa Fontanella Research Director

The average electric authorized return on equity continued its steady decline in 2021, hitting an all-time low. For gas utilities, the average authorized return on equity increased in 2021.

For detailed data

Access RRA's electric and gas rate cases as of year-end 2021 data tables.

Table of Contents

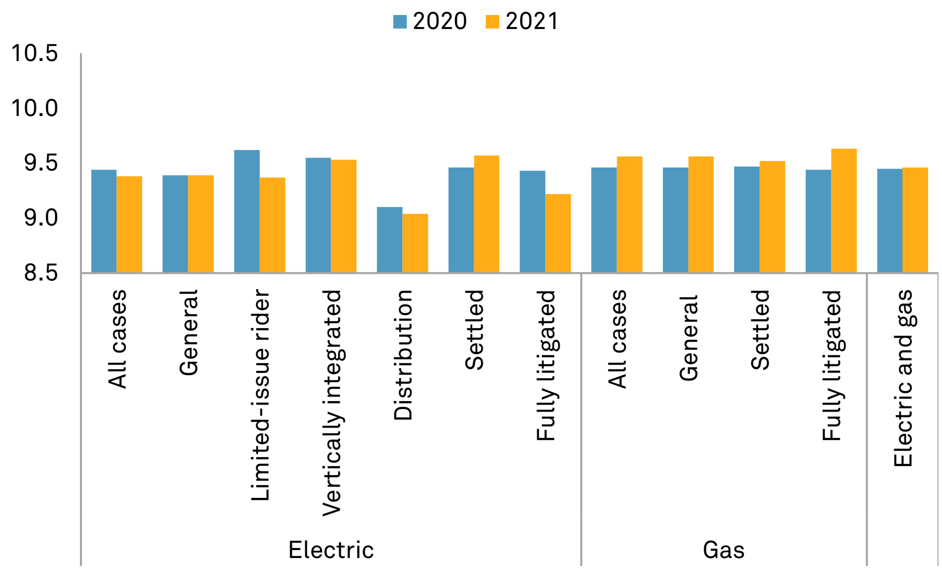
Executive Summary

Introduction

Amid ongoing virus challenges, 2021 was a record year in terms of rate case activity. Rate case activity neared all-time highs, with almost 150 decisions issued by state public utility commissions in 2021, the highest level since the early 1980s. The average ROE authorized for electric utilities fell to 9.38% for rate cases decided in 2021 from the 9.44% average for cases decided in 2020. The average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% observed in 2020.

While the reasons for a rate case filing are numerous, the main driver of new filings continues to be capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems, build new natural gas, solar and wind generation, and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Among other reasons for rate filings are changes in expenses and cost of capital, and the impact of broader economic and sector-wide forces.

Average authorized return on equity (%)



Electric averages	2020	2021
All cases	9.44	9.38
General rate cases	9.39	9.39
Limited-issue rider cases	9.62	9.37
Vertically integrated cases	9.55	9.53
Distribution cases	9.10	9.04
Settled cases	9.46	9.57
Fully litigated cases	9.43	9.22
Gas averages		
All cases	9.46	9.56
General rate cases	9.46	9.56
Settled cases	9.47	9.52
Fully litigated cases	9.44	9.63
Composite electric and gas averages		
Electric and gas	9.45	9.46
U.S. Treasury		
30-year bond yield	1.56	2.06

Data compiled Jan. 26, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; U.S. Department of the Treasury

About this report

This report, which is updated quarterly, offers a detailed overview of completed electric and gas rate case decisions in the U.S. The information presented in this report utilizes the data compiled by RRA for its rate case database, available on the S&P Capital IQ Pro platform. RRA endeavors to follow all “major” rate cases for investor-owned utilities nationwide, with “major” defined as a case in which the utility’s request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those that involve significant rate base additions that are recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply.

The Take

Rate case activity for investor-owned electric and gas utilities in the U.S. neared all-time highs in 2021, with about 150 rate cases decided, the highest level since the 1980s. The average authorized return on equity for electric utilities approved in cases decided during 2021 was the lowest annual average in RRA’s rate case database, which includes all major rate cases decided since 1980. For gas utilities, the average authorized ROE remained close to the lowest-ever levels.

Interest rates, including long-term U.S. Treasury bond yields that are used to represent the risk-free rate in utility ratemaking, have remained historically low, exerting downward pressure on authorized ROEs over the past several years. The average ROE authorized for electric utilities fell to 9.38% for rate cases decided in 2021 from the 9.44% average for cases decided in 2020. The average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% observed in 2020.

Authorized returns may edge higher in 2022, as the U.S. Federal Reserve is poised to embark on a course of interest rate hikes beginning in March, as part of its efforts to extinguish soaring inflation.

State regulatory support and the authorization of adequate returns to ensure ongoing capital attraction in the utility sector will be instrumental, as the industry shifts away from fossil fuels to renewables and storage and invests in strengthening the nation’s power grid against climate and other risks.

Overview of electric and gas authorizations

The average authorized return on equity for electric utilities approved in cases decided during 2021 was the lowest annual average in RRA's rate case database, which includes all major rate cases decided since 1980. For gas utilities, the average authorized ROE remained close to historical lows.

The average ROE authorized for electric utilities fell to 9.38% for rate cases decided in 2021 from the 9.44% average for cases decided in 2020. There were 54 electric ROE determinations reflected in the calculations for 2021 versus 55 in 2020.

The average ROE authorized for gas utilities was 9.56% for cases decided during 2021, up from the 9.46% observed in 2020. There were 42 gas cases that included an ROE determination in 2021 versus 34 gas cases in 2020.

The electric ROE average in 2021 was weighed down by three ROE determinations in Illinois and Vermont that were calculated utilizing a formulaic approach tied to U.S. Treasury bond yields. Excluding these three ROE determinations, the average return authorized for electrics in 2021 was 9.48%.

In addition, the electric data set includes several limited-issue rider cases. There is, however, little difference between the ROE averages including rider cases and those excluding rider cases in 2021; historically, the annual average authorized ROEs in electric cases that involve limited-issue riders were meaningfully higher than those approved in general rate cases, driven primarily by substantial ROE premiums authorized in generation-related limited-issue rider proceedings in Virginia. However, these premiums were approved for limited durations and have since begun to expire. As a result, the gap between the average ROE observed in the rider cases and that observed in general rate cases has narrowed. Limited-issue rider cases in which a separate ROE is determined have had little use in the gas industry, as most of the gas riders rely on ROEs approved in a previous base rate case. Excluding the rider cases, the average authorized ROE was 9.39% in electric general rate cases decided in 2021, equal to that observed in 2020.

In 2021, the median ROE authorized in all electric utility rate cases was 9.39%, versus 9.45% in 2020; for gas utilities, this metric was 9.60% in 2021, versus 9.42% in 2020.

The 2020 and 2021 calendar-year results reflect the impact of interest rate cuts by the Federal Reserve and the regulatory reaction to the COVID-19 pandemic-induced recession.

From a longer-term perspective, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline in authorized ROEs was less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014. The calendar-year averages hovered between 9.5% and 9.8% through 2019, falling below 9.5% for the first time in 2020.

These declines in ROE have been occurring at the same time that rate case activity has been on an upswing. There have been 100 or more cases adjudicated in ten of the last 12 calendar years. This count includes electric and gas cases where no ROEs were specified; however, withdrawn cases are not included. Rate case activity in 2021, at 150 cases, was the most robust observed in any year during the 1990-2021 period. In 2019 and 2020 there were about 130 cases decided in each year.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits have contributed to an active rate case agenda over the last decade.

Due to COVID-19 and the challenging economic landscape, during 2020 many utilities and state commissions found creative ways to limit the immediate impact of rate hikes by pushing rate changes into a future period or agreeing to forgo rate hikes and using accounting mechanisms, such as the accelerated recovery of excess accumulated deferred tax liabilities, to mitigate requested increases. In 2021, utilities were back before the state commissions seeking the highest combined increase in electric and gas rates since RRA began tracking cases.

Currently, there are almost 90 electric and gas rate cases pending, implying that 2022 will be another active year for rat case decisions, even if it does not match the 2021 case total.

Rising interest rates over the past several years also likely contributed to the increased rate case activity. After holding rates near zero for several years, the Federal Reserve began raising the federal funds rate in 2015. Before the pandemic hit, the Fed, after more than a decade without a cut, lowered rates three times in 2019, due to signs of a slowing economy.

Additionally, when the coronavirus outbreak shut down the U.S. economy in March 2020, the Fed took swift action, cutting the federal funds rate to near zero and beginning to purchase Treasury and mortgage-backed securities to provide additional economic stimulus.

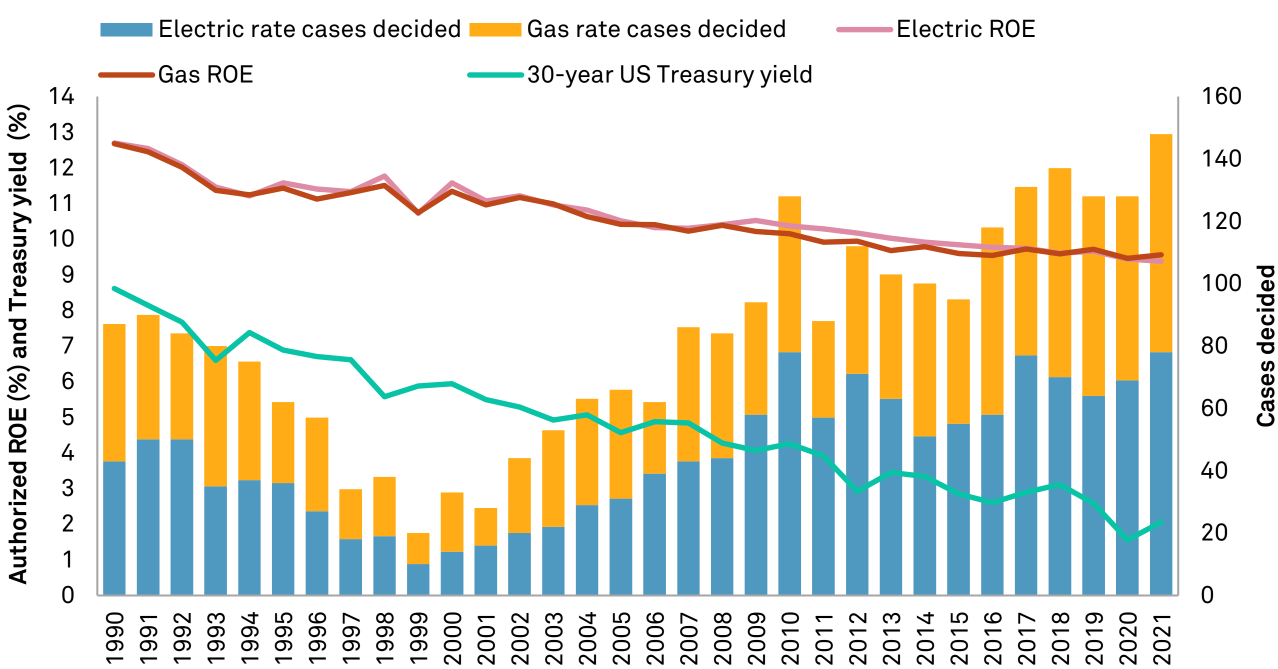
Amid increasing concerns over inflation, the Fed is expected to begin increasing the federal funds rate in March.

While changes in the federal funds rate do not move in lockstep with longer-term treasuries, and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs would also change in a similar fashion. However, several factors impact the timing and magnitude of such a shift. For example, normal regulatory lag, i.e., the amount of time it takes for a utility to put together a rate case filing and tender it to the commission and then for the commission to process the case, would without any other influences delay a change in average authorized ROEs relative to interest rates.

It is also worth noting that while both interest rates and authorized ROEs have generally been declining since 1990, the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of regulators' often-unstated understanding that the drop in interest rates caused by Federal Reserve intervention was unusual. Consequently, regulators did not necessarily fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

In more recent periods, with the focus on affordability and the need to maintain universal service as the pandemic drags on, regulators have been more apt to further lower authorized ROEs to mitigate the level of bill increases. These concerns are likely to continue, as regulators begin to grapple with rate increases that result from the recovery of pandemic-related costs and stranded costs related to the energy transition. These considerations could be further impacted by the pace of the economic recovery, rising natural gas prices and the significant level of planned capital spending expected in the industry, particularly to fund the energy transition.

Average electric and gas authorized ROEs and number of rate cases decided



Data compiled Jan. 26, 2022.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

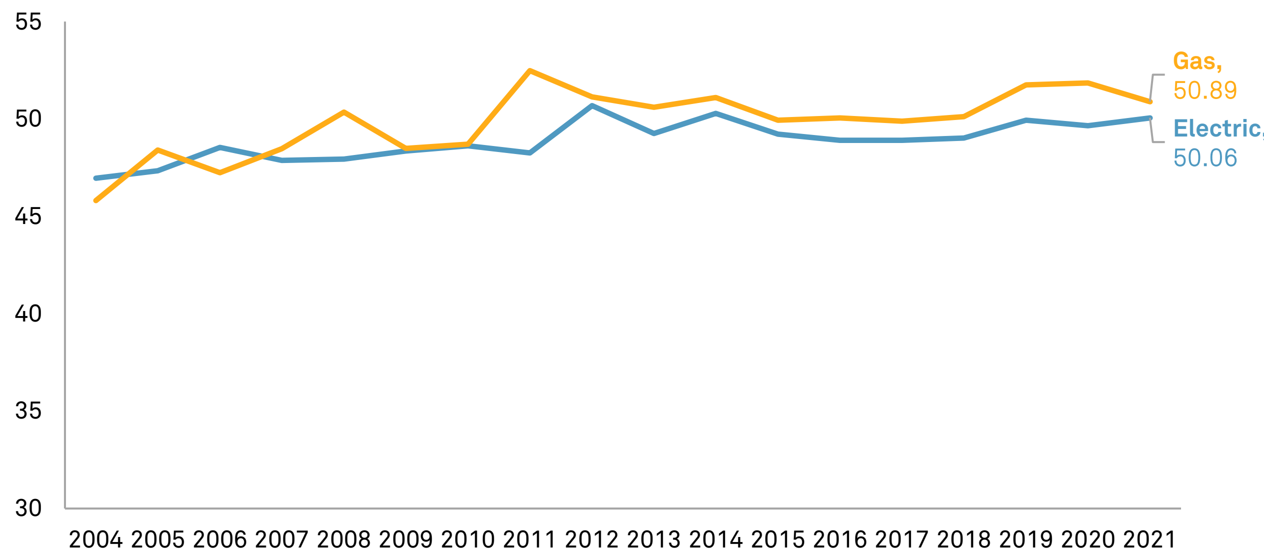
Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017.

Over the last five years, 2021, 2020, 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 50.06%, 49.66%, 49.94%, 49.02% and 48.90%, respectively. The average equity ratios authorized gas utilities were 50.89%, 51.86%, 51.75%, 50.12% and 49.88%, respectively.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis. For the bulk of the period since 2004, allowed equity ratios for gas utilities have been above those authorized for electrics.

Average authorized capital structures (%)



Data compiled Jan. 26, 2022.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view.

RRA has observed that there can be significant differences between average ROEs based upon the types of proceedings/decisions in which these ROEs were established.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

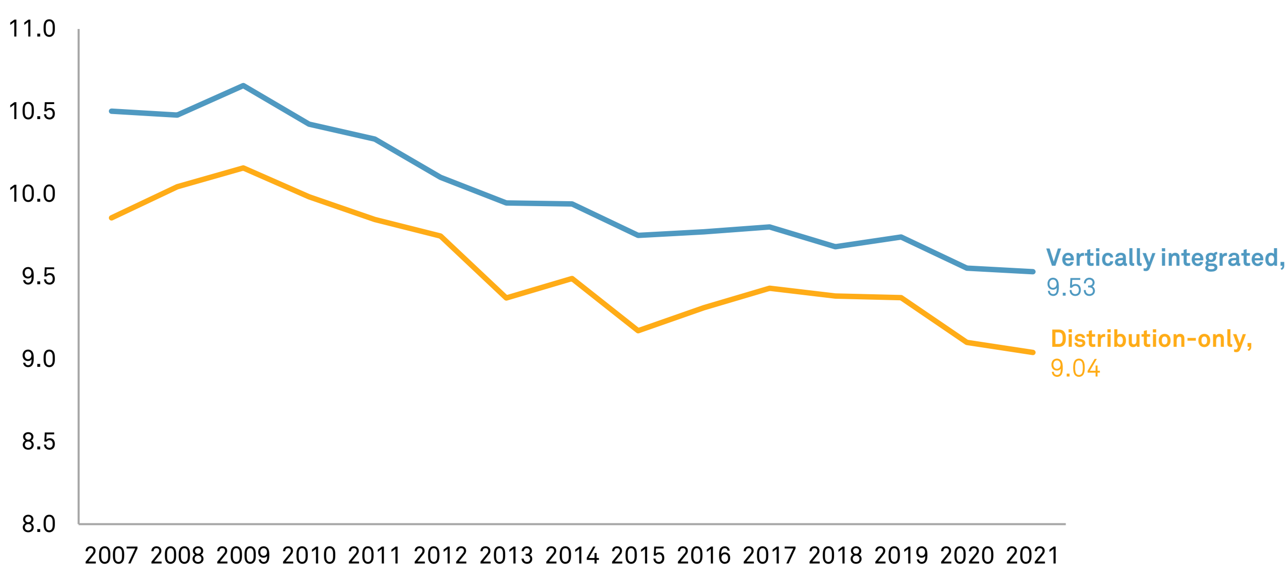
Comparing electric vertically integrated cases versus delivery-only proceedings over the past several years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.53% in cases decided in 2021, versus the 9.55% average posted in 2020. For electric distribution-only cases, the industry average ROE was 9.04% in 2021, versus 9.10% in 2020.

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

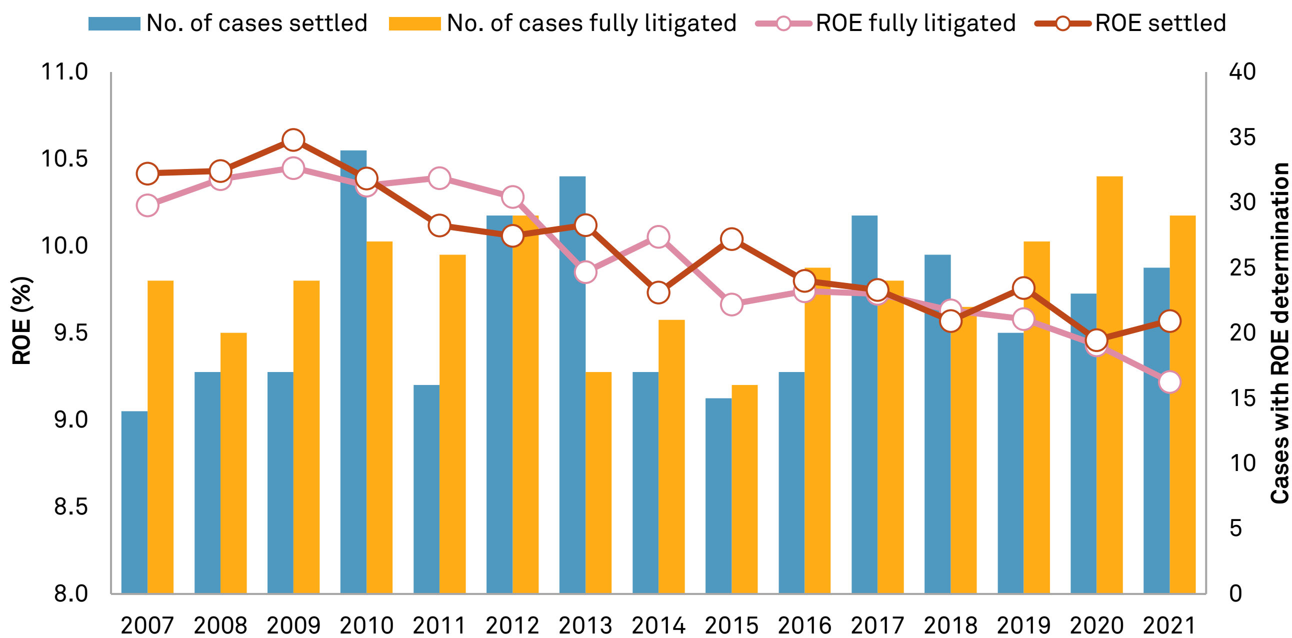
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

Average authorized electric ROEs (%)



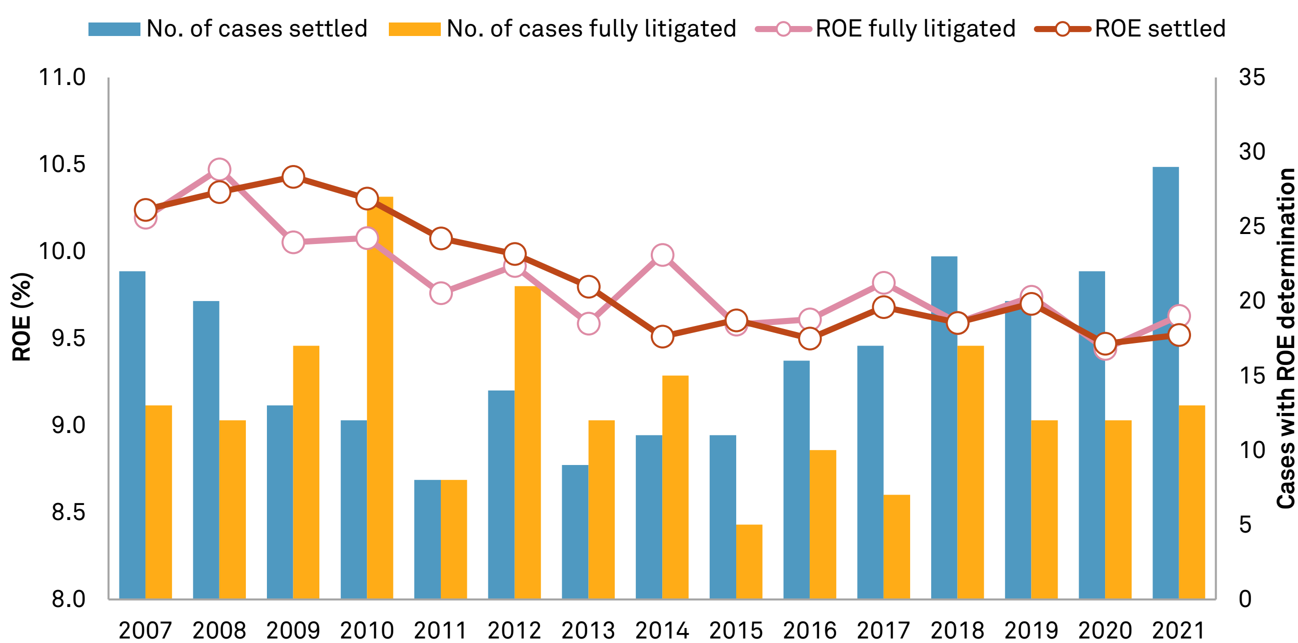
Data compiled Jan. 26, 2022.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled Jan. 26, 2022.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled Jan. 26, 2022.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Major Energy Rate Case Decisions

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2017, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past three years.

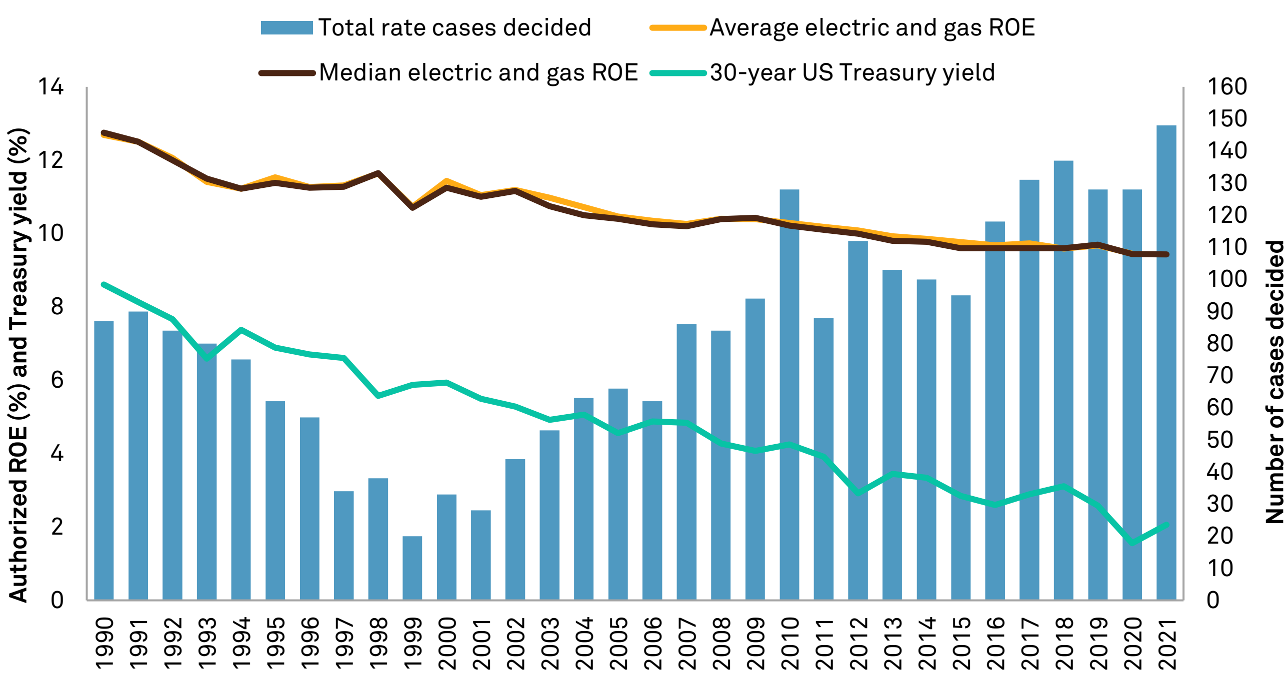
Tables 3 and **4** provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2021 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

Table 6 and the graph below track the combined average and median equity return authorized for all electric and gas rate cases since 1990. As the table indicates, since 1990, authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs that has occurred over this time frame.

Composite electric and gas authorized ROEs and number of rate cases



Data compiled Jan. 26, 2022.
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; U.S. Department of the Treasury

Further Reading

The rate case process: a conduit to enlightenment

Rate base: How would you rate your knowledge of this utility industry fundamental?

The Commissions

State Regulatory Evaluations — Energy Sept. 3, 2021

A variety of stranded cost recovery, abatement strategies emerging in US energy transition.

Energy utility capex plans on-track for record-breaking 2021 and 2022

The Big Picture: 2022 Electric, Natural Gas and Water Utilities Outlook

State Regulatory Evaluations — Energy

Major Utility Cases in Progress in the U.S.

Major utility cases in progress — Pending significant non-rate case activity

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Market Intelligence, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For nearly 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation.

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Schedule A
Summary of Total Cost of Service by Function

Schedule A

No.	Description	Reference	Total Company	Non-Electric Adjustment/Transfer	Total Electric	Known & Measurable	Adjusted Total Electric to Texas	Normalized Allocation to Production	Transmission	Distribution	Customer
			(A)	(B)	(C)	(I)	(J)	(K)	(L)	(M)	(N)
1	Recoverable Fuel Cost	WP D-1.1.1	$ 272,844,778	$ -	$ 272,844,778	$ -	$ 272,844,778	$ 272,844,778	$ -	$ -	$ -
2	Nacogdoches O&M costs recoverable in PSA	Schedule B-9	13,420,509	-	13,420,509	-	13,420,509	13,420,509	-	-	-
3	Non-Recoverable Fuel Cost	WP D-1.1.1	16,511,649	-	16,511,649	(665,043)	15,846,606	15,846,606	-	-	-
4	Non-Fuel O&M	Sch D-1, D-2, Less (Line 1 + 2 + 3)	735,485,974	(829,067)	734,656,908	(52,150,999)	682,505,909	209,692,507	190,200,881	148,477,578	134,134,942
5	Total O&M		$ 1,038,262,910	$ (829,067)	$ 1,037,433,843	$ (52,816,042)	$ 984,617,801	$ 511,804,399	$ 190,200,881	$ 148,477,578	$ 134,134,942
6											
7	Depreciation & Amortization	Schedule E-1	$ 268,470,823	$ (9,961,371)	$ 258,509,452	$ (111,743,752)	$ 146,765,700	$ 48,755,043	$ 21,899,841	$ 64,550,916	$ 11,559,900
8											
9	Taxes Other Than Income Taxes	Schedule E-2	1,943,325	-	1,943,325	-	1,943,325	661,622	-	1,281,702	-
10	Federal Income Taxes	Schedule E-3	-	-	-	-	-	-	-	-	-
11	Other Expenses	Schedule E-4	33,247,101	(18,713,593)	14,533,507	(7,554,037)	6,979,470	661,835	-	828,576	5,489,058
12	Total Other Expenses		$ 35,190,425	$ (18,713,593)	$ 16,476,832	$ (7,554,037)	$ 8,922,794	$ 1,323,457	$ -	$ 2,110,279	$ 5,489,058
13											
14	Total Expenses (before Return)	Line 5 + 7 + 12	$ 1,341,924,158	$ (29,504,031)	$ 1,312,420,127	$ (172,113,832)	$ 1,140,306,295	$ 561,882,899	$ 212,100,723	$ 215,138,773	$ 151,183,900
15											
16	Return										
17	Debt Service	Schedule C-3	$ 159,561,089	$ (17,842,507)	$ 141,718,582	$ 1,396,488	$ 143,115,070	$ 57,619,483	$ 23,754,546	$ 61,741,042	$ -
18	Non-Nuclear Decommissioning	Schedule C-3	8,000,000	-	8,000,000	-	8,000,000	8,000,000	-	-	-
19	General Fund Transfer	Schedule C-3	114,000,000	-	114,000,000	7,000,000	121,000,000	39,166,703	10,799,372	52,127,496	18,906,429
20	Internally Generated Funds for Construction	Schedule C-3	198,693,044	(12,258,563)	186,434,481	(66,616,839)	119,817,642	11,028,856	22,828,153	79,940,319	6,020,314
21	Sub-Total		$ 480,254,133	$ (30,101,070)	$ 450,153,062	$ (58,220,350)	$ 391,932,712	$ 115,815,041	$ 57,382,071	$ 193,808,856	$ 24,926,743
22											
23	Less:										
24	Depreciation & Amortization	Schedule C-3	$ (268,470,823)	$ 9,961,371	$ (258,509,452)	$ 111,743,752	$ (146,765,700)	$ (48,755,043)	$ (21,899,841)	$ (64,550,916)	$ (11,559,900)
25	Interest and Dividend Income	Schedule C-3	(2,966,885)	-	(2,966,885)	(1,303,431)	(4,270,316)	(1,738,965)	(1,015,085)	(1,234,220)	(282,045)
26	Contribution in Aid of Construction	Schedule C-3	(41,398,937)	-	(41,398,937)	(2,229,044)	(43,627,981)	(638,352)	(31,769)	(42,957,860)	-
27	Sub-Total		$ (312,836,645)	$ 9,961,371	$ (302,875,274)	$ 108,211,278	$ (194,663,996)	$ (51,132,360)	$ (22,946,695)	$ (108,742,996)	$ (11,841,945)
28											
29	Cash Flow Return Requested	Line 21 + 27	$ 167,417,488	$ (20,139,700)	$ 147,277,788	$ 49,990,927	$ 197,268,716	$ 64,682,681	$ 34,435,377	$ 85,065,860	$ 13,084,798
30											
31	**Total Cost of Service**	Line 14 + 29	**$ 1,509,341,646**	**$ (49,643,731)**	**$ 1,459,697,915**	**$ (122,122,904)**	**$ 1,337,575,011**	**$ 626,565,580**	**$ 246,536,099**	**$ 300,204,634**	**$ 164,268,698**
32											
33	Less Other (Non-Rate) Revenue										
34	Other Revenue	Schedule E-5	$ (171,511,285)	$ 29,890,394	$ (141,620,891)	$ (2,814,513)	$ (144,435,404)	$ (4,856,163)	$ (126,768,935)	$ (8,617,291)	$ (4,193,014)
35	Sub-Total		$ (171,511,285)	$ 29,890,394	$ (141,620,891)	$ (2,814,513)	$ (144,435,404)	$ (4,856,163)	$ (126,768,935)	$ (8,617,291)	$ (4,193,014)
36											
37	**Total Retail Electric Revenue Requirement**	Line 31 + 35	**$ 1,337,830,361**	**$ (19,753,337)**	**$ 1,318,077,024**	**$ (124,937,417)**	**$ 1,193,139,607**	**$ 621,709,417**	**$ 119,767,164**	**$ 291,587,342**	**$ 160,075,684**
38											
39	**Pass-Through Costs**										
40	Recoverable Fuel and Purchased Power (w/o Fixed Nacogdoches Costs) [1]						$ 272,844,778				
41	Nacogdoches O&M						13,420,509				
42	Nacogdoches Debt Service						42,967,242				
43	Transmission by Others (FERC 565)						119,767,164				
44	ERCOT Administration Fees						8,425,351				
45	Energy Efficiency Program						26,649,169				
46	Green Building Program						2,840,901				
47	Solar Rebate Program						1,255,630				
48	Service Area Lighting (SAL) [2]						18,125,371				
49							$ 506,296,114				
50											
51	**Base Revenue Requirement**						**$ 686,843,493**				

Notes:
1 Includes the portion of PSA recoverable through SAL pass-through
2 Service Area Lighting revenue reflects the identified base cost of service (excluding PSA)

Austin Energy
Electric Cost of Service and Rate Design

Work Paper C-3.3.1
Historical Capital Spending

WP C-3.3.1

No.	Fund Acct	Description	Reference	Actual FY 2019	Actual FY 2020	Actual FY 2021	Three-Year Average	Adjustments	Test Year
				(A)	(B)	(C)	(D)	(E)	(F)
1									
2		**Capital Spending**							
3	Fund 3060	NEPA		$ 31,730,768	$ 43,990,575	$ 24,517,126	$ 33,412,823		$ 33,412,823
4	Fund 3070	South Texas Project (STP)		6,444,488	8,997,308	6,369,200	7,270,332		7,270,332
5	Fund 3080	Fayette Power Plant (FPP)		601,521	4,255,880	763,099	1,873,500		1,873,500
6	Fund 3120	Alternate Energy		516,183	2,569,076	42,836	1,042,698		1,042,698
7	Fund 3220	Power Production		10,227,944	3,537,378	2,969,678	5,578,333		5,578,333
8	Fund 3230	Transmission		36,962,060	43,513,316	38,893,525	39,789,634		39,789,634
9	Fund 3240	Distribution Substation		11,326,653	11,842,223	21,520,988	14,896,621		14,896,621
10	Fund 3250	Distribution		98,945,772	92,194,247	84,703,541	91,947,854		91,947,854
11	Fund 3260	Customer Services Billing & Meter		38,831	59,045	365,474	154,450		154,450
12	Fund 3290	Support Services		18,979,181	38,019,576	168,446,082	75,148,280	(47,507,850)	27,640,429
13	Fund 3300	Capital Outlay (vehicles)		3,618,917	6,143,892	7,293,625	5,685,478		5,685,478
14	Fund 3310	Support Services		381,569	(64,524)	66,875	127,973		127,973
15	Fund 3330	Nacogdoches Generating Facility		394,605,233	200,926	35,100	131,613,753	(131,613,753)	-
16									
17		Total Capital Spending		**$ 614,379,120**	**$ 255,258,919**	**$ 355,987,150**	**$ 408,541,730**	**$ (179,121,603)**	**$ 229,420,126**
18									
19	Fund 3290	Portion of Support Services Above for New AE Headquarters		$ 1,459,643	$ 790,357	$ 140,273,551	$ 47,507,850		
20									
21		**Contributions in Aid to Construction (CIAC)**							
22	Fund 3060	NEPA	WP C-3.5.1	$ -	$ -	$ -	$ -		$ -
23	Fund 3070	South Texas Project (STP)	WP C-3.5.1	145,690	907,305	5,895	352,963		352,963
24	Fund 3080	Fayette Power Plant (FPP)	WP C-3.5.1	-	-	-	-		-
25	Fund 3120	Alternate Energy	WP C-3.5.1	141,768	714,398	-	285,389		285,389
26	Fund 3230	Transmission	WP C-3.5.1	-	95,306	-	31,769		31,769
27	Fund 3240	Distribution Substation	WP C-3.5.1	-	609,744	-	203,248		203,248
28	Fund 3250	Distribution	WP C-3.5.1	45,289,658	41,581,136	41,393,042	42,754,612		42,754,612
29	0	0	WP C-3.5.1	-	-	-	-		-
30				**$ 45,577,116**	**$ 43,907,889**	**$ 41,398,937**	**$ 43,627,981**	**$ -**	**$ 43,627,981**
31									
32		**Debt Funding of Capital Costs**							
33	Fund 3060	NEPA		$ 58,175,000	$ 39,360,000	$ 10,400,000	$ 35,978,333		$ 35,978,333
34	Fund 3070	South Texas Project (STP)							-
35	Fund 3080	Fayette Power Plant (FPP)							-
36	Fund 3120	Alternate Energy							-
37	Fund 3220	Power Production							-
38	Fund 3230	Transmission		28,480,000	37,770,000	19,800,000	28,683,333		28,683,333
39	Fund 3240	Distribution Substation		10,170,000	9,580,000	9,300,000	9,683,333		9,683,333
40	Fund 3250	Distribution		30,550,000	49,070,000	37,100,000	38,906,667		38,906,667
41	Fund 3260	Customer Services Billing & Meter							-
42	Fund 3290	Support Services		-	-	88,000,000	29,333,333	(29,333,333)	-
43	Fund 3300	Capital Outlay (vehicles)							-
44	Fund 3310	Support Services		655,000	70,000	-	241,667		241,667
45	Fund 3330	Nacogdoches Generating Facility		394,605,233	-	-	131,535,078	(131,535,078)	-
46									
47		Total Debt Fund Capital Spending		**$ 522,635,233**	**$ 135,850,000**	**$ 164,600,000**	**$ 274,361,744**	**$ (160,868,411)**	**$ 113,493,333**
48									
49		**% Debt Funded**		**85.1%**	**53.2%**	**46.2%**	**67.2%**		
50									

Table 5: EPE's Current Long-term Issuer Credit Ratings[52]

Rating Agency	Current Credit Rating	Outlook
Moody's Investors Service ("Moody's")	Baa2	Stable
Fitch Ratings	BBB	Stable

On September 17, 2019, Moody's downgraded the Company on account of increasing and partly debt-funded capital expenditures, as well as ongoing pressure on cash flow from tax reform resulting from the loss of bonus depreciation as a result of the 2017 Tax Cuts and Jobs Act. The Company's Texas operations, which are the subject of this proceeding, provide electric service to approximately 335,000 retail customers.[53]

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. Because estimating the Cost of Equity is a comparative exercise, it is necessary to develop a proxy group of companies with risk profiles that are reasonably comparable to the subject company. As each company is unique, no two companies will have the exact business and financial risk profiles. In selecting a proxy group, my objective was to balance the competing interests of selecting companies that are representative of the risks and prospects faced by EPE, while at the same time ensuring that there is a sufficient number of companies in the proxy group. Consequently, the proxy group consists of companies with similar, but not identical, risk profiles. Based on those considerations, I began with the universe of companies that *Value Line* classifies as Electric Utilities, and applied the following screening criteria:

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends, or have cut their dividend in the last five years;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;

[52] Source: Bloomberg Professional Services.

[53] Source: S&P Global Market Intelligence. As of December 31, 2020.

Entergy Texas, Inc. | Credit Ratings

(MI KEY: 4199135; SPCIQ KEY: 39650194)

Agency All

BBB+

S&P Global Ratings

Issuer Credit Rating (Foreign Currency LT)
8/4/2016

CreditWatch/Outlook: Stable
5/3/2018

Baa2

Moody's

Long Term Rating (LT Issuer Rating Domestic)
1/28/2022

Outlook:

Current Ratings

S&P GLOBAL RATINGS (S&P Entity Name:Entergy Texas Inc.)

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	PREVIOUS RATING	ACTION	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Issuer Credit Rating							
Foreign Currency LT	BBB+	8/4/2016	6/18/2021	BBB+	CreditWatch/Outlook	Stable	5/3/2018
Local Currency LT	BBB+	8/4/2016	6/18/2021	BBB+	CreditWatch/Outlook	Stable	5/3/2018

MOODY'S

RATING TYPE	RATING	DATE	ACTION	OUTLOOK
Ratings Summary				
Long Term Rating (LT Issuer Rating Domestic)	Baa2	1/28/2022	Upgrade	
Outlook		1/28/2022		Stable
Ratings Detail				
First Mortgage Bonds (Domestic)	A3	1/28/2022	Upgrade	
LT Issuer Rating (Domestic)	Baa2	1/28/2022	Upgrade	
Pref. Stock (Domestic)	Ba1	1/28/2022	Upgrade	
Senior Secured Shelf (Domestic)	(P)A3	1/28/2022	Upgrade	

Ratings History

S&P GLOBAL RATINGS (S&P Entity Name:Entergy Texas Inc.)

RATING TYPE	RATING	RATING	ACTION	CREDITWATCH/	CREDITWATCH/

033

		DATE		OUTLOOK	OUTLOOK DATE
Foreign Currency LT					
Issuer Credit Rating	BBB+	8/4/2016	CreditWatch/Outlook	Stable	5/3/2018
Issuer Credit Rating	BBB+	8/4/2016	CreditWatch/Outlook	Positive	1/9/2017
Issuer Credit Rating	BBB+	8/4/2016	Upgrade | CreditWatch/Outlook	Stable	8/4/2016
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Positive	3/31/2015
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Stable	6/20/2012
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Negative	6/28/2011
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Stable	6/10/2009
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Negative	1/30/2008
Issuer Credit Rating	BBB	1/8/2008	New Rating | CreditWatch/Outlook	Watch Dev	1/8/2008
Local Currency LT					
Issuer Credit Rating	BBB+	8/4/2016	CreditWatch/Outlook	Stable	5/3/2018
Issuer Credit Rating	BBB+	8/4/2016	CreditWatch/Outlook	Positive	1/9/2017
Issuer Credit Rating	BBB+	8/4/2016	Upgrade | CreditWatch/Outlook	Stable	8/4/2016
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Positive	3/31/2015
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Stable	6/20/2012
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Negative	6/28/2011
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Stable	6/10/2009
Issuer Credit Rating	BBB	1/8/2008	CreditWatch/Outlook	Negative	1/30/2008
Issuer Credit Rating	BBB	1/8/2008	New Rating | CreditWatch/Outlook	Watch Dev	1/8/2008

MOODY'S

RATING TYPE	RATING	DATE	ACTION	OUTLOOK
LT Issuer Rating (Domestic)	**Baa2**	**1/28/2022**	**Upgrade**	
LT Issuer Rating (Domestic)	Baa3	9/13/2019	Rating Affirmation	
LT Issuer Rating (Domestic)	Baa3	10/1/2015	Rating Affirmation	
LT Issuer Rating (Domestic)	Baa3	1/31/2014	Upgrade	
LT Issuer Rating (Domestic)	Ba1	11/8/2013	On Watch - Possible Upgrade	
LT Issuer Rating (Domestic)	Ba1	12/14/2007	New	
Outlook		**1/28/2022**		**Stable**
Outlook		9/13/2019		Positive
Outlook		10/1/2015		Stable
Outlook		1/31/2014		Stable
Outlook		11/8/2013		Ratings Under Review
Outlook		12/14/2007		Stable

S&P Credit Ratings and Research provided by S&P Global Ratings

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'Last Review Date' indicates the date on which an Issue/Issuer Credit Rating was last formally reviewed within a twelve-month period or when a Credit Rating Action was last published. For certain dependent instruments, the 'Last Review Date' will only be updated in the event of a Credit Rating change of the linked organization.

Latest S&P Ratings available unless you are a subscriber of S&P Ratings history.

currently proposed by SPS) is equivalent to 25 basis points of ROE.[8] If SPS is permitted to retain the margin on off-system sales during the winter storm, the Commission should take the level of that margin and the effect on cash flow into account when setting ROE and capital structure.

In my opinion, these factors counsel for a more balanced capital structure and significantly lower return on equity than proposed by SPS.

II. UTILITY RISKS AND CREDIT FACTORS

Q. WHAT ARE SPS'S CURRENT CREDIT RATINGS?

A. SPS currently has a split rating among the ratings agencies, meaning the agencies have ascribed slightly different levels of creditworthiness to the utility. For the corporate credit rating, S&P has SPS rated A-, Fitch at BBB and Moody's at Baa2.[9] All of these ratings are "investment-grade."

Q. ARE HIGH CREDIT RATINGS GOOD FOR CUSTOMERS?

A. A higher credit rating generally provides a lower cost of debt. However, in order to establish an appropriate return on equity and capital structure, the Commission must consider the cost of the measures that are necessary to achieve a higher credit rating.

Q. PLEASE EXPLAIN THIS TRADE-OFF.

A. A utility's credit rating is primarily a function of its financial strength, regulatory environment, and economic outlook. A higher credit rating generally corresponds to access

[8] $ 11.5 million Texas jurisdictional amount* (1-tax rate of 0.22)/(Texas rate base of 3.333 billion *54.6% equity in capital structure) = ROE = 49 basis points if recovered over one year or 25 basis points if recovered over two years.

[9] Martin Direct at 21.

Q HOW IS THIS OBSERVABLE MARKET DATA USED IN FORMING YOUR RECOMMENDED RETURN ON EQUITY AND OVERALL RATE OF RETURN FOR SWEPCO?

A Generally, authorized returns on equity, credit standing, and access to capital have been quite robust for utilities over the last several years. The COVID-19 pandemic has created challenges for the U.S. economy as a whole, including utility companies. However, like the U.S. economy, utilities are expected to weather the economic downturn caused by the pandemic, and their financial strength will be restored as the economy recovers. In the meantime, it is critical that the Commission ensure that rates are increased no more than necessary to provide fair compensation and maintain financial integrity, and be especially concerned about rate impacts on the service area economies that are severely constrained due to current economic conditions.

I.E. SWEPCO Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF SWEPCO'S INVESTMENT RISK.

A The market's assessment of SWEPCO's investment risk is described by credit rating analysts' reports. SWEPCO witness Ms. Renee Hawkins testified that SWEPCO's current credit ratings from S&P and Moody's are A-, and Baa2, respectively. SWEPCO's credit ratings have remain unchanged since its last rate case in Docket No. 46449. The Company has a stable outlook from both agencies.[7]

Specifically, S&P states:

Outlook: Stable

The stable rating outlook on SWEPCO reflects our stable outlook on its parent, American Electric Power Co. Inc. (AEP). The stable outlook on AEP and its subsidiaries reflects our assessment of the company's

[7] Hawkins Direct Testimony at 5.

Schedule A
Summary of Total Cost of Service by Function

Schedule A

No.	Description	Reference	Total Company (A)	Non-Electric Adjustment/Transfer (B)	Total Electric (C)	Known & Measurable (I)	Adjusted Total Electric to Texas (J)	Normalized Allocation to: Production (K)	Transmission (L)	Distribution (M)	Customer (N)
1	Recoverable Fuel Cost	WP D-1.1.1	$ 272,844,778	$ -	$ 272,844,778	$ -	$ 272,844,778	$ 272,844,778	$ -	$ -	$ -
2	Nacogdoches O&M costs recoverable in PSA	Schedule B-9	13,420,509	-	13,420,509	-	13,420,509	13,420,509	-	-	-
3	Non-Recoverable Fuel Cost	WP D-1.1.1	16,511,649	-	16,511,649	(665,043)	15,846,606	15,846,606	-	-	-
4	Non-Fuel O&M	Sch D-1, D-2, Less (Line 1 + 2 + 3)	735,485,974	(829,067)	734,656,908	(52,150,999)	682,505,909	209,692,507	190,200,881	148,477,578	134,134,942
5	Total O&M		$ 1,038,262,910	$ (829,067)	$ 1,037,433,843	$ (52,816,042)	$ 984,617,801	$ 511,804,399	$ 190,200,881	$ 148,477,578	$ 134,134,942
6											
7	Depreciation & Amortization	Schedule E-1	$ 268,470,823	$ (9,961,371)	$ 258,509,452	$ (111,743,752)	$ 146,765,700	$ 48,755,043	$ 21,899,841	$ 64,550,916	$ 11,559,900
8											
9	Taxes Other Than Income Taxes	Schedule E-2	1,943,325	-	1,943,325	-	1,943,325	661,622	-	1,281,702	-
10	Federal Income Taxes	Schedule E-3	-	-	-	-	-	-	-	-	-
11	Other Expenses	Schedule E-4	33,247,101	(18,713,593)	14,533,507	(7,554,037)	6,979,470	661,835	-	828,576	5,489,058
12	Total Other Expenses		$ 35,190,425	$ (18,713,593)	$ 16,476,832	$ (7,554,037)	$ 8,922,794	$ 1,323,457	$ -	$ 2,110,279	$ 5,489,058
13											
14	Total Expenses (before Return)	Line 5 + 7 + 12	$ 1,341,924,158	$ (29,504,031)	$ 1,312,420,127	$ (172,113,832)	$ 1,140,306,295	$ 561,882,899	$ 212,100,723	$ 215,138,773	$ 151,183,900
15											
16	Return										
17	Debt Service	Schedule C-3	$ 159,561,089	$ (17,842,507)	$ 141,718,582	$ 1,396,488	$ 143,115,070	$ 57,619,483	$ 23,754,546	$ 61,741,042	$ -
18	Non-Nuclear Decommissioning	Schedule C-3	8,000,000	-	8,000,000	-	8,000,000	8,000,000	-	-	-
19	General Fund Transfer	Schedule C-3	114,000,000	-	114,000,000	7,000,000	121,000,000	39,166,703	10,799,372	52,127,496	18,906,429
20	Internally Generated Funds for Construction	Schedule C-3	198,693,044	(12,258,563)	186,434,481	(66,616,839)	119,817,642	11,028,856	22,828,153	79,940,319	6,020,314
21	Sub-Total		$ 480,254,133	$ (30,101,070)	$ 450,153,062	$ (58,220,350)	$ 391,932,712	$ 115,815,041	$ 57,382,071	$ 193,808,856	$ 24,926,743
22											
23	Less:										
24	Depreciation & Amortization	Schedule C-3	$ (268,470,823)	$ 9,961,371	$ (258,509,452)	$ 111,743,752	$ (146,765,700)	$ (48,755,043)	$ (21,899,841)	$ (64,550,916)	$ (11,559,900)
25	Interest and Dividend Income	Schedule C-3	(2,966,885)	-	(2,966,885)	(1,303,431)	(4,270,316)	(1,738,965)	(1,015,085)	(1,234,220)	(282,045)
26	Contribution in Aid of Construction	Schedule C-3	(41,398,937)	-	(41,398,937)	(2,229,044)	(43,627,981)	(638,352)	(31,769)	(42,957,860)	-
27	Sub-Total		$ (312,836,645)	$ 9,961,371	$ (302,875,274)	$ 108,211,278	$ (194,663,996)	$ (51,132,360)	$ (22,946,695)	$ (108,742,996)	$ (11,841,945)
28											
29	Cash Flow Return Requested	Line 21 + 27	$ 167,417,488	$ (20,139,700)	$ 147,277,788	$ 49,990,927	$ 197,268,716	$ 64,682,681	$ 34,435,377	$ 85,065,860	$ 13,084,798
30											
31	**Total Cost of Service**	Line 14 + 29	**$ 1,509,341,646**	**$ (49,643,731)**	**$ 1,459,697,915**	**$ (122,122,904)**	**$ 1,337,575,011**	**$ 626,565,580**	**$ 246,536,099**	**$ 300,204,634**	**$ 164,268,698**
32											
33	Less Other (Non-Rate) Revenue										
34	Other Revenue	Schedule E-5	$ (171,511,285)	$ 29,890,394	$ (141,620,891)	$ (2,814,513)	$ (144,435,404)	$ (4,856,163)	$ (126,768,935)	$ (8,617,291)	$ (4,193,014)
35	Sub-Total		$ (171,511,285)	$ 29,890,394	$ (141,620,891)	$ (2,814,513)	$ (144,435,404)	$ (4,856,163)	$ (126,768,935)	$ (8,617,291)	$ (4,193,014)
36											
37	**Total Retail Electric Revenue Requirement**	Line 31 + 35	**$ 1,337,830,361**	**$ (19,753,337)**	**$ 1,318,077,024**	**$ (124,937,417)**	**$ 1,193,139,607**	**$ 621,709,417**	**$ 119,767,164**	**$ 291,587,342**	**$ 160,075,684**
38											
39	**Pass-Through Costs**										
40	Recoverable Fuel and Purchased Power (w/o Fixed Nacogdoches Costs) [1]						$ 272,844,778				
41	Nacogdoches O&M						13,420,509				
42	Nacogdoches Debt Service						42,967,242				
43	Transmission by Others (FERC 565)						119,767,164				
44	ERCOT Administration Fees						8,425,351				
45	Energy Efficiency Program						26,649,169				
46	Green Building Program						2,840,901				
47	Solar Rebate Program						1,255,630				
48	Service Area Lighting (SAL) [2]						18,125,371				
49							$ 506,296,114				
50											
51	**Base Revenue Requirement**						**$ 704,968,864**				

Notes:
1 Includes the portion of PSA recoverable through SAL pass-through
2 Service Area Lighting revenue reflects the identified base cost of service (excluding PSA)

Austin Energy
Electric Cost of Service and Rate Design

Schedule A
Summary of Total Cost of Service by Function

Schedule A

No.	Description	Reference	Total Company	Non-Electric Adjustment/Transfer	Total Electric	Known & Measurable	Adjusted Total Electric to Texas	Normalized Allocation to Production	Transmission	Distribution	Customer
			(A)	(B)	(C)	(I)	(J)	(K)	(L)	(M)	(N)
1	Recoverable Fuel Cost	WP D-1.1.1	$ 272,844,778	$ -	$ 272,844,778	$ -	$ 272,844,778	$ 272,844,778	$ -	$ -	$ -
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11	Other Expenses	Schedule E-4	33,247,101	(18,713,593)	14,533,507	(7,554,037)	6,979,470	661,835	-	828,576	5,489,058
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48	Service Area Lighting (SAL) [2]						18,125,371				
49							$ 506,296,114				
50											
51	**Base Revenue Requirement**						**$ 686,843,493**				

Notes:
1 Includes the portion of PSA recoverable through SAL pass-through
2 Service Area Lighting revenue reflects the identified base cost of service (excluding PSA)

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California Daydreamin'
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Europe's Dilemmas
Federal Reserve
Housing Bubble 2
Inflation & Devaluation
Jobs
Trade
Transportation

Corporate Bond Credit Ratings Scales: Moody's, S&P, Fitch

How the Big Three US Credit Rating Agencies Classify Corporate Bonds and Loans by Credit Risk, or the Risk of Default.

Here is my cheat-sheet for the long-term corporate credit ratings that the three major US rating agencies Moody's, Standard & Poor's, and Fitch use and how they fit into major categories. The red line divides "investment grade" (above the line) from what is often called "speculative," "below investment grade," "high yield," or lovingly, "junk." The scale goes from very low-risk triple-A at the top to very high risk, and finally "default" at the bottom.

FRONT PAGE

Stock Market Swoon Pulls Rug Out from under Luxury Home Sales
by Wolf Richter • Jun 20, 2022
The June sell-off did a job on them.

THE WOLF STREET REPORT: What's Behind the Collapse of so Many Stocks since Feb 2021?
by Wolf Richter • Jun 19, 2022
This crash beneath the surface showed something had broken, that the magic had died, that hype and hoopla were suddenly unable to carry the day.

Credit Rating Scales by Agency, Long-Term

Moody's	S&P	Fitch	
Aaa	AAA	AAA	Prime
Aa1	AA+	AA+	High grade
Aa2	AA	AA	
Aa3	AA-	AA-	
A1	A+	A+	Upper medium grade
A2	A	A	
A3	A-	A-	
Baa1	BBB+	BBB+	Lower medium grade
Baa2	BBB	BBB	
Baa3	BBB-	BBB-	
Ba1	BB+	BB+	Non-investment grade speculative
Ba2	BB	BB	
Ba3	BB-	BB-	
B1	B+	B+	Highly speculative
B2	B	B	
B3	B-	B-	
Caa1	CCC+	CCC	Substantial risk
Caa2	CCC		Extremely speculative
Caa3	CCC-		Default imminent with little prospect for recovery
Ca	CC	CC	
	C	C	
C	D	D	In default
/			
/			

"Junk"

WOLFSTREET.com

Bonds can also be designated "NR" ("not rated") or "WR" ("withdrawn rating") after a rating agency has withdrawn its own ratings for a variety of reasons, such as lack of credible information.

New Vehicle Inventory, Stuck Near Record Lows, Gets Worse as Buyers Shift from Trucks to Economical Cars, which Vanish

by Wolf Richter • Jun 17, 2022

Average price jumps by $5,000 from year ago, to $45,495.

Morning After J-Pow, Second Time in a Row

by Wolf Richter • Jun 16, 2022

Someone might think, OK, I could speculate with the J-Pow Pattern at the next Fed meeting.

As Gasoline Prices Spike, Demand Destruction Spreads, with Long-Term Implications

by Wolf Richter • Jun 16, 2022

Wait… gasoline exports are rising.

Search

US Corporate A Effective Yield

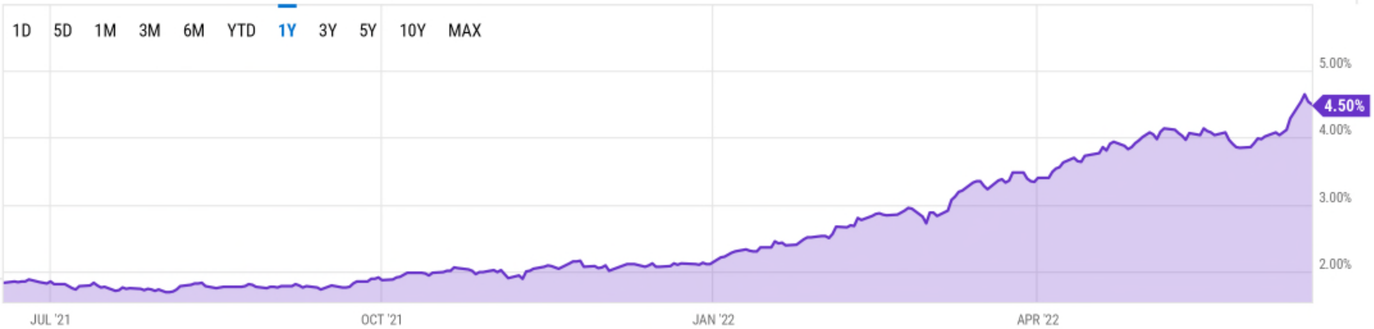
4.50% for Jun 16 2022

+ WATCHLIST

Overview Interactive Chart

Level Chart

VIEW FULL CHART



Basic Info

US Corporate A Effective Yield is at 4.50%, compared to 4.54% the previous market day and 1.88% last year. This is higher than the long term average of 4.48%.

Report	Bank of America Merrill Lynch	Region	United States
Category	Interest Rates	Source	Bank of America Merrill Lynch

Stats

Last Value	4.50%
Latest Period	Jun 16 2022
Last Updated	Jun 21 2022, 09:03 EDT
Next Release	Jun 22 2022, 09:00 EDT
Long Term Average	4.48%
Average Growth Rate	0.10%
Value from The Previous Market Day	4.54%
Change from The Previous Market Day	-0.88%
Value from 1 Year Ago	1.88%
Change from 1 Year Ago	139.4%
Frequency	Market Daily
Unit	Percent

Adjustment	N/A
Notes	Bank of America Merrill Lynch U.S. Corporate A Effective Yield

Historical Data

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Date	Value	Date	Value
June 16, 2022	4.50%	May 12, 2022	3.97%
June 15, 2022	4.54%	May 11, 2022	4.03%
June 14, 2022	4.65%	May 10, 2022	4.07%
June 13, 2022	4.54%	May 09, 2022	4.12%
June 10, 2022	4.29%	May 06, 2022	4.14%
June 09, 2022	4.12%	May 05, 2022	4.09%
June 08, 2022	4.08%	May 04, 2022	3.98%
June 07, 2022	4.04%	May 03, 2022	4.05%
June 06, 2022	4.08%	May 02, 2022	4.08%
June 03, 2022	4.02%	April 30, 2022	4.01%
June 02, 2022	3.98%	April 29, 2022	3.96%
June 01, 2022	3.99%	April 28, 2022	3.92%
May 31, 2022	3.92%	April 27, 2022	3.86%
May 30, 2022	3.86%	April 26, 2022	3.83%
May 27, 2022	3.85%	April 25, 2022	3.88%
May 26, 2022	3.86%	April 22, 2022	3.94%
May 25, 2022	3.91%	April 21, 2022	3.91%
May 24, 2022	3.97%	April 20, 2022	3.81%
May 23, 2022	4.08%	April 19, 2022	3.86%
May 20, 2022	4.04%	April 18, 2022	3.77%
May 19, 2022	4.08%	April 14, 2022	3.73%
May 18, 2022	4.10%	April 13, 2022	3.64%
May 17, 2022	4.14%	April 12, 2022	3.65%
May 16, 2022	4.04%	April 11, 2022	3.70%
May 13, 2022	4.07%	April 08, 2022	3.63%

Related Indicators

Corporate Bond Rates

Moody's Seasoned Aaa Corporate Bond Yield	4.41%	US Corporate AA Effective Yield	4.25%
Moody's Seasoned Baa Corporate Bond Yield	5.41%	US Corporate AAA Effective Yield	4.05%
		US Corporate BBB Effective Yield	5.19%

Search

US Corporate AA Effective Yield

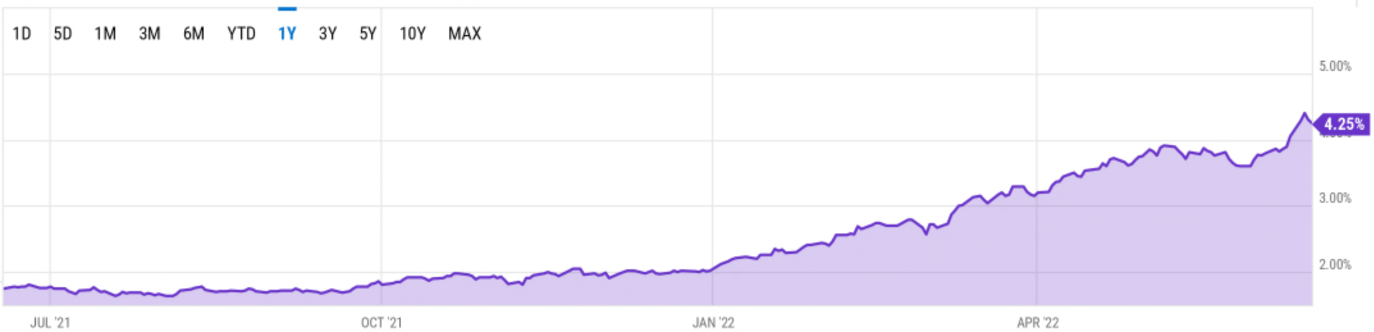
4.25% for Jun 16 2022

+ WATCHLIST

Overview Interactive Chart

Level Chart

VIEW FULL CHART



Basic Info

US Corporate AA Effective Yield is at 4.25%, compared to 4.30% the previous market day and 1.81% last year. This is higher than the long term average of 4.06%.

Report	Bank of America Merrill Lynch	Region	United States
Category	Interest Rates	Source	Bank of America Merrill Lynch

Stats

Last Value	4.25%	Value from The Previous Market Day	4.30%
Latest Period	Jun 16 2022	Change from The Previous Market Day	-1.16%
Last Updated	Jun 21 2022, 09:03 EDT	Value from 1 Year Ago	1.81%
Next Release	Jun 22 2022, 09:00 EDT	Change from 1 Year Ago	134.8%
Long Term Average	4.06%	Frequency	Market Daily
Average Growth Rate	0.40%	Unit	Percent

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Adjustment	N/A
Notes	Bank of America Merrill Lynch U.S. Corporate AA Effective Yield

Historical Data

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Date	Value	Date	Value
June 16, 2022	4.25%	May 12, 2022	3.71%
June 15, 2022	4.30%	May 11, 2022	3.78%
June 14, 2022	4.40%	May 10, 2022	3.83%
June 13, 2022	4.29%	May 09, 2022	3.89%
June 10, 2022	4.05%	May 06, 2022	3.91%
June 09, 2022	3.89%	May 05, 2022	3.88%
June 08, 2022	3.86%	May 04, 2022	3.76%
June 07, 2022	3.82%	May 03, 2022	3.82%
June 06, 2022	3.86%	May 02, 2022	3.85%
June 03, 2022	3.79%	April 30, 2022	3.75%
June 02, 2022	3.76%	April 29, 2022	3.74%
June 01, 2022	3.77%	April 28, 2022	3.69%
May 31, 2022	3.70%	April 27, 2022	3.63%
May 30, 2022	3.60%	April 26, 2022	3.61%
May 27, 2022	3.60%	April 25, 2022	3.66%
May 26, 2022	3.61%	April 22, 2022	3.72%
May 25, 2022	3.65%	April 21, 2022	3.70%
May 24, 2022	3.71%	April 20, 2022	3.60%
May 23, 2022	3.81%	April 19, 2022	3.64%
May 20, 2022	3.76%	April 18, 2022	3.56%
May 19, 2022	3.81%	April 14, 2022	3.53%
May 18, 2022	3.83%	April 13, 2022	3.44%
May 17, 2022	3.87%	April 12, 2022	3.45%
May 16, 2022	3.78%	April 11, 2022	3.50%
May 13, 2022	3.81%	April 08, 2022	3.44%

Related Indicators

Corporate Bond Rates

Moody's Seasoned Aaa Corporate Bond Yield	4.41%	US Corporate AAA Effective Yield	4.05%
Moody's Seasoned Baa Corporate Bond Yield	5.41%	US Corporate BBB Effective Yield	5.19%
US Corporate A Effective Yield	4.50%		

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PROVIDED IN NATIVE EXCEL FORMAT

- Debt Cost and Return on Equity.xlsx
- Exhibit BSL-1.xlsx
- Exhibit BSL-2.xlsx
- Exhibit BSL-3.xlsx
- Exhibit BSL-4.xlsx
- Exhibit BSL-5.xlsx